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EXHIBIT 1

DECLARATION OF SETH SCHWARTZ

I, Seth Schwartz, declare as follows:

INTRODUCTION

1. My name is Seth Schwartz, and I am the President of Energy Ventures Analysis, Inc. ("EVA"). I have been retained by the National Mining Association ("NMA"), the national trade association of the U.S. coal industry, to provide a declaration regarding the irreparable harm which the coal industry, coal miners and states and communities dependent on coal production will suffer if the Court does not grant NMA's motion to stay the implementation of the Clean Power Plan ("CPP") until the Court has ruled on its petition to review the final rule.
2. I have prepared an analysis of the impacts of the final CPP, announced by the Environmental Protection Agency ("EPA") on August 3, 2015. The analysis and the supporting data and sources are described in detail in my attached report titled "Evaluation of the Immediate Impact of the Clean Power Plan Rule on the Coal Industry" (the "Schwartz Report"). This Declaration is a summary of my opinions based on the analysis described in the Report.
3. I have been a principal at EVA since 1981 and the president since 2008. EVA has been performing analyses of U.S. energy markets since its founding in 1981. EVA analyzes and publishes regular reports on the coal, natural gas and power markets, including forecasts of supply, demand and prices. I manage EVA's practice

analyzing U.S. coal markets. Our clients include energy producers, consumers, transporters, investors and regulators. EVA works for regulatory agencies, including state public utility commissions as well as federal agencies. I have testified as an expert witness on coal markets in numerous court, arbitration and regulatory hearings, including federal and state district courts, public utility commissions, and the U.S. Supreme Court (original jurisdiction).[1]

CONCLUSIONS

4. My overall conclusions are as follows:

- The CPP will result in a fundamental restructuring of the U.S. power sector. The use of coal for electric generation will be slashed, to be replaced by an unprecedented expansion of electric generation produced using renewable resources. According to EPA, the rule will also result in the reduction of demand for electricity over the period 2020-2030, even though population and the economy will continue to grow and even though electric consumption in the United States has *never* declined over a sustained multi-year period absent a recession.[2]
- EPA's own forecast projects that the CPP will transform the supply of electricity and slash the share of power provided by coal generation. Since electricity use became widespread over 70 years ago, coal has fueled 39% -

[1] Schwartz Report at 2.
[2] Id. at 25 – 29.

56% of total power supply. The Department of Energy's Energy Information Administration's ("EIA") latest forecast projects that, without the CPP, coal will continue to supply 38% - 41% of generation through 2030. EPA projects that the CPP will cut coal's share of power supply to 33% by 2020 and just 27% by 2030. However, if EPA's projected 2020-30 decline in demand for electricity does not occur, coal's share of power generation would have to be cut to only 20% to meet EPA's CO_2 emission limits.[3]

- Although the compliance period for the rule does not begin until 2022, electric utilities will make final and irrevocable decisions shifting their generation portfolios away from coal during the period of time this case will be litigated before this court. Electric utility planning and infrastructure development entail extremely long lead times. Given the wholesale changes to the power grid that the rule requires, utilities will be forced to make final decisions to retire coal plants and substitute alternative resources within the next 12-24 months.[4]

- EPA itself anticipates that a large number of coal units will retire well before 2022—by *2016-18* in EPA's modeling—in order to comply with the rule. EPA is forecasting that 56 coal-fired power plants will retire from 2016 to

[3] Id. at 27.
[4] Id. at 30 – 47.

2018 directly due to the CPP, with all but 3 units retiring in 2016. These plants burned 55.3 million tons of coal in 2014.[5]

- Further, as compared with EPA's forecast when it published the proposed rule, EPA is now forecasting a much greater number of additional retirements of coal plants in 2016-18 in its "base case", which is its projection of what would happen without the CPP. These additional retirements are not forecast by the EIA nor have these retirements been announced by the facilities' owners. EPA thus appears to be artificially reducing the amount of coal generation in its base case in order to minimize the number of retirements that are attributed to the CPP. As discussed below, these base case retirements not forecasted by EIA should properly be considered as caused by the CPP. In total, in the base and CPP compliance cases together, EPA is forecasting that 238 coal-fired power plants will retire between 2016 and 2018, with all but 5 of these plants retiring in 2016-17. In 2014, these plants burned 171.5 million tons of coal, approximately 20 percent of total coal used for electric production.[6]
- These near-term power plant retirements will have a significant and immediate effect on coal companies, their employees, and the states and local communities that are dependent on the coal industry, as these

[5] Id. at 62.
[6] Id. at 64 – 68.

retirements will result in lost production and cutbacks in mining employment. Additionally, a number of the units that EPA forecasts as retiring in the next several years are served by coal mines that are adjacent to those units and which sell all or most of their output to the retiring units. Given EPA's projected coal generating plant retirements, 6 specific coal mines will close and 3 more will have to significantly curtail coal production. 1,856 coal miners will lose their jobs at these closed or curtailed mines. Virtually all of this will happen in 2016-2017, with the rest occurring by 2018.[7]

- The CPP will imperil the financial condition of coal companies, has already contributed to coal company bankruptcies and will likely contribute to additional, future coal company bankruptcies.

OUTLINE OF MY DECLARATION

5. My testimony covers the following topics:

    - Description of the Clean Power Plan rule, pages 6-9;
    - The need for affected generators to act immediately, pages 9-11;
    - EPA-modeled impact of the CPP on coal generation, pages 11-13;
    - EPA understated the impact of the CPP on coal demand by creating an artificially low base case, pages 13-19;

[7] Id. at 69 – 72.

- EPA's own model projects immediate retirements of coal-fired plants and lost coal production, pages 19-21;
- Under EPA's modeling, specific power plants and coal mines will close immediately, pages 21-23;
- The immediate harm is much greater using a more realistic base case, pages 23-25;
- The rule will damage the financial viability of coal companies, page 26; and,
- The recent example of the MATS rule shows the irreparable harm due to EPA rules, pages 27-29.

DESCRIPTION OF THE RULE[8]

6. The fundamental purpose of the CPP is to reduce emissions of carbon dioxide ("CO_2") from existing electric generating units ("EGUs"). EPA states that the CPP will reduce emissions from the electric power sector by 32% from the amount in 2005 by the year 2030, with substantial reductions required by the year 2022.

7. In order to achieve this reduction, EPA has assigned each state "interim" and "final" emissions limits, which EPA calls "goals." The "Interim Goals" must be achieved for the Interim Period 2022 – 2029 and the "Final Goals" must be

[8] I describe the rule further at id. 3 – 9.

achieved by the year 2030. EPA derived these goals by establishing a maximum emission rate achievable by two categories of existing EGUs—fossil steam units (principally fueled with coal) and stationary turbines fueled with natural gas (natural gas combined cycle gas turbines, or "NGCC" units).

8. EPA developed these rates by applying what it states is the Best System of Emissions Reduction ("BSER") for reducing CO_2 emissions from these facilities.[9] The emissions rate limit which EPA established for coal units (1,305 pounds CO_2 per MWh) is not a standard which can be achieved by reducing emissions at an existing coal-fired unit. The actual average emission rate for existing coal-fired units in 2012 was 2,215 pounds per MWh and the lowest emission rates in 2014 of the newest, most efficient coal-fired units in the U.S. were 1,837-1,867 pounds per MWh.[10]

9. EPA did not base the BSER on applying emissions control technology or system of operating practices that could be implemented at existing coal-fired units. Rather, EPA calculated the 1,305 lbs./MWh coal rate (41% below the actual average rate in 2012) and the 771 lbs./MWh natural gas rate by conducting a BSER analysis that relied on reducing coal generation and increasing the use of lower or zero-emitting power facilities to achieve the emissions reductions on an

[9] The BSER for the Final Goal in 2030 was set in pounds CO_2 per megawatt-hour ("MWh") at 1,305 for fossil steam (principally coal-fired) units and 771 for NGCC units.
[10] Schwartz Report at 4 – 5.

aggregate basis. Under EPA's analysis, BSER for coal-fired units was calculated using a combination of 4.3% heat rate improvements for existing coal-fired EGUs, displacement of generation from existing coal-fired units by existing NGCC units (which have much lower CO_2 emission rates), and displacement of existing fossil-fuel units (both coal and NGCC) by new generation from zero-emitting renewable sources (primarily wind and solar).

10. EPA established alternative "emission rate" and "mass-based" goals for each state. EPA established the emission rate goal for each state based upon the BSER (1,305 lbs./MWh for coal and 771 for NGCC) times the ratio of fossil steam and NGCC generation in the 2012 baseline year. EPA established the mass-based maximum emission limit, converting from an emission rate to quantity of CO_2. While EPA did not explicitly assume that states could reduce electricity demand through demand reduction programs in developing the BSER, EPA's analysis, as discussed below, depends critically on EPA's assumption that electric consumption will decline in the future even as the economy and population grow.[11]

11. The Final Goals require individual state emissions reductions ranging from 7% to 48% from the corresponding state's 2012 rate. The Interim Goals for each state for the period 2022-2029, on average, require a reduction of 26% from the state's corresponding 2012 actual emission rate. EPA further requires states to establish

[11] Id. at 25 – 28.

interim "steps" to demonstrate that they will comply with their Interim Goal. EPA set interim goals for Step 1, which covers the period 2022-2024, which would require most states to achieve over half of their required final reductions by this 2022-2024 period.[12]

NEED FOR AFFECTED GENERATORS TO ACT IMMEDIATELY

12. As is set out in more detail in my report,[13] the electric power industry requires long lead times to plan, permit and construct new power plants to generate electricity and new transmission lines to connect the power plants and deliver the electricity to customers. Studies by the North American Electric Reliability Corporation ("NERC")[14] and a variety of regional transmission organizations concluded that the time to plan, permit and construct new generating capacity was over 5 years for NGCC plants and over 3 years for wind and solar plants.[15] The new transmission lines needed to connect the new capacity would take at least 5 years and as much as 11 years to complete.[16]

13. The above timelines do not include the necessary planning processes that utilities must undertake before they can move forward with a specific resource decision. This planning process is particularly pronounced for regulated electric utilities,

[12] Id. at 6 – 9.
[13] Id. at 30 – 47.
[14] NERC is chartered by the Federal Energy Regulatory Commission under the Federal Power Act "to assure the reliability of the bulk power system in North America." www.nerc.com
[15] Schwartz Report at 33 – 36.
[16] Id. at 37 – 41.

which own a majority of the affected EGUs. These utilities regularly file an integrated resource plan ("IRP") with the state public utility commission to obtain approval for their long-term decisions of how to supply their customers with electricity. The IRPs include plans to retire existing power plants and to build new plants and transmission lines. This IRP process can take a year, longer if the proceeding involves contested case procedures or is challenged in court. Since the issuance of the proposed CPP, many utilities already have been including the likely effect of the CPP on their resource decisions, which favors retiring coal-fired units and replacing them with natural gas or renewables. Issuance of the final rule will now cause many utilities to include CPP-caused coal plant retirements in their IRPs, thus accelerating the move towards these retirements.[17]

14. Coal-fired power plants require large capital investments for regular maintenance as well as for compliance with new environmental regulations. For instance, there has been a plethora of new environmental regulations which will require major capital investment in the next few years in order to continue operations of these power plants. But many of these units will be forced to retire in 2022 in order to comply with the rule. Faced with the 2022 retirement date, these units will choose not to make the near-term investments needed to keep the unit operational

[17] Id. At 41 – 46.

through 2022 and instead will choose to retire in the near future.[18] This is reflected in EPA modeling of the impacts of the rule, discussed below.

15. In sum, as detailed further in my report, given the long lead times needed to develop the significant amount of electric utility infrastructure needed to comply with the rule, utilities must immediately make final and irrevocable investment decisions. These decisions will include retiring a significant portion of the existing coal-fired electric generating fleet. Thus, unless the CPP is stayed by this Court, the retirement of a significant number of coal units will become locked in and irreversible. [19]

EPA-MODELED IMPACT OF THE CPP ON COAL GENERATION

16. The CPP will force states and affected EGUs to achieve the CO_2 emission goals by reducing the consumption of coal. Coal-fired units accounted for 75% of CO_2 emissions from the power sector in 2012[20] and had much higher emission rates than the other sources of power generation (NGCC units emit less than half of coal[21] and nuclear, hydro and renewables emit no carbon dioxide). All of the methods by which power generators could comply with the CPP (heat rate improvements, replacement by gas-fired generation, replacement by renewable

[18] Id. at 46 – 47.
[19] Ibid.
[20] Id. at 4.
[21] The 2012 average emission rate of all NGCC units was 903 pounds CO_2 per MWh, just 41% of the average 2,215 pounds CO_2 per MWh for coal-fired units.

power generation and reduced electricity demand) will result in reduced coal burn.[22]

17. EPA's own modeling of the impacts of the CPP understates the impact of the rule on coal generation, for the reasons set forth in the next section below. EPA's modeling has also habitually understated the effect of its rules, as is shown in the final section of this declaration. Nevertheless, it is useful to review EPA's modeling of the impact of the rule because even EPA is forced to concede that the rule will cause a large reduction in coal-fired generation and coal consumption. EPA presented its analysis of the impact of the CPP for the years 2020, 2025 and 2030 in its regulatory impact analysis ("RIA"). Compared to its base case analysis without the CPP, EPA projected that the CPP would cause the retirement of 13-15 gigawatts ("GW") of coal-fired plants by 2020 (6%-7% of total coal-fired capacity), growing to 21-27 GW (10%-13%) by 2025 and 24-33 GW (11%-16%) by 2030.[23] EPA projected even larger negative impacts on the amount of electricity produced from coal-fired generation (down 22%-23% by 2030)[24] and coal burn (down 103-123 million tons in 2025, or 14%-17%).[25] EPA's modeling

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[22] Schwartz Report at 10.
[23] EPA, "Regulatory Impact Analysis for the Clean Power Plan Final Rule", August 2015, Table 3-12, http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants. The range depends upon whether one uses EPA's analysis of the rate-based compliance option or the mass-based option.
[24] Id, Table 3-11.
[25] Id, Table 3-15.

shows that the coal regions of the country most affected by the rule will be Appalachia and the West.[26]

EPA'S UNDERSTATES THE IMPACT OF THE CPP ON COAL DEMAND BY CREATING AN ARTIFICIALLY LOW BASE CASE

18. EPA used the Integrated Planning Model ("IPM"), created by the consulting firm ICF International, to analyze the impacts of the final rule on the electric power markets.[27] EPA also used the IPM as a critical element in evaluating the economic feasibility of its building blocks and the energy impacts of the rule, including the effect EPA's overall plan would have on the reliability of the interconnected grid.[28] EPA used a "base case" in the IPM model as the "business-as-usual scenario that would be expected under market and regulatory conditions in the absence of this rule."[29] EPA measured the impact of the CPP final rule by comparing its projections of electricity generation, generating capacity, fuel consumption and electricity prices to its base case.[30]

19. EPA used a different base case to analyze the final rule as compared with the proposed rule. EPA stated that the new base case was based on what it described as "updates" to the IPM model consisting of "primarily routine calibrations with

[26] Id.
[27] Schwartz Report at 11.
[28] See, e.g., EPA, Technical Support Document: Resource Adequacy and Reliability Analysis, 2015, http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.
[29] Id at 3-4.
[30] Schwartz Report at 11 – 15.

the Energy Information Agency's (*sic*) (EIA) Annual Energy Outlook (AEO)."[31] In reality, however, the changes in the base case forecast were dramatic and very different from both EPA's previous forecast for the proposed rule and EIA's actual AEO 2015 reference case forecast (EIA's forecast without considering the effect of the CPP). Compared to EPA's own base case forecast for the proposed rule, EPA's new base case reduced its forecast of coal generation in 2025 by 16% (273 million MWh)[32] and coal burn by 14% (134 million tons).[33] The changes compared to EIA's AEO2015 reference case are equally dramatic. In 2025, EPA's new base case projects coal generation to be 18% below EIA's forecast (301 million MWh)[34] and coal burn to be 100 million tons lower.[35]

20. The changes by EPA in its base case (without the CPP) cause a significant understatement in EPA's evaluation of the impact of the CPP on the demand for coal for power generation. By assuming less coal generation in its base case, EPA concludes that less coal generation will need to retire to comply with the rule than

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[31] Id at 17 – 18. The U.S. Energy Information Administration is an agency of the Department of Energy created by Congress to monitor the energy industry and track energy market trends. It "collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment." About EIA at http://www.eia.gov/about/. EIA's mission includes publishing an Annual Energy Outlook ("AEO"), which describes and quantifies expected future energy trends. Its latest such report is AEO2015. AEO2015 includes a "reference case" for the future of the energy industry based on current regulations. This reference case thus projects electric generation by type of generating facility assuming the CPP is not in place. Schwartz Report at 21.

[32] Id., Exhibit 10, at 20.

[33] Id., Exhibit 22, at 53.

[34] Id., Exhibit 12, at 23.

[35] Id., Exhibit 24, at 55.

would be the case if EPA had used its original base case or EIA's AEO2015 reference case forecast.[36]

21. EIA's most recent Annual Energy Outlook 2015 projection of electricity generation is a much more reliable basis for forecasting the electric power grid absent the CPP than EPA's new base case. As the federal agency specifically charged with monitoring the energy industry, EIA has better information and superior expertise than EPA as to the amount of coal generation that can be expected to exist if the rule were not adopted. EIA can also offer a more objective evaluation of the nation's energy future without the rule than can EPA. In addition, EPA's new base case is facially not credible. EPA's base case projections for 2016, beginning just a few months from now, assume that 53 coal-fired units will retire between now and then. None of these units has announced that they will retire by then or thereafter absent the CPP. Yet any unit intending to retire by the end of 2015 or even in 2016 would long since have announced that fact.[37]

22. Using EIA's AEO2015 reference case as the base case against which to measure the CPP's impacts therefore provides a more accurate picture of the extent to which the CPP will transform the electric power industry. Compared to AEO2015, in the space of one decade, from 2020 to 2030, EPA projects that the CPP will reduce the share of power supplied by coal-fired plants from 41% to

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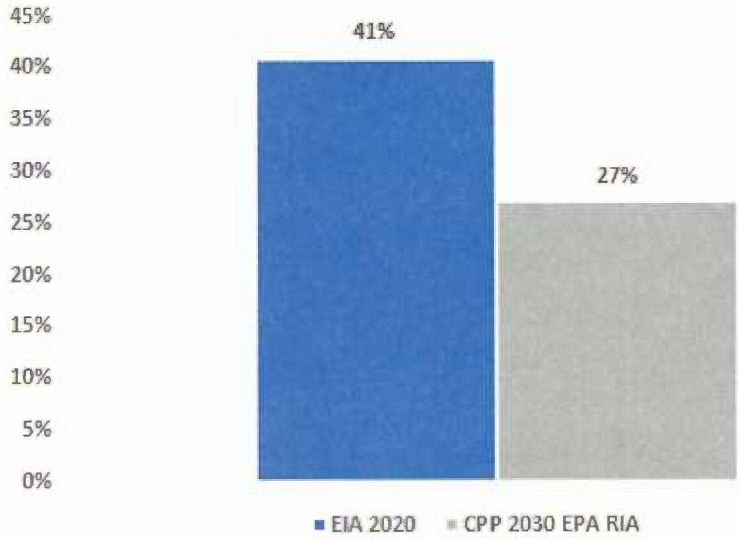
[36] Id. at 17 – 24.
[37] Id. at 24.

27%, replaced by generation from renewables and natural gas, as shown on Exhibit 1.[38]

Exhibit 1: Coal's Share of Electricity Supply in 2030 According to EPA's Projection under the CPP Compared to the EIA Forecast for 2020



23. This projected reduction in coal generation, however, depends on a critical assumption EPA has made about the amount of electricity the country will use between 2020 and 2030. EPA projects that electric consumption will fall during that decade.[39]

24. There is good reason to doubt that electric demand will decline as EPA projects given that population and the economy will continue to grow and, outside of recessions, electricity demand has *never* declined on a multi-year sustained basis. Neither the EIA nor EPA's base case predicts any such decline.[40]

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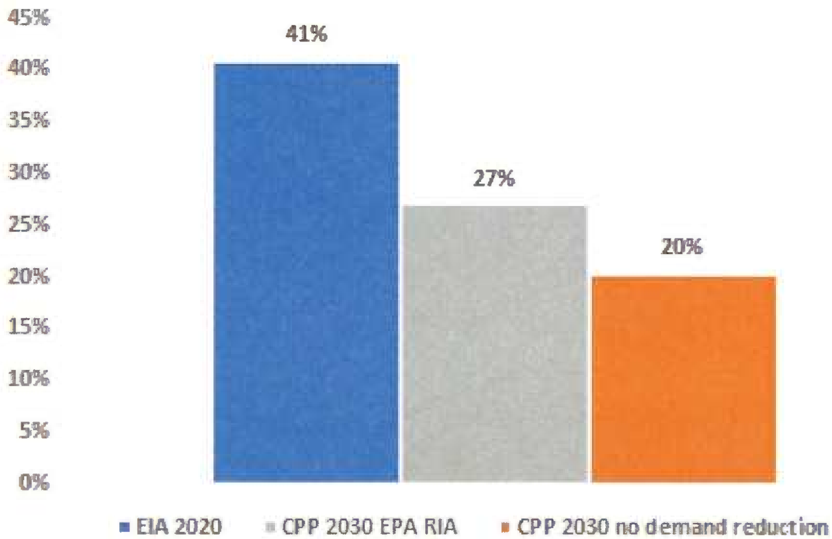
[38] Id. at 27.
[39] Id. at 24 – 26.
[40] Ibid.

Exhibit 2: Power Generation Forecasts under EIA AEO2015 and EPA IPM Model Base and CPP Cases (thousand GWh)

25. If the unprecedented demand reductions which EPA projects will be caused by the CPP fail to materialize, the displacement of coal generation would have to be much greater than the above chart shows. This is because the country would need to produce more electricity, but none of this new electricity could be supplied by coal due to its high CO_2 emissions. It is likely that the increased supply of electricity would come from new, lower-emitting natural gas-fired plants since EPA is already assuming unprecedented increases in renewable generation. Yet natural gas also produces CO_2 emissions, and these CO_2 emissions would have to be offset by even further reductions of coal. I project that, if EPA's assumed demand reduction does not occur and natural gas supplies that increment of

needed generation, the share of electricity supplied by coal would have to fall from 41% in 2020 to just 20% in 2030, as shown on Exhibit 3.[41]

Exhibit 3: Coal's Share of Electricity Supply in 2030 to Meet the CPP without Reduced Electricity Demand Compared to the EIA Forecast for 2020

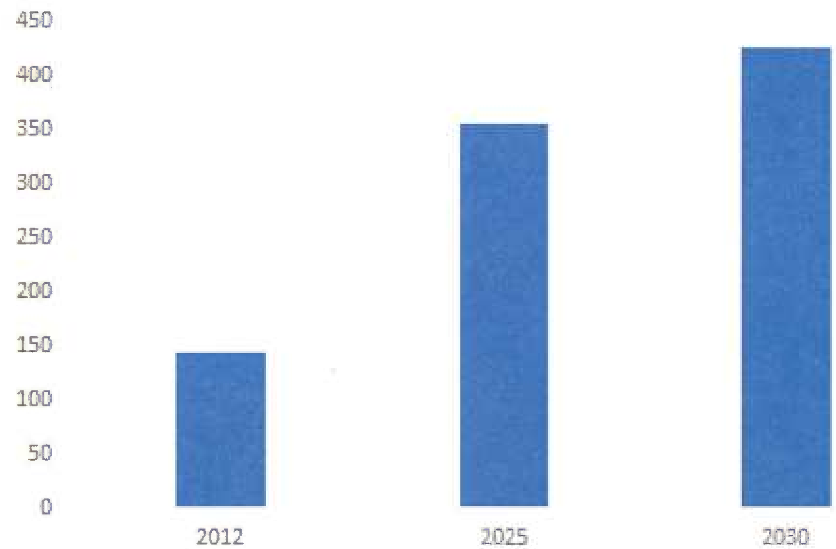


26. Even these numbers are likely to understate the impact on coal because EPA's assumptions as to the increased development of renewable resources are highly aggressive. EPA based its calculation of the BSER for existing coal units on an assumption of an unprecedented increase in generation from renewable sources (wind, solar, geothermal and hydro). EPA assumed that the annual construction of new renewable plants in the future could reach the maximum annual amount of increase for each type of renewable source in any of the past 5 years.[42] Under EPA's analysis, renewable generation from new wind and solar capacity must triple

[41] Id at 28.
[42] EPA, GHG Mitigation Measures Technical Support Document at 4-4.

from 2012 to 2030 in order to achieve the emission standards and state goals that comprise the CPP, as shown on Exhibit 4. If this increase does not occur, natural gas generation will have to increase to take its place, and even more coal generation will have to retire to offset the increased CO_2 emissions.[43]

Exhibit 4: EPA's Projected Wind and Solar Generation under CPP Rate-Based Compliance



EPA'S OWN MODEL PROJECTS IMMEDIATE RETIREMENTS OF COAL-FIRED PLANTS AND LOST COAL PRODUCTION

27. While EPA only published in the RIA its projections of the impacts of the CPP for the years 2020, 2025 and 2030, it has also disclosed its projections for the years 2016 and 2018 in supporting files posted on its website.[44] The model results show

[43] Schwartz Report at 28 – 29.

[44] See http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html. Note that EPA did not run the IPM model for all years, grouping the years into model run years to increase the speed of modeling. The year 2016 represents years 2016 and 2017, while the model year 2018 represents the actual year 2018. Schwartz Report at 13.

that coal-fired power plants will retire immediately in 2016, 2017 and 2018 due to the CPP and that coal burn will be significantly reduced during those years as a result.[45]

28. Even using EPA's low base case with its artificially low amount of coal generation, EPA projects that coal-fired generating capacity in 2016 will be 10,793 – 11,430 MW lower due to the CPP than under the base case because of immediate coal plant retirements, increasing to 12,124 – 14,439 MW by 2018.[46] As a result, EPA projects that coal burn will decline by 16.6 – 21.8 million tons in 2016 and by 35.4 – 44.8 million tons in 2018 due to the CPP.[47] This will result in coal mines closing, job losses, lost income for coal producers and lost tax revenues for the states and surrounding communities.[48]

29. EPA's projection of declines in coal demand due to the CPP grow to huge levels by 2025 and 2030, when the full impact of the rule takes effect. Even starting from EPA's low base case, EPA projects that the decline in coal demand will be 103.0 – 123.0 million tons in 2025, growing to 181.2 – 186.1 million tons in 2030.[49] Exhibit 5 shows EPA's forecast of coal burn for power generation under its own

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[45] Id.at 14 – 15, 55.

[46] The range of capacity retirements reflects EPA's forecast under the rate-based and mass-based cases. See Base Case SSR.xls, Rate-Based SSR.xls, and Mass-Based SSR.xls at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

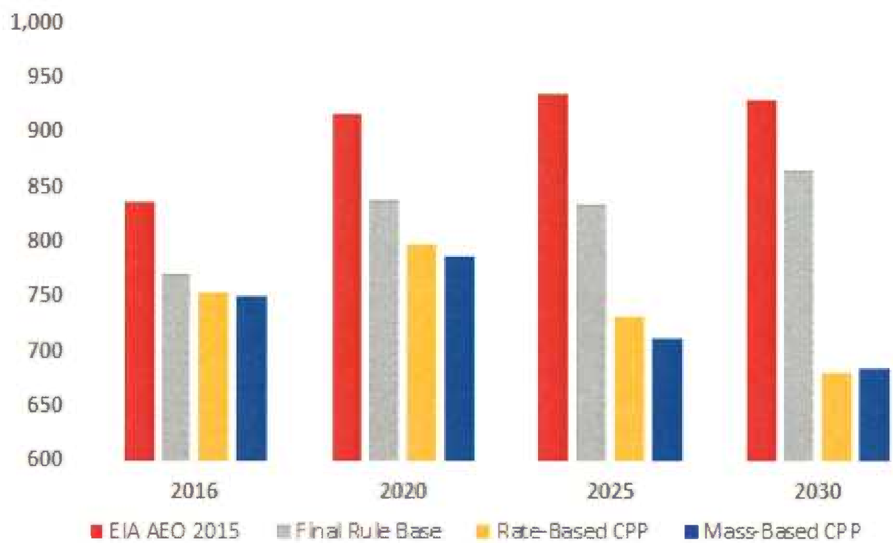
[47] Schwartz Report, Exhibit 22. The range reflects the IPM model projections under the rate-based and mass-based compliance cases.

[48] Ibid.

[49] Ibid.

model of the CPP (both rate and mass compliance strategies) compared to EIA's long-term forecast of coal demand in AEO2015 as well as EPA's base case. Compared to the EIA forecast, EPA projects an immediate loss of demand in 2016 of 82-87 million tons, growing to 245-250 million tons by 2030.[50]

Exhibit 4: EPA's Forecast of Coal Demand for Power Generation under the CPP Compared to EIA AEO 2015 (million tons)



UNDER EPA'S MODELING, SPECIFIC POWER PLANTS AND COAL MINES WILL CLOSE IMMEDIATELY

30. While EPA does not disclose the identity of the individual power plants which its IPM model projects will retire immediately due to the CPP, the individual plant information can be determined by analysis of the projected capacity retirements by state and power market region.[51] I have been able to match these data files to

[50] Id. at 52 – 56.
[51] I describe the methodology for determining the individual plants that the model shows as retiring. Id at 60 – 61.

identify 53 coal-fired plants which EPA projects will retire immediately in 2016 in EPA's rate-based compliance case and another 3 units which will retire in 2018.[52] These coal-fired plants burned 55 million tons of coal in 2014, including 36.1 million tons of subbituminous coal, 13.3 million tons of bituminous coal and 5.6 million tons of lignite.[53] This loss of demand will have a large negative impact on the coal market in 2016, forcing many mines to cut production or close.[54] Again, these figures are based on EPA modeling using EPA's new base case.

31. There are some mines which will suffer more than just reduced production as a result of the rule. Certain power plants purchase coal from mines which are dedicated to these plants and which have no other market. For these mines, if the power plant closes, the mine will have no choice but to close also. I identified 2 coal-fired power plants located in North Dakota—the Coyote and Coal Creek plants— and another 2 coal-fired units in Wyoming—at the Naughton and Jim Bridger plants— that EPA projects as closing immediately as a result of the rule and which burn coal from adjacent mines. Closure of these power plants will force the mines supplying them to close also. This will cost the jobs of 563 employees.[55]

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[52] Id at 62 – 64. The list of plant retirements projected by IPM under the mass-based case is similar, but slightly different.
[53] Ibid.
[54] Ibid.
[55] Id., Exhibit 32, at 70.

THE IMMEDIATE HARM IS MUCH GREATER USING A MORE REALISTIC BASE CASE

32. As described above, EPA significantly understated the immediate impact of the CPP on retirements of coal-fired power plants by projecting that many of these plants will retire in its base case anyway. In its base case, EPA projected that there will only be 214 gigawatts ("GW") of coal-fired generating capacity in 2016, falling to 208 GW in 2018[56] (these values are 31 and 35 GW less than the base case which EPA used to evaluate the proposed rule, respectively).[57] In contrast, EIA projected in AEO 2015 that there will be 266 GW of coal-fired capacity in 2016 and 261 GW in 2018.[58]

33. I have analyzed the EPA data files and have identified the coal-fired units which EPA projects will retire in its base case. There are a total of 180 coal-fired units EPA listed as retiring in 2016 in EPA's base case and another 2 units in 2018. The total coal burn at these units was 116.3 million tons in 2014.[59]

34. The units which EPA projects will retire in 2016 and 2018 in its base case should be considered as retiring due to the impact of the CPP. As described above, EPA has no basis for including these units in its base case. EIA does not think these units will retire in 2016 and the owners of these units have not announced that

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[56] Id, Exhibit 7, at 15.
[57] Id, Exhibit 9, at 19.
[58] Id, Exhibit 11, at 22.
[59] Id. Exhibit 31, at 66.

they will retire next year, even though the owners of these units, if they truly intended to take these units out of service by the beginning of next year, would have announced their intent to do so by now.[60]

35. At the same time, retirement of these units is necessary for states to comply with the CPP. As described above, the CPP gives each state a CO_2 emissions budget. That budget can only be met by significantly reducing electric generation from the existing coal-fired fleet. EPA's model shows that states will meet their budget both because of the assumed base case retirements and by retiring additional units. If, as is highly likely, the base case retirements do not occur because of factors other than compliance with the rule, they will nevertheless have to retire under the rule for states to meet their budgets.[61]

36. Including the plants which EPA projects will retire in its base case, EPA is forecasting that 238 coal-fired power plants will retire in 2016 and 2018, with all but 5 of these plants retiring in 2016. These plants burned a total of 171.5 million tons of coal in 2014, including 93 million tons of Powder River Basin coal, 61 million tons of bituminous coal, 10 million tons of lignite and 7 million tons of waste coal and petroleum coke. This will cause a huge negative economic impact

[60] Id. at 23 – 24.
[61] Id., at 24.

on all coal producers, causing mine closures, job losses and irreparable economic harm to the coal producers and the surrounding communities. [62]

37. In addition, I have identified 9 coal-fired stations (with 15 generating units) which EPA projects as closing either in its base case or as a result of the rule and which purchase coal from dedicated coal mines. Closure of these generating units will cause these coal mines to close or significantly reduce production;[63] 10 coal mines will close, production will be reduced by 22.3 million tons per year, and 1,856 jobs people will lose their jobs. Virtually all of this will happen in 2016-2017, with the rest occurring by 2018.[64]

38. Exhibit 5 is a chart of (a) the coal generating units that EPA projects will close either in its base case or as a result of the rule which (b) are tied to mines which will lose all or most of their mine production as a result of closure of these units:[65]

Exhibit 5: Coal-Fired Plants Projected by EPA to Close in 2016 and 2018 that Are Closely Tied to a Particular Coal Mine

			Capacity Retired Due to CPP (MW)			Captive Coal Supply			Jobs Lost		
State	Station	Units	Base Case	Rate-Based	Total	Company	Mines	1000 tons	CPP	Base	Total
ND	Coal Creek	1		558	558	North American	Falkirk	3,408	207		207
ND	Coyote	1		427	427	Westmoreland	Beulah	2,624	154		146
ND	Lewis & Clark	1	52		52	Westmoreland	Savage	285		12	12
ND	Milton Young	1	250		250	BNI Coal	Center	1,545		63	63
ND	RM Heskett	1	30		30	Westmoreland	Beulah	140			8
OH	Conesville	4-6	1,530		1,530	Westmoreland	Buckingham	1,701		359	359
						Westmoreland	Oxford	1,888		207	207
TX	San Miguel	1	391		391	Kiewit	San Miguel	2,256		232	232
WY	Jim Bridger	1-3	1,058	530	1,588	PacifiCorp	Bridger UG	3,370	105	210	315
						Lighthouse	Black Butte	2,458	44	88	132
WY	Naughton	1-3	490	210	700	Westmoreland	Kemmerer	2,696	53	123	175
			3,801	**1,725**	**5,526**			**22,371**	**563**	**1,293**	**1,856**

[62] Id., at 64.
[63] Id., Exhibit 29, at 62.
[64] Id., at 69 – 72
[65] Id., Exhibit 32 at 70.

THE RULE WILL DAMAGE THE FINANCIAL VIABILITY OF COAL COMPANIES

39. The CPP can have no other result than to imperil the financial viability of coal companies. Domestic power production is, by a large margin, the largest market for U.S. coal. The CPP effectively sets a cap on U.S. coal production at a significantly reduced level. The market now perceives that coal has only a limited future, and it has reacted accordingly.[66]

40. The coal industry was already in a state of severe financial distress, in part due to the impact of other recent EPA regulations (most notably the Mercury and Air Toxics, or "MATS", rule), as well as the recent decline in the price of natural gas, the stronger U.S. dollar, and slowing overseas economic growth. The prospect of a massive decline in coal demand due to the CPP has further depressed coal company stock market values and will make it impossible for coal companies to raise capital to finance their operations. Since the announcement of the proposed CPP in June 2014, public coal company stock prices have declined by 62% - 99%. Three large coal companies have filed for bankruptcy since the start of 2015. This trend will continue unless the CPP is stayed and overturned in court.[67]

[66] Id. at 56 – 59.
[67] Id. At 59.

THE RECENT EXAMPLE OF THE MATS RULE SHOWS THE IRREPARABLE HARM DUE TO EPA RULES

41. The coal industry has just suffered irreparable harm due to the imposition of EPA's MATS rule, which was allowed to take effect while the Court considered whether to uphold the validity of the rule. While the MATS rule has recently been remanded by the Supreme Court, the rule caused many coal units to close, and those closures are now permanent.[68]

42. The MATS rule was proposed by EPA on March 16, 2011 and the final rule was announced on December 21, 2011[69] Compliance was required by April 16, 2015, with a one-year extension available from the states. The National Mining Association immediately filed a petition to review the MATS rule with this Court, which was denied on April 15, 2014.

43. Like the CPP, EPA used the IPM model to analyze the impact of the MATS rule, compared to its then-current base case forecast, and found that most coal-fired plants would decide to construct emissions controls and there would be very few retirements of coal-fired units as a result of MATS, just 4,700 MW. EPA went so far as to speculate that even this small amount might be overestimated due to local

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[68] Id. at 73 – 83.

[69] The proposed rule was published in the Federal Register on May 3, 2011 and the final rule was published on February 16, 2012, with an effective date of April 16, 2012.

conditions which could not be captured by IPM.[70] EPA concluded that coal burn would be reduced by less than 1%.[71]

44. EPA's projection of the impact of the MATS rule was massively wrong, not just in the long-term, but immediately. Immediately after the rule was issued, power companies began announcing that they would retire coal-fired units due to the effect of the MATS rule. In 2012 alone, power companies retired 10,308 MW of coal-fired capacity, with the vast majority of these decisions attributed to the MATS rule.[72] EIA promptly published a forecast in July 2012 that 27 GW of coal-fired capacity would retire from 2012 to 2015, principally due to the MATS rule.[73] Actually, for the period 2012 through May 2015, the retirements of coal units reported to EIA has totaled 33,357 MW, and still counting.[74] Even this understates the impact of the MATS rule, because some plants have chosen to comply by switching from burning coal to natural gas, which EIA does not count as retirement.[75]

45. The immediate impact on the coal industry was devastating. Coal burn fell by 109 million tons in 2012 from 2011 its level (12%).[76] While this was partly due to the low price of natural gas in 2012, even after natural gas prices recovered in 2014 to

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[70] EPA Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 3-17.
[71] Schwartz Report at 74.
[72] Ibid.
[73] Id., at 75.
[74] Id., at 74.
[75] Id. at 75.
[76] EIA, "Electric Power Monthly", July 2015, Table 2.1A.

above the 2011 level, coal consumption was still 80 million tons below its 2011 demand.[77] Total U.S. coal production fell from 1,094 million tons in 2011 to 985 million tons in 2013, largely due to the decline in demand for power generation.[78] Total employment fell from 91,611 jobs in 2011 to 80,396 jobs in 2013.[79]

46. While it is still possible that the Court could vacate the MATS rule, it would come far too late to save the lost investment and jobs in the coal industry. Power companies have stated publicly that the coal-fired plants which they retired would not be restarted even if the MATS rule were vacated.[80] Even EPA's Administrator, Gina McCarthy has stated that "The majority of power plants have already decided and invested in a path to achieve compliance with the Mercury Air Toxics Standards."[81]

CONCLUSIONS

47. The final CPP rule will cause immediate and irreparable harm to the coal industry if the implementation is not stayed by this Court. Even under EPA's own model, which greatly understates the impact of the CPP, there are many coal-fired power plants which will close in 2016 due to the impact of the CPP. Beyond the general

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[77] Id, Table 4.2.
[78] EIA, "Coal Industry Annual", 2013 and 2013, Table 1. EIA has not published 2014 official data yet, but data from the Mine Safety and Health Administration indicates that 2014 coal production was about 994 million tons.
[79] Id, Table 18.
[80] Schwartz Report at 82 – 83.
[81] Alan Neuhauser, *McCarthy: Clean Power Plan Unaffected by Supreme Court*, U.S. NEWS, July 7, 2015, available at http://www.usnews.com/news/articles/2015/07/07/mccarthy-clean-power-plan-unaffected-by-supreme-courts-mercury-rule-rebuke.

harm to the coal industry, there are specific power plants and specific coal mines which EPA itself projects will close in 2016. If the final rule is later vacated by the Court, it will be too late to save the investment and jobs at these mines.

48. Moreover, apart from the predicted 2016 retirements, because of the very long lead time required for planning, permitting and construction of electric power plants, power companies will need to make immediate decisions whether to retire and replace their coal-fired units to comply with the CPP by 2022. The Court does not need to speculate that this CPP rule, unprecedented in its scope, will cause immediate and irreparable harm to the coal industry. The Court can look at the recent example of EPA's MATS rule, which, while smaller in scope, caused massive plant and mine retirements before the Court ever ruled on the validity of the rule. Even if the MATS rule were to be vacated, EPA itself claims that this would not reverse the impact on the coal-fired plants. The adverse impacts of the CPP on the coal industry will be immediate and irreparable.

49. I, Seth Schwartz, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Seth Schwartz

Dated: October 14, 2015

Evaluation of the Immediate Impact of the Clean Power Plan Rule on the Coal Industry

October 2015

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Introduction

Energy Ventures Analysis, Inc. ("EVA") was retained by National Mining Association ("NMA") to evaluate the impact of the final rule promulgated by the U.S. Environmental Protection Agency ("EPA") under Section 111(d) of the Clean Air Act known as the Clean Power Plan ("CPP"). On behalf of its members, which include most of the U.S. coal producers, NMA has filed a petition for review of the CPP with the U.S. Court of Appeals for the D.C. Circuit and is filing a motion to stay the implementation of the CPP until the Court has ruled on its petition. EVA has been asked by NMA to evaluate the impact of the CPP on the U.S. coal industry during the litigation if the stay is not granted.

EVA projects that the CPP will cause a massive reduction in the consumption of coal by the U.S. electric power industry, based on a review of EPA's own impact analysis. Indeed, significantly reducing coal for electric production is the expressed intent of the CPP, as it is the only way to accomplish the significant reduction in emissions of carbon dioxide from existing electric fossil-fueled generating units sought by EPA.

The coal industry will experience the consequences of this transition away from coal immediately. Because the electric power industry requires long lead times to plan, permit, and construct power plants and the associated infrastructure, the power industry will act promptly to comply with EPA's required transformation of the electric sector. To comply with the CPP, utilities must commit immediately to coal plant retirements and to the investment of billions of dollars to build new non-carbon emitting or lower carbon-emitting power plants to ensure sufficient resources will be available to meet the electricity demand of their customers. Once committed, the decision to retire and replace existing coal-fired power plants will be irrevocable.

As power companies close coal-fired power plants, the mines which supply them will be forced to close as well, and the coal mining industry will lose jobs and the value of their investments, while also incurring massive mine closing costs. Approximately 90 percent of the coal sold in the United States from U.S. mines is supplied to electric utilities. Like the electric utility industry, the coal industry is highly capital intensive and must make investment decisions that have long lead times. The industry cannot wait another year or two to make the decisions necessary to adjust to the new market reality that the CPP imposes. The coal industry thus will suffer irreparable harm as a result of the CPP while the Court reviews the many challenges to the rule.

Experience and Qualifications

The author of this report is Mr. Seth Schwartz, president of EVA. EVA has been performing analyses of U.S. energy markets since its founding in 1981. EVA analyzes and publishes regular reports on the coal, natural gas and power markets, including forecasts of supply, demand and prices. Mr. Schwartz leads EVA's practice analyzing U.S. coal markets. He has testified as an expert witness on coal markets in numerous court, arbitration and regulatory hearings, including:

- Supreme Court of the United States (Wyoming v. Oklahoma, 1992)
- Federal district courts in Pennsylvania, Virginia, Missouri, Indiana, Kentucky, Florida, Ohio, Alabama, and West Virginia;
- State courts in Virginia, Kentucky, Pennsylvania, Colorado, Wyoming, Texas and West Virginia;
- U.S. bankruptcy courts in Delaware, Kentucky, Missouri, Tennessee and Louisiana; and,
- Regulatory hearings of the Surface Transportation Board, the Federal Energy Regulatory Commission and public utility commissions in the states of Utah, Texas, Florida, Georgia, and Ohio.

Mr. Schwartz has been a member of the Working Group for the Annual Energy Outlook prepared by the U.S. Energy Information Administration and testified at FERC's Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure regarding the CPP proposed rule.

Mr. Schwartz's and EVA's clients include energy producers, consumers, transporters, investors and regulators. EVA works for regulatory agencies, including state public utility commissions as well as federal agencies.

I. Overview of the Clean Power Plan Rule

On August 3, 2015, EPA released the final CPP.[1] The rule, a key component of the President's Climate Action Plan, is also referred to as the "Section 111(d) Rule" for the section of the Clean Air Act cited by EPA as the authority for it. Press coverage of the rule has also referred to it as the "existing source performance standard" because it authorizes the setting of "standards of performance" for CO_2 emissions from "existing" power plants. Described by EPA itself as "historic,"[2] it represents EPA's most aggressive attempt to use the Clean Air Act to regulate greenhouse gases emissions from stationary sources.

EPA has identified the energy sector as the largest anthropogenic source of greenhouse gases, as shown on Exhibit 1, primarily from the emission of CO_2 from the combustion of fossil fuels.

Exhibit 1: US Greenhouse Gas Emissions by Sector (million metric tons)[3]

Sector	1990	2005	2012	2013
Energy	5,290.5	6,273.6	5,482.2	5,636.6
Industrial Processes and Product Use	342.1	367.4	361.2	359.1
Agriculture	448.7	494.5	523.0	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	39.8	23.3
Waste	206.0	189.2	138.9	138.3
Total Emissions	**6,301.1**	**7,350.2**	**6,545.1**	**6,673.0**
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(880.4)	(881.7)
Net Emissions (Sources and Sinks)	**5,525.2**	**6,438.3**	**5,664.7**	**5,791.2**

The energy sector includes emissions from power generation, transportation, industrial, residential and commercial energy consumption. The emissions from power generation in 2012 comprised 31% of total GHG emissions and 37% of emissions from the energy sector, as shown on Exhibit 2.

[1] EPA, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units", final rule, page 8.

[2] EPA Fact Sheet: Overview of the Clean Power Plan, available at http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants.

[3] From Table ES-4 of "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, U.S. Environmental Protection Agency, April 15, 2015, http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.

Exhibit 2: GHG Emissions from Generation of Electricity from Combustion of Fossil Fuels[4]

GHG Emissions (million metric tons)	1990	2005	2012	2013
--- Coal	1,547.6	1,983.8	1,511.2	1,575.0
--- Natural Gas	175.3	318.8	492.2	441.9
--- Petroleum	97.5	97.9	18.3	22.4
--- Geothermal	0.4	0.4	0.4	0.4
Total CO2 from fossil fuel combustion EGUs	**1,820.8**	**2,400.9**	**2,022.1**	**2,039.7**

The CPP requires states to develop plans that regulate CO_2 emissions from “affected electric generating units” or “affected EGUs,” defined to include any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014 and that meets the following criteria:

- A boiler, IGCC, or combustion turbine (either simple cycle or combined cycle);
- Capable of combusting at least 250 mmBtu per hour;
- Combusts fossil fuel for more than 10 percent of its total annual heat input
  - Combustion turbines have an additional criteria that they combust over 90 percent natural gas; and,
- Sells greater than 219,000 MWh per year and one-third of its potential electric output to a utility distribution system.

The Clean Power Plan is highly complex, but it centers around two key components—“emission standards” and “state goals.” The achievement of either will demonstrate compliance with the rule. The “emission standards” are based on EPA’s technical analysis of emission reduction opportunities deemed achievable and expressed in terms of the amount of CO_2 emitted (in pounds) per unit of electricity generated (in megawatt-hours, or “MWh”) for each fossil fuel. Specifically, EPA analyzed three emission reduction strategies, referred to as “building blocks,” which EPA claims to be the “best system of emission reduction:” efficiency improvements at coal-fired EGUs, followed by displacement of both coal- and gas-fired EGUs with renewable energy resources, and then further displacement of coal-fired EGUs with gas-fired EGUs. Applying those three “building blocks,” EPA determined that, by 2030, fossil steam EGUs (primarily coal-fired) should be required to meet an “emission standard” of 1,305 lbs./MWh and gas-fired EGUs (natural gas combined cycle, or “NGCC”) should be required to meet an “emission

[4] From Table 3-5, “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013”, Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15 2015, http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.

standard" of 771 lbs./MWh. The emission standards begin to apply in 2022, but phase in over the course of an "interim compliance period."

These "emission standards" are not based upon the ability of each category to actually achieve these rates using emission control technology or operational practices that EGUs can implement at the facility. According to EPA, the average emission rate for all coal-fired EGUs in 2012 was 2,215 pounds CO_2 per MWh.[5] The newest, most efficient coal-fired plants in the U.S. (John W. Turk plant in Arkansas and James E. Rogers Energy Complex unit 6 in North Carolina) reported emission rates in calendar year 2014 of 1,867 and 1,837 pounds CO_2 per MWh, respectively.[6] There is no possible way for existing coal units to install technology or make operational changes to lower their emissions rate to anything near 1,305 lbs./MWh.

The Clean Power Plan itself does not impose these "emission standards" directly. Rather, it requires states to develop individual plans for achieving the "emission standards" and provides several pathways for compliance. Those pathways rely on "state goals" that reflect the average emission rate that all of the affected EGUs in the state would meet in the aggregate if they each achieved the "emission standards" individually. The state goals thus vary from state to state based on each state's unique mix of coal- and gas-fired EGUs—the goal for states with 100% coal generation is 1,305 lbs./MWh, the goal for states with 100% gas generation is 771 lbs./MWh, and all states with some of both are somewhere in between.[7] EPA also converted its rate-based goals into mass-based goals. The mass-based goals represent the total tons of CO_2 that can be emitted by affected EGUs within a state, regardless of how much electricity is generated in the process. EPA claims those mass-based goals are equivalent to the rate-based goals. However, the state mass-based goals are uniformly less stringent (requiring a smaller percentage reduction) than the rate-based goals, as shown on Exhibits 3 and 4.

[5] Source: EPA Data File: Goal Computation Appendix 3 at http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

[6] The Turk Station, owned by Southwestern Electric Power Company and James E. Rogers unit 6, owned by Duke Energy Carolinas, reported 4,127,881 and 4,262,209 tons of CO_2 emissions (EPA Air Markets Program Data at http://ampd.epa.gov/ampd/), respectively and 4,422,641 MWh and 4,641,277 MWh of net generation (see EIA923_Schedules_2_3_4_5_M_12_2014_Data_Early_Release.xls. http://www.eia.gov/electricity/data/eia923/).

[7] Like the emission standards upon which they are based, the state goals phase in between 2022 and 2030.

To implement either approach—rate-based or mass-based—each state must assign to each of its "affected EGUs" a numeric emission limitation that will be used to demonstrate compliance with the state goals. States following the rate-based approach have three options in imposing unit-specific rate-based emission limitations: (i) require affected EGUs to meet the EPA-established "emission standards" (1,305 or 771 lbs./MWh, depending on the fuel); (ii) require affected EGUs to the meet the state's rate-based goal (one emission rate somewhere between 1,305 or 771 lbs./MWh, depending on the state); or (iii) require affected EGUs to meet custom-designed limitations, assuming the state can demonstrate to EPA that the combined effect of those limits will achieve the state's goal. States following the mass-based approach must simply ensure that the total mass of CO_2 emissions from its affected EGUs will remain below the state's goal by requiring each unit to reduce its CO_2 emissions on a ton per year basis. For added flexibility, the Clean Power Plan authorizes states to allow its affected EGUs to incorporate into their compliance demonstrations some sort of credit for actions taken at other facilities through a market-based emissions trading program. Regardless of the pathway chosen by a state, some variety of trading program will likely be necessary for affected EGUs to achieve compliance with the Clean Power Plan.

The actual emission rates in 2012 for each state as well as the Interim and Final Goals are shown in Exhibit 3.[8] The total reduction in emission rates is 35% from 2012 to 2030, with a reduction of 26% to be achieved to meet the Interim Goal average 2022 – 2029. Of the 50 affected states and tribes, 31 must achieve over 70% of the total reduction required by the Final Goal in order to comply with the Interim Goal. Further, EPA established three interim "steps" with performance rates. States must meet these interim performance rates or establish different interim performance rates which demonstrate compliance with the Interim Goal average for 2022-2029. As shown on Exhibit 3, the majority (56% on average) of the emission reductions must be achieved by 2022 in Step 1 in order to comply with the Interim Goal.

The mass-based goals are shown in Exhibit 4.[9] The mass-based emission reduction goals require a lower percentage reduction from 2012 actual emissions than the rate-based

[8] Source: EPA Data File: Goal Computation Appendix 1-5 file at http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents. State goals are provided in Appendix 5; average calculated based on share of affected generation. Actual 2012 emission rate of affected units calculated from data in Appendix 1.
[9] Ibid. State goals are provided in Appendix 5. Actual 2012 emissions of affected units calculated from data in Appendix 1.

standard, by approximately 15% for the Interim Goal and 25% for the Final Goal. Exhibit 4 also shows the "adjusted baseline" emissions in 2012 for each state. EPA made adjustments to the actual emissions from affected units to account for new affected units which completed construction after January 1, 2012 and were under construction prior to January 8, 2014 (after which they are new EGUs), as well as unusual events in the baseline year (high hydro generation or a major plant outage).

Exhibit 3: Statewide Rate-Based CO_2 Emission Goals (pounds per MWh)

State/Tribe	2012 Actual Rate	Interim Goal - Step 1 (2022-2024)	Interim Goal (2022-2029)	Final (2030)	Interim Emission Reduction	Final Emission Reduction	Share of Final Reduction in Interim Goal	Share of Final Reduction in Step 1
Alabama	1,518	1,244	1,157	1,018	24%	33%	72%	55%
Arizona	1,552	1,263	1,173	1,031	24%	34%	73%	55%
Arkansas	1,779	1,411	1,304	1,130	27%	36%	73%	57%
California	963	961	907	828	6%	14%	41%	1%
Colorado	1,973	1,476	1,362	1,174	31%	40%	76%	62%
Connecticut	846	899	852	786	-1%	7%	0%	0%
Delaware	1,254	1,093	1,023	916	18%	27%	68%	48%
Florida	1,247	1,097	1,026	919	18%	26%	67%	46%
Georgia	1,600	1,290	1,198	1,049	25%	34%	73%	56%
Idaho	858	877	832	771	3%	10%	30%	0%
Illinois	2,208	1,582	1,456	1,245	34%	44%	78%	65%
Indiana	2,021	1,578	1,451	1,242	28%	39%	73%	57%
Iowa	2,195	1,638	1,505	1,283	31%	42%	76%	61%
Kansas	2,319	1,654	1,519	1,293	35%	44%	78%	65%
Kentucky	2,166	1,643	1,509	1,286	30%	41%	75%	59%
Lands of the Fort Mojave Tribe	858	877	832	771	3%	10%	30%	0%
Lands of the Navajo Nation	2,121	1,671	1,534	1,305	28%	38%	72%	55%
Lands of the Uintah and Ouray	2,145	1,671	1,534	1,305	28%	39%	73%	56%
Louisiana	1,618	1,398	1,293	1,121	20%	31%	65%	44%
Maine	873	888	842	779	4%	11%	33%	0%
Maryland	2,031	1,644	1,510	1,287	26%	37%	70%	52%
Massachusetts	1,003	956	902	824	10%	18%	57%	26%
Michigan	1,928	1,468	1,355	1,169	30%	39%	75%	61%
Minnesota	2,033	1,535	1,414	1,213	30%	40%	76%	61%
Mississippi	1,185	1,136	1,061	945	10%	20%	52%	21%
Missouri	2,008	1,621	1,490	1,272	26%	37%	70%	53%
Montana	2,481	1,671	1,534	1,305	38%	47%	81%	69%
Nebraska	2,161	1,658	1,522	1,296	30%	40%	74%	58%
Nevada	1,102	1,001	942	855	15%	22%	65%	41%
New Hampshire	1,119	1,006	947	858	15%	23%	66%	43%
New Jersey	1,091	937	885	812	19%	26%	74%	55%
New Mexico	1,798	1,435	1,325	1,146	26%	36%	72%	56%
New York	1,140	1,095	1,025	918	10%	20%	52%	20%
North Carolina	1,780	1,419	1,311	1,136	26%	36%	73%	56%
North Dakota	2,368	1,671	1,534	1,305	35%	45%	78%	66%
Ohio	1,900	1,501	1,383	1,190	27%	37%	73%	56%
Oklahoma	1,565	1,319	1,223	1,068	22%	32%	69%	50%
Oregon	1,089	1,026	964	871	12%	20%	58%	29%
Pennsylvania	1,682	1,359	1,258	1,095	25%	35%	72%	55%
Rhode Island	918	877	832	771	9%	16%	58%	28%
South Carolina	1,791	1,449	1,338	1,156	25%	35%	71%	54%
South Dakota	2,229	1,465	1,352	1,167	39%	48%	83%	72%
Tennessee	2,015	1,531	1,411	1,211	30%	40%	75%	60%
Texas	1,566	1,279	1,188	1,042	24%	33%	72%	55%
Utah	1,874	1,483	1,368	1,179	27%	37%	73%	56%
Virginia	1,477	1,120	1,047	934	29%	37%	79%	66%
Washington	1,566	1,192	1,111	983	29%	37%	78%	64%
West Virginia	2,064	1,671	1,534	1,305	26%	37%	70%	52%
Wisconsin	1,996	1,479	1,364	1,176	32%	41%	77%	63%
Wyoming	2,331	1,662	1,526	1,299	35%	44%	78%	65%
Total	**1,696**	**1,358**	**1,257**	**1,095**	**26%**	**35%**	**73%**	**56%**

Exhibit 4: Statewide Mass-Based CO_2 Emission Goals (tons)

State/Tribe	2012 Actual Emissions	2012 Adjusted Baseline	Interim (2022-2029)	Final (2030)	Interim Emission Reduction	Final Emission Reduction	Share of Reduction in Interim Goal
Alabama	75,571,781	75,571,781	62,210,288	56,880,474	18%	25%	71%
Arizona	40,465,035	40,465,035	33,061,997	30,170,750	18%	25%	72%
Arkansas	39,935,335	43,416,217	33,683,258	30,322,632	16%	24%	65%
California	46,100,664	49,720,213	51,027,075	48,410,120	-11%	-5%	0%
Colorado	41,759,882	43,209,269	33,387,883	29,900,397	20%	28%	71%
Connecticut	6,659,803	6,659,803	7,237,865	6,941,523	-9%	-4%	0%
Delaware	4,809,281	5,540,292	5,062,869	4,711,825	-5%	2%	0%
Florida	118,395,844	124,432,195	112,984,729	105,094,704	5%	11%	41%
Georgia	62,851,752	62,843,049	50,926,084	46,346,846	19%	26%	72%
Idaho	703,517	1,438,919	1,550,142	1,492,856	-120%	-112%	0%
Illinois	96,106,169	102,208,185	74,800,876	66,477,157	22%	31%	72%
Indiana	107,299,591	110,559,916	85,617,065	76,113,835	20%	29%	70%
Iowa	38,135,386	38,135,386	28,254,411	25,018,136	26%	34%	75%
Kansas	34,353,105	34,655,790	24,859,333	21,990,826	28%	36%	77%
Kentucky	91,372,076	92,775,829	71,312,802	63,126,121	22%	31%	71%
Lands of the Fort Mojave Tribe	583,530	583,530	611,103	588,519	-5%	-1%	0%
Lands of the Navajo Nation	31,416,873	31,416,873	24,557,793	21,700,587	22%	31%	71%
Lands of the Uintah and Ouray Reservation	3,314,097	3,314,097	2,561,445	2,263,431	23%	32%	72%
Louisiana	43,028,425	44,391,194	39,310,314	35,427,023	9%	18%	49%
Maine	1,795,630	2,072,157	2,158,184	2,073,942	-20%	-15%	0%
Maryland	20,171,027	20,171,027	16,209,396	14,347,628	20%	29%	68%
Massachusetts	13,125,248	13,125,248	12,747,677	12,104,747	3%	8%	37%
Michigan	69,860,454	69,860,454	53,057,150	47,544,064	24%	32%	75%
Minnesota	28,263,179	34,668,506	25,433,592	22,678,368	10%	20%	51%
Mississippi	25,903,886	27,443,309	27,338,313	25,304,337	-6%	2%	0%
Missouri	78,039,449	78,039,449	62,569,433	55,462,884	20%	29%	69%
Montana	17,924,535	19,147,321	12,791,330	11,303,107	29%	37%	78%
Nebraska	27,142,728	27,142,728	20,661,516	18,272,739	24%	33%	73%
Nevada	15,536,730	15,536,730	14,344,092	13,523,584	8%	13%	59%
New Hampshire	4,642,898	4,642,898	4,243,492	3,997,579	9%	14%	62%
New Jersey	15,207,143	19,269,698	17,426,381	16,599,745	-15%	-9%	0%
New Mexico	17,339,683	17,339,683	13,815,561	12,412,602	20%	28%	72%
New York	34,596,456	34,596,456	33,595,329	31,257,429	3%	10%	30%
North Carolina	58,566,353	67,277,341	56,986,025	51,266,234	3%	12%	22%
North Dakota	33,370,886	33,757,751	23,632,821	20,883,232	29%	37%	78%
Ohio	102,239,220	102,434,817	82,526,513	73,769,806	19%	28%	69%
Oklahoma	52,862,077	52,862,077	44,610,332	40,488,199	16%	23%	67%
Oregon	7,659,775	9,042,668	8,643,164	8,118,654	-13%	-6%	0%
Pennsylvania	116,657,632	119,989,743	99,330,827	89,822,308	15%	23%	65%
Rhode Island	3,735,786	3,735,786	3,657,385	3,522,225	2%	6%	37%
South Carolina	35,893,265	35,893,265	28,969,623	25,998,968	19%	28%	70%
South Dakota	3,184,962	5,121,124	3,948,950	3,539,481	-24%	-11%	0%
Tennessee	41,222,026	41,387,231	31,784,860	28,348,396	23%	31%	73%
Texas	240,730,037	251,848,335	208,090,841	189,588,842	14%	21%	64%
Utah	30,822,343	32,166,243	26,566,380	23,778,193	14%	23%	60%
Virginia	27,365,439	35,733,502	29,580,072	27,433,111	-8%	0%	0%
Washington	7,360,183	15,237,542	11,679,707	10,739,172	-59%	-46%	0%
West Virginia	72,318,917	72,318,917	58,083,089	51,325,342	20%	29%	68%
Wisconsin	42,317,602	42,317,602	31,258,356	27,986,988	26%	34%	77%
Wyoming	49,998,736	50,218,073	35,780,052	31,634,412	28%	37%	77%
Total	**2,178,716,430**	**2,265,735,254**	**1,844,537,775**	**1,668,104,080**	**15%**	**23%**	**65%**

II. Impact of the CPP on Electric Power Generation

There is no question that, by design, the CPP will reduce generation from coal and replace it with generation from lower-emitting sources (natural gas and renewables). In addition, EPA analysis shows that the success of the CPP depends critically on EPA's assumption that electricity demand will fall in absolute terms between 2020 and 2030 despite population and economic growth and despite the fact that electric consumption has *never* fallen over such an extended period. If electricity consumption grows during that period, the CPP will require even greater amounts of both renewable generation and natural gas generation, and, to offset the CO_2 emissions from this increased natural gas generation, even further reduction in coal generation.

A. Summary of Impacts on Power Supply and Demand

The purpose of the CPP is to reduce coal-fired generation, increase natural gas-fired generation, increase renewable energy generation, and encourage demand reduction projects to reduce the growth of electricity demand.

- **Coal-fired generation and coal consumption will decline significantly.** The stated objective of the CPP is to reduce emissions of CO_2 from power generation. Coal-fired EGUs both emit more total CO_2 and have the highest CO_2 emission rate as compared with any other source of power generation. There are, however, no available controls for reducing CO_2 emission rates from coal. Therefore, EPA intends to achieve significant reductions in CO_2 emissions from the power sector by reducing the combustion of coal. Each of EPA's Building Blocks are intended to achieve this result:
    - <u>**Block 1:**</u> Improved heat rates for existing coal-fired generation as a way of reducing CO_2 emissions per ton of coal used for coal generation, thereby reducing the number of tons of coal used for power generation;
    - <u>**Block 2:**</u> Re-dispatch of gas-fired NGCC plants ahead of coal-fired plants, displacing electricity generated with coal; and,
    - <u>**Block 3:**</u> Increased generation from renewable power sources, displacing coal-generated electricity.
- **Generation from natural gas-fired NGCC plants will increase significantly.** To accomplish the displacement of coal-fired generation with natural gas generation under building block 2, EPA assumes that existing natural gas generation will increase from a current capacity factor of approximately 44 percent

to a 75 percent capacity factor, on a net summer basis.[10] This dramatic increase in natural gas-fired generation will add significantly to the increased use of natural gas for power generation that has recently occurred due to cyclical market forces.

- **Generation from renewable power sources will increase significantly.** EPA's building block 3 analysis assumes that the United States has the potential to increase non-hydro renewable generation by a total of 706 TWh in the years 2022 through 2030, and EPA's analysis assumes that an increase of at least 540 TWh will be required during that time period to achieve the emission standards and state goals that comprise the CPP. To put this in perspective, this increase is more than twice the total generation from all non-hydro renewable power sources in 2014 of 248 TWh.[11] Those conclusions are based on the highly aggressive assumption that generation from each of five different renewable energy resources can increase at maximum historical rates for seven years straight during the interim compliance period.
- **Demand for electricity will grow less than would have been the case without the CPP.** Although not expressly required in the final CPP, and not accounted for in setting the CPP emission standards and state goals, EPA expects that the CPP will encourage states to mandate demand reduction programs to significantly reduce the demand for electricity. Indeed, EPA projects an unprecedented decline in electricity demand between 2020 and 2030. As noted, without that decline, the increase in renewable and gas-fired generation would be even greater, as would the reduction in coal generation.

B. EPA's Analysis of the Impacts of the CPP

EPA projected the impacts of the CPP on power generation, capacity, emissions, and compliance costs using the Integrated Planning Model ("IPM") developed by its consultant, ICF International. EPA also used the IPM as a critical element in evaluating the economic feasibility of its building blocks and the energy impacts of the rule, including the effect EPA's overall plan would have on the reliability of the interconnected grid.[12] EPA

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[10] The maximum generating capacity of a power plant can be stated using several different criteria, including nameplate capacity and net dependable capacity. The industry typically relies upon the net summer dependable capacity, which is frequently less than the net winter capacity due to atmospheric and cooling water conditions.

[11] EIA, Electric Power Monthly, February 2015, Tables 1.2 and 1.3, http://www.eia.gov/electricity/monthly/.

[12] See, e.g., EPA, Technical Support Document: Resource Adequacy and Reliability Analysis, 2015, http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

summarized the results of the IPM modeling analysis in its Regulatory Impact Analysis ("RIA").

In the RIA, EPA presented two scenarios designed to achieve the CPP: the "rate-based" plan and the "mass-based" plan.[13] These scenarios are designed for each state to comply with the corresponding state limits (rate-based and mass-based). The IPM model did not analyze the impact of interstate trading but did allow states to procure generation resources outside of the state and to use demand side energy efficiency measures to comply with the CPP.

The "Base Case" for the RIA analysis is a "business-as-usual" scenario expected by EPA under market and regulatory conditions in the absence of the CPP. EPA stated that it updates the IPM base case to reflect the latest electricity demand forecasts as well as expected costs and availability of existing and new generating resources.[14]

In the RIA, EPA provided the results of its IPM model forecast of the power industry under the base case, rate-based CPP compliance and mass-based CPP compliance for the years 2020, 2025, and 2030. As stated in the RIA, the IPM model results for the year 2025 reflect the impacts of complying with the Interim Goals and the model results for the year 2030 reflect the impacts of complying with the Final Goal.[15] The RIA also presents the IPM model results for the year 2020, which is prior to the first year of the compliance period, because "EPA expects states and affected EGUs to perform voluntary activities that will facilitate compliance with interim and final goals."[16]

The years 2020, 2025 and 2030 were selected for the RIA because they "reflect the basic run-year structure in IPM, as configured by EPA."[17] EPA did not run the IPM model for each year, but rather uses individual years to reflect the impacts on the power industry in multi-year periods, as stated by EPA in the model documentation:

> "Although IPM is capable of representing every individual year in an analysis time horizon, individual years are typically grouped into model run years to increase the speed of modeling. While the model makes decisions only for run years,

[13] EPA, "Regulatory Impact Analysis for the Clean Power Plan Final Rule", August 2015, page ES-3.
[14] Id, page 3-4.
[15] Id, page 3-12.
[16] Id, page ES-5.
[17] Id, page 3-12.

information on non-run years can be captured by mapping run years to the individual years they represent." [18]

Although not displayed in the RIA, the IPM model also calculated impacts for years prior to 2020 and after 2030. The IPM model run years and the mapping to analysis years are shown on Exhibit 5:

Exhibit 5: Mapping of IPM Model Run Years

IPM Model Run Year	Years Represented
2016	2016 – 2017
2018	2018
2020	2019 – 2022
2025	2023 – 2027
2030	2028 – 2033
2040	2034 – 2045
2050	2046 – 2054

EPA found that the proposed CPP would have the following impacts on coal-fired power generation in the years 2025 and 2030 compared to the base case (without the CPP):[19]

- Under the rate-based compliance scenario, coal-fired electricity generation would be 12% lower in 2025 and 23% lower in 2030 than the base case;
- Under the mass-based compliance scenario, coal-fired electricity generation would be 15% lower in 2025 and 22% lower in 2030 than the base case;
- Under the rate-based compliance scenario, coal-fired generating capacity would be 23,000 MW lower in 2025 and 27,000 MW lower in 2030 than the base case; and,
- Under the mass-based compliance scenario, coal-fired generating capacity would be 29,000 MW lower in 2025 and 38,000 MW lower in 2030 than the base case.

As noted, while EPA only presented the results for the model years 2020, 2025 and 2030 in the RIA, the supporting files available on EPA's website all contain the IPM model

[18] EPA, "Documentation for EPA Base Case v.5.13 using the Integrated Planning Model", November 2013, page 7-1, http://www.epa.gov/airmarkets/documents/ipm/Documentation.pdf.
[19] Id, pages 3-26 and 3-30.

results for the 7 model years shown above, including 2016 and 2018. The IPM model results of the power generation mix for the years 2016, 2018, 2020, 2025 and 2030 are summarized on Exhibit 6 for the base case and the rate-based compliance case.[20]

Exhibit 6: EPA Impact Analysis of the CPP on Power Generation Mix (thousand MWh)[21]

	Base Case					Rate-Based Compliance				
	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
Generation (billion kWh)										
Coal & Pet Coke	**1,335**	**1,389**	**1,448**	**1,410**	**1,443**	**1,309**	**1,329**	**1,379**	**1,241**	**1,116**
Coal	*1,323*	*1,378*	*1,437*	*1,395*	*1,427*	*1,297*	*1,318*	*1,367*	*1,231*	*1,106*
Waste Coal	*7*	*7*	*7*	*7*	*7*	*7*	*7*	*7*	*7*	*6*
Petroleum Coke	*6*	*4*	*5*	*8*	*10*	*6*	*4*	*6*	*4*	*3*
Natural Gas & Oil Total	**1,339**	**1,293**	**1,209**	**1,327**	**1,411**	**1,368**	**1,346**	**1,250**	**1,310**	**1,368**
NGCC existing	*1,249*	*1,196*	*1,111*	*1,152*	*1,042*	*1,274*	*1,222*	*1,126*	*1,206*	*1,230*
NGCC new	-	*18*	*33*	*113*	*324*	-	*39*	*53*	*53*	*100*
Combustion Turbine	*22*	*18*	*15*	*23*	*22*	*29*	*26*	*20*	*30*	*27*
Oil/Gas Steam	*67*	*62*	*51*	*39*	*22*	*65*	*59*	*51*	*21*	*11*
Non-Hydro Renewables	**316**	**388**	**406**	**436**	**473**	**315**	**394**	**410**	**429**	**504**
Wind	*216*	*297*	*299*	*309*	*312*	*216*	*304*	*305*	*311*	*313*
Solar	*29*	*30*	*39*	*49*	*76*	*29*	*30*	*39*	*45*	*114*
Geothermal	*17*	*17*	*22*	*25*	*27*	*17*	*17*	*22*	*25*	*27*
Landfill Gas	*11*	*11*	*11*	*11*	*11*	*11*	*11*	*11*	*11*	*11*
Biomass	*23*	*21*	*22*	*23*	*25*	*23*	*22*	*23*	*22*	*23*
Biomass Co-firing	*19*	*12*	*14*	*18*	*23*	*19*	*11*	*11*	*15*	*15*
Hydro	**283**	**284**	**310**	**340**	**340**	**283**	**284**	**311**	**340**	**341**
Conventional Hydro	*272*	*273*	*300*	*331*	*331*	*272*	*273*	*300*	*330*	*331*
Pumped Storage	*10*	*11*	*10*	*9*	*10*	*11*	*11*	*11*	*10*	*11*
Nuclear	**767**	**764**	**798**	**799**	**783**	**761**	**758**	**792**	**791**	**777**
Other	**18**	**18**	**18**	**17**	**17**	**18**	**18**	**18**	**17**	**17**
Municipal Solid Waste	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*
Other	*10*	*10*	*10*	*10*	*9*	*11*	*10*	*10*	*10*	*9*
Total	**4,057**	**4,136**	**4,190**	**4,328**	**4,467**	**4,055**	**4,130**	**4,160**	**4,128**	**4,122**
New Energy Efficiency						-	-	25	207	348

As shown on Exhibit 6, EPA's IPM model projects that the power generation mix will change immediately in 2016 due to the impact of the CPP, as the power industry will make changes to their business plans immediately to reflect their long-term decisions for compliance with the CPP. Coal generation in the 2016 model year (reflecting 2016 and 2017) is projected by IPM to be 2.0% lower in the rate-based compliance case than in the

[20] EPA, IPM model documentation and run files, system support resources, "Base Case SSR.xls" and "Rate-Based SSR.xls", Summary and Tables 1-16 tabs, available at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

[21] Note: The results are the same as shown in the RIA Table 3-11, with additional detail shown in italics, except that the generation from biomass co-firing in coal units is included with Non-Hydro Renewables rather than with coal generation.

base case, and is projected to be 4.3% lower in 2018 (which is both a model run year and the same forecast year).

IPM also projects that a significant number of coal-fired EGUs will retire immediately in 2016 due to the CPP. As shown on Exhibit 7, IPM projects that there will be 10,793 MW less coal-fired generating capacity in 2016 under the rate-based approach to the CPP than in the base case without the CPP.

The IPM model results of generation capacity for the years 2016, 2018, 2020, 2025 and 2030 are presented on Exhibit 7 for the base case and the rate-based compliance case.[22]

Exhibit 7: EPA Impact Analysis of the CPP on Generation Capacity (thousand MW)[23]

	Base Case					Rate-Based Compliance				
	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
Generation Capacity (1000 MW)										
Coal	**214**	**208**	**208**	**208**	**207**	**203**	**196**	**195**	**187**	**183**
Natural Gas & Oil Total	**463**	**467**	**466**	**473**	**506**	**456**	**459**	**456**	**447**	**452**
NGCC existing	*231*	*233*	*233*	*233*	*233*	*230*	*231*	*231*	*231*	*231*
NGCC new	*-*	*2*	*4*	*15*	*44*	*-*	*5*	*7*	*7*	*14*
Combustion Turbine	*140*	*140*	*141*	*143*	*147*	*137*	*137*	*137*	*138*	*138*
Oil/Gas Steam	*92*	*92*	*88*	*82*	*82*	*90*	*86*	*81*	*71*	*70*
Non-Hydro Renewables	**102**	**124**	**130**	**139**	**154**	**102**	**126**	**132**	**137**	**174**
Wind	*77*	*99*	*100*	*103*	*103*	*77*	*101*	*101*	*103*	*104*
Solar	*16*	*16*	*21*	*26*	*40*	*16*	*16*	*21*	*24*	*60*
Geothermal	*3*	*3*	*3*	*4*	*4*	*3*	*3*	*3*	*4*	*4*
Landfill Gas	*2*	*2*	*2*	*2*	*2*	*2*	*2*	*2*	*2*	*2*
Biomass	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*
Hydro	**101**	**101**	**106**	**112**	**112**	**101**	**101**	**106**	**112**	**112**
Conventional Hydro	*79*	*79*	*84*	*90*	*90*	*79*	*79*	*84*	*90*	*90*
Pumped Storage	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*
Nuclear	**97**	**96**	**100**	**100**	**99**	**96**	**95**	**100**	**99**	**98**
Other	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Total	**982**	**1,002**	**1,016**	**1,037**	**1,082**	**963**	**982**	**994**	**988**	**1,025**
New Energy Efficiency	-	-	-	-	-	-	-	9	79	132

[22] EPA, IPM model documentation and run files, system support resources, "Base Case SSR.xls" and "Rate-Based SSR.xls", Summary and Tables 1-16 tabs, available at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

[23] Note: The results are the same as shown in the RIA Table 3-12, with additional detail shown in italics, including the "capacity" from new demand reduction shown in the last line.

C. EIA's Analysis of the Impacts of the Proposed CPP

The U.S. Department of Energy's Energy Information Administration ("EIA") issued its analysis of the proposed CPP in a report "Analysis of the Impacts of the Clean Power Plan" in May 2015. EIA was created by Congress to monitor the energy industry and energy market trends and, as a part of that mission, "collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment."[24] This information is widely used by policymakers and business. EIA has not yet had time to examine EPA's final CPP, but its analysis of the proposed CPP is useful because the final CPP is more stringent than the proposed CPP, requiring 9 percent more emission reductions as compared with the proposed rule. Thus, EIA's analysis can be used as a conservative, low-end forecast of the effects of the final CPP. The impacts projected by EIA were also very similar to those projected by EPA in EPA's analysis of the proposed rule.

As shown on Exhibit 8, EIA projected the impact in the year 2020 of the proposed CPP to its base case forecast in its Annual Energy Outlook ("AEO") and found that:

- Coal-fired electricity generation would be 22% lower than the AEO base case;
- Generation from natural gas and renewables would be 24% and 16% higher than the AEO base case, respectively, replacing coal-fired generation;
- Total generation would be 1.0% lower than the AEO base case, due to lower demand for electricity;
- 8,000 MW of new natural gas-fired NGCC capacity would be built; and,
- 46,000 MW of coal-fired generation capacity would be closed in 2020, 17.5% of the total coal fleet, which EIA had already projected would be 41,000 MW smaller than it was in 2013 due to coal-fired plant retirements for other reasons (including the impact of other EPA regulations).

[24] About EIA at http://www.eia.gov/about/; http://www.eia.gov/about/legislative_timeline.cfm.

Exhibit 8: U.S. EIA Analysis of the Impacts of the Proposed CPP[25]

	Actual 2005	Actual 2013	2020 Forecast AEO	2020 Forecast CPP	Impacts of CPP
Generation (billion kWh)					
Coal	2,013	1,586	1,709	1,340	(369)
Natural Gas	761	1,118	1,117	1,382	265
Nuclear	782	789	804	804	-
Hydro	270	267	292	295	3
Renewables	87	263	386	446	60
Oil/other	142	47	43	41	(2)
Total	**4,055**	**4,070**	**4,351**	**4,308**	**(43)**
Generation Capacity (1000 MW)					
Coal	313	304	263	217	(46)
Natural Gas/Oil	442	470	482	490	8
Nuclear	100	99	101	101	-
Hydro	78	79	80	80	-
Renewables	21	88	127	151	24
Other	24	25	26	26	-
Total	**978**	**1,065**	**1,079**	**1,065**	**(14)**

D. Impact of EPA Changes to the IPM Base Case

Prior to analyzing the impact of the final CPP, EPA "updated" the IPM model from the version used to analyze the impacts of the proposed rule (v.5.13). According to EPA:

> "These updates are primarily routine calibrations with the Energy Information Agency's (EIA) Annual Energy Outlook (AEO), including updating the electric demand forecast consistent with the AEO 2015 and an update to natural gas supply. Additional updates, based on the most up-to-date information and/or public comments received by the EPA, include unit-level specifications (e.g., pollution control configurations), planned power plant construction and closures, and updated cost and performance for onshore wind and utility-scale solar technologies. This IPM modeling platform incorporates federal and most state laws and regulations whose provisions were either in effect or enacted and clearly delineated in March 2015. This update also includes two non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule and Combustion Residuals from Electric Utilities (CCR). Additionally, all new capacity projected by the model is compliant with Clean Air Act 111(b) standards, including the final standards of performance for GHG emissions from new sources."

[25] U.S. Energy Information Administration, "Analysis of the Impacts of the Clean Power Plan", May 2015, page 23.

EPA's explanation of its "updates," however, is misleading. Far from "routine calibrations", the changes made to IPM in the Base Case were far-reaching and served to minimize the impacts attributed to the final CPP. As shown on Exhibit 9, the projected generation capacity changes were:

- A massive increase in expected renewable generation capacity (wind, solar and hydro) by 21 GW immediately in 2016, growing to 57 GW by 2030;
- Corresponding large reductions in coal-fired capacity by 31 GW immediately in 2016 and by 36 GW from 2018 to 2025; and,
- Lower projected capacity of gas-fired combined cycle plants by 15 GW in 2025 and 35 GW 2030.

As an example of the changes EPA made to its modeling platform between the proposed CPP and the final CPP, in the proposed CPP, Monticello Units 1 and 2 (two 556 MW units in Texas) were modeled as retired as a result of EPA's rate-based goal.[26] However, in its final CPP modeling, without explanation, EPA treats Monticello Units 1 and 2 as already retired before 2016—and does not even include them in its 2016 base case. But Monticello is still operating as reflected in the proposed rule base case, and, were it properly treated in the final rule modeling, EPA's modeling should show Monticello as shut down as a result of the final CPP.

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[26] Comments of Luminant Generation Company, LLC on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Appendix H, Docket EPA-HQ-OAR-2013-0602=33559, http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-33559.

Exhibit 9: Changes to Generation Capacity in the IPM Base Case between the Proposed and Final Rule[27]

	Proposed Rule Base Case					Final Rule Base Case				
	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
Generation Capacity (1000 MW)										
Coal	**245**	**243**	**244**	**244**	**240**	**214**	**208**	**208**	**208**	**207**
Natural Gas & Oil Total	**457**	**458**	**460**	**489**	**541**	**463**	**467**	**466**	**473**	**506**
NGCC existing	*219*	*219*	*219*	*219*	*219*	*231*	*233*	*233*	*233*	*233*
NGCC new	*4*	*7*	*12*	*39*	*84*	-	*2*	*4*	*15*	*44*
Combustion Turbine	*146*	*146*	*146*	*149*	*156*	*140*	*140*	*141*	*143*	*147*
Oil/Gas Steam	*88*	*85*	*83*	*82*	*82*	*92*	*92*	*88*	*82*	*82*
Non-Hydro Renewables	**81**	**90**	**92**	**103**	**107**	**102**	**124**	**130**	**139**	**154**
Wind	*64*	*71*	*72*	*80*	*84*	*77*	*99*	*100*	*103*	*103*
Solar	*8*	*9*	*10*	*11*	*11*	*16*	*16*	*21*	*26*	*40*
Geothermal	*3*	*4*	*4*	*5*	*5*	*3*	*3*	*3*	*4*	*4*
Landfill Gas	*2*	*2*	*2*	*2*	*2*	*2*	*2*	*2*	*2*	*2*
Biomass	*4*	*5*	*5*	*5*	*5*	*4*	*4*	*4*	*4*	*4*
Hydro	**101**	**101**	**101**	**101**	**101**	**101**	**101**	**106**	**112**	**112**
Conventional Hydro	*79*	*79*	*79*	*79*	*79*	*79*	*79*	*84*	*90*	*90*
Pumped Storage	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*
Nuclear	**99**	**103**	**103**	**103**	**101**	**97**	**96**	**100**	**100**	**99**
Other	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Total	**988**	**1,000**	**1,005**	**1,044**	**1,095**	**982**	**1,002**	**1,016**	**1,037**	**1,082**

The changes in the base case power generation mix were equally dramatic, as shown on Exhibit 10. These Exhibit 10 figures reflects changes in actual electric production by different types of power generation, in contrast to the Exhibit 9 figures, which represent electric generation capacity, not actual generation from that capacity. The changes in total generation due to "updating the electric demand forecast consistent with the AEO 2015" were actually very small, less than 1.0% through 2020, rising to 2.0% by 2030. In contrast, the changes that EPA made to its forecast of the mix of generation in its base case included:

- Lower coal generation by 12% - 16% throughout the forecast period;
- Increased gas generation by 18% immediately in 2016, falling to a slight decline by 2030; and,
- Huge increases in renewable power generation throughout the period, rising by 2030 to increases of 35% for wind, 22% for hydro and 308% for solar power.

[27] EPA, IPM model documentation and run files, system support resources, "Base Case SSR.xls", Summary and Tables 1-16 tabs, for Base Case v.5.15 and v.5.13, http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html and http://www.epa.gov/airmarkets/programs/ipm/psmodel.html.

Exhibit 10: Changes to Generation Forecast in the IPM Base Case between the Proposed and Final Rule[28]

	Proposed Rule Base Case					Final Rule Base Case				
	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
Generation (billion kWh)										
Coal & Pet Coke	**1,577**	**1,654**	**1,648**	**1,683**	**1,648**	**1,335**	**1,389**	**1,448**	**1,410**	**1,443**
Coal	*1,561*	*1,637*	*1,629*	*1,661*	*1,626*	*1,323*	*1,378*	*1,437*	*1,395*	*1,427*
Waste Coal	*9*	*9*	*9*	*9*	*9*	*7*	*7*	*7*	*7*	*7*
Petroleum Coke	*7*	*8*	*9*	*13*	*13*	*6*	*4*	*5*	*8*	*10*
Natural Gas & Oil Total	**1,139**	**1,082**	**1,158**	**1,263**	**1,454**	**1,339**	**1,293**	**1,209**	**1,327**	**1,411**
NGCC existing	*1,038*	*964*	*1,003*	*920*	*811*	*1,249*	*1,196*	*1,111*	*1,152*	*1,042*
NGCC new	*29*	*52*	*84*	*279*	*598*	-	*18*	*33*	*113*	*324*
Combustion Turbine	*16*	*13*	*19*	*27*	*23*	*22*	*18*	*15*	*23*	*22*
Oil/Gas Steam	*56*	*54*	*52*	*37*	*23*	*67*	*62*	*51*	*39*	*22*
Non-Hydro Renewables	**256**	**282**	**299**	**335**	**350**	**316**	**388**	**406**	**436**	**473**
Wind	*174*	*195*	*197*	*221*	*232*	*216*	*297*	*299*	*309*	*312*
Solar	*14*	*16*	*17*	*18*	*19*	*29*	*30*	*39*	*49*	*76*
Geothermal	*17*	*24*	*27*	*34*	*36*	*17*	*17*	*22*	*25*	*27*
Landfill Gas	*11*	*11*	*11*	*11*	*11*	*11*	*11*	*11*	*11*	*11*
Biomass	*23*	*25*	*29*	*31*	*32*	*23*	*21*	*22*	*23*	*25*
Biomass Co-firing	*16*	*11*	*19*	*20*	*21*	*19*	*12*	*14*	*18*	*23*
Hydro	**278**	**279**	**280**	**280**	**280**	**283**	**284**	**310**	**340**	**340**
Conventional Hydro	*270*	*270*	*270*	*270*	*270*	*272*	*273*	*300*	*331*	*331*
Pumped Storage	*8*	*9*	*9*	*10*	*10*	*10*	*11*	*10*	*9*	*10*
Nuclear	**784**	**820**	**817**	**817**	**797**	**767**	**764**	**798**	**799**	**783**
Other	**26**	**26**	**26**	**25**	**27**	**18**	**18**	**18**	**17**	**17**
Municipal Solid Waste	*14*	*14*	*14*	*14*	*14*	*8*	*8*	*8*	*8*	*8*
Other	*12*	*12*	*12*	*11*	*13*	*10*	*10*	*10*	*10*	*9*
Total	**4,060**	**4,143**	**4,227**	**4,404**	**4,557**	**4,057**	**4,136**	**4,190**	**4,328**	**4,467**

[28] Ibid.

E. Comparison of the IPM Base Case and EIA Annual Energy Outlook

One of the most influential EIA publications is its Annual Energy Outlook, which is a projection of U.S. energy markets through 2040. Its latest "AEO" is AEO2015. As stated by EIA:

> "Projections in the *Annual Energy Outlook 2015* (AEO2015) focus on the factors expected to shape U.S. energy markets through 2040. The projections provide a basis for examination and discussion of energy market trends and serve as a starting point for analysis of potential changes in U.S. energy policies, rules, and regulations, as well as the potential role of advanced technologies"[29]

The AEO2015 reference case is EIA's base case, which it uses to project changes to the energy sector that a given set of policy changes would cause. AEO2015 thus does not include the impacts of the CPP, as stated by EIA:

> "The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan."[30]

EIA's forecast of electricity capacity and generation in the AEO2015 reference case is shown on Exhibit 11.

[29] EIA, Annual Energy Outlook 2015 at http://www.eia.gov/forecasts/aeo/.
[30] EIA, Annual Energy Outlook 2015 at http://www.eia.gov/forecasts/aeo/preface.cfm.

Exhibit 11: EIA AEO 2015 Forecast of Capacity and Generation[31]

	2012	2013	2016	2018	2020	2025	2030
Capacity (MW)							
Coal	**305**	**300**	**266**	**261**	**260**	**257**	**257**
Natural Gas & Oil Total	**451**	**452**	**467**	**470**	**461**	**465**	**489**
Combined Cycle	211	214	227	232	229	238	260
Combustion Turbine	140	143	143	144	143	147	155
Oil/Gas Steam	100	96	97	94	89	79	74
Non-Hydro Renewables	**71**	**76**	**106**	**108**	**109**	**112**	**118**
Wind	59	60	80	82	82	83	86
Solar	3	6	16	16	16	16	17
Geothermal	3	3	3	3	4	5	7
Other	6	7	7	7	7	7	7
Hydro	**101**	**101**	**101**	**102**	**102**	**102**	**102**
Conventional Hydro	78	78	79	79	79	80	80
Pumped Storage	22	22	22	22	22	22	22
Nuclear	**102**	**99**	**100**	**100**	**101**	**101**	**102**
Total	**1,029**	**1,029**	**1,040**	**1,042**	**1,034**	**1,038**	**1,069**
Generation (GWh)							
Coal	**1,500**	**1,572**	**1,549**	**1,600**	**1,696**	**1,711**	**1,700**
Natural Gas & Oil Total	**1,152**	**1,044**	**1,096**	**1,074**	**1,015**	**1,103**	**1,222**
Natural Gas	*1,132*	*1,020*	*1,073*	*1,053*	*1,000*	*1,087*	*1,207*
Petroleum	*20*	*24*	*23*	*21*	*15*	*16*	*15*
Non-Hydro Renewables	**189**	**222**	**297**	**321**	**335**	**362**	**393**
Wind	*141*	*168*	*219*	*230*	*231*	*234*	*243*
Solar	*4*	*9*	*28*	*33*	*33*	*34*	*36*
Geothermal	*16*	*17*	*17*	*19*	*27*	*38*	*52*
Other	*28*	*29*	*34*	*39*	*45*	*56*	*61*
Hydro	**276**	**269**	**273**	**293**	**294**	**296**	**296**
Conventional Hydro	*274*	*266*	*270*	*290*	*291*	*293*	*293*
Pumped Storage	*2*	*3*	*3*	*3*	*3*	*3*	*3*
Nuclear	**769**	**789**	**781**	**798**	**804**	**808**	**808**
Total	**3,886**	**3,896**	**3,996**	**4,086**	**4,145**	**4,281**	**4,420**

The differences between EPA's base case in IPM for the final rule and the EIA AEO2015 reference case, shown on Exhibit 12, are startling. Beginning immediately in 2016 and continuing through the base case forecast, EPA projects 52 GW less coal-fired generation capacity. EPA's base case replaces these retirements, in part, with increased capacity and generation from renewables (wind, solar, and hydro). EPA also projects increased generation from natural gas power plants to displace coal generation in 2016 and throughout the forecast period.

[31] EIA Annual Energy Outlook 2015 beta browser at http://www.eia.gov/beta/aeo/.

Exhibit 12: Differences between the EPA and EIA Base Case[32]

	2016	2018	2020	2025	2030	2040
Capacity (MW)						
Coal	(52)	(54)	(52)	(49)	(50)	(54)
Natural Gas & Oil Total	(3)	(3)	5	9	17	28
Non-Hydro Renewables	(4)	16	21	27	35	228
Hydro	0	(0)	5	10	10	10
Nuclear	(4)	(4)	(1)	(1)	(3)	(46)
Other	5	4	4	4	3	2
Total	**(58)**	**(40)**	**(18)**	**(1)**	**13**	**168**
Generation (GWh)						
Coal	(214)	(211)	(248)	(301)	(257)	(399)
Natural Gas & Oil Total	243	219	194	224	189	376
Non-Hydro Renewables	19	67	71	73	80	387
Hydro	9	(9)	16	44	44	37
Nuclear	(14)	(34)	(6)	(9)	(25)	(358)
Other	18	18	17	16	16	15
Total	**61**	**50**	**45**	**47**	**47**	**60**

By using a much lower forecast of coal generation in its base case, EPA has significantly reduced the impact on coal generation attributed to the CPP, as compared with the impacts that would have been predicted had EPA not changed the base case and as compared with the impacts that would have been predicted had EPA used the EIA AEO2015 reference case. Because the CPP effectively caps coal generation in order to achieve the Interim and Final Goals, both the coal generation retirements in EPA's base case and the coal generation retirements in its regulatory cases are necessary for compliance. Had EPA used the EIA AEO2015 forecast as its base case, with its much lower number of coal retirements, the amount of coal retirements attributable to the CPP would have been about 50 GW greater.

The much greater number of coal retirements in EPA's base case as compared to AEO2015 is completely unjustified. The large incremental number of units that EPA counts as retiring between now and the beginning of its base case (2016), as compared with AEO2015, cannot be accounted for by utility announcements of further retirements since AEO2015 was issued. EPA's 2012 Mercury and Air Toxics Standards ("MATS") rule

[32] EIA Annual Energy Outlook 2015 beta browser at http://www.eia.gov/beta/aeo/. EPA IPM model documentation and run files, system support resources, "Base Case SSR.xls", Summary and Tables 1-16 tabs, for Base Case v.5.15, http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

caused a large number of retirements, but these were accounted for in AEO2015, and EPA does not claim that MATS caused more units to retire than were included in AEO2015. Given that utilities will have been required to announce plans to close units at the beginning of 2016 long before now, it is not possible that the additional retirements that EPA has included in its 2016 base case will actually occur absent the CPP.

F. Comparison of the IPM CPP Case and EIA Annual Energy Outlook

In the short amount of time since EPA's issuance of the CPP, analysis firms, including EVA, have not had sufficient time to perform detailed modeling analyses of the final rule. But a good surrogate exists that corrects for the arbitrary changes EPA made to its base case. It is possible to compute the difference between the EIA AEO2015 reference case forecast, a true "base case" reflecting the projected mix of electric resources absent the CPP, and the EPA IPM forecast of what the mix of resources will be given compliance with the CPP. This likely understates impacts, as the IPM model historically has understated the impact of EPA's rules.[33] Nevertheless this comparison provides a useful initial and likely understated projection of impacts. The results are shown on Exhibit 13, using the rate-based goals analysis in the RIA (impacts are slightly greater using the mass-based goals). This comparison shows:

- Decline in coal generation of 15% in 2016, growing to a decline of 34% by 2030;
- Lower coal generating capacity (retirements) of 63 GW (24%) in 2016, growing to 74 GW (29%) in 2030;
- Increased generation from natural gas of 25% in 2016, declining to 12% by 2030;
- Increased generation from non-hydro renewables of 6% in 2016, growing to 28% by 2030;
- Increased generation from hydroelectricity of 6% in 2020, growing to 15% by 2030; and,
- Reduced total generation of 7% by 2030 due to demand reduction.

[33] For instance, EPA used IPM to predict that the MATS rule would retire less than 5 GW of coal-fired capacity, yet the actual figure turned out to be about ten times that amount.

Exhibit 13: Impact of the CPP Compared to the EIA AEO 2015[34]

	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
Generation (billion kWh)										
Coal	(240)	(271)	(317)	(470)	(584)	-15%	-17%	-19%	-27%	-34%
Natural Gas & Oil Total	272	272	235	207	146	25%	25%	23%	19%	12%
Non-Hydro Renewables	19	74	75	66	111	6%	23%	22%	18%	28%
Hydro	10	(9)	17	44	45	4%	-3%	6%	15%	15%
Nuclear	(20)	(40)	(12)	(17)	(31)	-3%	-5%	-2%	-2%	-4%
Other	18	18	17	16	16	NA	NA	NA	NA	NA
Total	**59**	**44**	**15**	**(153)**	**(298)**	**1%**	**1%**	**0%**	**-4%**	**-7%**
Generation Capacity (1000 MW)										
Coal	(63)	(66)	(65)	(70)	(74)	-24%	-25%	-25%	-27%	-29%
Natural Gas & Oil Total	(11)	(11)	(5)	(18)	(36)	-2%	-2%	-1%	-4%	-7%
Non-Hydro Renewables	(4)	18	23	25	56	-4%	16%	21%	22%	47%
Hydro	0	(0)	5	10	10	0%	0%	5%	10%	10%
Nuclear	(5)	(5)	(2)	(2)	(4)	-5%	-5%	-2%	-2%	-4%
Other	5	4	4	4	3	NA	NA	NA	NA	NA
Total	**(78)**	**(60)**	**(40)**	**(50)**	**(45)**	**-7%**	**-6%**	**-4%**	**-5%**	**-4%**

Additionally, and importantly, EPA projects that the CPP will cause electricity demand to decline compared to the EIA AEO2015 forecast and even to steadily decline after 2020. EPA thinks that states will implement programs that provide subsidies for end use consumers to reduce electric consumption. Some states already operate these types of program, but none operate at the level EPA projects under the CPP and none have led to actual reductions in electricity demand. Exhibit 14 shows the EIA AEO2015 forecast of electric power generation compared to EPA's base case forecast and EPA's forecast under the rate-based compliance case.[35]

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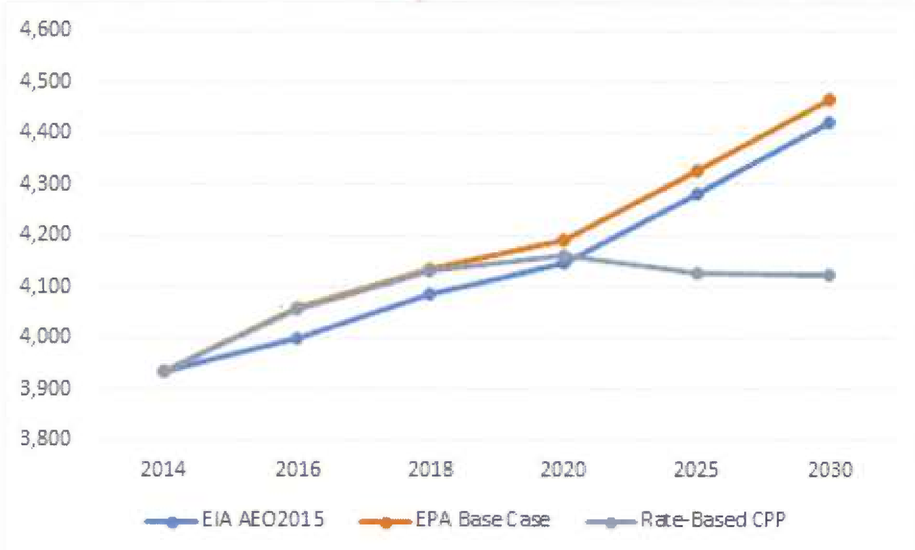
[34] EIA Annual Energy Outlook 2015 beta browser at http://www.eia.gov/beta/aeo/. EPA IPM model documentation and run files, system support resources, "Base Case SSR.xls", Summary and Tables 1-16 tabs, for Base Case v.5.15, http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

[35] The slight difference between the EIA AEO2015 forecast and the EPA base case forecast is not explained but could be due to EPA including some industrial power plants in its IPM model.

Exhibit 14: Power Generation Forecasts under EIA AEO2015 and EPA IPM Model Base and CPP Cases (thousand GWh)[36]



Even assuming EPA's projection of an unprecedented reduction in electricity demand occurs, the CPP will transform the power industry's supply of electric power by fuel source. Exhibit 15 shows the share of generation and generating capacity in 2020 under the AEO2015 Reference Case compared to EPA's projections for 2030 under the Rate-Based CPP Case. Assuming EPA's forecast of reduced electric demand is correct, the share of electricity supplied by coal will drop from 41% in 2020 to just 27% in 2030. Coal generation will be replaced by natural gas and renewables.

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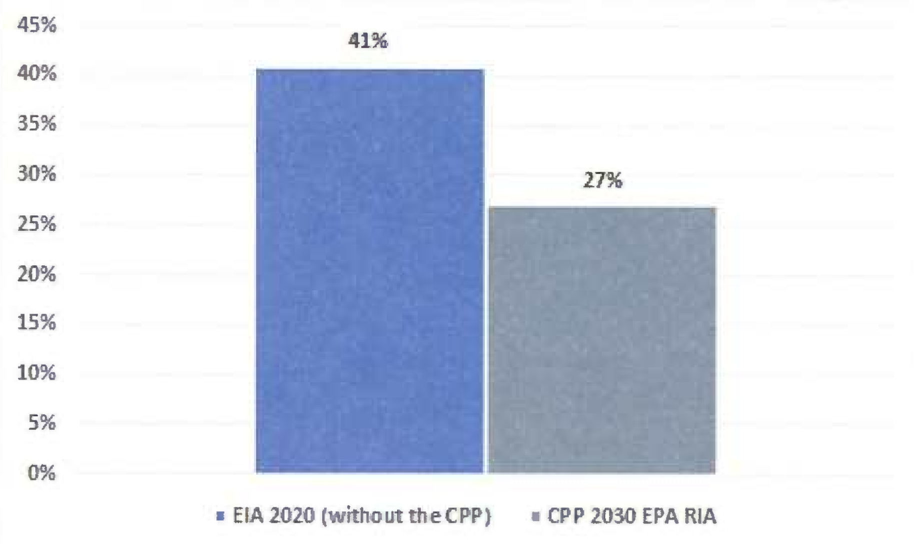
[36] Actual 2014 power sector generation from Electric Power Monthly July 2015 at http://www.eia.gov/electricity/monthly/. EIA AEO2015 forecast at http://www.eia.gov/beta/aeo/. EPA, IPM model documentation and run files, system support resources, "Base Case SSR.xls" and "Rate-Based SSR.xls", Summary tab, at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

Exhibit 15: Share of Power Supply from Coal under EIA AEO2015 and Projected CPP[37]

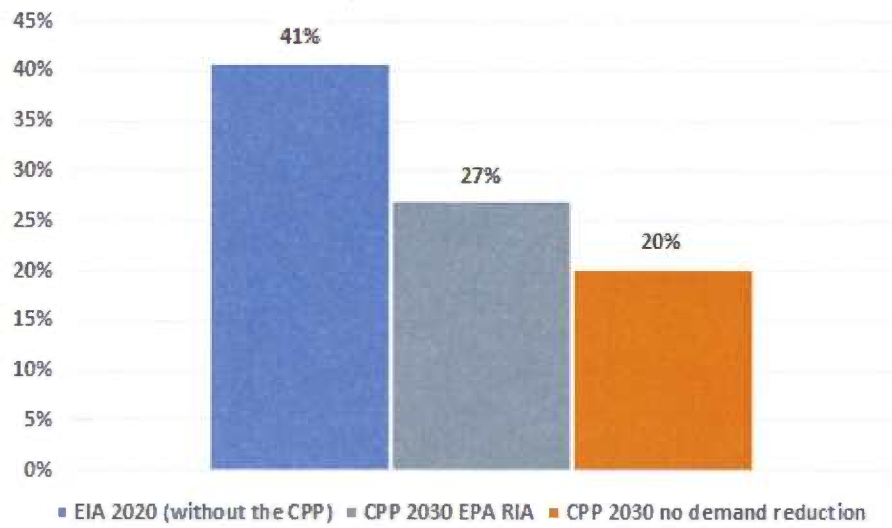


If the unprecedented demand reduction projected by EPA does not occur, the changes in electric generation mix would be even more pronounced. In order for states to continue to meet the CO_2 reduction requirements that EPA has set for them, the demand that is not reduced as EPA projects would have to be met by increased generation from non-coal sources, either carbon-free sources, like renewables or lower-carbon natural gas generation. Since EPA's building block for renewables already assumes extremely high levels of growth in renewables, it is likely that this demand would be met by natural gas generation. However, increasing natural gas generation would increase CO_2 emissions. These increases in CO_2 emissions would have to be met by a further reduction in coal generation, even though emissions from new gas units are less than the coal units which they would replace.

Using all of EPA's assumptions for meeting the 2030 rate-based goals, but assuming that EPA's projected demand reductions would have to be met by increased gas generation from efficient new NGCC units, the impact on coal generation is shown on Exhibit 16. The share of electricity demand supplied by coal generation would fall from 41% (projected by EIA AEO2015 in 2020 without the CPP) to just 20% in 2030.

[37] EIA AEO2015 forecast at http://www.eia.gov/beta/aeo/. EPA, IPM model documentation and run files, system support resources, "Rate-Based SSR.xls", Table 1-16 tab, at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

Exhibit 16: Coal's Share of Power Supply under EIA AEO2015 in 2020 and CPP in 2030 with no Demand Reduction



The CPP will cause the share of power generation provided by coal-fired plants to fall to levels far below anything recorded since EIA began keeping records in 1949. From 1949 to 2014, the share of power generated from coal always has been between 39% and 56%. EIA's AEO2015 forecast projects that, without the CPP, coal will continue to supply 38% - 41% of total generation from 2015 through 2030.[38] Including the effect of its lower base case, EPA projects that the CPP will cause the share of power to be supplied by coal to drop precipitously to 33% at the beginning of the CPP and fall to just 27% of generation by 2030 (this share is boosted by the assumption of lower generation due to demand reduction). If demand is not reduced as EPA projects, coal's share of generation would have to fall to just 20% (half of its lowest historical level) to meet EPA's CO_2 emission goals.

EPA relies upon projections of huge growth in generation from renewable energy sources (primarily wind and solar) to achieve its emission reduction targets under the CPP. EPA set the BSER (and the resulting state goals) for existing EGUs in large part by assuming that their generation would be displaced by generation from incremental (additions above the base amount) renewable energy, which it called Building Block 3. EPA based its determination of the amount of incremental renewable energy generation which could be supplied by using the historical annual growth in renewable capacity from 2010 – 2014.

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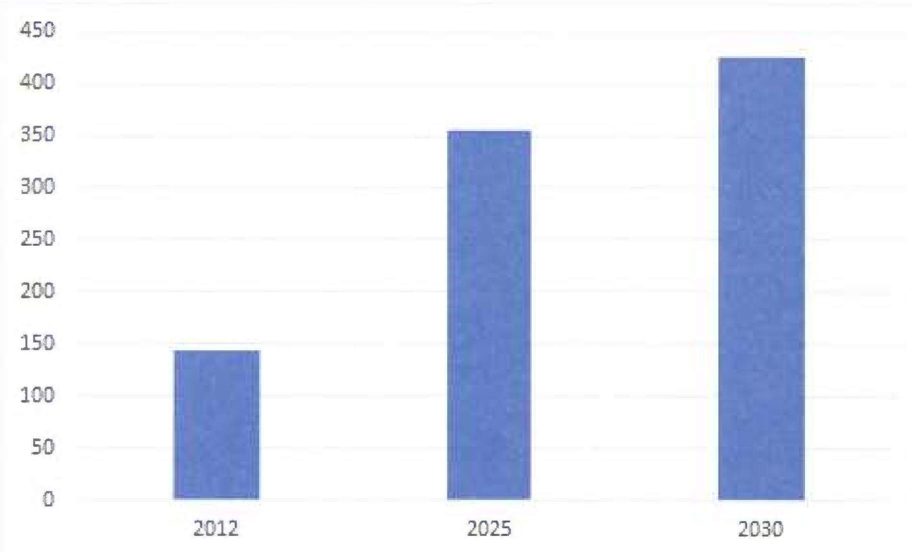
[38] Historical data from EIA Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector, EIA Total Energy browser at http://www.eia.gov/beta/MER/?tbl=T07.02B#/?f=A. EIA AEO2015 forecast at http://www.eia.gov/beta/aeo/.

EPA started with the base amount of renewable generation in 2022 projected by its IPM model and added to that base the average annual historical growth in capacity (times an assumed capacity factor) through 2024, then added the *maximum* historical annual increase for each renewable technology in every year after 2024.[39]

Exhibit 17 shows EPA's projected increase in wind and solar renewable generation under its rate-based CPP compliance case. EPA projects that wind and solar electricity generation will triple from 145 GWh in 2012 to 427 GWh in 2030.

Exhibit 17: EPA Projected Wind and Solar Generation under CPP Rate-Based Compliance (GWh)[40]



[39] EPA, GHG Mitigation Measures Technical Support Document, pages 4-1 to 4-6.
[40] EPA, IPM model documentation and run files, system support resources, "Rate-Based SSR.xls", Table 1-16 tab, at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html. Historical 2012 data from EIA Annual Energy Outlook 2015 beta browser at http://www.eia.gov/beta/aeo/.

III. Explaining the Immediate Impacts of the CPP on the Electric Power Industry

The CPP is a wide-ranging rule which will affect every aspect of the electric power industry, including generation, transmission, and retail sales. Most notably, the CPP is intended to change the country's electricity generation mix by reducing the amount of generation from coal-fired EGUs and replacing it with increased generation from sources with lower CO_2 emissions, primarily natural gas-fired EGUs and renewable generation resources, as well as reducing electric demand. To comply, the electric power industry will need to deploy new electricity generation resources, by constructing new NGCC and renewable power plants and implementing subsidized demand-reduction programs, while retiring existing coal-fired capacity. The industry will also need to construct new transmission lines to account for the dramatic shift in generation required by the CPP. This section describes the process and timing for the power industry to make the decisions and investments necessary to comply with the CPP, which explains why impacts associated with the rule will begin immediately, even though compliance is not required until the interim period begins in 2022.

A. Electric Power Industry Decision Process for Generation Investment

To generate and deliver electric power to customers, the electric power industry must engage in three principal activities:

- **Generation:** The production of electricity at a power plant (fossil fuel, nuclear, or renewable);
- **Transmission:** The bulk transfer of electricity at high voltage from power plants to distribution networks; and
- **Distribution:** The retail delivery of electricity to customers.

The economics of generation of electricity are driven by the economies of scale; it is more economic and efficient to generate electricity from large power plants. The size of new power projects is huge, with the typical generating capacity in hundreds of megawatts ("MW"): coal (400-800 MW), NGCC (300-1,200 MW), nuclear (800-1,200 MW), and wind farms (50-300 MW). One thousand MW will power approximately 800,000 homes. The construction costs for these projects are enormous, ranging from at least $100 million to over $5 billion in the case of the new nuclear plants. As a result, the construction of a new power plant involves long lead times for planning, permitting, and construction.

The principal ownership model for electric generating resources is a vertically-integrated regulated power company. These companies own the generation, transmission, and distribution systems to supply their customers. They are regulated monopolies with a defined service territory and an obligation to serve their customers' electricity demand within that territory. They have regulated rates, based upon the cost of service and a return on capital for the investment required to supply their customers. State authorities regulate electricity rates through public utility commissions. The ownership of regulated utilities includes investor-owned companies (the largest category of electric utilities), electric cooperatives (owned by their ratepayers), municipal utilities (owned by local governments), state agencies, and federal agencies.

The other major category of electric power companies are independent power producers, which generate and sell electricity at the wholesale level. Wholesale power is regulated by the Federal Energy Regulatory Commission ("FERC"). These companies build and own power plants that sell power to the wholesale grid, which is operated by independent system operators that supply retail power companies (utilities and retail marketers). Independent power producers are typically investor-owned companies who rely on revenues from the sale of wholesale power and do not supply retail customers.

In 2014, electric utilities (including investor-owned companies, cooperatives, and public entities) generated 2,381 million MWh of electricity (60.5% of the total), while independent power producers generated 1,554 million MWh (39.5%). Both utilities and independent power producers will be affected by the CPP.

The decision to build a new power plant is complex due to the number of applicable regulations, permits required and necessary approvals.[41] In most cases, construction of a new power plant requires submission of an application to a state agency with the authority to approve or disapprove the siting decision (in most states, through issuance of a Certificate of Public Convenience and Necessity, or CPCN). The independent system operator, which manages the wholesale transmission system, will also require a

[41] Generators in competitive markets face additional hurdles to development of generation resources. Investment decisions in competitive markets are not just a matter of gaining the proper regulatory approvals in order for new generation to be built. In these markets, costs are not automatically passed along to rate-payers, and investment decisions are based on signals in the market. Prices for electricity in these areas are generally kept low because there is an incentive to operate as economically as possible, and a significant amount of scrutiny must go into any investment decision to ensure it will be economically viable. An example of a competitive market is the Electric Reliability Council of Texas ("ERCOT") market, which serves a majority of Texas. It covers 75% of Texas and is comprised of approximately 550 electric generating units.

transmission study and approve the connection of the new power plant to the system. In addition, a number of environmental permits are required. For major-emitting units, including nearly all fossil fuel-fired EGUs, the Clean Air Act requires the owner to obtain a New Source Review (NSR) permit from state or federal permitting authorities before construction of the facility can begin, either under the Prevention of Significant Deterioration (PSD) program, for areas in attainment of federal air quality standards, or under the nonattainment NSR program, for areas that are not in compliance with federal standards. The NSR/PSD permit process requires time-consuming modeling, development of site-specific control technology requirements, and significant public participation, typically through a public hearing and comments.[42] New gas-fired plants that require service from a natural gas pipeline system also require approval from FERC.

In most states, regulated utilities must also file a formal Integrated Resource Plan ("IRP") with the public utility commission for approval. Preparing the plan requires many months of modeling and analysis to complete. The approval process, which typically entails notice-and-comment and even contested case proceedings, can take a year or more. The IRP evaluates the future demand for electricity and the alternatives to supply the electricity most economically for their customers. An IRP typically projects future demand and supply for a 10-20 period and considers all of the options for power supply, including supply-side (new power plants) and demand-side management. New power plant options that must be considered include the entire range of alternatives, including coal, gas, nuclear, wind, solar, hydro, and other renewables.

[42] The Virginia Department of Environmental Quality states on its web site: "After a proposed power plant has received approval from the State Corporation Commission (SCC) and location approval from the local government, it must apply for all applicable permits from DEQ. Depending on the plant, this could include permits for air, water and/or waste. Air permits that are issued to power plants undergo a very rigorous review and can take a year or more to issue depending on the size and make-up of the plant. The review includes the determination of the Best Available Control Technology (BACT) for each criteria pollutant being emitted and may require a determination of the Maximum Achievable Control Technology (MACT) for Hazardous Air Pollutants (HAPs) if the potential emissions of HAPs is over 10 tons per year (tpy) for a single HAP or 25 tpy for multiple HAPs. In addition to control technology reviews, the source must also conduct air quality analyses. This involves running multiple computer models (simulations) to demonstrate the plant will not cause or significantly contribute to an exceedance of any of the National Ambient Air Quality Standards (NAAQS). For most power plants, the air permit process involves multiple opportunities for public comment. Comment is usually taken either in written form or orally at a public hearing. Comments received from the public are taken into consideration prior to a permit being issued." See http://www.deq.virginia.gov/Programs/Air/PermittingCompliance/Permitting/PowerPlants.aspx.

All of the approvals required for a new power project are subject to intervention and litigation from other interested parties, including competing power suppliers, customer groups, and environmental organizations. Litigation can delay a project for years and may result in its cancellation.

B. Time Needed to Construct New Generating Capacity

The stated goal of the CPP is to "spur private investments in low-emitting and renewable power sources"[43] (gas-fired NGCC, nuclear and renewables like wind and solar) to replace generation from "carbon-intensive power plants"[44] (i.e. coal). Compliance will require construction of new low-emitting (gas-fired NGCC) and zero-emitting (nuclear and renewables) power plants in order to replace coal-fired generation. The long lead time for planning, permitting, and construction of new facilities is described below.

New Natural Gas-Fired Combined-Cycle Capacity

As shown in EPA's RIA, the largest source of new generating capacity to replace retiring coal plants for compliance with the CPP in 2022 will come from the construction of new gas-fired NGCC power plants. Specifically, EPA projects 2,700 MW of new NGCC capacity will be constructed by that time. As the primary source of replacement generation capacity, the length of time needed to construct new gas-fired NGCC plants will be a critical factor in power companies' compliance strategy for the CPP.

The North American Electric Reliability Corporation ("NERC"), the entity chartered by the Federal Energy Regulatory Commission in accordance with the Federal Power Act with ensuring the reliability of the North American grid, released a study in April 2015, which included an assessment of the lead time which it takes for construction of new generation. NERC collected information from its industry members and concluded that new gas-fired NGCC capacity would take 64 months for planning, permitting, and construction.[45]

The time which it takes to plan, permit, and construct new NGCC capacity can be illustrated by the experience of Virginia Electric and Power Company ("Vepco," sometimes known as Dominion Virginia Power). Vepco has been building large new NGCC capacity to serve growing demand for electricity and to replace its retiring coal-fired capacity. Vepco has recently completed the 1,329 MW Warren County power plant, is constructing

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[43] EPA, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, Federal Register June 18, 2014, page 34833.
[44] Ibid.
[45] North American Electric Reliability Corporation, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan Phase I", April 2015, page 37 at http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

the 1,358 MW Brunswick County power plant, and is permitting the 1,588 MW Greensville power plant. Each of these projects are highly-efficient new NGCC plants costing $1.1 - $1.3 billion to construct (not including the cost of financing during construction).

The major planning and permitting actions include:

- Air permit from the Virginia Department of Environmental Quality;
- Power transmission studies with PJM Interconnection;
- Approval of an IRP from the Virginia State Corporation Commission (the name of the public service commission in Virginia which regulates utilities);
- Approval of the gas pipeline connection from FERC to supply the fuel; and,
- Certificate of Public Convenience and Necessity from the SCC.

While some of these planning and permitting actions can be accomplished in parallel, the major permits (air and interconnection) need to be in place before final approval of the CPCN by the SCC. For the Warren County and Brunswick County plants, these planning and permitting actions took a total of 25 months to complete (Greensville is still underway, as the CPCN approval was just filed in July 2015, 20 months after the initial interconnection request was filed with PJM). The CPCN hearings have taken 9 months from filing to approval.

The time which it takes to construct a plant can be best measured from the time when Vepco signed the contract for engineering, procurement, and construction ("EPC") with a contractor to design and manage the project to its actual (or expected) completion. The actual time to construct the Warren County plant was 41 months and the time to construct the Brunswick County and Greensville plants is projected to be 46 and 44 months, respectively. Vepco signed its EPC contracts prior to final approval of the CPCN, risking some capital commitment before final approval in order to expedite the process. The total time for the planning, permitting, and construction of these three large projects has been 58 – 62 months, or about 5 years.

The time to accomplish each of the major tasks to plan, permit, and construct these plants is shown in Exhibit 18. Critically, these times do not include the time necessary to plan, permit, and construct electric transmission lines which are often needed to bring the new power supply to major metropolitan areas. As discussed below, the need to build transmission infrastructure can add years to the timeline for constructing and delivering new electric generation.

Exhibit 18: Time to Construct Vepco's New NGCC Power Plants

Action	Warren County	Brunswick County	Greensville
Capacity (MW)	1,329	1,358	1,588
Capital Cost (mm)	$1,091	$1,270	$1,330
Air Permit			
PSD Permit Application	Jan-10	Dec-11	Nov-14
PSD Permit Issued	Dec-10	Mar-13	
PJM Interconnection Service Agreement			
Queue Request submitted		Jul-11	Oct-13
Feasibility Study Report complete		Dec-11	Feb-14
System Impact Study complete	Jul-11	Aug-12	Oct-14
Facilities Study Report complete	Jul-11	Oct-12	Jun-14
Integrated Resource Plan			
IRP Filed with Virginia SCC	Sep-10	Aug-12	Aug-14
SCC Final Order	Nov-10	Oct-12	
Gas Pipeline Approval			
FERC Application for CPCN		Jan-13	Mar-15
Certificate of Public Convenience and Necessity			
Solicitation for Power Supply Generation			Nov-14
Proposals Submittal Date			Dec-14
Filed with Virginia SCC	May-11	Nov-12	Jul-15
SCC Staff Testimony	Nov-11	Mar-14	
Public Hearing	Dec-11	Apr-13	
Final Approval by SCC	Feb-12	Aug-13	
Project Construction			
Announced Decision to Build		Feb-12	Mar-15
EPC Contract Announced	Aug-11	Aug-12	Apr-15
Boiler Contract Announced		Nov-12	
Turbine Contract Announced			May-15
Commercial Operation	Dec-14	May-16	Dec-18
Months to Complete			
Permitting and SCC Approval	25	25	
Construction from EPC Contract	41	46	44
Total	**60**	**58**	**62**

New Renewable Generation Capacity

A major share of the emission reductions required by the CPP are projected to come from construction of new renewable energy projects, principally commercial scale wind and solar power plants. Compared to its base case (which already assumes that generation from non-hydro renewables will double from 2014 to 2030), EPA projects that compliance with the CPP in the year 2030 will result in additional generation of 31 billion kWh from

20,000 MW of new renewable power plants. Compared to the 75 GW of existing wind and solar generating capacity at the end of 2014,[46] EPA projects the construction of another 88 GW of additional wind and solar renewable capacity by 2030 to comply with the CPP.

NERC also collected information on the lead time for development of new wind and solar generating capacity. For utility-scale projects over 50 MW, NERC concluded that the planning, permitting, and construction time for a wind project would take 40 months and a solar project would take 37-42 months.[47]

Again, however, this lead time does not include the time needed to construct transmission, which will typically exceed the time for constructing the renewable generating facility itself. Renewable energy is typically located in rural areas and depends on long-line transmission systems to deliver the power to metropolitan areas.

New Nuclear Generation

While neither EPA nor EIA project that compliance with the CPP will be achieved through construction of new nuclear power plants, nuclear power would be an option for meeting the emission-reduction requirements that EPA established for the states. New nuclear generation would be a source of zero-emitting power capacity. However, the lead time to plan, permit, and construct a nuclear power plant would be much longer than NGCC or renewables. There are 4 new nuclear units under construction in the United States at two sites: Vogtle units 3 and 4 in Georgia and VC Summer units 3 and 4 in South Carolina. As shown on Exhibit 19, the total time to plan, permit and construct these new units, based on the most recent projected completion date is 12 – 14 years.

[46] EIA, "Electric Power Monthly, February 2015, Table 6.01.
[47] North American Electric Reliability Corporation, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan Phase I", April 2015, page 37 at http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

Exhibit 19: Lead Time to Construct New Nuclear Units

	South Carolina E&G Summer 2-3	Georgia Power Vogtle 3-4
Capacity (MW)	2,200	2,200
Capital cost ($mm)	$11,888	$11,039
Nuclear Regulatory Commission		
Early site permit application		8/15/2006
Application for a combined license	3/27/2008	3/28/2008
Final environmental impact statement	4/22/2011	3/31/2011
Authorization of a combined license	3/30/2012	2/10/2012
Public Service Commission		
Application for CPCN	5/30/2008	8/1/2008
Approval of CPCN	3/2/2009	3/17/2009
Construction Schedule		
Start detailed design	9/11/2007	
Approve EPC contract	5/23/2008	
Start site development	6/23/2008	
Complete nuclear fuel load first unit	2/15/2019	4/15/2019
Substantial completion first unit	8/10/2019	9/18/2019
Complete nuclear fuel load second unit	12/5/2019	12/28/2019
Substantial completion second unit	5/28/2020	6/25/2020
Months to complete	155	169
Years to complete	12.7	13.9

New Transmission Capacity

New generating capacity will require construction of new high-voltage transmission lines to connect the capacity to the existing transmission system. In the cases of renewables, especially wind generation capacity, the transmission investment can be substantial because the wind resources are generally located in remote areas long distances from the load centers.

As described by Edison Electric Institute ("EEI"), a trade organization of investor-owned utilities, transmission projects have "heavy development costs and long lead times [which] include pre-construction activities, such as development and siting approvals."[48] EEI expects that the CPP will require new transmission investment to replace retiring coal-fired plants, as it stated in its annual report on transmission projects:

[48] Edison Electric Institute, "Transmission Investment: Adequate Returns and Regulatory Certainty Are Key", June 2013, page 8, http://www.eei.org/issuesandpolicy/transmission/Pages/default.aspx.

> "One driver that could significantly alter forecasted investment is the implementation of EPA environmental regulations that may result in significant retirements of coal-fueled power plants and a greater reliance on new natural gas-fueled plants. Electric transmission will be required to connect new resources and be flexible enough to accommodate drastic changes in flows and dispatch. As these environmental regulations are finalized and implemented, we may see transmission investment rising to meet those challenges in the coming years."[49]

According to EEI, 46% of the total investment ($22.1 billion) in transmission investment projects in the 2015 annual report were to support the development of renewable resources, including wind, solar, hydroelectricity, geothermal, biomass, and biofuels.[50] One of the projects cited by EEI as an example of the development challenges for new transmission projects supporting renewable generation investments is the Prairie Wind Transmission project. Prairie Wind Transmission was formed in May 2008 to build a new double-circuit 345-KV transmission line 108 miles from western Kansas near the Flat Ridge Wind Farm "to move power from wind farms located in remote areas to load centers and help contribute to the development of wind generation in Kansas."[51] The project timeline included:

- approval from FERC December 2008;
- approval of a notification to construct from the Southwest Power Pool June 2010;
- approval of a siting permit from the Kansas Corporation Commission June 2011;
- construction started August 2012; and,
- completion of the last segment of transmission line November 2014.

The total time to complete this transmission project was 6 years.

In its survey, NERC found that the construction time alone for a new high-voltage (over 300 KV) transmission line was over 3 years and for an ultra-high-voltage (over 500 KV) the construction would be over 6 years. Including the time for surveying, land and right-of-way acquisition, and permitting, the total time to develop a new transmission line would be 6 – 11 years, assuming overlap of permitting and right-of-way acquisition.[52]

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[49] Edison Electric Institute, "Transmission Projects: At A Glance", March 2015, page viii, http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx.
[50] Id at page 171.
[51] Kansas State Corporation Commission, "Order Granting Siting Permit", Docket No: PWTE-600-MIS, page 20, http://prairiewindtransmission.com/recentnews.aspx.
[52] North American Electric Reliability Corporation, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan Phase I", April 2015, page 39, http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The Electric Reliability Council of Texas ("ERCOT"), the organization responsible for the reliable planning and operation of the electric grid for most of Texas, filed comments on the impacts of the proposed CPP,[53] stating:

> "The retirement of a large amount of coal-fired and/or gas steam resource capacity in the ERCOT region would have a significant impact on the reliability of the transmission system. The transmission system is currently designed to reliably deliver power from existing generating resources to customer loads, with the existing legacy resources that are located near major load centers serving to relieve constraints and maintain grid reliability. Retirement of these resources would result in a loss of real and reactive power, potentially exceeding thermal transmission limitations and the ability to maintain stable transmission voltages while reliably moving power from distant resources to major load centers. A significant amount of transmission system improvements would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of coal-fired and gas steam resources were to be displaced. If new natural gas combined cycle resources were to locate at or near retiring coal-fired and gas steam resources, the impact would be lessened.
>
> In the ERCOT region, it takes at least five years for a new major transmission project to be planned, routed, approved and constructed. As such, in order for major transmission constraints to be addressed in a timely fashion, the need must be seen at least five years in advance."

PJM Interconnection, the regional transmission organization which coordinates the movement of wholesale electricity in all or parts of 13 states, released a report on the power supply reliability and transmission needs driven by potential fossil-fuel generator retirements due to the impacts of the proposed CPP.[54] The principal conclusion of the report was "Having Enough Time is Essential"[55] for transmission solutions to support state compliance with the CPP. As PJM stated:

> "Whenever transmission solutions are considered, one of the most critical factors is the time necessary to identify the need for a transmission solution, to obtain siting approvals and to complete construction – all of which often take years. Generator retirements also present timing challenges. As with the business decisions plant owners faced with the Mercury and Air Toxics Standard (MATS) rule, the CPP rule will prompt owners to consider whether to repower or retire their units. The timing of those decisions and notification of retirement plans to PJM will directly affect the timing and scope of new transmission and the feasibility of completing construction within deadlines."[56]

[53] Electric Reliability Council of Texas, "ERCOT Analysis of the Reliability Impact of the Clean Power Plan", November 17, 2014, page 14, http://www.ercot.com/news/presentations/index.html.
[54] PJM Interconnection, "Reliability Scenario Studies Related to the Proposed Clean Power Plan, July 31, 2015, page 4, http://www.pjm.com/.
[55] Id, page 5.
[56] Ibid.

Power plant owners will need to promptly file their notification of retirement of coal-fired plants with PJM in order for PJM to have enough time to plan, permit, design, site, and construct the needed transmission lines to support replacement generation capacity. As PJM stated in its evaluation of the proposed CPP:

> "Under certain conditions and implementation scenarios and depending on the timing of the many moving parts, new transmission and/or transmission improvements might not be completed in time to maintain reliability. For example, assuming that EPA's rule is finalized in 2015 and that state plans are submitted by the end of 2017, then during the three remaining years until EPA's 2020 interim deadline, the following would need to occur:
>
> 1. Generation unit owners' retirement decisions are made and announced.
> 2. Decisions are made on the development of replacement generation.
> 3. Reliability criteria violations are identified and transmission solutions developed.
> 4. Transmission facilities are designed, sited and constructed.
>
> Once the PJM Board approves transmission upgrades, historical experience shows that the pace at which transmission can be completed can range from five years (the Carson-Suffolk 500 kV line) to more than 16 years (the Wyoming-Jackson's Ferry 765 kV line). Moreover, if a number of large-scope transmission projects are required across the United States, the lack of equipment availability could increase lead-time substantially.
>
> PJM's MATS experience suggests that build rates may not ensure that the necessary transmission will be in service before retirements occur. It could depend on the notice given and the aggregate impact of all generation decisions in a given area. For example, roughly 20,000 MW of retirements required $2 billion of transmission upgrades elsewhere. PJM requested that some retiring generation units remain in service beyond their requested retirement dates to ensure reliability in locations where transmission upgrades could not be completed prior to the unit's planned deactivation date. In addition, most MATS-driven transmission enhancements were upgrades to existing facilities, not greenfield transmission projects, which require more time to reach commercial operation. More greenfield transmission projects will be required if replacement resources are not located near the sites where generators retire.
>
> Replacement resources may drive the need for new transmission; if a replacement resource's location and size do not match that of a deactivating resource, a transmission upgrade will likely be required. Overlaying the generator deactivation timeline will be a generator addition timeline, driven by evolving market factors. Essentially, the location and size of both retiring generators and replacement resources will be unknown for some time and will remain a moving target for transmission system changes.
>
> Generation interconnection projects typically enter the queue three to five years before their desired in-service dates. Newly queued generation projects historically have had a low success rate – more than 80 percent of interconnection requests for capacity ultimately withdraw from the queue prior to reaching commercial operation. A successful replacement resource would have to anticipate the retirement of at-risk generators. Otherwise, the grid will face the likelihood of

significant delays between the retirement of at-risk generators and the completion of replacement resources. Reliability studies that look more than three years out must hypothesize build rates, locations and fuel sourcing."[57]

C. Planning and Commitments to Projects for Compliance with the CPP Must Begin Immediately

The period of time from the issuance of the final CPP rule August 3, 2015 until the start of compliance in January 2022 is short compared to the time that the power industry will need to plan, permit, and construct the large number of new NGCC and renewable power projects to replace the large number of coal-fired generating facilities that the CPP will force to close. The total time to develop new NGCC projects is about 5 years, including the 3.5 years needed to actually construct the plant. In order to have a new NGCC plant on line by January 2022, power companies will have to make major financial commitments through contracts for the EPC, turbine and boiler contractors no later than early 2018 (at least 3.5 years prior to compliance). But in order for utilities to be ready by early 2018 to make these investment commitments, utilities will need to examine the requirements of the rule, develop plans to reengineer their systems as the rule requires, and work with their regulators, financial institutions, and stakeholders in developing a viable, least-cost compliance plan. States and power companies will thus take steps to begin compliance planning immediately after the publication of the final CPP rule.

In the short period of time since the final rule was announced, regulated utilities have already begun seeking approval of projects which will be needed to comply with the CPP. For example, DTE Electric (also known as Detroit Edison) recently filed for approval to enter into a new 20-year contract for firm natural gas transmission capacity to support the construction of a new natural gas pipeline, NEXUS Gas Transmission, which will cost $2.2 billion to construct. Mr. Matthew Paul testified for DTE explaining that it needed to contract for new, long-term natural gas transmission capacity due to the change in its generation fleet caused by new EPA regulations, both MATS and the CPP, as follows:[58]

> **"Q. Why does DTE Electric expect a fundamental shift from a heavily weighted coal generation fleet to more natural gas fired generation?**
>
> A. The Company's expectation of a fundamental shift from a heavily weighted coal generation fleet to more natural gas fired generation is primarily driven by new environmental regulations. The Environmental Protection Agency (EPA) finalized the

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[57] Ibid.

[58] DTE Electric Company 2016 PSCR Plan Application, Testimony of Matt Paul, September 30, 2015, http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=17920&submit.x=21&submit.y=10.

first ever national standards to reduce mercury and other toxic air pollution (Mercury and Air Toxics Standards – MATS) from coal and oil-fired power plants. In addition, the EPA finalized its Clean Power Plan (CPP) that includes establishing final emission guidelines for states to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA is establishing carbon dioxide (CO_2) emission performance rates representing the best system of emission reduction (BSER) for existing fossil fuel-fired EGUs. These regulatory developments, along with the planned retirement of a number of coal fired generating units, are causing the currently expected fundamental shift from a heavily weighted coal generation fleet toward lower carbon resources including a substantial increase in natural gas fired generation.

Q. What are the anticipated changes to DTE Electric's generation portfolio?

A. DTE Electric expects that over the next 15 years, a significant portion of its coal generation fleet will be retired, as described above. Based on preliminary analysis of the Clean Power Plan, DTE Electric expects that natural gas combined cycle gas turbine (CCGT) generation will likely be the most economic source of replacement generation. Based on the Clean Power Plan Final Rule, DTE Electric expects to retire more than half of the Company's coal-fired generation capacity by 2030. DTE Electric's natural gas requirements are estimated to increase to in excess of 100 Bcf per year as the current long-term plan includes three new CCGTs being built by 2030.

Q. Are similar generation portfolio changes expected throughout Michigan and the Midcontinent Independent System Operator (MISO) region?

A. Yes, a significant amount of coal-to-gas switching is currently expected to occur throughout Michigan and the MISO region. Driven by environmental regulations, the Company currently expects that 60 percent of the coal-fired capacity in Michigan, representing 30 percent of the state's total generation capacity, will retire by 2030. MISO is estimating approximately 13 GW of coal-fired generation retirements due to MATS and as much as an additional 28 GW due to the CPP. These retirements are expected to cause a continued MISO capacity reserve margin decline, leading to capacity shortages in Zone 7 (Michigan's lower-peninsula) by 2016 and shortages across the region as early as 2020. Because gas-fired generation is widely considered to be the most economic replacement generation capacity, MISO estimates that nearly 20 GW of new gas-fired generation will be built by 2020. Driven by increased natural gas demand for power generation, total Michigan natural gas demand is currently expected to increase by nearly 20 percent between 2015 and 2025.

Q. Are there any concerns regarding natural gas supply to power plants?

A. Yes. Electric generation will be more dependent on natural gas as a source of fuel in the future. As gas-fired generation becomes more prevalent and the MISO reserve margin decreases, it is imperative that DTE Electric enter into firm gas supply and gas transportation contracts to ensure electric reliability."

Once DTE makes this large, long-term commitment to a firm supply of natural gas, due in large part to the CPP, DTE will have committed to retiring some of its coal capacity and the demand for coal will be irrevocably reduced, regardless of the future court decisions on the legality of the CPP.

Indeed, the lead times to comply with the CPP are so long that most regulated power utilities were forced to begin initial planning after the rule was proposed, even though they recognized that until the final rule was issued they would be basing their planning on mere guesswork as to what the final rule would require. Examples of how utilities began considering the impact of the proposed CPP in their IRPs include the following:

Oklahoma Gas & Electric ("OG&E") 2014 IRP: OG&E's IRP stated: "OG&E's 2014 IRP is designed to meet the existing environmental obligations while at the same time also considering the potential of future environmental regulations, even though certainty of these rules, including the potential regulation of greenhouse gas emissions, are not settled."[59] With regard to the CPP, the IRP stated:

> "On June 18, 2014, the EPA published a rule for existing power plants. This proposed rule would require the State of Oklahoma to propose a plan to reduce CO_2 emissions in the state by 43% in 2030 compared to 2012, with an interim requirement for an average 40% reduction between 2020 and 2029. OG&E is still reviewing the details of this important rule. EPA has stated that it anticipates finalizing the rule by June 1, 2015. OG&E's plan to convert two coal units to natural gas will reduce CO_2 emissions from OG&E's generation fleet, positioning the Company to provide a meaningful contribution to any state CO_2 reductions ultimately required by the EPA. OG&E has accounted for the considerable uncertainty regarding regulation of greenhouse gas emission by including a carbon tax in its sensitivity analyses."[60]

OG&E has begun its plan to convert two large coal-fired units from coal to natural gas, in part due to the consideration of EPA's future CPP rule.

Southwestern Public Service ("SPS") 2015 IRP: Under the section titled Implications of GHG Regulations for Resource Planning, the 2015 IRP filed by SPS stated:

> "As a result of the significant uncertainty, SPS has not modeled the proposed and modified GHG regulations in its 2015 IRP. Given the uncertainties, SPS cannot model the proposed and modified rules, but SPS has continued the practice of modeling carbon proxy pricing to simulate a carbon-regulated future. However, unless the final rules are dramatically different from the proposed rules, SPS can expect pressure to continue its downward carbon trajectory, while at the same time facing challenges for operating its fossil resources, to overall affordability, and for maintenance of fuel diversity. Accordingly, SPS's 2015 IRP is premised on the existing uncertainty and a key driver of SPS's preferred resource plan."[61]

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[59] Oklahoma Gas & Electric, 2014 Integrated Resource Plan, filed with the Arkansas Public Service Commission September 8, 2014, Docket 07-006-u, page 11.
[60] Id at page 15.
[61] Southwest Public Service 2015 Integrated Resource Plan, filed with the New Mexico Public Regulation Commission July 16, 2015, page 38.

The Action Plan for the period 2016-2019 recommended by the IRP is to purchase 140 MW of photovoltaic solar no later than December 2016 and to construct a large gas-fired combustion turbine within the 2018-2020 period.[62]

Kentucky Utilities Company ("KU") 2015 IRP: KU explicitly considered the impacts of the proposed CPP in its 2015 IRP, stating:

> "In June 2014, the Environmental Protection Agency ("EPA") issued its preliminary Clean Power Plan ("CPP"), containing regulations for CO_2 emissions from existing generating units. The final rules are expected in summer 2015, with state plans expected to be filed no sooner than one year later. Based on the proposed CPP, from 2020-2029, Kentucky's CO_2 emissions would need to average 1,844 lbs/MWh. Beginning in 2030, Kentucky's annual CO_2 emissions would need to average 1,763 lbs/MWh. The Companies modeled these proposed statewide limits as a "carbon cap" for their generating fleet. All of the Companies' generation units are economically dispatched to ensure that CO_2 emissions do not exceed the proposed cap."[63]

Appalachian Power Company ("APCo") 2015 IRP: APCo filed its 2015 IRP on July 1, 2015. While APCo did not know what the final form of the CPP would be at that time, it included a carbon tax as a proxy for the CPP in order to simulate the impact, stating:

> "APCo cannot reasonably predict what form the final rule (CPP) will take, or what will be required of the Company in state plans that are developed by the states and ultimately approved by the EPA. It is not practical for APCo to identify a CPP compliance strategy at this time, because it is not yet clear how many actions the Company may take would count towards compliance with a rulemaking that is not yet final. As a proxy for modelling the effect of, and cost-effective means of complying with, this pending environmental regulation, this IRP utilizes a carbon tax, in conjunction with an "Early Coal Retirement" scenario."[64]

Northern States Power Company ("NSP") 2015 IRP: While NSP recognized that the final CPP could change, and compliance deadlines could be delayed by litigation, it still is planning its generation resources (retirements and new builds) considering the likely impact of the CPP, as it stated:

> "The proposed 111(d) process will determine what compliance alternatives are available, whether each our jurisdictions will implement rate-based or mass-based programs, whether they will collaborate with other states in multi-state plans, and how much of 2016-2030 Preferred Plan the CO_2 reduction burden they will assign

[62] Id at page 2.
[63] Kentucky Utilities Company, 2015 Integrated Resource Plan, filed with the Virginia Corporation Commission, Case No. PUE-2015-00037, Exhibit 1, page 6, http://www.scc.virginia.gov/docketsearch#caseDocs/134456.
[64] Appalachian Power Company, 7/1/2015 Integrated Resource Plan, filed with the Virginia State Corporation Commission, Case No. PUE-2015-00036, page ES-12, http://www.scc.virginia.gov/docketsearch/DOCS/32y301!.PDF.

to the Company versus other utilities. We will not definitively know our share of the responsibility for meeting the attainment requirements in any of the states we serve, or our compliance options, until the states submit and EPA approves a state plan.

Any final rule is likely to face legal challenges, which depending whether or not the rule is stayed during litigation, may affect the timeline for state implementation plan (SIP) development. If the rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later with compliance beginning in 2020. If the rule is stayed, it is unknown what the compliance obligations will be or when compliance obligations will begin. Even though this is an arena in flux, we can see change afoot and believe it to be reasonable to plan our resources accordingly."[65]

Ameren 2014 IRP: Ameren indicated that the final CPP would require it to accelerate the retirement of its coal units and promptly begin construction of a replacement NGCC plant, stating:

"Should the rule **(CPP)** be implemented as proposed, Ameren Missouri would have to significantly alter its preferred resource plan in such a way as to lead to much higher capacity reserves by advancing and adding natural gas-fired generation, as early as 2020, and uneconomically dispatching those resources, which would not otherwise be needed until 2034 to meet customer demand and reserve margin requirements for reliability. Figure 1.7 illustrates the changes that could have to be made to Ameren Missouri's preferred resource plan to comply with the proposed regulations.

"The changes include 1) advancing the retirement of Meramec by three years to the end of 2019, 2) constructing a 1,200 MW combined cycle generation facility to be operational by the beginning of 2020, 3) altering the operation of the new combined cycle and existing coal resources such that gas generation runs more(about twice what it would run otherwise)and coal generators run less than they would under current methods for economic dispatch in MISO, and 4) constructing additional wind (or possibly nuclear) resources in the 2022-2030 timeframe. Making these changes would result in additional costs to customers of approximately $4 billion over the 15 year period starting in 2020 while achieving roughly the same level of annual carbon dioxide emission reductions a few years earlier than under our preferred plan."[66]

[65] Northern States Power Company (Xcel Energy Company), 1/2/2015 Upper Midwest Resource Plan 2016–2030, filed with the Minnesota Public Utilities Commission, Docket No. E002/CN-12-1240. Page 7, https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/03-Preferred-Plan.pdf.
[66] Ameren Corporation, 10/1/2014 Integrated Resource Plan, filed with the Missouri Public Service Commission, 17-18 of Executive Summary, https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter1.pdf?la=en.

Indianapolis Power & Light 2014 IRP: IPL assumed that there would be a cost similar to the CPP in its IRP and that coal generation would be replaced by natural gas and renewables, stating:

> "IPL assumed that there will be a cost associated with emitting CO_2 in seven of its eight scenarios due to the EPA's proposed Clean Power Plan rule. This cost will result in coal generation being partially replaced with natural gas fired generation resulting in higher off-peak energy prices (as coal generation normally sets the off-peak price). It may also result in additional renewable generation."[67]

The planning process to implement the final rule is thus underway. By next year, power companies will begin making large and irrevocable financial commitments to construct new generating capacity, especially new NGCC and renewable generation plants, as well as high-voltage transmission lines, to support the integration of new renewable generation.

D. Decisions to Close Coal-Fired Power Plants will be Irrevocable

If the Court does not impose a stay on the implementation of the CPP, the states and the affected power companies will have no option but to proceed with plans and decisions to comply with the rule. While the states are performing their analysis in order to submit their state plans by September 6, 2016, the affected power companies will be evaluating their options to comply with the CPP. In order to construct new generation and transmission capacity and have it in place by the first year of compliance (January 1, 2022), power companies will need to begin their initial investment in replacement generating capacity, including purchasing sites, contracting for new natural gas pipeline capacity, filing for permits and preparing IRPs for submission to the states. By 2017, these plans will need to be approved so that construction can begin.

At the same time, power companies will be evaluating other investment decisions required to maintain their coal-fired power plants. These decisions include normal maintenance capital as well as investment to comply with the host of other new environmental rules promulgated by EPA. They will include in their analysis of the investment decisions the expected cost to comply with the final CPP rule. This additional cost is likely to change the decisions from investing in maintaining their coal-fired capacity to closing the capacity, in part to comply with the CPP rule.

[67] Indianapolis Power & Light, 10/31/2014 Integrated Resource Plan, filed with the Indiana Utility Regulatory Commission, Page 7, http://www.in.gov/iurc/files/IPL_2014_IRP_Report.pdf.

Once the power companies make decisions to close their coal-fired plants, these decisions will be irrevocable. They will have entered into binding settlement agreements on environmental compliance, filed for approval at the public service commission and signed contract for construction of replacement capacity. As demonstrated by the power industry's experience with the MATS rule, reversal of the CPP rule by the D.C. Court will come too late to undo many decisions to close coal-fired power plants.

IV. Impact of the CPP on the Coal Mining Industry

The CPP will have a massive negative impact on the U.S. coal mining industry. The electric power industry is the primary market for U.S. coal. If the final CPP rule is not stayed by the Court, coal producers will reduce capital investment needed to supply coal past 2021 and coal mining companies, already weakened by the market declines since 2011, will face financial challenges, up to and including bankruptcy restructuring. Coal companies will initiate the long-term process of closing mining operations and reducing their workforce in anticipation of the decreased demand for coal.

In addition, EPA has projected the specific coal generating units that will retire because of the rule in the period 2016-18. Based on this projection, it is possible to project immediate and irreparable injury to specific coal mines, their workers, and the surrounding communities that depend on the economic activity and tax base these mines provide.

A. Reliance of the Coal Industry on Demand by Coal EGUs

The power industry is the principal market for the U.S. coal industry and, for many mines, it is the only market. According to EIA, in 2014 the electric power industry accounted for 858 million tons of coal consumption out of total production of 985 million tons (87%).[68] Many mines are dedicated to a specific power plant and have no other market. Demand for coal by EGUs drives investment, employment, and profitability in the coal industry.

B. Lead Times to Invest in New Coal Production Capacity

The coal mining industry requires a long lead time to develop and maintain mine production capacity. Like any natural resource industry, coal reserves deplete over time and must be replaced by the acquisition of new reserves and the development of new mines. These investments require substantial capital and must be planned years in advance of production. The capital investment in coal production includes:

- New mines to replace depleting existing mines;
- Additional coal reserves to extend the life of existing mines; and,
- Replacement of mining equipment and development of new areas at existing mines.

Exhibit 20 presents the results of EVA's analysis of the time that it takes to develop a new coal mine operation. This study is a list of all mines which were producing at a capacity

[68] EIA, "Monthly Energy Review," July 2015, Tables 6.1 and 6.2, http://www.eia.gov/totalenergy/data/monthly/.

of 1.0 million tons per year or greater in calendar year 2014 which had no production in 2004, 10 years earlier. The date of initial development was the earliest date when the mine received its first permit or the company announced the development of the mine or the acquisition of the coal reserves. The analysis shows that the average time for a new coal mine development is about 5.5 years, with larger mine projects taking even longer.

Exhibit 20: Time Required to Develop New Coal Mines[69]

State	Company	Mine Complex	Type	2014	2015 H1	First Permit or Reserves	MSHA Permit	First Production	Full Production	Months to Full Production
IN	Alcoa	Liberty Mine	S	1,221	549	Dec-12	Nov-09	Jan-13	Jan-14	49.9
IN	Alliance Resource	Gibson South	U	792	1,346	Oct-06	Aug-06	Apr-14	Jan-15	101.8
KY	Alliance Resource	River View	U	9,340	4,730	Apr-06	Mar-09	Aug-09	Jul-10	51.7
WV	Alliance Resource	Tunnel Ridge	U	5,627	3,279	Feb-07	Nov-00	Apr-10	May-12	140.4
WV	Arch Coal	Mountain Laurel	U	1,973	955	Jul-04	Mar-04	Oct-05	Oct-07	42.8
WV	Arch Coal	Beckley	U	974	512		Jan-06	Oct-07	Jan-09	35.9
WV	Arch Coal	Leer	U	2,713	1,552	Apr-07	Jan-07	Oct-11	Jan-14	84.5
KY	Armstrong Coal	Equality Boot	S	2,803	1,141	Dec-06	Dec-08	Sep-10	Jan-11	49.7
KY	Armstrong Coal	Kronos	U	2,515	1,247	Mar-08	Sep-10	Sep-11	Oct-12	55.8
KY	Armstrong Coal	Midway	S	1,293	599	Mar-07	Apr-08	Jul-08	Jan-09	22.4
KY	Armstrong Coal	Parkway	U	1,125	611	Dec-06	Dec-08	Apr-09	Jul-09	31.4
PA	Consol Energy	Harvey	U	3,171	1,819	Jan-09	Jan-14	Jan-14	Mar-14	62.8
IL	Foresight Energy	Deer Run	U	5,565	1,762	Jul-06	Mar-09	Jan-11	Sep-12	75.1
IL	Foresight Energy	Sugar Camp	U	9,098	5,706	Dec-04	Mar-08	Jan-10	Mar-12	88.2
IL	Foresight Energy	Williamson	U	6,482	2,890	Jan-04	Nov-04	Oct-06	Mar-08	50.7
TX	Luminant Mining	Kosse	S	9,460	2,651	Aug-04	Apr-06	Apr-09	Apr-12	93.2
WV	Patriot Coal	Blue Creek #1	U	1,231	594	Feb-09	Jul-08	Oct-09	Jul-10	23.8
WV	Patriot Coal	Blue Creek #2	U	362	155	Feb-09	Jul-08	Jul-09	Jul-10	24.1
IN	Peabody	Bear Run	S	8,446	4,127	Mar-05	Jan-10	Jan-10	Jul-11	76.5
IN	Peabody	Wild Boar	S	2,195	1,012	Nov-08	Oct-10	Oct-10	Jan-11	26.0
NM	Peabody	El Segundo	S	8,441	3,650	Dec-05	Jan-06	Apr-08	Oct-10	58.4
IL	Prairie State	Lively Grove	U	4,557	3,019	Jun-05	May-08	Jan-11	Jan-12	79.5
KY	Rhino Energy	Pennyrile	U	221	394	May-12	Aug-09	Apr-14	Jul-15	71.8
IN	Sunrise Coal	Carlisle	U	3,050	1,217	Jun-03	Jun-03	Jan-07	Apr-08	58.8
WV	United Coal	Affinity	U	1,070	585	May-07	Feb-01	Apr-11	Apr-13	148.1
IN	Vectren	Oaktown #1	U	3,341	1,596	Dec-07	Jan-07	Oct-09	Apr-11	51.6
IN	Vectren	Oaktown #2	U	2,092	1,138	Dec-07	Nov-08	Jan-13	Oct-13	70.6
IL	White Oak	White Oak	U	1,737	2,971	Jan-06	Dec-10	Apr-13	Oct-14	106.5
									Average	**65.4**

These lead times, however, are only for mine construction. As discussed below, acquiring coal reserves adds to the lead time required before production can begin.

Even existing mining operations need substantial investment to maintain production, which requires significant lead time. The longest lead time to maintain operations is the acquisition of additional coal reserves. In the largest U.S. producing region, the Powder River Basin ("PRB") of Wyoming and Montana, almost all of the coal is owned by the federal government. Coal leasing is controlled by the Bureau of Land Management

[69] Sources: Mine Safety and Health Administration web site at www.msha.gov/drshome/, company financial filings, state mine permit agencies.

("BLM"). PRB coal mines are very large operations that mine millions and tens of millions of tons of coal per year over multi-decadal periods. Given the scale of the operation, they do not acquire all the coal they will mine at once. Instead, mining involves a continual process of acquiring coal reserves years before they will actually be mined.

In order to lease additional coal reserves, the operators of the existing mines in the PRB must apply to the BLM for a new coal lease (known as a lease by application, or "LBA").

The LBA process is very time-consuming. Operators typically apply for a new LBA when the mine remaining reserve life falls below 10-15 years. That allows sufficient time for the BLM to evaluate the application, perform its environmental reviews, issue a record of decision, conduct a competitive lease auction, and award the new coal lease. After receiving the lease, the operator must modify its mine plan and receive approval from the state mining agency before it can start mining on the new lease. The LBA process is subject to litigation and delays from organizations opposed to coal mining. The competitive auction requires a large bonus bid and the LBA applicant is uncertain whether it will win the auction or whether its bonus bid will be high enough to satisfy the BLM market value (which BLM does not reveal).

The history of the LBA process in the Wyoming PRB is detailed on Exhibit 21. While the early LBAs were leased about 3 years after the initial application, LBAs issued after 2005 typically have taken 6-7 years to complete. The LBAs with pending actions (shaded on Exhibit 20) had initial applications over 9 years old and still have not been leased.

Exhibit 21: Time Required to Lease Reserves in the Powder River Basin[70]

				Bid	Key LBA Dates				Years to Action		
Tract	LBA Number	Acres	mm Tons	$MM	Application	ROD	Sale	Effective	ROD	Sale	Lease
Jacobs Ranch	WYW117924	1,708.6	147.4	$20.1	10/10/89	8/16/91	9/26/91	10/1/92	1.8	2.0	3.0
West Black Thunder	WYW118907	3,492.5	417.8	$71.9	12/22/89	6/17/92	8/12/92	10/1/92	2.5	2.6	2.8
North Antelope	WYW119554	3,064.0	393.6	$87.0	3/2/90	8/26/92	9/28/92	10/1/92	2.5	2.6	2.6
West Rocky Butte	WYW122586	463.2	55.0	$16.5	12/4/90	10/23/92	1/7/93	1/1/93	1.9	2.1	2.1
Eagle Butte	WYW124783	1,059.2	166.4	$18.5	7/25/91	1/6/95	4/5/95	8/1/95	3.5	3.7	4.0
North Rochelle	WYW127721	1,481.9	157.6	$30.6	7/22/92	6/13/97	9/25/97	1/1/98	4.9	5.2	5.4
Antelope	WYW128322	617.2	60.4	$9.1	12/29/92	7/10/96	12/4/96	2/1/97	3.5	3.9	4.1
Powder River	WYW136142	4,224.2	532.0	$109.6	3/23/95	4/20/98	6/30/98	9/1/98	3.1	3.3	3.4
Thundercloud	WYW136458	3,545.5	412.0	$158.0	4/14/95	7/30/98	10/1/98	1/1/99	3.3	3.5	3.7
Horse Creek	WYW141435	2,818.7	275.6	$91.2	2/14/97	6/23/00	9/7/00	12/1/00	3.4	3.6	3.8
North Jacobs Ranch	WYW146744	4,982.2	537.5	$379.5	10/2/98	11/28/01	1/16/02	5/1/02	3.2	3.3	3.6
NARO South	WYW154001	2,956.7	297.5	$274.1	3/10/00	5/6/04	6/29/04	9/1/04	4.2	4.3	4.5
NARO North	WYW150210	2,369.4	324.6	$299.1	3/10/00	7/16/04	12/29/04	3/1/05	4.4	4.8	5.0
Little Thunder	WYW150318	5,083.5	718.7	$611.0	3/23/00	8/13/04	9/22/04	3/1/05	4.4	4.5	4.9
West Roundup	WYW151134	2,802.5	327.2	$317.7	7/28/00	9/9/04	2/16/05	5/1/05	4.1	4.6	4.8
West Hay Creek	WYW151634	921.2	142.7	$42.8	8/31/00	10/1/04	11/17/04	1/1/05	4.1	4.2	4.3
West Antelope	WYW151643	2,809.1	195.0	$146.3	9/12/00	10/25/04	11/15/04	3/1/05	4.1	4.2	4.5
South Maysdorf	WYW174407	2,900.2	288.1	$250.8	9/20/01	8/6/07	4/22/08	8/1/08	5.9	6.6	6.9
North Maysdorf	WYW154432	445.9	54.7	$48.1	9/20/01	8/6/07	1/29/09	5/1/09	5.9	7.4	7.6
Eagle Butte West	WYW155132	1,428.0	255.0	$180.5	12/28/01	10/18/07	2/20/08	5/1/08	5.8	6.2	6.3
Belle Ayr North	WYW161248	1,671.0	221.7	$210.6	7/6/04	7/30/10	7/13/11	11/1/11	6.1	7.0	7.3
West Antelope II North	WYW163340	2,837.6	350.3	$297.7	4/6/05	4/1/10	5/11/11	7/1/11	5.0	6.1	6.2
West Antelope II South	WYW177903	1,908.6	56.4	$49.3	4/6/05	4/1/10	6/15/11	9/1/11	5.0	6.2	6.4
South Hilight	WYW174596	1,976.7	222.7	$300.0	10/7/05	3/1/11	12/14/11	5/1/12	5.4	6.2	6.6
Caballo West	WYW172657	1,024.0	130.2	$143.4	3/15/06	7/28/10	8/17/11	11/1/11	4.4	5.4	5.6
South Porcupine	WYW176095	3,243.0	401.8	$446.0	9/27/06	8/10/11	5/17/12	8/1/12	4.9	5.6	5.8
North Porcupine	WYW173408	6,364.3	721.2	$793.3	9/27/06	10/17/11	6/28/12	10/1/12	5.1	5.8	6.0
Hay Creek II	WYW172684	1,253.3	166.3	rejected	3/24/06	5/1/13	9/18/13		7.1	7.5	9.4
Action Pending											
North Hilight	WYW164812	4,529.8	467.6		10/7/05	2/1/12			6.3		*9.8*
West Hilight	WYW172388	2,370.5	377.9		1/17/06						*9.5*
West Coal Creek	WYW172585	1,151.3	57.0		2/10/06	6/10/11	*rejected*		5.3		*9.5*
West Jacobs Ranch	WYW172685	5,944.4	669.6		3/24/06	*1/7/15*			8.8		*9.4*
Maysdorf II North	WYW173360	1,338.4	148.6		8/31/06	8/30/12	8/21/13		6.0	7.0	*8.9*
Maysdorf II South	WYW180711	2,305.9	233.6		8/31/06	8/30/12			6.0		*8.9*
Belle Ayr West	WYW180238	1,874.3			8/1/11						
Antelope Ridge	WYW180384	8,261.9			9/23/11						

Entering into a new LBA requires a huge financial commitment by the lessee. Recent LBAs have cost over $1.00 per ton of mineable reserves, with 20% of the lease bonus to be paid on the effective date and the remainder paid at the rate of 20% per year. For a large mine, producing 100 million tons per year, an LBA which will extend its life for just 4 years will require a capital cost of $400 million. Operators cannot afford to finance these lease commitments if the demand for the coal is highly uncertain.

The demand by mine operators for new leases has slowed due to the downturn in the demand for PRB coal, caused at least in part by the plant retirements due to MATS from

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[70] Source: U.S. Bureau of Land Management web site at http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/lba_title.html.

2012 to 2015. Wyoming PRB coal production has fallen from 426 million tons in 2011 to just 382 million tons in 2014. Because of the downturn in demand and the decline in the market, new LBAs in the Wyoming PRB came to a halt in 2012. The last successful lease auction was on June 28, 2012 and the last LBA application was on September 23, 2011. Since then, there have been two auctions—one for the Maysdorf II North LBA, for which no bids were made, and one for the Hay Creek II LBA, for which only one bid was made (and rejected by BLM). No new lease sales are currently scheduled.

The issuance of the final CPP rule locks in significant and further declines in the demand for PRB coal. As a result, PRB coal producers will likely defer any new LBA actions (applications and competitive purchases). If the Court does not issue a Stay of the CPP, operators in the PRB will continue to consume their existing reserves and will not replace them with new LBAs. If the Court later reverses the CPP, coal operators in the PRB will have spent at least 5 years mining their existing reserves without replacing them, which could constrain the amount of coal they will be able to offer to power generators until reserves can be replenished.

C. Impact of the CPP on Coal EGUs and Coal Demand

As described above, the CPP will have a major impact on the continued operation of existing coal-fired power plants. As EPA's own analysis shows, many existing power plants will retire, convert to natural gas, or operate at reduced levels, resulting in a precipitous drop in coal demand. Specifically, the results of EPA's IPM model in the rate-based compliance case (using EPA's base case) project a loss of coal demand of 41 million tons by 2020 and 103 million tons by 2025, with even greater losses in the mass-based compliance case. By the date of compliance with the Final Goal in 2030, the losses for coal demand due to the CPP grow to over 180 million tons per year (21% of total coal demand). The impact is experienced across all coal-producing regions, with EPA projecting particularly pronounced effects in Appalachia and the West. The IPM model results are shown on Exhibit 22.

Exhibit 22: EPA Projection of the Impact of the CPP on Coal Demand for Power Generation[71]

Coal Region	2016	2018	2020	2025	2030
Final Rule Base Case					
Appalachia	152.7	142.5	143.1	121.5	120.0
Interior	227.8	253.7	268.1	284.3	304.6
West	383.2	400.5	421.2	421.3	434.5
Imports	1.5			1.5	1.0
Waste Coal	6.3	6.3	6.3	6.3	6.3
National	**771.4**	**803.1**	**838.7**	**835.0**	**866.4**
Final Rule: Rate-Based Compliance					
Appalachia	153.9	142.2	141.0	99.9	94.5
Interior	228.6	253.7	271.1	276.4	257.5
West	364.5	365.5	379.4	348.5	321.3
Imports	1.5			0.9	1.0
Waste Coal	6.3	6.3	6.3	6.3	5.9
National	**754.8**	**767.7**	**797.8**	**732.0**	**680.3**
Final Rule: Mass-Based Compliance					
Appalachia	153.4	141.5	140.6	98.3	96.9
Interior	228.7	253.7	270.0	270.2	264.3
West	359.8	356.7	369.3	335.9	316.6
Imports	1.5			1.3	1.0
Waste Coal	6.3	6.3	6.3	6.3	6.3
National	**749.6**	**758.2**	**786.2**	**712.0**	**685.2**
Change from Base Case in Final Rule: Rate-Based					
Appalachia	1.2	(0.3)	(2.1)	(21.6)	(25.5)
Interior	0.9	(0.0)	3.0	(7.9)	(47.1)
West	(18.6)	(35.0)	(41.8)	(72.9)	(113.2)
Imports	0.0	0.0	0.0	(0.5)	0.0
Waste Coal	0.0	0.0	0.0	(0.0)	(0.4)
National	**(16.6)**	**(35.4)**	**(40.9)**	**(103.0)**	**(186.1)**
Change from Base Case in Final Rule: Mass-Based					
Appalachia	0.7	(1.0)	(2.4)	(23.3)	(23.1)
Interior	0.9	(0.0)	1.9	(14.1)	(40.3)
West	(23.4)	(43.8)	(51.9)	(85.5)	(117.9)
Imports	0.0	0.0	0.0	(0.2)	0.0
Waste Coal	0.0	0.0	0.0	0.0	0.0
National	**(21.8)**	**(44.8)**	**(52.4)**	**(123.0)**	**(181.2)**

The coal demand losses would also have been much greater had EPA not changed its base case model results from the analysis provided along with the proposed rule. The

[71] EPA, IPM model documentation and run files, system support resources, "Base Case SSR.xls", "Rate-Based SSR.xls", "Mass-Based SSR.xls", Coal Pivot Table tab, for IPM v.5.15, http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

IPM base case forecast that EPA used in the final rule reduced projected coal demand as compared with the base case that EPA used in the proposed rule. This reduction in the base case projected lower coal production of 99 – 134 million tons per year throughout the forecast period from 2016 – 2030, as shown on Exhibit 23, even before the effect of the CPP. For the reasons discussed above, EPA's changed base case is not justified and contradicts EIA's reference case. Nevertheless, the reduction in coal production that EPA assumed in its final rule base case are reductions that are necessary for states to comply with the final rule, because achieving the final rule CO_2 emission reduction goals requires the elimination of coal generation that EPA included in the base case.

Exhibit 23: Change in EPA's Base Case Forecast of Coal Demand for Power Generation (million tons)[72]

Coal Region	2016	2018	2020	2025	2030
Proposed Rule Base Case					
Appalachia	180.0	177.2	170.4	163.3	152.6
Interior	238.2	264.4	277.4	294.5	313.9
West	467.1	485.1	480.8	498.2	488.3
Imports	1.5			3.6	3.8
Waste Coal	9.2	9.2	9.2	9.2	9.2
National	**896.0**	**936.0**	**937.8**	**968.8**	**967.8**
Change in Base Case from Proposed Rule					
Appalachia	(27.3)	(34.7)	(27.3)	(41.7)	(32.6)
Interior	(10.4)	(10.7)	(9.3)	(10.2)	(9.3)
West	(84.0)	(84.6)	(59.6)	(76.9)	(53.8)
Imports	0.0	0.0	0.0	(2.1)	(2.8)
Waste Coal	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)
National	**(124.6)**	**(132.9)**	**(99.1)**	**(133.8)**	**(101.4)**

Thus, in computing the effect of the CPP on U.S. coal production, it is necessary to include both the reduced coal production that EPA assumed in its base case (above reductions assumed by EIA in its reference case) *and* the reductions that EPA predicted the CPP will cause. By 2020, these reductions would be 140 million tons in the rate-based case and 152 million tons in the mass-based case, growing to over 280 million tons per year by 2030 in both cases.

Another way of evaluating the likely impact of the CPP is to compare the EIA AEO2015 forecast as the base case and the EPA IPM model results for coal demand as a result of the CPP. Exhibit 24 shows the difference between EPA's "updated" base case for the

[72] Ibid.

final CPP and EIA's latest long-term forecast of coal demand for power generation in AEO2015. EPA's base case is between 60 and 100 million tons per year below EIA's reference case without the CPP. Thus, the coal demand losses due to the CPP would have been much greater than projected by EPA if it had used EIA's forecast as its base case, as it did for the proposed CPP, rather than the modified base case that EPA used on modeling the final rule.

Exhibit 24: EPA's Base Case Forecast of Coal Demand for Power Generation Compared to EIA AEO 2015 (million tons)[73]

Comparison of Final Rule Base Case with AEO 2015					
National	**2016**	**2018**	**2020**	**2025**	**2030**
Final Rule	771.4	803.1	838.7	835.0	866.4
AEO 2015	837.0	863.0	917.0	935.0	930.0
Difference	**(65.6)**	**(59.9)**	**(78.3)**	**(100.0)**	**(63.6)**

For the reasons noted above, EPA's reasons for adjusting the AEO2015 reference case in computing the agency's base case lack credibility and artificially reduce the impact of the CPP. Thus, the best measure of the impact of the CPP on national coal demand for power generation is the difference between the EIA AEO2015 reference case forecast and the EPA IPM projection of coal demand under the CPP. This comparison truly reflects the difference between coal demand as it will exist absent the CPP and as it will exist given the CPP.

The impacts are shown on Exhibit 25 for both the rate-based and mass-based CPP compliance cases projected by EPA. In both cases, the rule causes an immediate and material impact to national coal demand for power generation, with coal burn falling by 10% (over 80 million tons) in 2016, growing to over 26% by 2030.

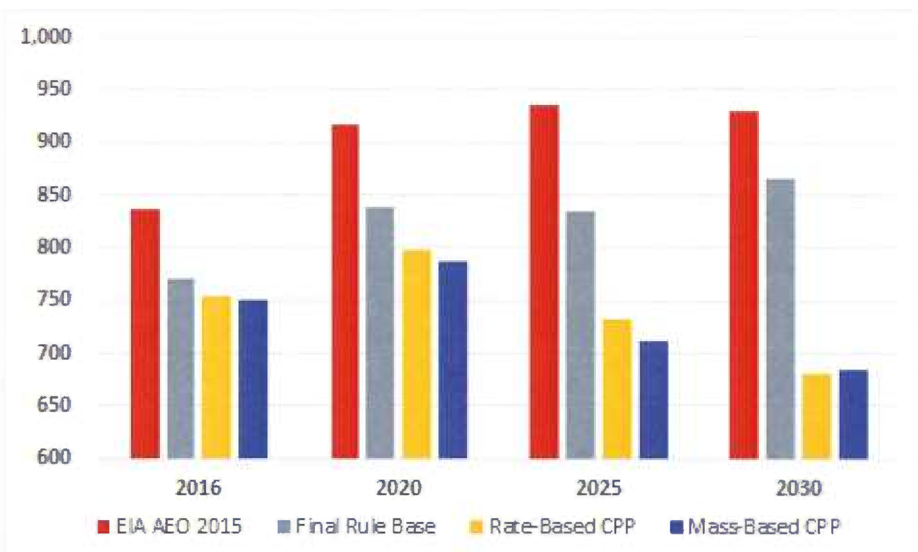
[73] EIA Annual Energy Outlook 2015 beta browser at http://www.eia.gov/beta/aeo/.

Exhibit 25: EPA's Forecast of Coal Demand for Power Generation under the CPP Compared to EIA AEO 2015 (million tons)[74]

National	2016	2018	2020	2025	2030
Rate-Based CPP	754.8	767.7	797.8	732.0	680.3
AEO 2015	837.0	863.0	917.0	935.0	930.0
Difference	**(82.2)**	**(95.3)**	**(119.2)**	**(203.0)**	**(249.7)**
Percent Change	-10%	-11%	-13%	-22%	-27%
Mass-Based CPP	749.6	758.2	786.2	712.0	685.2
AEO 2015	837.0	863.0	917.0	935.0	930.0
Difference	**(87.4)**	**(104.8)**	**(130.8)**	**(223.0)**	**(244.8)**
Percent Change	-10%	-12%	-14%	-24%	-26%

The net impact of the CPP on projected national coal burn is shown on Exhibit 26. Compared to the EIA AEO2015 forecast in 2030 of 930 million tons, EPA projects that the CPP will reduce coal demand to 680 – 585 million tons. Further, EPA forecasts that the reduction in coal burn will start immediately in 2016, dropping to 750 – 755 million tons under the CPP from EIA's forecast of 837 million tons.

Exhibit 26: EPA's Forecast of Coal Demand for Power Generation under the CPP Compared to EIA AEO 2015 (million tons)



D. Financial Impact of the CPP Rule on Coal Companies

The coal industry is in a precarious financial condition. The market for coal has declined domestically due to the MATS rule and competition from natural gas. The export market

[74] EIA Annual Energy Outlook 2015 beta browser at http://www.eia.gov/beta/aeo/.

for U.S. coal has declined due to slower world growth and the stronger U.S. dollar. But while coal companies were in an extremely weak position financially when EPA first announced the proposed CPP, it is the CPP itself that is now causing a collapse. Stock prices and the credit ratings for all of the major US coal companies have crashed.

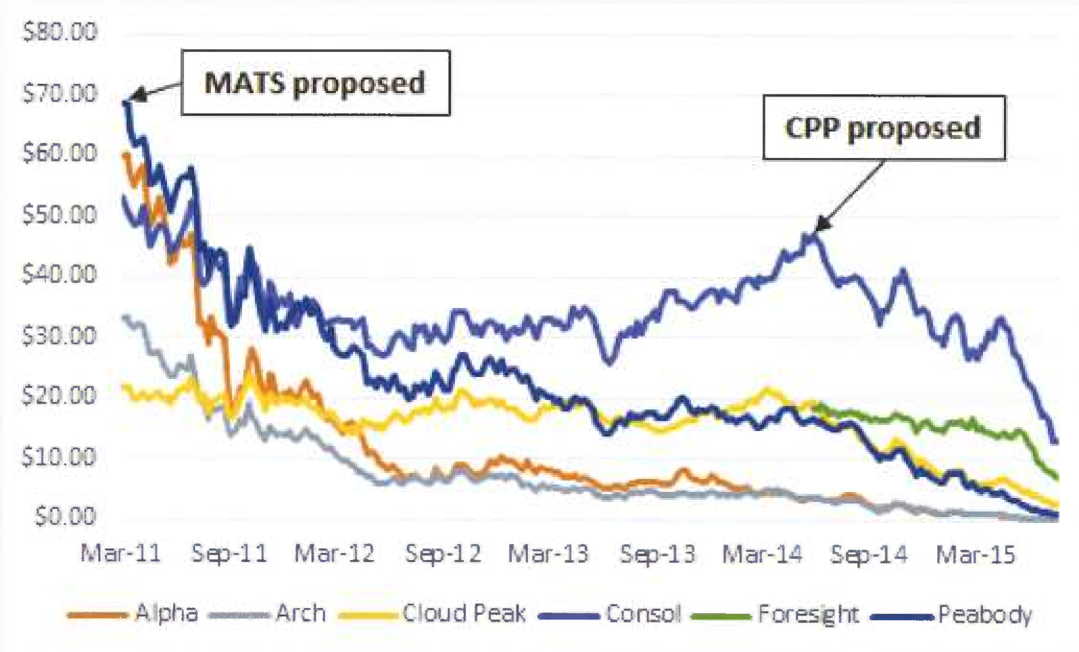
The CPP amounts to a cap on coal production in 2022 at levels that are greatly reduced even from today's relatively low levels, and declining thereafter through 2030. The rule thus amounts to the elimination of the possibility that the coal industry can grow in the future. Instead, the rule locks the industry into a sharp decline.

The rule therefore cannot help but cripple the financial condition of coal companies. Equity markets value growth. An industry with no growth has little value to investors. As a result, by any financial measure—market capitalization, share price, bond rating, access to capital markets—the rule impairs the ability of coal companies as going concerns.

The coal industry was already in financial distress following the announcement of the MATS rule. This is dramatically illustrated by Exhibit 27, which shows the stock prices for the largest U.S. coal producers from the date of the announcement of the proposed MATS rule in March 2011 to the week of August 10, 2015. The companies include the largest producers in the major coal basins:

- PRB: Peabody Energy (BTU), Arch Coal (ACI) and Cloud Peak Energy (CLD);
- Appalachia: Consol Energy (CNX), Alpha Natural Resources (ANR) and Arch Coal; and,
- Illinois Basin: Foresight Energy (FELP) and Peabody.

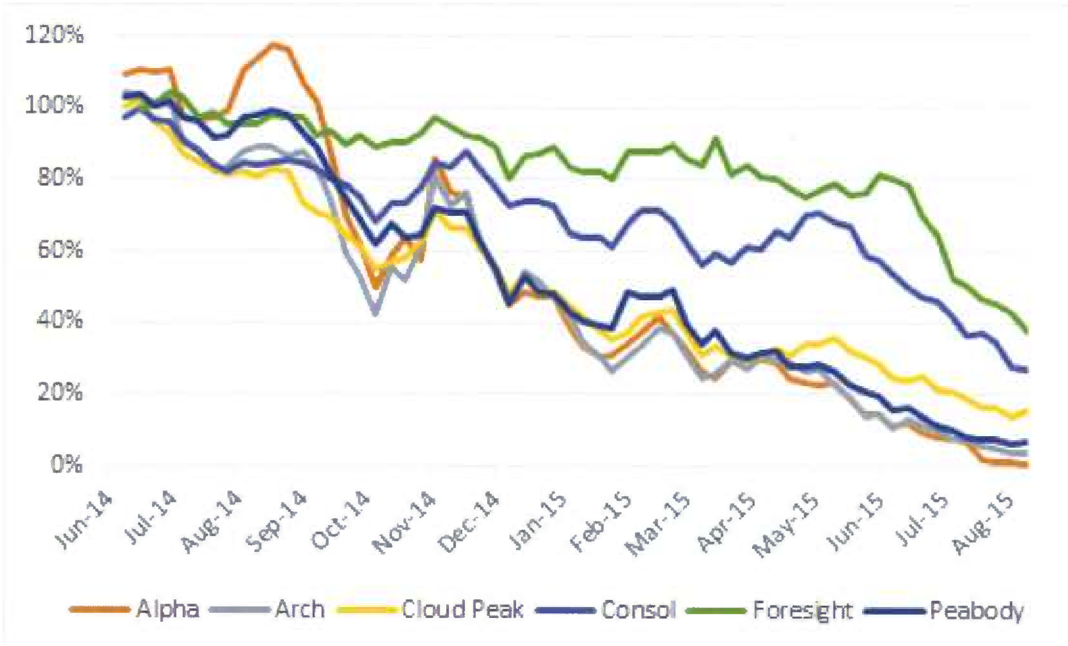
Exhibit 27: Stock Chart of Major Public U.S. Coal Producers, March 2011 – August 2015[75]



The CPP has significantly exacerbated the financial problems of the coal industry. These company stock prices all have fallen by 62% - 99% since the CPP was proposed on June 2, 2014 as shown on Exhibit 28. Alpha became the largest U.S. coal producer to file for bankruptcy on the date the final CPP rule was announced, August 3, 2015. Two other major coal companies, Patriot Coal Company and Walter Energy, have filed Chapter 11 bankruptcy during 2015, as have a number of smaller producers.

[75] Source: Google finance on August 17, 2015.

Exhibit 28: Stock Chart of Major Public U.S. Coal Producers, June 2014 – August 2015[76]



Even the largest coal producers are facing restrictions on their ability to finance their operations. Since the CPP was proposed, Alpha has lost its authority to self-bond its mining operations for its reclamation obligations in Wyoming. This can restrict the companies' ability to obtain any new mine permits.

The prospect of a large decline in coal demand due to the CPP is likely to make it even more difficult for coal producers to raise capital, either through issuing debt or equity. Without access to capital markets, coal companies will continue to reduce investment and employment. It is possible that the final CPP rule will trigger more bankruptcy filings as well, given the already heavily depressed financial condition of the companies.

[76] Ibid.

E. Projecting Specific and Immediate Harm to Coal Companies

1. Identifying Specific Coal Generating Units that the CPP Will Cause to Retire

As discussed above, EPA's own analysis of the impact of the CPP shows that many coal-fired EGUs will close immediately in 2016 and 2018 due to the CPP.[77] While EPA did not reveal these immediate impacts in the RIA, EPA's IPM modeling results confirm that coal-fired EGU capacity will be lower in 2016 due to the effect of the CPP. Those results are publicly available and can be found in tables provided on EPA's website.[78]

In addition, further information on the specific EGUs which EPA projects will close early due to the CPP can be determined from additional IPM model documentation files, which are also available on EPA's website.

Through an analysis of EPA's own modeling runs, EVA has identified each coal-fired EGU that EPA projects will retire in the years 2016 and 2018 under the two CPP cases (rate-based and mass-based) but for which retirement has not already been announced. EVA's analysis of EPA's IPM modeling results included the following steps:

- Determine the MW by year projected to retire by IPM from the "CapacityRetrofits.xls" files for the base case, the rate-based compliance case and the mass-based compliance case. This file lists each coal EGU retirement by model year, state, IPM power region, and emission control type. It does not provide the unit name, but provides a unique unit ID code assigned to each unit in the IPM model run.[79]
- For each unique unit ID code, determine additional information on the year which the unit came on line from the "DAT File.xls" for each case.[80]

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[77] As discussed earlier, the IPM model was run for years 2016 and 2018, but not 2017. The run year 2016 is intended to be representative of 2017 also.

[78] EPA, IPM model documentation and run files, system support resources, "Base Case SSR.xls", "Rate-Based SSR.xls", and "Mass-Based SSR.xls", Summary and Tables 1-16 tabs, available at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

[79] See "Base Case Capacity Retrofits.xls", "Rate-Based Capacity Retrofits.xls", and "Mass-Based Capacity Retrofits.xls" in the IPM Run Files which can be downloaded at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

[80] See "Base Case DAT File.xls", "Rate-Based DAT File.xls", and "Mass-Based DAT File.xls" in the IPM Run Files which can be downloaded at http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html.

- Match the state, capacity, and year on line data to the list of all plants in the IPM model provided on the "NEEDS_v515.xls" file to identify the specific coal-fired unit by name. This file also provides whether the unit has an announced retirement year as an input to the IPM model (meaning that the unit has already decided to retire for other reasons).[81]
- The result is a list of each coal-fired unit that the IPM model projects will retire, but is not already scheduled for retirement, in the three IPM modeling runs—the base case, the rate-based compliance case, and the mass-based compliance case.

The list of all coal-fired EGUs which are projected to retire by IPM in years 2016 and 2018 in the rate-based compliance case which were not projected to retire before 2020 in either the NEEDS input file or the base case is shown on Exhibit 29.[82] This Exhibit also shows the actual 2014 coal burn by unit using the data from EIA's Form 923 database.[83]

[81] See the National Electric Energy Data System (NEEDS) v.5.15 database "NEEDS_v515.xlsx" which can be downloaded at http://www.epa.gov/airmarkets/programs/ipm/psmodel515.html.
[82] This analysis addresses the rate-based compliance case. The coal retirements under the mas-based case are similar, but greater, so the impacts would be even larger under the mass-based case.
[83] Source: EIA923_Schedules_2_3_4_5_M_12_2014_Data_Early_Release.xls. Includes a small amount of petroleum coke, http://www.eia.gov/electricity/data/eia923/.

Exhibit 29: Coal-Fired EGUs Projected by EPA to Retire in 2016 and 2018 in the Rate-Based CPP Case

NEEDS_v515 ID	Plant Name	State	Capacity MW	Retire Year Input	Retire Year Base	Retire Year Rate	Retire Year Mass	2014 Coal Burn (tons)
10_B_1	Greene County	AL	254	9999	2020	2016	2016	498,304
3_B_1	Barry	AL	138	9999	2025	2016	2016	11,605
3_B_2	Barry	AL	137	9999	2025	2016	2016	12,469
3_B_3	Barry	AL	249	9999	2025	2016	2016	229,763
6009_B_1	White Bluff	AR	815	9999	0	2016	0	3,198,910
160_B_3	Apache	AZ	175	9999	0	2016	2016	752,427
492_B_5	Martin Drake	CO	46	9999	0	2016	2016	69,188
641_B_6	Crist	FL	291	9999	0	2016	2016	591,188
703_B_1BLR	Bowen	GA	724	9999	2040	2016	2016	1,380,821
703_B_2BLR	Bowen	GA	724	9999	2040	2016	2016	1,333,715
703_B_3BLR	Bowen	GA	892	9999	2040	2016	2016	1,672,967
703_B_4BLR	Bowen	GA	862	9999	2040	2016	2016	2,091,182
708_B_1	Hammond	GA	110	9999	0	2016	2016	65,993
708_B_2	Hammond	GA	110	9999	0	2016	2016	84,789
708_B_3	Hammond	GA	110	9999	0	2016	2016	84,673
1104_B_1	Burlington	IA	198	9999	0	2016	2016	725,440
879_B_51	Powerton	IL	384	9999	0	2016	2016	1,443,239
879_B_61	Powerton	IL	384	9999	0	2016	0	1,291,079
879_B_62	Powerton	IL	384	9999	0	2016	0	1,258,728
883_B_7	Waukegan	IL	328	9999	0	2016	2016	869,007
883_B_8	Waukegan	IL	361	9999	0	2016	0	850,104
889_B_3	Baldwin Energy	IL	608	9999	0	2016	0	2,420,204
963_B_32	Dallman	IL	77	9999	0	2018	2016	183,162
6085_B_14	R M Schahfer	IN	431	9999	0	2016	2016	903,148
1252_B_9	Tecumseh Energy	KS	73	9999	0	2016	2016	262,790
1364_B_1	Mill Creek	KY	303	9999	0	2016	0	860,047
1364_B_2	Mill Creek	KY	301	9999	0	2016	0	787,103
1743_B_6	St Clair	MI	307	9999	0	2016	2016	686,165
1843_B_3	Shiras	MI	41	9999	0	2016	0	4,021
50835_B_1	TES Filer City	MI	30	9999	0	2016	2016	119,997
50835_B_2	TES Filer City	MI	30	9999	0	2016	2016	122,322
2104_B_4	Meramec	MO	339	9999	0	2018	2030	1,372,425
2168_B_MB2	Thomas Hill	MO	291	9999	0	2016	2016	1,165,195
6195_B_1	John Twitty Energy	MO	187	9999	0	2016	2016	471,805
6073_B_1	Victor J Daniel Jr	MS	510	9999	0	2016	0	965,065
50931_B_BLR1	Yellowstone Energy	MT	26	9999	0	2016	2016	120,773
50931_B_BLR2	Yellowstone Energy	MT	26	9999	0	2016	2016	120,771
6030_B_1	Coal Creek	ND	558	9999	0	2018	2018	3,408,268
8222_B_B1	Coyote	ND	427	9999	0	2016	2016	2,248,483
2952_B_4	Muskogee	OK	505	9999	0	2016	0	1,884,481
2952_B_5	Muskogee	OK	517	9999	0	2016	0	2,194,105
6098_B_1	Big Stone	SD	475	9999	0	2016	2030	1,780,371
3403_B_1	Gallatin	TN	225	9999	0	2016	2016	888,907
3403_B_2	Gallatin	TN	225	9999	0	2016	2016	865,070
3403_B_3	Gallatin	TN	263	9999	2025	2016	2016	798,853
3403_B_4	Gallatin	TN	263	9999	2025	2016	2016	929,017
6139_B_1	Welsh	TX	528	9999	0	2016	2016	1,725,490
6139_B_3	Welsh	TX	528	9999	0	2016	2016	1,812,562
6193_B_061B	Harrington	TX	339	2031	2030	2016	2016	1,284,513
56163_B_4	KUCC	UT	75	9999	0	2016	2016	153,796
54304_B_1A	Birchwood Power	VA	238	9999	0	2016	0	372,657
4041_B_7	South Oak Creek	WI	294	9999	0	2016	2016	622,109
8023_B_1	Columbia	WI	554	9999	0	2016	2016	1,651,262
4158_B_BW42	Dave Johnston	WY	106	9999	0	2016	2030	501,612
4162_B_2	Naughton	WY	210	9999	0	2016	2016	829,807
8066_B_BW73	Jim Bridger	WY	530	9999	0	2016	2016	2,033,261
			18,116					**55,065,208**

As can be seen, EPA's own IPM analysis projects that 56 coal-fired EGUs totaling 18,116 MW will retire in 2016 or 2018 due to the CPP. Only 3 of these units (974 MW) are projected to retire in 2018; the rest are projected to retire immediately in 2016. None of these units have announced a retirement date before 2031 in the NEEDS database.[84] Of these 56 units, only 6 are projected to retire before 2030 in the EPA base case (without the CPP in place).

EPA does not attempt to explain why the IPM model projects that the CPP will cause these plants to close immediately in 2016 or 2018 even though the first compliance date is not until 2022. However, this result is consistent with the analysis provided above regarding the character of, and the many other challenges facing, the power industry. The existing coal-fired power plants face must make capital expenditures every year. Some of these capital costs are for regular maintenance, but many are for compliance with the numerous other regulations that EPA has promulgated for coal-fired electric generation with near-term compliance deadlines. These include regional haze regulations, phase 2 of the Cross State Air Pollution Rule, EPA's Coal Combustion Residuals rule, the MATS rule, the Section 316(b) water intake rule, and others, all of which have near-term compliance deadlines. Power companies faced with the threat of retirement by the CPP will seek to avoid investing the additional capital needed to comply with these other programs, and therefore will retire units deemed to be uneconomic under the CPP as soon as possible.

The total coal burned at the units that EPA projects will close immediately due to the CPP was 55.3 million tons in 2014, including 13.3 million tons of bituminous coal, 36.1 million tons of subbituminous coal (mostly Powder River Basin), 5.6 million tons of lignite, and 0.3 million tons of petroleum coke.

In addition, as noted, due to the changes EPA made to its base case analysis, EPA projects the retirement of additional units that EPA does not attribute to the CPP but that are not currently projected to retire either in EPA's own NEEDS database or in AEO2015. These units have no announced plans to close, but EPA's model projects that they will close immediately for economic reasons even without the CPP. As also discussed, if EPA's analysis were consistent with the EIA AEO2015 reference case, these retirements would no longer be included in the base case modeling results. It is reasonable to assume, however, that these retirements, when removed in the base case, would then appear in

[84] The column under "Retire Year" labeled "Input" shows the announced date used by NEEDS to force retirement in the IPM model. Where it shows the year as "9999", there is no announced retirement plan.

the policy case as retirements caused by the rule. EPA included these units in the base case because of the unjustified assumption that these units cannot survive into 2016 given current, pre-CPP market economics. It is therefore reasonable to assume that, if they could survive pre-CPP market conditions, they would be the first ones that the CPP forced into retirement to enable states to reduce coal generation in the amount required for states to meet their EPA-assigned emission reduction goals.

In addition to the 56 coal units projected by EPA to retire in 2016 and 2018 due to the CPP, there are another 182 coal-fired units that EPA has projected will retire in the both the base case and the rate-based CPP case in 2016 and 2018 that do not have announced retirement plans in the NEEDS database prior to 2021 (there are 5 units of the 182 total which have later retirement dates in the NEEDS database). EPA projects all but 2 of these units to retire in 2016. These retiring plants total 43,598 MW and burned 116.3 million tons of coal in 2014.

The total capacity of the 238 coal-fired power plants projected by EPA to retire early is 61,714 MW, of which 60,190 MW is projected to retire in 2016. The total 2014 coal burn at these retiring plants was 171.5 million tons, of which 165.2 million tons were burned at plants projected to retire in 2016. This would equal a decline of 20% of the total 2014 coal burn for power generation of 849.2 million tons.[85] The majority of the 2014 coal burn at the retiring plants, 93 million tons, was PRB coal, along with 61 million tons of bituminous coal, 10 million tons of lignite, and 7 million tons of waste coal and petroleum coke. The total capacity retired and tons of coal burn are summarized by state on Exhibit 30.

The complete list of all 61,714 MW of coal-fired EGUs projected to retire early in 2016 and 2018 by EPA's IPM model is shown on Exhibit 31.

[85] EIA, "Electric Power Monthly", July 2015, Table 2.1.A.

Exhibit 30: Capacity and 2014 Coal Burn at Coal-Fired EGUs Projected by EPA to Retire in 2016 and 2018

	MW Retired by Year			Tons of Coal Burn		
State	2016	2018	Total	2016	2018	Total
AL	2,254		2,254	3,667,864		3,667,864
AR	2,493		2,493	9,769,009		9,769,009
AZ	470		470	1,626,946		1,626,946
CA	33		33	57,797		57,797
CO	46		46	69,188		69,188
CT	383		383	499,319		499,319
DE	430		430	397,113		397,113
FL	2,364	550	2,914	3,899,242	1,365,478	5,264,720
GA	4,042		4,042	7,000,752		7,000,752
IA	1,097		1,097	2,910,108		2,910,108
IL	6,680	77	6,757	23,498,634	183,162	23,681,796
IN	2,132		2,132	5,168,195		5,168,195
KS	306		306	1,195,073		1,195,073
KY	3,246		3,246	8,617,946		8,617,946
LA	2,217		2,217	7,928,164		7,928,164
MI	4,433		4,433	11,910,692		11,910,692
MN	152		152	464,841		464,841
MO	1,392	339	1,731	4,390,682	1,372,425	5,763,107
MS	870		870	1,310,424		1,310,424
MT	139		139	792,061		792,061
NC	3,772		3,772	6,032,110		6,032,110
ND	806	558	1,364	3,964,605	3,408,268	7,372,873
NH	540		540	543,854		543,854
NJ	1,252		1,252	264,898		264,898
NY	511		511	987,021		987,021
OH	1,530		1,530	3,539,048		3,539,048
OK	1,462		1,462	5,653,243		5,653,243
OR	585		585	1,853,491		1,853,491
PA	1,968		1,968	7,684,570		7,684,570
SC	275		275	671,685		671,685
SD	475		475	1,780,371		1,780,371
TN	1,678		1,678	4,801,496		4,801,496
TX	1,786		1,786	7,225,365		7,225,365
UT	126		126	605,714		605,714
VA	1,728		1,728	3,237,238		3,237,238
WA	1,340		1,340	4,474,939		4,474,939
WI	2,067		2,067	5,353,133		5,353,133
WV	609		609	1,847,818		1,847,818
WY	2,500		2,500	9,531,423		9,531,423
Total	**60,190**	**1,524**	**61,714**	**165,226,072**	**6,329,333**	**171,555,405**

Exhibit 31: Coal-Fired EGUs Projected by EPA to Retire in 2016 and 2018

			Capacity	Retire Year				2014 Coal Burn (tons)					
NEEDS_v515 ID	Plant Name	State	MW	Input	Base	Rate	Mass	Bituminous	Subbituminous	Lignite	Waste Coal	Pet Coke	Total
10_B_1	Greene County	AL	254	9999	2020	2016	2016	441,990	56,314	0	0	0	498,304
3_B_1	Barry	AL	138	9999	2025	2016	2016	11,605	0	0	0	0	11,605
3_B_2	Barry	AL	137	9999	2025	2016	2016	12,469	0	0	0	0	12,469
3_B_3	Barry	AL	249	9999	2025	2016	2016	229,763	0	0	0	0	229,763
3_B_4	Barry	AL	362	9999	2016	2016	2016	659,583	0	0	0	0	659,583
56_B_1	Charles R Lowman	AL	80	9999	2016	2016	2016	76,850	0	0	0	0	76,850
8_B_10	Gorgas	AL	703	9999	2016	2016	2016	1,756,612	0	0	0	0	1,756,612
8_B_8	Gorgas	AL	161	9999	2016	2016	2016	234,418	0	0	0	0	234,418
8_B_9	Gorgas	AL	170	9999	2016	2016	2016	188,260	0	0	0	0	188,260
6009_B_1	White Bluff	AR	815	9999	0	2016	0	0	3,198,910	0	0	0	3,198,910
6641_B_1	Independence	AR	836	9999	2016	2016	2016	0	3,295,673	0	0	0	3,295,673
6641_B_2	Independence	AR	842	9999	2016	2016	2016	0	3,274,426	0	0	0	3,274,426
126_B_4	H Wilson Sundt Generating	AZ	120	9999	2016	2016	2016	120,014	0	0	0	0	120,014
160_B_2	Apache	AZ	175	9999	2016	2016	2016	0	754,505	0	0	0	754,505
160_B_3	Apache	AZ	175	9999	0	2016	2016	0	752,427	0	0	0	752,427
10769_B_CFB	Rio Bravo Poso	CA	33	9999	2016	2016	2016	52,646	0	0	0	5,151	57,797
492_B_5	Martin Drake	CO	46	9999	0	2016	2016	0	69,188	0	0	0	69,188
568_B_BHB3	Bridgeport	CT	383	9999	2016	2016	2016	0	499,319	0	0	0	499,319
594_B_4	Indian River Generating	DE	430	9999	2016	2016	2016	397,113	0	0	0	0	397,113
628_B_1	Crystal River	FL	375	2021	2016	2016	2016	614,010	0	0	0	0	614,010
628_B_2	Crystal River	FL	494	2021	2016	2016	2016	863,836	0	0	0	0	863,836
641_B_4	Crist	FL	75	9999	2016	2016	2016	26,628	0	0	0	0	26,628
641_B_5	Crist	FL	75	9999	2016	2016	2016	110,613	0	0	0	0	110,613
641_B_6	Crist	FL	291	9999	0	2016	2016	591,188	0	0	0	0	591,188
641_B_7	Crist	FL	465	9999	2016	2016	2016	847,033	0	0	0	0	847,033
643_B_1	Lansing Smith	FL	162	9999	2016	2016	2016	254,804	33,264	0	0	0	288,068
643_B_2	Lansing Smith	FL	195	9999	2016	2016	2016	148,708	39,217	0	0	0	187,925
663_B_B2	Deerhaven Generating	FL	232	9999	2016	2016	2016	369,941	0	0	0	0	369,941
667_B_1	Northside Generating	FL	275	9999	2018	2018	2018	403,795	0	0	0	294,621	698,416
667_B_2	Northside Generating	FL	275	9999	2018	2018	2018	467,410	0	0	0	199,652	667,062
703_B_1BLR	Bowen	GA	724	9999	2040	2016	2016	1,380,821	0	0	0	0	1,380,821
703_B_2BLR	Bowen	GA	724	9999	2040	2016	2016	1,333,715	0	0	0	0	1,333,715
703_B_3BLR	Bowen	GA	892	9999	2040	2016	2016	1,672,967	0	0	0	0	1,672,967
703_B_4BLR	Bowen	GA	862	9999	2040	2016	2016	2,091,182	0	0	0	0	2,091,182
708_B_1	Hammond	GA	110	9999	0	2016	2016	65,993	0	0	0	0	65,993
708_B_2	Hammond	GA	110	9999	0	2016	2016	84,789	0	0	0	0	84,789
708_B_3	Hammond	GA	110	9999	0	2016	2016	84,673	0	0	0	0	84,673
708_B_4	Hammond	GA	510	9999	2016	2016	2016	286,612	0	0	0	0	286,612
1073_B_3	Prairie Creek	IA	36	9999	2016	2016	2016	0	94,173	0	0	0	94,173
1073_B_4	Prairie Creek	IA	128	9999	2016	2016	2016	0	298,591	0	0	0	298,591
1091_B_3	George Neal North	IA	519	9999	2016	2016	2016	0	1,176,433	0	0	0	1,176,433
1104_B_1	Burlington	IA	198	9999	0	2016	2016	0	725,440	0	0	0	725,440
1167_B_8	Muscatine Plant #1	IA	53	9999	2016	2016	2016	0	114,832	0	0	0	114,832
1167_B_9	Muscatine Plant #1	IA	163	9999	2016	2016	2016	0	500,639	0	0	0	500,639
6017_B_1	Newton	IL	598	9999	2016	2016	2016	0	1,891,595	0	0	0	1,891,595
6017_B_2	Newton	IL	599	9999	2016	2016	0	0	1,960,344	0	0	0	1,960,344
856_B_2	E D Edwards	IL	263	9999	2016	2016	2016	0	1,072,069	0	0	0	1,072,069
856_B_3	E D Edwards	IL	335	9999	2016	2016	2016	0	1,186,628	0	0	0	1,186,628
879_B_51	Powerton	IL	384	9999	0	2016	2016	0	1,443,239	0	0	0	1,443,239
879_B_61	Powerton	IL	384	9999	0	2016	0	0	1,291,079	0	0	0	1,291,079
879_B_62	Powerton	IL	384	9999	0	2016	0	0	1,258,728	0	0	0	1,258,728
883_B_7	Waukegan	IL	328	9999	0	2016	2016	0	869,007	0	0	0	869,007
883_B_8	Waukegan	IL	361	9999	0	2016	0	0	850,104	0	0	0	850,104
884_B_4	Will County	IL	510	9999	2016	2016	2016	0	1,621,438	0	0	0	1,621,438
887_B_1	Joppa Steam	IL	167	9999	2016	2016	2016	0	736,500	0	0	0	736,500
887_B_2	Joppa Steam	IL	167	9999	2016	2016	2016	0	739,500	0	0	0	739,500
887_B_3	Joppa Steam	IL	167	9999	2016	2016	2016	0	702,000	0	0	0	702,000
887_B_4	Joppa Steam	IL	167	9999	2016	2016	2016	0	751,100	0	0	0	751,100
887_B_5	Joppa Steam	IL	167	9999	2016	2016	2016	0	666,300	0	0	0	666,300
887_B_6	Joppa Steam	IL	167	9999	2016	2016	2016	0	735,517	0	0	0	735,517
889_B_3	Baldwin Energy Complex	IL	608	9999	0	2016	0	0	2,420,204	0	0	0	2,420,204
892_B_1	Hennepin Power	IL	67	9999	2016	2016	2016	0	285,259	0	0	0	285,259
892_B_2	Hennepin Power	IL	215	9999	2016	2016	2016	0	743,645	0	0	0	743,645
898_B_4	Wood River	IL	86	9999	2016	2016	2016	0	377,463	0	0	0	377,463
898_B_5	Wood River	IL	368	9999	2016	2016	2016	0	1,499,896	0	0	0	1,499,896
963_B_32	Dallman	IL	77	9999	0	2018	2016	183,162	0	0	0	0	183,162
963_B_33	Dallman	IL	188	9999	2016	2016	2016	397,019	0	0	0	0	397,019
1008_B_2	R Gallagher	IN	140	9999	2016	2016	2016	223,314	0	0	0	0	223,314
1008_B_4	R Gallagher	IN	140	9999	2016	2016	2016	223,072	0	0	0	0	223,072
6085_B_14	R M Schahfer	IN	431	9999	0	2016	2016	212,670	690,478	0	0	0	903,148
6085_B_15	R M Schahfer	IN	472	9999	2016	2016	2016	0	1,283,780	0	0	0	1,283,780
995_B_7	Bailly	IN	160	9999	2016	2016	2016	366,567	0	0	0	0	366,567
995_B_8	Bailly	IN	320	9999	2016	2016	2016	666,822	0	0	0	0	666,822
997_B_12	Michigan City	IN	469	9999	2016	2016	2016	249,232	1,252,260	0	0	0	1,501,492
1250_B_3	Lawrence Energy Center	KS	50	9999	2016	2016	2016	0	230,026	0	0	0	230,026
1252_B_9	Tecumseh Energy Center	KS	73	9999	0	2016	2016	0	262,790	0	0	0	262,790
1295_B_1	Quindaro	KS	72	9999	2016	2016	2016	0	318,850	0	0	0	318,850
1295_B_2	Quindaro	KS	111	9999	2016	2016	2020	0	383,407	0	0	0	383,407

			Capacity	Retire Year				2014 Coal Burn (tons)					
NEEDS_v515 ID	Plant Name	State	MW	Input	Base	Rate	Mass	Bituminous	Subbituminous	Lignite	Waste Coal	Pet Coke	Total
1355_B_1	E W Brown	KY	101	9999	2016	2016	2016	202,510	0	0	0	0	202,510
1355_B_2	E W Brown	KY	166	9999	2016	2016	2016	348,697	0	0	0	0	348,697
1355_B_3	E W Brown	KY	411	9999	2016	2016	2016	746,349	0	0	0	0	746,349
1364_B_1	Mill Creek	KY	303	9999	0	2016	0	860,047	0	0	0	0	860,047
1364_B_2	Mill Creek	KY	301	9999	0	2016	0	787,103	0	0	0	0	787,103
1379_B_1	Shawnee	KY	134	9999	2016	2016	2016	428,254	0	0	0	0	428,254
1379_B_2	Shawnee	KY	134	9999	2016	2016	2016	434,969	0	0	0	0	434,969
1379_B_3	Shawnee	KY	134	9999	2016	2016	2016	424,871	0	0	0	0	424,871
1379_B_4	Shawnee	KY	134	9999	2016	2016	2016	425,186	0	0	0	0	425,186
1379_B_5	Shawnee	KY	134	9999	2016	2016	0	420,748	0	0	0	0	420,748
1379_B_6	Shawnee	KY	134	9999	2016	2016	0	423,949	0	0	0	0	423,949
1379_B_7	Shawnee	KY	134	9999	2016	2016	0	482,899	0	0	0	0	482,899
1379_B_8	Shawnee	KY	134	9999	2016	2016	0	425,980	0	0	0	0	425,980
1379_B_9	Shawnee	KY	134	9999	2016	2016	0	413,748	0	0	0	0	413,748
1384_B_1	Cooper	KY	116	9999	2016	2016	2016	170,400	0	0	0	0	170,400
1384_B_2	Cooper	KY	225	9999	2016	2016	2016	282,666	0	0	0	0	282,666
6823_B_W1	D B Wilson	KY	417	9999	2016	2016	2016	1,241,064	0	0	0	98,506	1,339,570
1393_B_6	R S Nelson	LA	550	9999	2016	2016	2016	0	1,791,371	0	0	0	1,791,371
6055_B_2B1	Big Cajun 2	LA	593	9999	2016	2016	2016	0	2,435,534	0	0	0	2,435,534
6055_B_2B3	Big Cajun 2	LA	588	9999	2016	2016	2016	0	2,401,375	0	0	0	2,401,375
6190_B_2	Brame Energy Center	LA	486	9999	2016	2016	2016	0	1,299,884	0	0	0	1,299,884
1702_B_1	Dan E Karn	MI	255	9999	2016	2016	2016	99,324	456,433	0	0	0	555,757
1702_B_2	Dan E Karn	MI	260	9999	2016	2016	2016	85,608	495,159	0	0	0	580,767
1710_B_1	J H Campbell	MI	260	9999	2016	2016	2016	0	942,908	0	0	0	942,908
1710_B_2	J H Campbell	MI	351	9999	2016	2016	2016	319,110	655,144	0	0	0	974,254
1710_B_3	J H Campbell	MI	825	9999	2016	2016	2016	0	2,847,579	0	0	0	2,847,579
1733_B_1	Monroe	MI	668	9999	2016	2016	2016	374,591	1,692,175	0	0	0	2,066,766
1733_B_2	Monroe	MI	748	9999	2016	2016	2016	270,571	1,121,791	0	0	0	1,392,362
1743_B_6	St Clair	MI	307	9999	0	2016	2016	135,709	550,456	0	0	0	686,165
1745_B_16	Trenton Channel	MI	47	9999	2016	2016	2016	8,064	93,446	0	0	0	101,510
1745_B_17	Trenton Channel	MI	47	9999	2016	2016	2016	8,064	93,446	0	0	0	101,510
1745_B_18	Trenton Channel	MI	47	9999	2016	2016	2016	8,064	93,446	0	0	0	101,510
1745_B_19	Trenton Channel	MI	47	9999	2016	2016	2016	8,064	93,446	0	0	0	101,510
1825_B_3	J B Sims	MI	73	9999	2016	2016	2016	113	0	0	0	0	113
1831_B_4	Eckert	MI	67	9999	2016	2016	2016	0	55,019	0	0	0	55,019
1831_B_5	Eckert	MI	65	9999	2016	2016	2016	0	103,476	0	0	0	103,476
1831_B_6	Eckert	MI	64	9999	2016	2016	2016	0	148,039	0	0	0	148,039
1832_B_1	Erickson	MI	151	9999	2016	2016	2016	0	566,420	0	0	0	566,420
1843_B_3	Shiras	MI	41	9999	0	2016	0	0	210,879	0	0	0	210,879
4259_B_1	Endicott	MI	50	9999	2016	2016	2016	131,829	0	0	0	0	131,829
50835_B_1	TES Filer City	MI	30	9999	0	2016	2016	96,167	12,648	0	0	11,182	119,997
50835_B_2	TES Filer City	MI	30	9999	0	2016	2016	98,225	12,677	0	0	11,420	122,322
10075_B_1	Taconite Harbor	MN	78	9999	2016	2016	2016	0	255,973	0	0	0	255,973
10075_B_2	Taconite Harbor	MN	74	9999	2016	2016	2016	0	208,868	0	0	0	208,868
2080_B_2	Montrose	MO	158	9999	2016	2016	2016	0	585,159	0	0	0	585,159
2098_B_6	Lake Road	MO	92	9999	2016	2016	2016	0	167,694	0	0	0	167,694
2104_B_1	Meramec	MO	119	9999	2016	2016	2018	0	432,084	0	0	0	432,084
2104_B_2	Meramec	MO	120	9999	2016	2016	2018	0	395,309	0	0	0	395,309
2104_B_4	Meramec	MO	339	9999	0	2018	2030	0	1,372,425	0	0	0	1,372,425
2132_B_3	Blue Valley	MO	51	9999	2016	2016	2016	17,154	0	0	0	0	17,154
2161_B_3	James River Power	MO	41	9999	2016	2016	2016	0	4,859	0	0	0	4,859
2161_B_4	James River Power	MO	56	9999	2016	2016	2016	0	131,746	0	0	0	131,746
2161_B_5	James River Power	MO	97	9999	2016	2016	2016	0	283,711	0	0	0	283,711
2168_B_MB1	Thomas Hill	MO	180	9999	2016	2016	2016	0	735,966	0	0	0	735,966
2168_B_MB2	Thomas Hill	MO	291	9999	0	2016	2016	0	1,165,195	0	0	0	1,165,195
6195_B_1	John Twitty Energy Center	MO	187	9999	0	2016	2016	0	471,805	0	0	0	471,805
6061_B_1	R D Morrow	MS	180	9999	2016	2016	2016	209,661	0	0	0	0	209,661
6061_B_2	R D Morrow	MS	180	9999	2016	2016	2016	135,698	0	0	0	0	135,698
6073_B_1	Victor J Daniel Jr	MS	510	9999	0	2016	0	628,024	337,041	0	0	0	965,065
10784_B_BLR1	Colstrip Energy LP	MT	35	9999	2016	2016	2016	0	0	0	266,008	0	266,008
50931_B_BLR1	Yellowstone Energy LP	MT	26	9999	0	2016	2016	0	0	0	0	120,773	120,773
50931_B_BLR2	Yellowstone Energy LP	MT	26	9999	0	2016	2016	0	0	0	0	120,771	120,771
6089_B_B1	Lewis & Clark	MT	52	9999	2016	2016	2016	0	0	284,509	0	0	284,509
2712_B_1	Roxboro	NC	364	9999	2016	2016	2016	895,739	0	0	0	0	895,739
2712_B_2	Roxboro	NC	662	9999	2016	2016	2040	1,356,507	0	0	0	0	1,356,507
2712_B_3A	Roxboro	NC	346	9999	2016	2016	2016	611,162	0	0	0	0	611,162
2712_B_3B	Roxboro	NC	346	9999	2016	2016	2016	611,162	0	0	0	0	611,162
2718_B_1	G G Allen	NC	162	9999	2016	2016	2016	121,754	0	0	0	0	121,754
2718_B_2	G G Allen	NC	162	9999	2016	2016	2016	111,900	0	0	0	0	111,900
2718_B_5	G G Allen	NC	266	9999	2016	2016	2016	296,345	0	0	0	0	296,345
2727_B_1	Marshall	NC	380	9999	2016	2016	2016	705,387	0	0	0	0	705,387
2727_B_2	Marshall	NC	380	9999	2016	2016	2016	797,494	0	0	0	0	797,494
2727_B_4	Marshall	NC	660	9999	2016	2016	2016	482,849	0	0	0	0	482,849
54755_B_BLR2	Roanoke Valley II	NC	44	9999	2016	2016	2016	41,811	0	0	0	0	41,811
2790_B_B1	R M Heskett	ND	30	9999	2016	2016	2016	0	0	120,942	0	0	120,942
2823_B_B1	Milton R Young	ND	250	9999	2016	2016	2016	0	0	1,545,190	0	0	1,545,190
56786_B_1	Spiritwood	ND	99	9999	2016	2016	2016	0	0	49,990	0	0	49,990
6030_B_1	Coal Creek	ND	558	9999	0	2018	2018	0	0	3,408,268	0	0	3,408,268
8222_B_B1	Coyote	ND	427	9999	0	2016	2016	0	0	2,248,483	0	0	2,248,483

			Capacity	Retire Year				2014 Coal Burn (tons)					
NEEDS_v515 ID	Plant Name	State	MW	Input	Base	Rate	Mass	Bituminous	Subbituminous	Lignite	Waste Coal	Pet Coke	Total
2364_B_1	Merrimack	NH	112	9999	2016	2016	2016	140,745	0	0	0	0	140,745
2364_B_2	Merrimack	NH	332	9999	2016	2016	2016	309,204	0	0	0	0	309,204
2367_B_4	Schiller	NH	48	9999	2016	2016	2016	50,256	0	0	0	0	50,256
2367_B_6	Schiller	NH	48	9999	2016	2016	2016	43,649	0	0	0	0	43,649
2403_B_2	PSEG Hudson Generating	NJ	613	9999	2016	2016	2016	87,824	0	0	0	0	87,824
2408_B_1	PSEG Mercer Generating	NJ	318	9999	2016	2016	2016	56,504	0	0	0	0	56,504
2408_B_2	PSEG Mercer Generating	NJ	321	9999	2016	2016	2016	120,570	0	0	0	0	120,570
2549_B_67	C R Huntley Generating	NY	218	9999	2016	2016	2016	0	316,091	0	0	0	316,091
2549_B_68	C R Huntley Generating	NY	218	9999	2016	2016	2016	0	411,534	0	0	0	411,534
2554_B_2	Dunkirk Generating Plant	NY	75	9999	2016	2016	2016	0	259,396	0	0	0	259,396
2840_B_4	Conesville	OH	780	9999	2016	2016	2016	1,768,678	0	0	0	0	1,768,678
2840_B_5	Conesville	OH	375	9999	2016	2016	2016	931,584	0	0	0	0	931,584
2840_B_6	Conesville	OH	375	9999	2016	2016	2016	838,786	0	0	0	0	838,786
2952_B_4	Muskogee	OK	505	9999	0	2016	0	0	1,884,481	0	0	0	1,884,481
2952_B_5	Muskogee	OK	517	9999	0	2016	0	0	2,194,105	0	0	0	2,194,105
6772_B_1	Hugo	OK	440	9999	2016	2016	2016	0	1,574,657	0	0	0	1,574,657
6106_B_1SG	Boardman	OR	585	2021	2016	2016	2016	0	1,853,491	0	0	0	1,853,491
10113_B_CFB1	John B Rich Memorial	PA	40	9999	2016	2016	2016	0	0	0	335,862	0	335,862
10113_B_CFB2	John B Rich Memorial	PA	40	9999	2016	2016	2016	0	0	0	335,862	0	335,862
10603_B_031	Ebensburg Power	PA	51	9999	2016	2016	2016	0	0	0	471,408	0	471,408
10641_B_B1	Cambria Cogen	PA	44	9999	2016	2016	2016	0	0	0	331,472	0	331,472
10641_B_B2	Cambria Cogen	PA	44	9999	2016	2016	2016	0	0	0	334,790	0	334,790
3140_B_1	PPL Brunner Island	PA	312	9999	2016	2016	2016	575,906	0	0	0	0	575,906
3140_B_2	PPL Brunner Island	PA	371	9999	2016	2016	2016	651,400	0	0	0	0	651,400
3140_B_3	PPL Brunner Island	PA	744	9999	2016	2016	2016	1,179,560	0	0	0	0	1,179,560
50039_B_1	Kline Township Cogen	PA	52	9999	2016	2016	2016	0	0	0	542,014	0	542,014
50611_B_031	WPS Westwood	PA	30	9999	2016	2016	2016	0	0	0	395,026	0	395,026
50879_B_BLR1	Wheelabrator Frackville	PA	42	9999	2016	2016	2016	0	0	0	538,189	0	538,189
50888_B_BLR1	Northampton Generating	PA	112	9999	2016	2016	2016	0	0	0	529,186	0	529,186
54634_B_1	St Nicholas Cogen	PA	86	9999	2016	2016	2016	0	0	0	1,463,895	0	1,463,895
6249_B_1	Winyah	SC	275	9999	2016	2016	2016	671,685	0	0	0	0	671,685
6098_B_1	Big Stone	SD	475	9999	0	2016	2030	0	1,780,371	0	0	0	1,780,371
3403_B_1	Gallatin	TN	225	9999	0	2016	2016	425,603	463,304	0	0	0	888,907
3403_B_2	Gallatin	TN	225	9999	0	2016	2016	406,898	458,172	0	0	0	865,070
3403_B_3	Gallatin	TN	263	9999	2025	2016	2016	395,956	402,897	0	0	0	798,853
3403_B_4	Gallatin	TN	263	9999	2025	2016	2016	542,304	386,713	0	0	0	929,017
3407_B_1	Kingston	TN	132	9999	2016	2016	2030	231,862	0	0	0	0	231,862
3407_B_2	Kingston	TN	132	9999	2016	2016	2030	298,182	0	0	0	0	298,182
3407_B_3	Kingston	TN	132	9999	2016	2016	2030	218,847	0	0	0	0	218,847
3407_B_4	Kingston	TN	132	9999	2016	2016	2030	259,558	0	0	0	0	259,558
3407_B_5	Kingston	TN	174	9999	2016	2016	2030	311,200	0	0	0	0	311,200
6139_B_1	Welsh	TX	528	9999	0	2016	2016	0	1,725,490	0	0	0	1,725,490
6139_B_3	Welsh	TX	528	9999	0	2016	2016	0	1,812,562	0	0	0	1,812,562
6183_B_SM-1	San Miguel	TX	391	9999	2016	2016	2016	0	0	2,402,800	0	0	2,402,800
6193_B_061B	Harrington	TX	339	2031	2030	2016	2016	0	1,284,513	0	0	0	1,284,513
50951_B_1	Sunnyside Cogen	UT	51	9999	2016	2016	2016	0	0	0	451,918	0	451,918
56163_B_4	KUCC	UT	75	9999	0	2016	2016	153,796	0	0	0	0	153,796
10071_B_1A	Portsmouth Genco LLC	VA	19	9999	2016	2016	2016	10,393	0	0	0	0	10,393
10071_B_1B	Portsmouth Genco LLC	VA	19	9999	2016	2016	2016	10,062	0	0	0	0	10,062
10071_B_1C	Portsmouth Genco LLC	VA	19	9999	2016	2016	2016	9,959	0	0	0	0	9,959
10071_B_2A	Portsmouth Genco LLC	VA	19	9999	2016	2016	2016	10,656	0	0	0	0	10,656
10071_B_2B	Portsmouth Genco LLC	VA	19	9999	2016	2016	2016	10,264	0	0	0	0	10,264
10071_B_2C	Portsmouth Genco LLC	VA	19	9999	2016	2016	2016	10,236	0	0	0	0	10,236
3797_B_3	Chesterfield	VA	98	9999	2016	2016	2016	51,654	0	0	0	0	51,654
3797_B_4	Chesterfield	VA	162	9999	2016	2016	2016	396,438	0	0	0	0	396,438
3797_B_5	Chesterfield	VA	325	9999	2016	2016	2016	755,867	0	0	0	0	755,867
3797_B_6	Chesterfield	VA	652	9999	2016	2016	2016	1,376,100	0	0	0	0	1,376,100
52007_B_BLR1	Mecklenburg Power	VA	69	9999	2016	2016	2016	116,043	0	0	0	0	116,043
52007_B_BLR2	Mecklenburg Power	VA	69	9999	2016	2016	2016	106,909	0	0	0	0	106,909
54304_B_1A	Birchwood Power	VA	238	9999	0	2016	0	372,657	0	0	0	0	372,657
3845_B_BW21	Transalta Centralia	WA	670	2021	2016	2016	2016	0	2,269,111	0	0	0	2,269,111
3845_B_BW22	Transalta Centralia	WA	670	2026	2016	2016	2016	0	2,205,828	0	0	0	2,205,828
4041_B_7	South Oak Creek	WI	294	9999	0	2016	2016	0	622,109	0	0	0	622,109
4072_B_7	Pulliam	WI	78	9999	2016	2016	2016	0	226,535	0	0	0	226,535
4072_B_8	Pulliam	WI	135	9999	2016	2016	2016	0	301,152	0	0	0	301,152
4078_B_3	Weston	WI	326	9999	2016	2016	2016	0	1,048,832	0	0	0	1,048,832
4125_B_8	Manitowoc	WI	58	9999	2016	2016	2016	3,614	0	0	0	14,358	17,972
4125_B_9	Manitowoc	WI	58	9999	2016	2016	2016	7,769	0	0	0	30,491	38,260
8023_B_1	Columbia	WI	554	9999	0	2016	2016	0	1,651,262	0	0	0	1,651,262
8023_B_2	Columbia	WI	564	9999	2016	2016	2016	0	1,447,011	0	0	0	1,447,011
10151_B_BLR1A	Grant Town Power Plant	WV	40	9999	2016	2016	2016	0	0	0	229,133	0	229,133
10151_B_BLR1B	Grant Town Power Plant	WV	40	9999	2016	2016	2016	0	0	0	249,363	0	249,363
3954_B_3	Mt Storm	WV	529	9999	2016	2016	2016	1,369,322	0	0	0	0	1,369,322
4158_B_BW41	Dave Johnston	WY	106	9999	2016	2016	2016	0	506,606	0	0	0	506,606
4158_B_BW42	Dave Johnston	WY	106	9999	0	2016	2030	0	501,612	0	0	0	501,612
4162_B_1	Naughton	WY	160	9999	2016	2016	2016	0	619,135	0	0	0	619,135
4162_B_2	Naughton	WY	210	9999	0	2016	2016	0	829,807	0	0	0	829,807
4162_B_3	Naughton	WY	330	9999	2016	2016	2016	0	1,246,725	0	0	0	1,246,725
8066_B_BW71	Jim Bridger	WY	531	9999	2016	2016	2016	0	1,740,151	0	0	0	1,740,151
8066_B_BW72	Jim Bridger	WY	527	9999	2016	2016	2016	0	2,054,126	0	0	0	2,054,126
8066_B_BW73	Jim Bridger	WY	530	9999	0	2016	2016	0	2,033,261	0	0	0	2,033,261
			61,714					50,875,989	103,238,183	10,060,182	6,474,126	906,925	171,555,405

2. Projecting How These Retirements Will Cause Immediate and Irreparable Harm to the Coal Industry

The closure of these coal-fired power plants will cause immediate harm to the coal industry in 2016. The coal-fired power plants which EPA projects will retire immediately in 2016 and 2018 have existing coal suppliers who will be forced to close their mines, lay off workers, write-off existing capital investment, and incur reclamation costs earlier than anticipated. Other stakeholders will be harmed as well, including employees and their families, local governments who will lose property taxes, government and private landowners who will lose royalties, states which will lose severance taxes, and equipment vendors and other suppliers that serve the mines. Industry funds dependent on production taxes that have been established to pay for reclamation of abandoned mine lands and provide workers compensation for black lung disease will lose revenues.

In many cases, when a power plant closes it is not possible to identify the specific mines that will close as a result because most power plants have multiple suppliers and most coal mines have multiple customers. The plant closure reduces the overall demand in the market, and this results in injury to coal suppliers who produce and sell less coal. The reductions in demand also results in mine closures, but in most cases a specific mine closure cannot necessarily be traced to a specific power plant closure.

However, there are some cases where the power plant has a dedicated supply from a specific coal mine and the closure of the power plant means the mine must close or cut production in response. Of the 238 coal generating units that IPM projects will retire—either in its base case (above the amount that have announced retirements) or in its policy case—EVA has identified those units which are closely tied to a specific coal mine. These are shown on Exhibit 32.

Exhibit 32: Coal-Fired Plants Projected by EPA to Close in 2016 and 2018 and Job Losses at the Captive Coal Mines

			Capacity Retired Due to CPP (MW)			Captive Coal Supply			Jobs Lost		
State	Station	Units	Base Case	Rate-Based	Total	Company	Mines	1000 tons	CPP	Base	Total
ND	Coal Creek	1		558	558	North American	Falkirk	3,408	207		207
ND	Coyote	1		427	427	Westmoreland	Beulah	2,624	154		146
ND	Lewis & Clark	1	52		52	Westmoreland	Savage	285		12	12
ND	Milton Young	1	250		250	BNI Coal	Center	1,545		63	63
ND	RM Heskett	1	30		30	Westmoreland	Beulah	140			8
OH	Conesville	4-6	1,530		1,530	Westmoreland	Buckingham	1,701		359	359
						Westmoreland	Oxford	1,888		207	207
TX	San Miguel	1	391		391	Kiewit	San Miguel	2,256		232	232
WY	Jim Bridger	1-3	1,058	530	1,588	PacifiCorp	Bridger UG	3,370	105	210	315
						Lighthouse	Black Butte	2,458	44	88	132
WY	Naughton	1-3	490	210	700	Westmoreland	Kemmerer	2,696	53	123	175
			3,801	**1,725**	**5,526**			**22,371**	**563**	**1,293**	**1,856**

These plants can in turn be divided into those which IPM predicts will close as a result of the CPP, using EPA's base case, and those which IPM predicts to close in EPA's base case. The plants with dedicated coal mines which are projected by EPA to close due to compliance with the CPP include:

Coal Creek unit 1: This 558 MW plant in North Dakota is projected to close in 2018 in the rate-based CPP case. It is supplied by the adjacent Falkirk mine owned by NACCO. Coal Creek units 1 and 2 are the only customers for the Falkirk mine and it will have to cut production if unit 1 is closed in 2018. Falkirk mine produced a total of 7,985,648 tons[86] in 2014, of which 3,408,268 tons (43%) were burned at Coal Creek unit 1. The closure of Coal Creek unit 1 will force the layoff of a similar percent of its workforce, or 207 of its 482 employees.[87]

Coyote plant: Coyote is a 427 MW unit in North Dakota and is projected to close in 2016 in the rate-based CPP case. Coyote is the primary customer for the Beulah mine owned by Westmoreland Coal and it will have to close if the plant is closed in 2016. Beulah mine produced a total of 2,763,576 tons[88] in 2014, of which 2,248,483 tons (81%) were burned at Coyote. The closure of Coyote will force the layoff of all of the 154 employees[89] at the mine.[90]

[86] Mine Safety and Health Administration at http://www.msha.gov/drs/drshome.htm.
[87] Ibid.
[88] Ibid.
[89] Ibid.
[90] NACCO Industries has won a coal supply contract to replace Beulah mine at Coyote, so one could argue that Beulah will have to cut production anyway. However, then the impact of the closure of Coyote plant will fall on the new Coyote Creek mine, which is under construction and already has 52 employees building the mine, so the impact is similar.

Plants with dedicated coal mines which are projected by EPA to close in 2016 in the base case as well as the CPP cases include:

Milton R. Young unit 1: This 250 MW plant in North Dakota is projected to close in 2016 in the base and rate-based CPP cases. It is supplied by the adjacent Center mine owned by BNI Coal, a subsidiary of Allete. Milton Young units 1 and 2 are the only customers for the Center mine and it will have to cut production if unit 1 is closed in 2016. Center mine produced a total of 3,975,634 tons[91] in 2014, of which 1,545,190 tons (39%) were burned at Milton Young unit 1. The closure of Milton Young unit 1 will force the layoff of a similar percent of its workforce, or 63 of its 162 employees.[92]

Lewis & Clark plant: This 52 MW plant is located in Montana and is the primary customer for the Savage mine, owned by Westmoreland Coal. The plant is projected to close in 2016 in the base and rate-based CPP cases. In 2014, the Savage mine produced 333,922 tons,[93] of which 284,509 tons were consumed at this plant. The closure of the plant will force the mine to layoff most or all of its 12 employees.[94]

San Miguel plant: This 391 MW plant is located in Texas and is the primary customer for the San Miguel mine, operated by Kiewit Mining Group. The plant is projected to close in 2016 in the base and rate-based CPP cases. In 2014, the San Miguel mine produced 2,255,871 tons,[95] all of which were consumed at this plant. The closure of the plant will force the mine to layoff all of its 232 employees.[96]

Naughton plant: Naughton has 3 units, located in Wyoming, with total capacity of 700 MW. Units 1 and 3 are projected to retire in both the base and mass-based case, while unit 2 is projected to retire in the mass-based case only. Naughton is the primary customer for the adjacent Kemmerer mine, owned by Westmoreland Coal. Naughton is the primary customer for the mine, burning 2,695,667 tons in 2014, 61% of total production of 4,399,253 tons. Closure of Naughton would force Kemmerer to lay off 175 of its 286 employees.[97]

Jim Bridger units 1-3: The Jim Bridger station has 4 units located in Wyoming, jointly-owned by PacifiCorp and Idaho Power. Units 1-3 total 1,588 MW and are projected to

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[91] Mine Safety and Health Administration at http://www.msha.gov/drs/drshome.htm.
[92] Ibid.
[93] Ibid.
[94] Ibid.
[95] Ibid.
[96] Ibid.
[97] Ibid.

close in 2016, with unit 3 in the rate-based case, and units 1 and 2 in both cases. In 2014, these units burned 5,827,538 tons out of the total plant burn of 7,843,550 tons (67.4%). The station is supplied by 3 mines, with 2014 production: Jim Bridger Surface (1,990,376 tons), Bridger Underground (3,369,731 tons), and Black Butte (4,017,845 tons).[98] The Bridger mines are owned by the power plant owners, while Black Butte is a joint venture of Lighthouse Resources and Anadarko Petroleum. All of the coal from the Bridger mines is supplied to the station, while Black Butte supplied 2,891,538 tons (72% of production). The closure of 3 of the 4 units at Jim Bridger would force the Bridger Underground mine to close (315 employees) plus a reduction of 72% of the Black Butte employees (132 out of 183 employees), leaving only the Jim Bridger Surface mine to supply unit 4.

Conesville plant: Conesville has 3 operating units (4-6) located in Ohio with a total of 1,530 MW. All of the units are projected to retire in the base case and the rate-based compliance case. The plant burned 3,539,048 tons in 2014 and took deliveries from 3 mines: Buckingham mine (1,700,774 tons), Oxford's #3 and Snyder mines (1,887,748 tons) and a small amount from Kimble's Stonecreek mine (40,520 tons). This was 100% of the production from the Buckingham mine (which was bought by Westmoreland Coal at the end of 2014) and all of the production from the Oxford mine (owned by Westmoreland Resource Partners). The closure of Conesville plant would result in the closure of the Buckingham (359 employees) and Oxford mines (207 employees).[99]

Just these few examples (9 power plants and 10 coal mines) alone indicate that, according to EPA's own projections, the CPP will have the following impacts by 2018:

- reduced coal production: 22.4 million tons
- lost jobs: 1,856

[98] Ibid.
[99] Ibid.

V. Closure of Coal-Fired Plants under the Mercury and Air Toxics Rule is an Example of the Future Impact of the CPP

The Mercury and Air Toxics Rule ("MATS") is a recent example of the impact that a major final EPA rule can have on decisions to close coal-fired power plants while an appeal is pending. A brief summary of the timeline of the status of this rule is:

- On March 16, 2011, EPA proposed Clean Air Act Section 112 air toxics standards for all coal-fired and oil-fired EGUs requiring the application of maximum achievable control technology ("MACT"), published in the Federal Register on May 3, 2011;
- On December 21, 2011, EPA announced the final rule regulating emissions of mercury, hydrogen chloride, and filterable particulate matter from existing coal-fired and oil-fired power plants; the final rule was published in the Federal Register on February 16, 2012, to be effective April 16, 2012;
- Compliance with the final MATS rule was scheduled to be achieved by April 16, 2015 (3 years after the effective date), with extensions available for one year to April 16, 2016 on a case-by-case basis;
- On February 16, 2012, National Mining Association filed a petition for review of the final MATS rule with the U.S. Court of Appeals for the D.C. Circuit;
- On April 15, 2014, the D.C. Circuit denied the petitions to review the MATS rule;
- On July 14, 2014, National Mining Association filed a Writ of Certiorari to the Supreme Court of the United States; and
- On June 29, 2015, the Supreme Court held that EPA had adopted MATS unlawfully, and therefore reversed and remanded the decision of the D.C. Circuit Court.

The MATS rule created a requirement for all existing coal-fired EGUs to comply with new emissions limits for mercury, hydrogen chloride, and particulate matter. The owners of these power plants had to plan for compliance with MATS by April 16, 2015 (or as late as April 16, 2016 with a one-year extension). Power plant owners were faced with the decision whether to invest capital in expensive new emission controls on existing coal-fired EGUs or close these power plants and replace them with new sources of power (gas-fired NGCC or renewables).

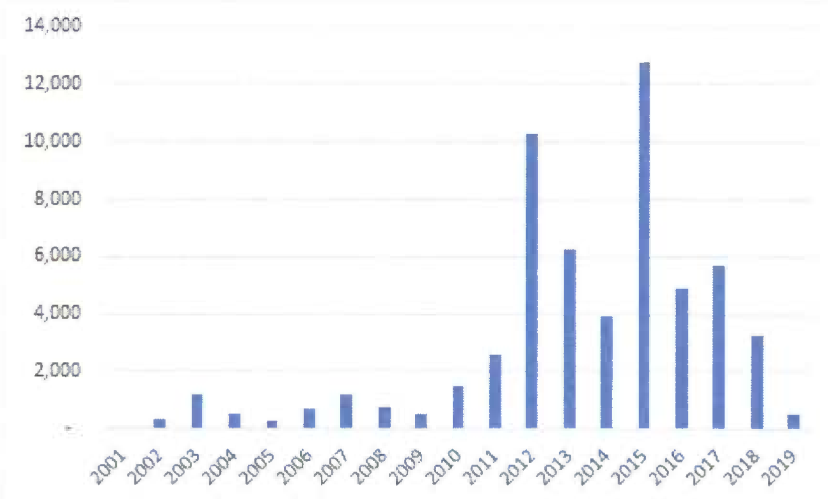
The long lead time required to replace coal-fired plants created the same problem under MATS as it will under the CPP – the power industry could not wait until the Court ruled on the legality of the MATS rule in order to decide whether to close and replace a coal-fired power plant. If the power industry had waited until the D.C. Court ruled in April 2014, there would have been only one year to comply with MATS, not enough time to build new capacity to replace their coal units (nor enough time to add emission controls to the coal-fired units[100]). And waiting for the Supreme Court's decision would have exceeded the compliance deadline.

Like the CPP, EPA analyzed the projected impact of the MATS rule on power generation and coal consumption using its IPM model. In its RIA, EPA projected that almost all of the affected coal-fired plants would construct emissions controls to comply with MATS and that only 4,700 MW of coal-fired capacity (less than 2 percent) would be retired by 2015 due to MATS.[101] EPA opined that even that small amount of closed capacity could be overestimated due to local operating conditions.[102] EPA also concluded that the impact of MATS on coal demand would be very small, projecting that coal burn by the power industry in 2015 would be 998 million tons in the base case and 989 million tons with MATS, a decline of less than 1%.[103]

EPA's projection of the impact of MATS was highly inaccurate. Immediately after EPA released the final MATS rule, power companies began announcing that they would retire coal-fired capacity (or convert plants to natural gas to preserve the generating capacity but avoid the large capital cost to comply with MATS). Prior to the final MATS rule, total retirements of coal-fired capacity for the previous 11 years were just 9,745 MW, 3.1% of the existing capacity. Because of MATS, power companies retired more capacity than in all of those years combined—10,308 MW—in 2012 alone. For the period 2012 – 2015 (including actual retirements through May 2015 and planned retirements reported to EIA), total retirements of coal-fired capacity have totaled 33,357 MW, more than seven times EPA's projection. Actual retirements and planned retirements reported to EIA from 2001 to 2019 are shown on Exhibit 33.

[100] Under the CPP, there is no option to build emission controls for emissions of CO_2 as there is no practical technology which can be applied to reduce CO_2 emissions.
[101] EPA Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 3-17.
[102] Id at page 3-18.
[103] Id at page 3-21.

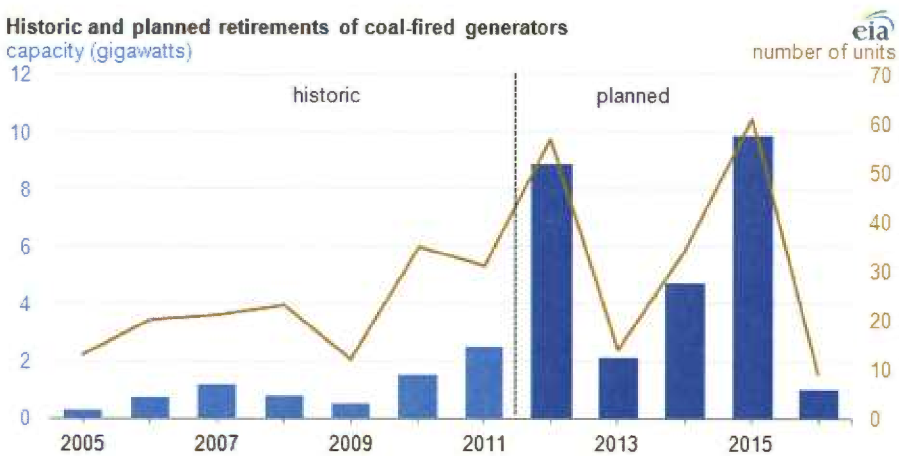
Exhibit 33: Retirements of Coal-Fired Generating Capacity (MW)[104]



Even this understates the surge of retirements due to MATS, because the EIA data do not include coal-fired plants which have switched to burning natural gas instead of retiring.

Shortly after MATS was published, EIA recognized that this rule would contribute to a wave of retirements of coal-fired power plants. EIA published an article in July 2012 reporting the surge of planned retirements, which would peak in 2015, the year of MATS compliance, which included the chart shown in Exhibit 34.

Exhibit 34: Planned Retirement of Coal-Fired Generators, 2012 (MW)[105]



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[104] Sources: EIA Electric Power Annual reports 2001-2013, Tables 4.3 and 4.6, Electric Power Monthly February 2014, February 2015 and June 2015, Tables 6.1, 6.4 and 6.6.
[105] Sources: EIA, "27 gigawatts of coal-fired capacity to retire over next five years", July 27, 2012 at http://www.eia.gov/todayinenergy/detail.cfm?id=7290#.

While the cost of compliance with MATS was not the only factor causing coal-fired plants to retire (the reduced price of natural gas was the other major issue), it was the major factor cited by many power companies as the reason for retiring their coal-fired units, instead of simply reducing operations.

Reflecting the long lead times in utility planning, companies did not wait until the MATS compliance deadline to retire units and begin the process of acquiring replacement resources. They proceeded with the necessary planning immediately so as to be in a position to announce the retirements move to alternative generation soon after the final rule was adopted. Examples include the following:

- **FirstEnergy:** On January 26, 2012, shortly after the final MATS rule was announced, FirstEnergy Corporation announced that it would retire six coal-fired plants located in Ohio, Pennsylvania, and Maryland by September 1, 2012. The total capacity of these coal-fired plants (Bay Shore 2-4, Eastlake, Ashtabula, Lake Shore, Armstrong and R. Paul Smith) was 2,689 MW. FirstEnergy directly attributed the decision to close the plants to the new MATS rule. The president of FirstEnergy Generation, James Lash was quoted: "The decision is not in any way a reflection of the fine work done by the employees at the affected plants, but is related to the impact of new environmental rules. We recently completed a comprehensive review of our coal-fired generating plants and determined that additional investments to implement MATS and other environmental rules would make these older plants even less likely to be dispatched under market rules. As a result, it was necessary to retire the plants rather than continue operations."[106]
- **Monongahela Power Company:** On February 8, 2012, FirstEnergy's regulated subsidiary Monongahela Power announced that it would close another three coal-fired plants (Albright, Willow Island, and Rivesville) with a total capacity of 660 MW. In its filing with the Public Service Commission on April 30, 2012, the company stated: "Prior to announcing the deactivation of three subcritical coal-fired power plants, Mon Power completed an extensive study of its older, unscrubbed regulated coal-fired units to evaluate the condition of those units and to determine the expected impact of significant changes in environmental regulations. The study showed that additional needed capital investments, particularly to comply with Mercury and Air Toxics Standards ("MATS") Rules and other environment rules,

[106] See http://generationhub.com/2012/01/26/firstenergy-officially-pulling-the-plug-on-coal-ca.

would not be cost effective and would make it even less likely that these plants would be dispatched into the PJM wholesale power market."[107]

- **Public Utility Commission of Ohio ("PUCO"):** In July 2012, The PUCO Chairman, Todd Snitchler, made a presentation to the National Association of Regulatory Utility Commissioners in which he stated that 28 generating units with a capacity of 6.1 GW have announced retirement in Ohio. He attributed the retirements to a combination of the capital cost of installing air emissions controls to meet MATS as well as other environmental regulations and current low gas prices.[108]
- **PacifiCorp:** In its Form 10-Q filed with the Securities and Exchange Commission ("SEC") on October 31, 2012, PacifiCorp stated: "As a result of recent testing and evaluation, PacifiCorp currently anticipates that retiring the Carbon Facility in early 2015 will be the least-cost alternative to comply with the MATS and other environmental regulations. PacifiCorp continues to assess compliance alternatives and potential transmission system impacts that could otherwise impact PacifiCorp's ultimate decision with respect to the Carbon Facility, including timing of retirement and decommissioning."[109] The Carbon plant was a 172 MW coal unit which retired in April 2015.
- **Southern Company:** On January 7, 2013, Georgia Power Company, owned by Southern Company, announced its request for approval from the Georgia Public Service Commission to decertify and retire units 1-5 of the Yates coal fired power station in Coweta County by April 16, 2015, the effective date of the US Environmental Protection Agency's MATS rule.[110] The company also announced its plans to convert Yates units 6 and 7 from coal to natural gas. "The fuel switches are the result of the company's evaluation of the MATS rule, other existing and expected environmental regulations, and economic analyses."[111]

  In the same press release, the company also announced its request to decertify units 1-4 at Plant Kraft in Chatham County, as well as units 3 and 4 at Plant Branch

[107] Response by Monongahela Power Company to the Public Service Commission of West Virginia, Case No. 11-1274-E-P, April 30, 2011.
[108] Ohio Public Utilities Commission, Todd A, Snitchler, Chairman, "The Utility Mercury Air Toxics Standard", available at http://generationhub.com/2012/07/17/coal-retirements-create-headache-for-ohio-puco.
[109] PacifiCorp, SEC Form 10-Q for the quarterly period ended September 30, 2012, page 28.
[110] "Georgia Power seeks approval to retire generating units at four plants." January 7, 2013. http://www.georgiapower.com/about-us/media-resources/newsroom.cshtml
[111] Ibid.

in Putnam County. In the company's Integrated Resource Plan (IRP), filed January 31, 2013, Southern Company stated "the Company's evaluation of the MATS rule has also led to the conclusion that the most cost-effective compliance option for certain of the Company's coal-and oil-fired units is retirement. The units for which the Company has made such a determination and seeks decertification in the 2013 Decertification Application are Plant Branch units 3 and 4, Plant Kraft Units 1-4[112], Plant McManus Units 1 and 2, and Plant Yates Unit 1-5."[113]

Southern Company's 2013 IRP was approved July 11, 2013.[114] Plant Yates units 1-5 were retired in April of 2015 and units 6 and 7 began running on natural gas in June and May of 2015, respectively. The Kraft plant received a one year extension under the MATS rule for retirement and is scheduled to retire in April of 2016.

- **Kentucky Power:** On December 6, 2013, Kentucky Power filed an application for a Certificate of Public Convenience and Necessity (CPCN) with the Kentucky Public Service Commission (KPSC) to convert Unit 1 at the Big Sandy Power Plant, located near Louisa, from a coal-fired unit to a natural gas fired unit.[115] In a press release published on December 9, 2013, the company said "Unit 1 is being retired as a coal-fired facility because it will no longer comply with Federal environmental standards after 2015."[116] In a post hearing brief given to the KPSC on June 14, 2014, Kentucky Power said "the April 2012 Mercury and Air Toxics Standards Rule means that Kentucky Power cannot continue to operate Big Sandy Unit 1 as a coal-fired generating unit without the installation of significant environmental retrofits .....MATS presented Kentucky Power with the following inescapable choice: convert Big Sandy Unit 1 to a natural gas-fired generating unit, or retire the unit and obtain the necessary capacity and energy from another course... without Big Sandy Unit 1 Kentucky Power will be unable to meet its allocated PJM Summer UCAP obligation through planning year 2019."[117] The

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[112] Kraft Units 1-3's primary fuel type is bituminous coal, while unit 4 runs on natural gas.

[113] "Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3 and Plant Bowen Unit 6." January 31, 2013, http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145981.

[114] Georgia Public Service Commission, Georgia Power Company's 2013 Integrated Resource Plan, Final Order, http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=148995.

[115] This application is commensurate with a stipulated settlement agreement in the Mitchell Plant Transfer case approved by the Commission October 14.

[116] "Kentucky Power Files to Convert Coal-Fired Units to Natural Gas." December 9, 2013, https://www.kentuckypower.com/info/news/viewRelease.aspx?releaseID=1482.

[117] "The Application of Kentucky Power Company for: (1) A Certificate of Public Convenience and Necessity Authorizing the Company to Convert Big Sandy Unit 1 to a Natural Gas-Fired Unit; and (2) for all other

plant's conversion was approved by the KPSC on August 1, 2014.[118] The plant is schedule to come online with natural gas as its primary fuel type in May of 2016.

On December 19, 2012, Kentucky Power announced that it would retire Big Sandy Unit 2 in May of 2015. In a Q&A press release on the Big Sandy Unit 2 Decommissioning, published by Kentucky Power's owner, American Electric Power Company (AEP), the company stated "the retirement is part of the AEP's plan for complying with the Mercury Air Toxic Standards for existing power plants that were approved by the U. S. Environmental Protection Agency in December 2011."[119] The unit retired from operation in May of 2015.

- **American Electric Power:** On July 11, 2013, American Power Electric published a press release stating that it expects to retire its coal-fueled Muskingum River Plant Unit 5 in Beverly, Ohio, in 2015.[120] The plant's retirement also satisfies a settlement agreement with the U.S. EPA that requires AEP to retire, refuel or retrofit Unit 5 with an SO2 scrubber by the end of 2015. The plant was closed in May of 2015, and the following month the company published a Q&A press release on the plant's decommissioning, stating "The retirement is part of the AEP's plan for complying with the Mercury Air Toxics Standards for existing power plants that were approved by the U.S. Environmental Protection Agency in December 2011."[121]

  On September 17, 2013, American Power Electric announced that it would retire the coal-fueled Tanners Creek 4 generating unit in Lawrenceburg, Indiana.[122] The following August, in a Q&A press release on the plant's decommissioning, the company stated "The retirement is part of the AEP's plan for complying with the Mercury Air Toxics Standards for existing power plants that were approved by the U.S. Environmental Protection Agency in December 2011."[123]

Required Approvals and Relief." June 16, 2014, http://psc.ky.gov/PSCSCF/2013%20cases/2013-00430/20140616_Kentucky%20Power%20Company_Post-Hearing%20Brief.pdf.

[118] "Public Service Commission Approves Big Sandy Unit 1 Conversion to Natural Gas Generation." August 1, 2014, https://www.kentuckypower.com/info/news/viewRelease.aspx?releaseID=1606.

[119] "Big Sandy Unit 2 Decommissioning". June 2015, http://www.aep.com/environment/PlantRetirements/docs/bigsandy/JUN15%20FAQ-BigSandyUnit2Decommissioning.pdf.

[120] "News Release: AEP Expects to Retire 585-Megawatt Coal-Fueled Unit in Ohio." July 1, 2013, http://www.aep.com/newsroom/newsreleases/?ID=1820.

[121] "Muskingum River Plant decommissioning." June 2015, https://www.aep.com/environment/PlantRetirements/docs/MuskingumRiver/JUN15%20FAQ-MuskRiverDecommissioning.pdf.

[122] "AEP To Retire Entire Tanners Creek Plant in Indiana." September 17, 2013, http://www.aep.com/newsroom/newsreleases/?ID=1834.

[123] "Tanners Creek Plant Decommissioning." August 2014, http://www.aep.com/environment/PlantRetirements/docs/tannerscreek/FAQ-TannersDecommissioning.pdf.

- **<u>Tennessee Valley Authority (TVA):</u>** On November 13, 2013, TVA published a press release stating that units 1 and 2 of its Paradise coal-fired plant do not meet the MATS particulate matter limit in their current configurations. "TVA must determine how to comply with MATS while maintaining adequate reliable generating capacity."[124] The following month, on December 5, 2013, TVA released its latest draft of the 2015 Integrated Resource Plan, stating that Paradise Units 1 and 2 would be retired, noting that the decision was "driven by stringent environmental regulations."[125]
- **<u>South Carolina Electric & Gas ("SCE&G"):</u>** On May 30, 2012, SCE&G filed its 2012 Integrated Resource Plan with the Public Service Commission of South Carolina. In this IRP, SCE&G stated: "Under the existing environmental regulations, the Company does not anticipate that it will be able to continue to operate these six units using coal as the fuel source unless the Company installs pollution control equipment."[126] The six units listed were Canadys 1-3, Urguhart 3, and McMeekin 1-2. SCE&G evaluated its options for these units, stating: "In the long run analysis, SCE&G wanted to determine the most economical disposition of these six coal units in a long-run least cost resource plan under existing environmental regulations." SCE&G determined that: "Retiring all six units in 2017 has the smallest levelized incremental revenue requirement over the 25 year study horizon."[127] SCE&G's retirement plans considered the possibility of obtaining an extension under the MATS rule, stating: "The EPA's MATS rule requires compliance in three years, by April 2015. The rule offers the potential of a one-year waiver which the EPA indicated would be liberally granted. A waiver for a second one-year extension is also available to preserve reliability, but the EPA does not expect to grant many of these waivers. Although SCE&G is considering applying for these waivers, it cannot assume that the waivers will be granted and has therefore begun analyzing the possibility of operating Units 2 and 3 at Canadys Station and Units 1 and 2 at McMeekin Station exclusively on natural gas by April 2015."[128] SCE&G directly attributed the cause of retirement or conversion from

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[124] "Paradise Fossil Plant Units 1 and 2- Mercury Air Toxics Standards Compliance Project." November 13, 2013, http://www.tva.gov/environment/reports/pafmats/.
[125] "TVA 2015 Integrated Resource Plan." December 2, 2013, http://www.tva.gov/environment/reports/irp/pdf/IRPWG%20December%20Session_final_web.pdf.
[126] South Carolina Electric & Gas Company's 2012 Integrated Resource Plan, Docket No. 2012-9-E, May 30, 2012, page 27, https://dms.psc.sc.gov/Web/Dockets/Detail/113925.
[127] Id at page 28.
[128] Id at page 30.

coal to natural gas of these plants as a response to the MATS rule, stating in a press release: "In 2012, in response to the EPA published Mercury Air Toxic Standards, SCE&G identified six coal-fired units, including the three at Canadys Station, that would be taken offline or switched from coal to using natural gas as a part of the integrated resource plan filed with the South Carolina Public Service Commission. The six units comprise 730 megawatts of generating capacity."[129]

All of these decisions to close coal-fired capacity were made well prior to the D.C. Circuit's decision on the petition for review of the MATS rule. Utilities could not afford to wait for the D.C. Court to issue its decision because they had to take steps to comply with MATS immediately, in case the rule was upheld. By the time that the Court upheld the rule on April 15, 2014, power companies had already begun construction of new capacity (mostly gas-fired NGCC) to replace the retiring coal plants. Had the Court vacated the rule, it would have been too late for utilities to change course and keep their coal plants open.

In the MATS case, the Supreme Court later reversed and remanded the case on June 29, 2015, two months after compliance with the MATS rule was required and ten months before compliance was required for units receiving the one-year extension. However, EPA itself has stated that the Supreme Court decision will not impact compliance with the rule given that, because of the long lead-times for electric utility planning, power companies are already locked into their compliance strategies. Immediately before the decision was issued, EPA Administrator Gina McCarthy stated that "[m]ost of [the regulated EGUs] are already in compliance, [and] investments have been made."[130] Ray Dotter, a PJM spokesman, accurately observed that "[f]or those stated to retire this spring, they're on a path to doing that."[131] For plants that retired earlier, he said: "You've shut the plant down, given up the permits, laid off your workers – it would be challenging to bring it back."[132] Pat Gallagher, director of the Environmental Law Program at the Sierra Club, stated that "[t]he number of plants where a decision will be dictated by the outcome of the Supreme Court case is close to nil."[133] Similarly, on April 14, 2015 (before the Supreme Court ruling), Bloomberg's Daily Environment Report published an article titled "Supreme Court

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[129] "SCE&G Accelerates Plans To Retire Coal-Fired Canadys Station", June 4, 2013, https://www.scana.com/news/news-detail/2013/06/04/sce-g-accelerates-plans-to-retire-coal-fired-canadys-station.

[130] *Available at* http://thehill.com/policy/energy-environment/246423-supreme-court-overturns-epa-air-pollution-rule.

[131] SNL Energy, "Supreme Court's eventual MATS ruling will be (mostly) moot", May 14, 2015.

[132] *Id.*

[133] *Id.*

MATS Decision Unlikely To Affect Power Company Compliance Plans,"[134] which quoted power company representatives from some of the largest operators of coal-fired power plants, including:

- **Ameren:** Steve Whitworth, senior director for environmental policy and analysis at Ameren Corp., said that given the uncertainty over litigation on the MATS rule, Ameren needed to move ahead with ensuring the company's four coal-fired power plants in Missouri had the necessary pollution control technology to comply. "Given that situation, we couldn't wait for the decision," Whitworth told Bloomberg BNA. "We had to be prepared to comply."

- **American Electric Power:** American Electric Power plans to retire 7,201 megawatts of coal-fired generating capacity by the end of 2016, including 24 coal-fired electric generating units by this spring, spokeswoman Melissa McHenry said. The units slated for retirement wouldn't be affected by a Supreme Court decision against the EPA, she said. "They have not been operated, staffed or maintained in a way that would support their continued operation," McHenry said.

- **FirstEnergy:** Stephanie Walton, a spokeswoman for FirstEnergy, said MATS has driven the deactivation of six coal-fired plants, with an additional three plant closures planned. Those three plants, the Eastlake, Lake Shore and Ashtabula plants in Ohio, are operating under "must-run" agreements with the grid operator but will be deactivated as of April 15, Walton said.

- **Tennessee Valley Authority:** The Supreme Court's decision won't have any effect on long-range decisions made by the Tennessee Valley Authority to close some plants and invest billions of dollars in others, TVA spokesman Duncan Mansfield told Bloomberg BNA. TVA has been making changes to its power portfolio for several years in anticipation of the MATS rule and other environmental regulations, Mansfield said. Also, a 2011 Clean Air Act settlement with the EPA led to TVA's commitment to retire 18 coal plants and spend $3 billion to $5 billion on pollution controls. The decisions include the retirement of some coal-fired power plants, the conversion of some coal facilities to natural gas and the installation of

[134] See http://www.bna.com/supreme-court-mats-n17179925278/.

scrubbers and selective catalytic reduction at coal-fired plants that will stay in operation, Mansfield said. "Basically, every time we make one of these decisions, it's a billion-dollar decision," he said. "It's not just MATS, but MATS is part of it."

- **Southern Company:** Southern Co. has made about $9 billion in investments in environmental control technology and anticipates spending an additional $2.1 billion over the next three years to comply with MATS and other environmental regulations, company spokesman Jack Bonnikson told Bloomberg BNA in an e-mail. Southern is installing scrubbers and other pollution control technology at coal plants with a total generating capacity of 13,500 megawatts, switching about 3,500 megawatts of capacity from coal to natural gas and retiring 3,500 megawatts of coal capacity, Bonnikson said.

The MATS rule was at least partially responsible for over 40,000 MW of coal-fired generating capacity retiring or converting from coal to natural gas during the period 2012 to 2015. These decisions were made prior to the ruling by the D.C. Court on the petition for review on April 15, 2014 and were implemented prior to the reversal by the Supreme Court on June 29, 2015. If the MATS rule had been vacated by the D.C. Court, it would have been too late to reverse most, if not all, of the decisions to stop burning coal at these units.

EXHIBIT 2

Technical Support Document (TSD) for the CAA Section 111(d) Emission Guidelines for Existing Power Plants

Docket ID No. EPA-HQ-OAR-2013-0602

CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule

U.S Environmental Protection Agency

Office of Air and Radiation

August 2015

Category-Specific Performance Rates and State Goal Setting Under 111(d)

This Technical Support Document (TSD) provides information that supports the EPA's determination of category-specific performance rates for fossil steam and stationary combustion turbine technology categories as well as the state emission rate and mass goals that encompass the likely affected fossil units in a state.[1] Section VI of the preamble discusses the category-specific performance rates more broadly along with some of the changes made between proposal and final based on comment. Section VII of the preamble describes the expression of the category-specific performance standards through a state goal metric reflecting likely covered fossil sources in a state. The Greenhouse Gas (GHG) Mitigation Measures TSD for CPP Final Rule explains the technical basis for the development of the Best System of Emission Reductions (BSER) that inform the category-specific performance rates and the subsequent state goals. This TSD provides detailed explanation of the data and the BSER-based calculations used to determine the category-specific performance rates and state goals. The TSD is organized as follows:

1. BSER factors informing the category-specific performance rates and state goals
    a. Block 1 - Heat rate improvement in the coal steam fleet
    b. Block 2 - Substitute increased generation from lower emitting existing NGCC units for reduced generation from higher emitting fossil steam EGUs
    c. Block 3 - Substitute generation from new zero emitting renewable energy (RE) generating capacity for reduced generation from higher emitting fossil EGUs
2. Form of the category-specific performance rates and state goals
3. Baseline data used to derive performance rates and state goals
    a. Emissions & Generation Integrated Resource Database (eGRID)
    b. Data sources for affected "under construction" units
    c. Region-level baseline
4. Methodology for determining category-specific performance rates
5. Methodology for converting category-specific performance rates into state emission rate goals
6. Methodology for converting state emission rate goals into mass goals
7. Appendix (attached Excel Workbook)
    - Appendix 1 – Underlying 2012 unit-level baseline inventory and data
    - Appendix 2 - Units that commenced operation post 2011, but commenced construction prior to 1/8/14
    - Appendix 3 – Underlying state-level data, adjustments, and region-level data
    - Appendix 4 – Computation of the category-specific performance rates (interim and final)
    - Appendix 5 - Computation of the state goal (interim and final)
    - Appendix 6 – State goal summary table
    - Appendix 7 – Calculation for generation adjustment in hydro-intensive states
    - Appendix 8 - Mass goal summary table
    - Appendix 9 – Description of 111(d) baseline data sources and development

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[1]The only natural gas fired EGUs currently considered affected units under the 111(d) applicability criteria are NGCC units capable of supplying more than 25 MW of electrical output to the grid. The data and rates for these units represents all emissions and MWh output associated with both the combustion turbines as well as all associated heat recovery steam generating units.

In EPA's technical evaluation, it assessed the cost and potential of each GHG emissions reducing technology identified (see GHG Mitigation Measures TSD). EPA relied on a similar building block structure as proposed, but revised the quantification of those building blocks based on comments. These revised building blocks levels were used to derive the category-specific performance rates provided in this final rule. The category-specific performance rates were then used to derive the state rate and mass goals.

1. BSER Factors Informing the Category-specific Performance Rates and State Goals

The GHG Mitigation Measures TSD describes three categories of emission reduction measures (building blocks) used in determining the category-specific performance rates. That document describes EPA's historical data review and analysis underlying each technology and informing EPA's assessment of its feasibility and cost-effectiveness as part of a BSER. It also explains how EPA made adjustments to the building blocks based on comments The technology estimates determined through EPA's analysis and documented in the GHG Mitigation Measures TSD are summarized below.

Table 1. 2030 Building Block Potential Identified for Each Region

	BB1 – Heat Rate Improvement (HRI) for Coal Fleet	**BB2** - TWh of Total NGCC Generation at 75 % Utilization, (Amount of NGCC Generation Potential Incremental to Baseline)	**BB3** - Incremental RE Potential (TWh)
Eastern Interconnection	4.3%	988, (253)	438
Western Interconnection	2.1%	306, (108)	161
Texas Interconnection	2.3%	204, (66)	107

Note - Totals are building block potential only (rounded). As evidenced in Section 4-step 8, not all of the building block potential is utilized in establishing BSER category-specific rates and state goals.

The building block data shown above are used to determine category-specific performance rates expressed in a lb/MWh rate. As these building blocks reflect both fossil and non-fossil measures, the corresponding category-specific performance rates also reflect fossil and non-fossil generation through the use of an adjusted emission rate described in the preamble and below.

2. Form of the Category-specific Performance Rates and State Goals

As described in Section VI of the preamble, EPA is promulgating a separate emission rate that quantifies BSER for each technology category covered under 111(d) applicability. Therefore, while similar adjustments are made to the generation levels of affected fossil steam and NGCC generation reflecting the building blocks, the adjustments are made and expressed at the source-category technology level rather than the combined affected EGU level:

Exhibit A - Simplified formula demonstrating category-specific emission performance rates

Final – Affected fossil steam and NGCC generation treated separately for quantifying BSER

$$\text{BSER for fossil steam} = \frac{\text{BSER adjusted emissions for affected fossil steam sources}}{\text{BSER adjusted generation for affected fossil steam sources}}$$

$$\text{BSER for NGCC} = \frac{\text{BSER adjusted emissions for affected NGCC sources}}{\text{BSER adjusted generation for affected NGCC sources}}$$

Note - adjusted generation and emissions includes generation and emissions from building block two and building block three

3. Baseline Data Used to Derive Performance Rates and State Goals

See Section VI of the Preamble for a description of EPA's identification of a baseline data.

Adjustments that the EPA made to the 2012 historical data

EPA received significant comments regarding unit-level data and applicability status. It has reviewed these comments and updated its 2012 unit-level data accordingly to better reflect unit-level operation in that year and likely unit-level applicability status. The updated unit-level data are available in appendix one and reflect changes based on comments.

In addition to unit-level data updates, the EPA also made some targeted baseline adjustments at the state-level to address commenter concerns about the representativeness of baseline year-data, even where correctly reported. These are highlighted below, but discussed in more detail in the Preamble Section VI.

State-level adjustments:

- EPA adjusted affected fossil baseline generation upwards in states with large hydro generation portfolios (adjustment calculations in appendix 7 and applied in appendix 3).
- EPA adjusted state-level generation upwards where a single unit outage – representing a significant portion of the generation portfolio – resulted in potentially unrepresentative state-level data (adjustment calculations in appendix 7 and applied in appendix 3).
- EPA adjusted state-level generation and emissions upwards to reflect the incremental impact of likely affected under construction fossil steam and NGCC capacity (including units commencing operation part way through 2012). (List of units available in appendix 2 and adjustment applied in appendix 3).

Once these adjustments were calculated, EPA summed the baseline data described above at the state and regional-level for the following categories. These totals reflect the adjusted baseline from which the performance rates and state goals are assessed.

- State and regional-level coal steam generation
- State and regional-level coal steam emissions
- State and regional-level oil/gas steam generation
- State and regional-level oil/gas steam emissions
- State and regional-level NGCC generation
- State and regional-level NGCC emissions
- State and regional-level NGCC capacity

All generation values are expressed as net generation. Emission rate values are net emission rates and expressed as lbs/MWh. The NGCC capacity expressed is net summertime capacity in megawatts. At proposal, there were a limited number of high utilization combustion turbines and integrated gasification combined cycle units (IGCCs) determined to be likely affected by 111(d) and placed in a separate "other" category when calculating state goals. In this final rule, the applicability language has been revised, and EPA's current assessment has not identified any simple-cycle combustion turbines that are likely affected units under this rule. The IGCCs that are likely affected by the rule are included with the coal steam totals consistent with comment, their fuel use, and reporting under subpart Da.

a. Emissions & Generation Integrated Resource Database (eGRID)

eGRID is an inventory of environmental attributes of the U.S. electric power system. It is a comprehensive source of air emissions data for the electric power sector, based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government. eGRID integrates many different data sources on power plants and power companies, including, but not limited to: the EPA, the Energy Information Administration (EIA), the North American Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission (FERC). Emissions data from the EPA are carefully integrated with generation data from EIA to produce useful values such as pounds per megawatt-hour (lb/MWh) of emissions, which allows direct comparison of the environmental attributes of electricity generation. EPA applied its eGRID methodology for matching the publicly available and reported 2012 emissions and generation data. The EPA relies on this most recent data to calculate category-specific performance rates and state goals.[2]

The state and region-level totals for each technology category described in the above bullets are intended to reflect the baseline totals for electric generating units (EGUs) that likely meet the applicability criteria as described in Preamble Section IV.D. [3]

b. Data sources for under construction units

At proposal, EPA relied on its National Electric Energy Data System (NEEDS). NEEDS includes basic geographic, operating, capacity, and other data on existing or under construction generating units. NEEDS was updated for EPA's new power sector modeling platform v.5.15 reflecting some of the unit-level information EPA received in the comment period. For a description of the sources used in preparing NEEDS v.5.15, see Documentation, Chapter 4: Generating Resources.[4] Several commenters identified units that were under construction and likely affected EGUs under the rule's applicability language, but that had not been included in the Proposal baseline. Per commenter suggestion, EPA performed an additional review of under construction units using EIA 860 data, NEEDS v.5.15, comments, the proposed 2012 unit-level data file, and other publically available sources. In most cases, commenter and publically available data supported one another. There were several instances where commenter and

[2] 2012 reflects the most recent data at the time EPA began its analysis for the Proposed Rule.
[3] The historical baseline development is described in more detail in Appendix 9
[4] Available at http://www.epa.gov/powersectormodeling/

reported data conflicted. In these cases, EPA generally relied on the publically available data to identify the likely affected under construction units to ensure consistent treatment across the fleet.

EPA notes that this baseline inventory does not constitute a final applicability determination, which are often done on a case-by-case basis. The actual inventory of affected units in a future year may vary from the baseline inventory of likely affected units.

c. Region-level data

The EPA aggregated unit-level data to the state level for purposes of state-specific emission rate and mass goal calculation discussed in Section VII of the Preamble. However, before calculating the state goal and mass equivalents, it further aggregated unit-level data to the regional level to calculate the category-specific performance standards. The regions reflect the Eastern, Western, and Texas Interconnections. These regions were used when quantifying the best system of emission reductions in order to capture the interstate effects of the building blocks. The rationale for the regional structure is explained in preamble section V.A. For each region, the EPA made BSER-related adjustments to the baseline data to determine the effect the three building block abatement measures could have on the average fossil steam rate and the average NGCC rate in that region. In making adjustments to region-level data, the EPA is simply identifying the BSER reductions that can be achieved on average at the regional level relative to baseline level. The EPA is not making any assertions about specific units or plant capability. The EPA recognizes the uniqueness and complexity of individual power plants, and is aware that there are site-specific factors that may prevent some EGUs from achieving performance equal to region-level assumptions for a given technology. Likewise, the EPA also recognizes that some EGUs are capable of, and regularly do, achieve performance levels that surpass the building block values assumed (e.g., greater than 75 percent utilization). In any case, the EPA is not making those unit-level evaluations in this exercise. The EPA is instead attempting to quantify what is feasible at the fleet-level based on application of the BSER values to historical regional-level data. Affected EGUs can then meet that emission rate through any particular use of abatement measures and/or emission reduction credits that it chooses. Therefore, the ability or inability of a specific EGU to under/overachieve the assumed technology value cannot be taken, on its own, as an indication of the appropriateness of the category-specific performance standards and the state goals estimated using this approach.

The aggregate baseline generation and emission rates constitute a representative baseline for the power fleet for units likely subject to 111(d) applicability criteria. As with other EPA regulations, there may be subsequent applicability determinations post rule finalization that arrive at a different status determination for a particular unit than the one assumed here. Moreover, the future year inventory of affected units will inherently vary due to scheduled fleet turnover. While EPA addressed unit-level data comments, there may also be areas where stakeholders disagree over unit-level representation in the baseline. However, it is the regional representation of the power sector based on historical data that ultimately informs the category-specific emissions rates. The large population size of units encompassed by the aggregate regional-level values used to quantify emission performance rates limit the ability of any unit-level inventory or data discrepancies to introduce a bias that alters this collective representation.

EPA received comments suggesting that it should remove units scheduled to retire from the baseline inventory. It also received comments suggesting that they should not be removed. EPA is using 2012 as a representative year for operating units as it is the most recently available data and does not try to forecast future generation and emission levels for these units. Even where fleet turnover is certain, (e.g., a scheduled retirement), the impact of that retirement is not. Removing units and generation from the baseline inventory without accounting for the shift in generation to other units would understate the amount of fossil generation in the baseline and distort its representativeness. Accounting for the shift in generation would begin to shift the baseline from a historical-data informed baseline to a projection-informed baseline. Factoring in retirements and replacing it with projected generation shifts would undermine the merits of relying on a historical data set and the certainty of reported data for units operating in 2012.

4. Methodology for Determining Category-specific Emission Performance Rates

EPA's methodology for calculating category-specific performance rates is described in the steps below. The implementation of each step is illustrated –using the Eastern Interconnection for year 2030 as an example - in the table below its description.[5][6]

Step 1: Compile 2012 unit-level data, aggregate to state-level, make baseline adjustments, and sum to regional baseline totals.

The EPA begins the category-specific performance rate calculation by starting with 2012 historical data. The underlying unit-level or plant-level data reflects emissions and generation reported by the facility (See Appendix 9 for more detailed explanation). EPA categorized each unit, using the classification system described in Appendix 9, as coal steam, O/G steam, or NGCC.[7] It also flagged units that fit these technology categories and were considered to have commenced construction by 1/08/2014[8]. EPA then aggregated the unit-level data for the coal steam, O/G steam, and NGCC units (not including those flagged as under construction) to the state level and calculated the state-specific emission rate for each technology category by dividing the total emissions by the total generation. This reflected the unadjusted 2012 data for units that commenced operation prior to 2012. For states that have likely affected EGUs in two different interconnections, EPA segmented these states into their relevant interconnect portions at this step (e.g., the Montana Eastern Interconnection and Montana Western Interconnection). EPA then made the aforementioned adjustments to the state-level values to address concerns addressed by commenters. This included adding in the expected incremental generation and emissions from likely affected units considered under construction. The resulting state-totals following these limited adjustments provided an adjusted 2012 baseline for all likely affected EGUs.[9] Complete data for these steps is available in appendices 1, 2 and 3. See the North Carolina example below illustrating the adjustment made to 2012 data reflecting under construction units.

EPA received stakeholder comment noting that the Lee and Dan NGCC plants and the Cliffside coal unit six commenced operation part way through 2012 and therefore should be treated as under construction since they were still under construction for part of the year and 2012 data was not representative of a full year's operation. EPA described in preamble section VI how it incorporated this type of adjustment into its baseline.

[5] As described in the GHG Mitigation Measures TSD, the building blocks have different assumed levels over the 2022-2030 time frame reflecting technology deployment assumptions. Therefore, the rates described below vary by year due to the amount of building block potential specified for that year.
[6] Note – values in tables are rounded for illustrative purposes. Actual calculations with all significant digits can be found in Appendix 1-5.
[7] EPA only flagged units as one of these technology categories if it determined it to be of that technology class and a likely affected EGU (e.g., greater than 25 MW). Units of this technology class, but determined to be not likely affected are categorized as exclude.
[8] "Commence" and "construction" defined in 40 CFR 60.2
[9] Adjustments accounting for significant unit-level outages, hydro outlier years, and under construction sources.

The example below illustrates where EPA first identified 2012 data from likely affected units that were not under construction (Table 2 - columns B & C), then identified under construction capacity (columns D and E), and then adjusted the baseline generation values up to reflect anticipated incremental baseline generation values assuming a more representative full-year utilization for these units (columns F & G). The emissions for these state are also adjusted upwards by multiplying each state's adjusted generation for a given technology by that technologies emission rate in that state.[10]

Table 2. Example of Adjustment to 2012 Data

A	B	C	D	E	F	G
	2012 Data for Affected Units (excluding under construction)		Adjustment for Affected Under Construction Units		Adjusted Baseline	
	Coal Generation (MWh)	NGCC Generation (MWh)	Under Construction Coal Capacity (MW)	Under Construction NGCC Capacity (MW)	Coal Generation (MWh)	NGCC Generation (MWh)
North Carolina	50,572,372	15,060,254	825	2,165	54,920,452	25,519,802

NGCC =15,060,254 MWh + (8784 hours × 2,165 MW × 55% capacity factor) = 25,519,802 MWh[11]

Coal = 50,572,372MWh + (8784 hours × 60% capacity factor × 825 MW) = 54,920,452 MWh

Step 2: Aggregate the adjusted historical emissions and generation to a regional level for coal steam, OG steam, and NGCC technology categories.

[10] For states that had under construction technology (e.g., NGCC), but no prior affected units of that generating technology in the state for which the benchmark emission rate could be identified, EPA used the average NGCC emission rate of 908 lb/MWh identified for all states that had affected NGCC EGUs in 2012 (Appendix 3).

[11] As described in the preamble section VI, EPA established a 55 percent capacity factor as representative of the incremental baseline impact of new NGCC units (60 percent for new coal) informed by both comments and a review of 2012 utilization patterns for units that recently commenced operation. The 2,165 MW capacity value reflects summertime capacity and includes the L.V Sutton Plant which was also under construction. 8,784 hours are used instead of 8,760 to be consistent with the number of hours in the 2012 leap year for which the baseline is premised. The under construction coal capacity in column D reflects Cliffside 6 which commenced operation part way through 2012, so was classified as under construction consistent with comment recommendation. The only exception to this adjustment is the Kemper IGCC under construction unit which receives the same assumptions it did at proposal of 70 percent capacity factor and an 800 lb/MWh emission rate that are relative to its unique circumstance as the only under construction facility with carbon capture and storage technology. (See file titled "supporting data informing capacity factor estimation for under construction sources-coal" in the docket for this rulemaking.

Once EPA has the adjusted state-level generation and emission for each state from step 1, it summed the state totals for all states in the same region to derive regional totals. EPA kept the technology-source categories separate at this stage to evaluate BSER impacts separately for each source category. These category-specific values become the basis for calculating the category-specific performance emission rates and subsequent state goals.

Table 3. Regional Baseline

A	B	C	D	E	F	G
	Coal		NGCC		OG Steam	
Interconnection	Emissions (1000 short tons)	Net Generation (GWh)	Emissions (1000 short tons)	Net Generation (GWh)	Emissions (1000 short tons)	Net Generation (GWh)
Eastern	1,356,066	1,230,448	328,220	734,535	52,979	74,241

Step 3: <u>Identify category-specific baseline emission rates for fossil steam and NGCC</u>

Fossil steam sources include both coal steam and oil/gas steam affected sources, whose data are combined to arrive at a fossil steam emission rate and generation total for each interconnection. This emission rate (Table 4 - column H) reflects the sum of coal emissions from column B and O/G steam emissions from column F divided by the baseline generation for each technology from columns C & G. Because the BSER involves both reductions in emissions intensity of sources (e.g., heat rate improvements) and reductions in generation of sources (e.g., shifting from fossil to renewable generation), the baseline emission rate and generation for each technology source category are utilized to assess the potential impact of the building blocks. All emission rates provided are on a <u>net</u> basis. This step is shown here for illustrative purposes, but combined with step 4 in appendix 4.

Table 4. Baseline Category-specific Emission Rates and Generation.

A	B	C	D	E	F	G	H	I	J	K
	Coal		NGCC		OG Steam		Fossil Steam		NGCC	
Interconnection	Emissions (1000 short tons)	Net Generation (GWh)	Emissions (1000 short tons)	Net Generation (GWh)	Emissions (1000 short tons)	Net Generation (GWh)	Emission Rate (lb/MWh)	Net Generation (GWh)	Emission Rate (lb/MWh)	Net Generation (GWh)
Eastern	1,356,066	1,230,448	328,220	734,535	52,979	74,241	2,160	1,304,689	894	734,535

Eastern fossil Steam Rate = $\frac{\text{coal emissions + OG emissions}}{\text{Coal gen + OG gen}}$ = *Eastern fossil steam rate* = $\frac{\text{1,356,066,366 tons +52,979,259 tons}^{12}}{\text{(1,230,447,795 MWh + 74,240,802 MWh)}}$ = 2,160 lbs/MWh

Eastern NGCC Rate = $\frac{\text{NGCC emissions}}{\text{NGCC gen}}$ = *Eastern NGCC Rate* = $\frac{\text{328,219,519 tons}}{\text{734,535, 157 MWh}}$ = 894 lb/MWh

Step 4: Calculate regional fossil steam emission rate resulting *from building block 1 heat rate improvement (HRI).*

After this baseline data are aggregated for each region, the EPA begins to adjust some of the data values to reflect each building block element of BSER. The EPA assumes a 2.1 percent heat rate improvement in the Western Interconnection, a 2.3 percent HRI in the Texas Interconnection, and a 4.3 percent heat rate improvement in the Eastern Interconnection applied only to the coal steam fleet. This is reflected by adjusting the coal emissions down by the region-specific heat rate improvement percentage and leaving the generation level unchanged. Subsequently, the fossil steam rate for the region is calculated by adding the adjusted coal emissions subsequent to the heat rate improvement assumption (Table 5 - column H) with the baseline OG steam emissions (column D) and dividing by the sum of the coal steam (column C) and OG steam generation (column E). There is no change in the NGCC rate from this step.

[12] Tons converted to lbs using 2,000 pounds to 1 short ton conversion

Table 5. Adjusted Fossil Steam Rate Reflecting Building Block 1								
A	B	C	D	E	F	G	H	I
	Baseline Coal		Baseline OG Steam		Baseline Fossil Steam	BB1		
Interconnection	Emissions (1000 short tons)	Net Generation (GWh)	Emissions (1000 short tons)	Net Generation (GWh)	Emission Rate (lb/MWh)	BB1 HRI Level	Post BB1 Coal Emissions (1000 short tons)	Fossil Steam Emission Rate Post BB1 (lb/MWh)
Eastern	1,356,066	1,230,448	52,979	74,241	2,160	4.3%	1,297,756	2,071

When the technology emission rate is recalculated with building block 1 reflected in the adjustment to the region's coal emissions, the region's fossil steam emission rate drops below its baseline value. Note that the fossil steam rate reflects the aggregation of both coal and OG steam data. This is not the final category-specific performance rate, rather it is an adjusted emission rate reflecting the application of building block 1 before moving on to the remaining building blocks. The bold areas in the equation below reflect the values that are adjusted from their baseline level at this step. In this example, the fossil steam rate drops from a baseline value of 2,160 lb/MWh to 2,071 lb/MWh after building block 1 application.

$$\textit{Eastern fossil steam rate} = \frac{\mathbf{(coal\ emissions \times (1\text{-}HRI\%)} + \text{(OG emissions)}}{\text{Coal gen} + \text{OG gen}} = \frac{\mathbf{(1{,}356{,}066{,}366\ tons) \times 0.957} + 52{,}979{,}259\text{ tons}}{(1{,}230{,}447{,}795\text{ MWh} + 74{,}240{,}802\text{ MWh})} = 2{,}071\text{ lbs/MWh}^{13}$$

<u>**Step 5:** Calculate regional fossil steam and NGCC generation levels resulting from building block 3 (incremental RE generation)</u>

Building Block 3 is based on lower-emitting generation replacing higher emitting generation. The GHG Mitigation Measures TSD describes how the incremental RE generation potential for each region was derived. As explained in the TSD, the building block 3 potential is defined as only incremental RE generation (incremental relative to 2012 levels). Therefore the computation of category-specific performance rates and state goals for the final rule only reflect this incremental RE total. All incremental building block 3 RE is assumed to emit zero tons of CO_2.

[13] To replicate the calculation, need to use a 2000 lbs:1short ton conversion ratio

For this final rule, EPA assumes that building block 3 incremental generation replaces existing fossil generation from the baseline levels. The replacement impact on each technology category is estimated on a pro-rata basis where the incremental building block 3 generation is first identified (Table 6 - column F), and then apportioned to replace either fossil steam (column D × column F = column I) or NGCC generation (column E × column F = column J) based on the share of baseline generation each technology category represents. For example, if a region had 100 MWh of potential building block 3 generation identified, and baseline fossil steam accounted for 70 percent of the region's generation from affected units and NGCC accounted for 30 percent, then the 100 MWh of incremental RE identified would be assumed to replace 70 MWh of fossil steam generation and 30 MWh of NGCC generation. The fossil steam generation and NGCC generation are decreased by the amount of RE MWh apportioned to that technology (column B – column I) and (column C – column J). The total baseline generation (columns B & C) equals the total remaining generation and renewable generation (columns G, H, I, and J) reflecting that replacement of fossil sources by incremental RE generation.

Table 6 - Adjusted Fossil Steam and NGCC Generation Reflecting Building Block 3

A	B	C	D	E	F	G	H	I	J
	Baseline Gen.		BB3						
Interconnection	Fossil Steam Net Generation (GWh)	NGCC Net Generation (GWh)	Fossil Steam Share of Total Fossil Gen.	NGCC Share of Total Fossil Gen.	Potential BB3 (GWh)	Remaining Fossil Steam (GWh)	Remaining NGCC Gen (GWh)	BB3 Assigned to Fossil Steam (GWh)	BB3 Assigned to NGCC (GWh)
Eastern	1,304,689	734,535	64%	36%	438,445	1,024,173	576,606	280,515	157,929

Eastern Fossil Steam Gen. = Baseline Fossil Steam gen. - (Potential BB3 Gen x fossil steam share of total fossil gen.)

Eastern Fossil Steam Gen. = 1,304,689 GWh – (438,445 GWh × 64%) = 1,024,173GWh

Eastern NGCC Gen. = Baseline NGCC gen - (Potential BB3 Gen × NGCC share of total fossil gen.)

Eastern NGCC Gen. = = *734,535 GWh– (438,445 GWh × 36%) = 576,606 GWh*

Step 6: Calculate regional fossil steam and NGCC generation resulting from building block 2 (incremental NGCC generation)

The "Remaining NGCC Generation" field in Table 7 - column C below indicates that there is less NGCC generation – relative to baseline levels - following building block 3 incorporation due to the assumption that some of the incremental RE would replace baseline NGCC generation. Moreover, there is significantly less generation than the potential identified in building block 2 that reflects a 75 percent utilization. If only implementing building block 3, the NGCC generation levels would be assumed to decrease under a pro-rata replacement approach. However, in the GHG Mitigation Measures TSD, the EPA described the abatement potential of replacing higher emitting fossil steam generation with lower emitting gas generation, identified as building block 2. This step of the rate calculation captures the change in source-category generation levels associated with building block 2 potential of a 75 percent potential utilization for the NGCC fleet.

To incorporate building block 2, the regional NGCC fleet summertime capacity is multiplied by 8,784 hours (the number of hours in the 2012 leap year) and then by 75 percent to get total potential net NGCC generation at a 75 percent capacity factor (Table 7 - column D). However, this 75 percent capacity factor represents a generation ceiling, and the region's NGCC generation is only adjusted up to this ceiling to the extent that such NGCC generation increases can replace remaining fossil steam generation.[14] Note that the combined remaining fossil steam and NGCC generation from columns F and G in this table reflect the remaining fossil steam and NGCC generation total after BB3 (columns B and C). Moreover, columns F and G combined with the RE potential assigned to each technology in columns I and J in the previous table sum to the total baseline fossil generation assumed for each region.

[14] The ceiling in the early interim period years is less than the 75 percent utilization level. The BB2 deployment schedule is discussed in the GHG Mitigation Measures TSD.

Table 7. Adjusted Fossil Steam and NGCC Generation Reflecting Replacement by Building Block 3 and Building Block 2 Generation						
A	B	C	D	E	F	G
	Post BB3		BB2			
Region	Remaining Fossil Steam (GWh)	Remaining NGCC Gen (GWh)	NGCC Potential at 75% CF (GWh)	Difference between NGCC generation levels at full BB2 utilization and Post BB3 NGCC levels (GWh)	Remaining Fossil Steam (GWh)	Remaining NGCC Gen (GWh)
Eastern	1,024,173	576,606	987,857	411,250	612,922	987,857

In the above example, NGCC generation is adjusted upwards by approximately 411,250 GWh (column E) to 987,857 GWh (column G) (which equals the NGCC fleet generation at 75 percent utilization) and the fossil steam generation is adjusted down by that same amount (column B - column F).

Eastern Fossil Steam Gen = Post BB3 fossil steam gen. - (NGCC Potential at 75% CF – Post BB3 NGCC Gen)[15]

Eastern Fossil steam Gen = 1,024,173 GWh – (987,857 GWh – 576,606 GWh) = 612,922 GWh

Eastern NGCC Gen = Post BB3 NGCC gen + (Step 6 change in fossil steam generation above)

Eastern NGCC Gen = 576,606 GWh + (1,024,173 GWh – 612,922 GWh) = 987,857 GWh

Step 7: Determine the adjusted category-specific performance rates for each region reflecting the heat rate improvement and generation shifts.

[15] If (NGCC Potential at 75 percent CF – Post BB3 NGCC Gen) is greater than post BB3 fossil steam gen, then the fossil steam generation amount is adjusted to zero and the NGCC generation amount is increased by the post BB3 fossil steam generation amount that it replaced.

Step four estimated the category-specific emission rates post building block 1. Steps five and six estimated the category-specific generation levels post building block 3 and 2, respectively. Combining the adjusted emission rates with the adjusted generation from those steps allows EPA to calculate a category-specific adjusted emission rate that reflects the expression of the three building blocks on the baseline. In this step, EPA was careful to apportion incremental generation in a manner consistent with the building block levels, and that respected the pro-rata nature of building block three. See Section VI of the preamble for further explanation.

For the regional fossil steam rate, EPA first calculates the numerator. EPA multiplies the fossil steam emission rate from step four (Table 8 - column F) (reflecting the heat rate improvement) by the remaining fossil steam generation following step six (column O). For building block 3, all renewable generation was assumed to equal zero so no numerator adjustment was made. As described in the preamble, EPA also captures a portion of the NGCC generation in the fossil steam rate reflecting the incremental building block 2 potential used;[16] this incremental NGCC generation is defined as the amount of total NGCC subsequent to both blocks 2 and 3 (column P) minus the amount of NGCC generation in the baseline (column E).[17] This level of reassignment is consistent with the maximum amount of incremental generation identified in building block two. This amount of NGCC generation is multiplied by the NGCC emission rate from step three (column C) to get the amount of incremental NGCC emissions assigned to the numerator of the fossil steam emission rate as part of building block 2.

[16] As described in the preamble sections VI and VIII and the Federal Plan Proposal, EPA reflected the incremental NGCC generation (and corresponding emissions) in the fossil steam rate source category rate and created a parallel compliance structure for quantifying NGCC ERCs which fossil steam sources may use in compliance.

[17] EPA also considered quantifying the amount of NGCC generation assigned to fossil steam generation as post step 6 levels minus post step 5 levels which would have resulted in a lower fossil steam rate. However, this definition would not have reflected a different BSER (generation and emission rates arrived at in step 4 through 6) because a similar adjustment would be made when measuring and quantifying NGCC ERCs available for compliance (ERCs are credits reflecting the incremental NGCC that fossil steam sources may use for compliance with their rate). In other words, there would be a nominally lower rate, but simultaneously more credits would be awarded for the same level of NGCC generation to comply with that rate. EPA determined that measuring incremental NGCC generation to include in the fossil steam rate was more appropriately done using a baseline level (premised on historical generation) as it best reflected the incremental levels defined in the building block and preserved the pro-rata intent of building block three. It also assured the total amount of MWhs of incremental RE and NGCC assigned to the steam and NGCC rates do not exceed the total identified in the building blocks. See section VI of the preamble for more discussion on how EPA considered this choice. The remaining fossil steam and NGCC generation levels after this step appropriately reflect the full building block two and three potential, and the portion of the NGCC emissions and generation levels included in the fossil steam rate appropriately reflect the amount of incremental building block two potential identified.

These emissions from fossil steam sources along with emissions from incremental NGCC EGUs are then divided by the total amount of remaining fossil steam generation, the renewable generation assigned to fossil steam, and the incremental NGCC defined above. This generation is the sum of 1) remaining fossil steam generation post step six (column O), 2) amount of renewable generation assigned to fossil steam generation (column M), and 3) the amount of NGCC generation defined above (column P -column E). Dividing this total emissions level by the total generation levels results in a regional fossil steam emission rate reflective of BSER.

For the regional NGCC emission rate, EPA performs a similar operation. The NGCC generation post step six (column P) is multiplied by the NGCC baseline emission rate from step three (column C) to estimate the total amount of NGCC emissions post building block 3 and building block 2. These emissions are then divided by the sum of the NGCC generation post step six (column P) and the amount of building block 3 renewable generation assigned to NGCC generation in step five (Column N).[18] This regional NGCC rate reflects the adjusted NGCC rate reflecting BSER.[19]

Table 8. Adjusted Fossil Steam and NGCC Generation Rates Reflecting all Three Building Blocks																	
	Adj. Baseline				BB1 HRI		BB3 - RE							BB2 - NGCC		Final Rates	
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Interconn	Fossil Steam Rate	NGCC Rate	Fossil Steam Gen	NGCC Gen	Fossil Steam Rate	NGCC Emission Rate	Fossil Steam Share of Total Fossil	NGCC Share of Total Fossil	Potential BB3	Remaining Fossil Steam	Remaining NGCC Gen	BB3 generation assigned to fossil steam	BB3 generation assigned to NGCC	Remaining Fossil Steam	Remaining NGCC Gen	Fossil Steam Rate	NGCC Rate
	lb/MWh	lb/MWh	GWh	GWh	lbs/MWh	lbs/MWh			GWh	GWh	GWh	GWh	GWh	GWh	GWh	lb/MWh	lb/MWh
Eastern	2,160	894	1,304,689	734,535	2,071	894	64%	36%	438,445	1,024,173	576,606	280,515	157,929	612,922	987,857	1,305	771

$$\textit{Eastern Fossil Steam Gen} = \frac{(\text{Post BB3\&2 fossil steam gen} \times \text{Post BB1 fossil steam emission rate}) + (\text{Incremental NGCC Generation} \times \text{baseline NGCC rate})}{(\text{Post BB3\&2 fossil steam gen} + \text{BB3 generation replacing fossil steam} + \text{incremental BB2 generation})}$$

$$\textit{Eastern Fossil steam Gen} = \frac{(612{,}922,\ 289\text{ MWh} \times 2{,}071\text{lb/MWh}) + ((987{,}857{,}765\text{ MWh} - 734{,}535{,}157\text{Wh}) \times 894\text{ lb/MWh})}{612{,}922{,}289\text{ MWh} + 280{,}515{,}465\text{ MWh} + (987{,}857{,}765\text{ MWh} - 734{,}535{,}157\text{ MWh})} = 1{,}305\text{ lb/MWh}$$

[18] The full NGCC generation (and corresponding emissions) expected under the BSER calculation from that source category is included in the NGCC rate, even though a portion of it is also reflected in the fossil steam rate. Failing to do so would leave the NGCC sources with a lower rate than what is expected post building block 2 and building block 3 when accounting for all of their generation and block three responsibility. Keeping the full NGCC generation amount in the NGCC rate recognizes the dual role NGCC has in terms of compliance responsibility as an affected EGU and a mitigation measure under building block two that that can offset fossil steam generation.

[19] As described later, EPA rounds the 2030 final rates up to the nearest integer (1,305 lb/MWh and 771 lb/MWh in this case)

$$\text{Eastern NGCC Gen} = \frac{(\text{Post BB3 NGCC gen} \times \text{NGCC baseline rate})}{(\text{Post BB3 NGCC gen} + \text{BB3 generation replacing NGCC gen})}$$

$$\text{Eastern NGCC Gen} = \frac{(987{,}857{,}765 \text{ MWh} \times 894 \text{ lb/MWh})}{(987{,}857{,}765 \text{ MWh} + 157{,}929{,}234 \text{ MWh})} = 771 \text{ lb/MWh}$$

Step 8: Identify the least stringent regional rate as the emission performance rate for the technology source category

After completing a regional assessment of building block potential impact on source category-specific rates, EPA evaluated the resulting fossil steam and NGCC rate for each region to identify the region with the least stringent emission rate. The least stringent (i.e., the highest) fossil steam rate and the least stringent NGCC emission rate among the three regions are identified and used to establish the source-category emission performance rates described in the preamble.

Table 9. Identify Least Stringent Rate for Each Technology Category (2030)

	Adjusted Rates	
Region	Fossil Steam Rate (lb/MWh)	NGCC Rate (lb/MWh)
Eastern Interconnection	1,305	771
~~Western Interconnection~~	~~360~~	~~690~~
~~Texas Interconnection~~	~~237~~	~~697~~

The completion of the previous steps results in a 2030 emission performance rate for each source category. However, as described in the GHG Mitigation Measures TSD, the building block 2 and building block 3 assumed potential changes for each year from 2022 through 2030. Thus this procedure is repeated for each of those years using the corresponding building block 2 and building block 3 assumptions for that year that reflect the deployment rate for those technologies.[20] This results in a set of decreasing annual adjusted emission rates for the years 2022-2029. However,

[20] The region with the least stringent rate can differ by year. For the fossil steam rate, the Eastern Interconnection is the limiting region in all years. For the NGCC rate, the Texas Interconnection is the limiting region for 2022 through 2026, and the Eastern Interconnection is the limiting region for 2027 through 2030.

this rulemaking issues category-specific emission performance rates for an interim and a final rate. Thus, the interim rate is derived by averaging the annual adjusted emission rates for 2022-2029. Once the interim and final rates are determined, EPA rounds any fractional number up to the nearest integer for these two values. This completed the quantification of BSER and established nationwide uniform category-specific rates.

For the Final CPP Rule category-specific rates (lbs/MWh):

Interim category-specific rate – Average of the adjusted yearly emission rates for the period 2022-2029

Final category-specific rate– The 2030 emission rate (as calculated above) becomes the final category-specific rate for 2030 and each year thereafter

Annual Category-specific Rates											
	2022	2023	2024	2025	2026	2027	2028	2029	2030	Interim	Final
Fossil Steam	1,741	1,681	1,592	1,546	1,500	1,453	1,404	1,355	1,304	1,534	1,305
NGCC	898	877	855	836	817	798	789	779	770	832	771

The assumptions used to arrive at the category-specific performance rates are not prescriptive of necessary actions that sources, states, or regions must take. As described in the preamble, these values are used only for calculating the emission performance rates and state goals. A state is not required to base its state plan on using the same set of measures or the same amount of any measure reflected in these assumptions. Likewise, the state plan, not these assumptions, determines the range of available measures a source may or must use to comply with the standards of performance established for it in the state plan and the extent to which the source may or must rely on any individual measure.

5. Methodology for Converting Category-specific Rates into State Emission Rate Goals

See section VII of the preamble for more discussion on this conversion. To calculate a state goal in the final CPP, EPA estimates the affected fleet rate for a state if all likely affected baseline EGUs meet the respective category-specific emission performance rates presented above (through any on-site or off-site means it chooses) while generating at the same baseline generation total. These blended state rates reflect the fleet emission rate from likely affected units in the state if they operated at baseline generation levels while meeting the category-specific rates.

For example, the 2030 nation-wide 111(d) source category rates determined at the regional level were 1305 lb/MWh and 771 lb/MWh respectively. The state of Arizona had baseline affected fossil generation consisting of 25.37 TWh of fossil steam generation and 26.78 TWh of NGCC generation. Arizona's 2030 state goal metric would be calculated as follows:

The fossil steam baseline generation is multiplied by the fossil steam category rate and the NGCC baseline generation is multiplied by the NGCC category rate. The emissions from the two are added together and then divided by the total baseline generation.

$$\text{Arizona State goal} = \frac{(25{,}370{,}640 \text{ MWh} \times 1{,}305 \text{ lb/MWh}) + (26{,}783{,}421 \text{ MWh} \times 771 \text{ lb/MWh})}{(25{,}370{,}640 \text{ MWh} + 26{,}783{,}421 \text{ MWh})} = \mathbf{1{,}031\ lb/MWh}$$

Another way to view this calculation is as a weighted average of the source category rates based on each state's baseline generation mix. For each state, EPA calculated a weighted average of the category-specific fossil steam rate and the category-specific NGCC using the state's baseline generation levels for each source category to determine the weights. Arizona state goal = (Fossil steam source category rate × Fossil steam baseline share of affected generation) + (NGCC source category rate × NGCC baseline share of affected generation)

Arizona State Goal = (48.65 % × 1,305) + (51.35% × 771) = **1,031 lb/MWh**.

EPA performs this calculation for each year from 2022-2030. These values are used to average the step 1 (2022-2024 average), step 2 (2025-2027 average), and step 3 (2028-2029 average) state rates shown in section VII of the preamble and further discussed in section VIII. It also performs this step for the interim state goal and final state goal. In other words, the interim state goal reflects the weighted average of the interim source-category rates.

EPA uses the representative baseline and calculations described above to derive category-specific rates and state emission rate goals. Once calculated, the system-wide impacts and feasibility of these state goals are further examined using EPA's power sector modeling.[21]

6. Methodology for Converting State Emission Rate Goals into State Mass Goals

[21] See Regulatory Impact Analysis for CPP Final Rule

The calculation of affected EGU mass goals includes two components. First, it includes the emissions associated with each state's emission rate goal, which is the product of the state emission rate goal and 2012 affected EGU generation. Second, it includes the emissions associated with the ability of affected EGUs to expand output under rate-based compliance if they deployed the amount of RE quantified under building block 3 that was not captured in the ultimate quantification of the source category-specific performance rates.

The procedure for quantifying this level of excess building block 3 generation applies to the values and calculations in Appendix 4. Below is an excerpt from Appendix 4 that displays building block 3 data and regional fossil steam and NGCC rates for 2030:[22]

	L	M	N	O	P	Q	R	S	T	U	V	W
4	BB3 - RE							BB2 - NGCC			Final Rates	
5	Fossil Steam Share of Total Fossil	NGCC Share of Total Fossil	Potential BB3	Remaining Fossil Steam	Remaining NGCC Gen	BB3 Replacing Fossil Steam	BB3 Replacing NGCC	Difference between NGCC generation levels at 75% utilization and Post BB3 NGCC levels (MWh)	Remaining Fossil Steam	Remaining NGCC Gen	Fossil Steam Rate	NGCC Rate
6			MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	lb/MWh	lb/MWh
7	64%	36%	438,444,700	1,024,173,131.57	576,605,922.60	280,515,465.25	157,929,234.48	411,250,843	612,922,288.97	987,856,765.20	1,304.1	770.5
8	52%	48%	160,974,866	133,150,511.26	121,552,103.89	84,152,593.57	76,822,272.03	184,936,809	-	254,702,615.14	360.3	690.4
9	47%	53%	106,610,547	72,899,648.11	81,054,180.52	50,481,832.29	56,128,714.66	122,596,052	-	153,953,828.63	237.2	697.0

Columns V and W in Appendix 4 display the regional fossil steam and NGCC rates after the full application of the building blocks. Any regional rates lower than the highest, unrounded regional rates (1,304.1 lbs/MWh for fossil steam and 770.5 lbs/MWh for NGCC)[23] indicate that the region contains more building block 3 generation potential than is necessary to achieve parity with the limiting region's rate. In order to quantify that

[22] The excerpt from Appendix 4 has been modified slightly to increase legibility.
[23] The highest regional fossil steam and NGCC rates are rounded up to the nearest whole number to produce the source category-specific emission performance rates.

amount of excess building block 3 generation, the EPA designed an optimization algorithm to reduce the region's building block 3 potential (column N) until the regional rate was equal to the limiting region's rate for each source category. The optimization algorithm is designed to:

- Minimize 'Potential BB3' (column N) in each region[24] for each year by changing values for 'Potential BB3,' 'Fossil Steam Share of Total Fossil,' and 'NGCC Share of Total Fossil' (columns L and M).[25]
- Subject to the following constraints:
    - 'Fossil Steam Share of Total Fossil' and 'NGCC Share of Total Fossil' must sum to 100 percent and neither value can exceed 100 percent nor be below 0 percent. The 'Share of Total Fossil' values control how the total amount of building block 3 generation is assigned to each subcategory in each region. For example, an 80 percent value under 'Fossil Steam Share of Total Fossil' indicates that 80 percent of all building block 3 generation in that particular region is being applied to the fossil steam subcategory.
    - 'Fossil Steam Rate' must be less than or equal to the unrounded fossil steam rate in the limiting region
    - 'NGCC Rate' must be less than or equal to the unrounded NGCC rate in the limiting region

After minimizing 'Potential BB3' for each region according to the procedure described above, the updated Appendix 4 values are:

[24] Each row is a different BSER region – row 7 is the Eastern Interconnection, row 8 is the Western Interconnection, and row 9 is the Texas Interconnection.
[25] Note that even when the minimization procedure increases the share of potential BB3 generation assigned to a subcategory of affected EGUs, the total amount of building block 3 generation assigned to that subcategory (i.e., potential BB3 generation multiplied by the share) is always reduced from the original value. The fossil steam and NGCC shares of total generation are allowed to vary in this computation because the RE quantified under building block 3 that was not captured in the source category-specific performance rate could be deployed and claimed for compliance by either fossil steam or NGCC units, as long as the amount of building block 3 generation assigned to that source category is not greater than the original value.

	L	M	N	O	P	Q	R	S	T	U	V	W
1												
2												
3												
4	BB3 - RE							BB2 - NGCC			Final Rates	
5	Fossil Steam Share of Total Fossil	NGCC Share of Total Fossil	Potential BB3	Remaining Fossil Steam	Remaining NGCC Gen	BB3 Replacing Fossil Steam	BB3 Replacing NGCC	Difference between NGCC generation levels at 75% utilization and Post BB3 NGCC levels (MWh)	Remaining Fossil Steam	Remaining NGCC Gen	Fossil Steam Rate	NGCC Rate
6			MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	lb/MWh	lb/MWh
7	64%	36%	438,444,700	1,024,173,131.57	576,605,922.60	280,515,465.25	157,929,234.48	411,250,843	612,922,288.97	987,856,765.20	1,304.1	770.5
8	5%	95%	53,596,923	214,684,939.35	147,395,618.05	2,618,165.48	50,978,757.87	159,093,294	55,591,644.99	306,488,912.40	1,304.1	770.5
9	0%	100%	47,732,996	123,381,480.40	89,449,899.41	-	47,732,995.77	114,200,333	9,181,147.41	203,650,232.40	1,095.9	770.5

The amount of 'Potential BB3' across all regions that is not needed to meet the limiting region's NGCC and fossil steam rates for 2030 is 166,255,493 MWh, obtained by subtracting the minimized building block 3 generation potential in column N (539,774,619 MWh) from the total potential identified in the quantification of building block 3 (706,030,112 MWh).[26] It is this difference in "Potential BB3" that was not captured in the ultimate quantification of the source category-specific performance rates, and that affected EGUs could deploy to expand output and associated emissions under rate-based compliance.

Note that the Eastern Interconnection (row 7), as the limiting region whose fossil steam and NGCC rates determined the source category-specific performance rates in 2030, requires all of the building block 3 generation potential quantified for that region.[27] However, because the final rule would allow affected EGUs in the Eastern Interconnection to claim RE from any region for use in compliance, the relevant value for this computational procedure to quantify emissions for mass goals (across all states) is the national-level difference in "Potential BB3" across all regions.

Note that in the Texas Interconnection (row 9), the fossil steam rate after minimizing "Potential BB3" has increased from 237.2 lbs/MWh to 1,095.9 lbs/MWh, which is still below the unrounded limiting region fossil rate of 1,304.1 lbs/MWh. However, the remaining difference between the regional fossil steam rate and the limiting region's fossil steam rate cannot be addressed by yet higher reduction in the region's "Potential

[26] All values rounded to the nearest MWh; for exact values refer to Appendix 5.
[27] The fossil steam and NGCC rates from the limiting region are rounded up to the nearest whole number to produce the source category-specific emission performance rate.

BB3", because the region would still need all of the remaining "Potential BB3" generation to achieve parity with the limiting region's rate for NGCC (as reflected by the "100 percent" value in column M). The 1,095.9 lbs/MWh steam rate result from this computation for the Texas Interconnection serves only as an indicator that the computation did not violate the criteria laid out above for calculating the building block 3 potential that was not captured in the source category-specific performance rates; this value is not used in any computation, including the computation below to quantify emissions associated with the ability of affected EGUs to expand output if they deployed this building block 3 potential.

The total amount of building block 3 generation not captured in the source category-specific performance rates for each year is displayed below:

BB3 Generation Not Captured in Source Category-specific Performance Rates									
	2022	2023	2024	2025	2026	2027	2028	2029	2030
MWh	94,975,762	90,713,246	92,966,029	102,634,454	111,033,910	113,468,333	131,936,775	150,167,508	166,255,493

The next step is to apportion the excess building block 3 generation to states on the basis of each state's 2012 adjusted share of affected EGU generation.[28] The state-level generation total can then be converted into a mass adjustment that reflects the ability of affected EGUs to increase their own output if deploying this building block 3 generation under rate-based compliance:

Mass Adjustment = State Emission Rate Goal × BB3 Generation Not Captured in Source Category-Specific Performance Rates × 2

The mass adjustment reflects the ability of affected EGUs to procure incremental RE to increase their own generation and emissions if subject to an applicable rate-based standard. In that rate-based compliance scenario, every zero-emitting MWh added to the denominator of an EGU's effective emission rate would enable that EGU to add another MWh of generation with twice the emissions intensity of the applicable rate-based standard, because the average intensity of that emitting MWh combined with the zero-emitting MWh would then equal the applicable rate-based standard and thus maintain that EGU's compliance.[29]

[28] The adjusted generation baseline for affected EGUs is described in Appendix 3.

[29] The assumption that one MWh of incremental RE enables one MWh of additional affected EGU generation is consistent with the historical performance of affected EGUs over time as well as expected future demand levels. Refer to the memorandum and accompanying spreadsheet 'Historical Fossil EGU Performance' for additional details, available in the docket.

As an example, a group of affected EGUs subject to (and already compliant with) an emission rate standard of 1,031 lbs/MWh (equal to the Arizona state goal in 2030), and assuming an illustrative generation level of 1,000 MWh for sake of simplicity, would be able to increase emissions by 2,062 lbs for each incremental MWh of RE procured:

$$\frac{1{,}031{,}000\ lbs + 0\ lbs + (1{,}031 \times 2)\ lbs}{1{,}000\ MWh + 1\ MWh + 1\ MWh} += \frac{1{,}033{,}062\ lbs}{1{,}002\ MWh} = \frac{1{,}031\ lbs}{MWh}$$

In this illustrative example, the group of affected EGUs was able to remain compliant at the 1,031 lbs/MWh rate while adding a MWh with emissions of 2,062 lbs and acquiring an incremental MWh of zero-emitting RE.[30] This example shows why the mass adjustment procedure assumes that the building block 3 potential not captured in the source category-specific compliance rates could allow additional emissions of twice the emission intensity represented by the applicable state goal.

The final step in calculating an affected EGU mass goal is to simply add the mass associated with the state emission rate to the mass adjustment described above, using this equation:.

Affected EGU Mass Goal = (State Emission Rate Goal × State's Adjusted 2012 Affected EGU Generation) + (State Emission Rate Goal × BB3 Generation Not Captured in Source Category-specific Performance Rates[31] × 2)

For example, Arizona's 2030 affected EGU mass goal would be calculated as follows:

Arizona Affected EGU Mass Goal for 2030 = (1,031 lbs/MWh × 52,154,061 MWh) + (1,031 lbs/MWh × 3,193,154 MWh × 2) = 30,170,750 tons

Affected EGU mass goal calculations and results are available for each state in Appendix 5.

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[30] The emissions quantified through this particular mass adjustment approach could also represent a variety of source-specific and fleet-wide actions that could result if affected EGUs procure incremental RE beyond what is required to demonstrate the source category-specific performance rate.
[31] State-specific values for building block 3 generation levels not captured in the source category-specific emission performance rates are available in Appendix 5.

7. APPENDIX

Appendix 1 – Underlying 2012 unit-level inventory and data (no adjustments)

See "Appendix 1-All Units (2012)" worksheet in the Excel attachment titled "Appendix 1-5: CO2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule"

Appendix 2 – Likely affected EGUs that commenced operation post 2011, but began construction prior to 1/8/14

See "Appendix 2 – Under construction" worksheet in the Excel attachment titled "Appendix 1-5: CO2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule". Note, this is largely a subset of the Appendix 1 worksheet.

Appendix 3 – Underlying state-level data, adjustments

See "Appendix 3 – state-level data" worksheet in the Excel attachment titled "Appendix 1-5: CO2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule"

Appendix 4 – Regional adjusted baseline and computation of the category-specific performance rates (interim and final)

See "Appendix 4 – category-specific calc." worksheet in the Excel attachment titled "Appendix 1-5: CO2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule"

Appendix 5 - Computation of the state goal (interim and final)

See "Appendix 5 – State Goals" worksheet in the Excel attachment titled "Appendix 1-5: CO2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule"

Appendix 6 –State Goals (lbs/MWh)

State Name	Interim	Final	State Name	Interim	Final
Alabama	1,157	1,018	Lands of the Navajo Nation	1,534	1,305
Arkansas	1,304	1,130	North Carolina	1,311	1,136
Arizona	1,173	1,031	North Dakota	1,534	1,305
California	907	828	Nebraska	1,522	1,296
Colorado	1,362	1,174	New Hampshire	947	858
Connecticut	852	786	New Jersey	885	812
Delaware	1,023	916	New Mexico	1,325	1,146
Florida	1,026	919	Nevada	942	855
Lands of the Fort Mojave Tribe	832	771	New York	1,025	918
Georgia	1,198	1,049	Ohio	1,383	1,190
Iowa	1,505	1,283	Oklahoma	1,223	1,068
Idaho	832	771	Oregon	964	871
Illinois	1,456	1,245	Pennsylvania	1,258	1,095
Indiana	1,451	1,242	Rhode Island	832	771
Kansas	1,519	1,293	South Carolina	1,338	1,156
Kentucky	1,509	1,286	South Dakota	1,352	1,167
Louisiana	1,293	1,121	Tennessee	1,411	1,211
Massachusetts	902	824	Texas	1,188	1,042
Maryland	1,510	1,287	Lands of the Uintah and Ouray Reservation	1,534	1,305
Maine	842	779	Utah	1,368	1,179
Michigan	1,355	1,169	Virginia	1,047	934
Minnesota	1,414	1,213	Washington	1,111	983
Missouri	1,490	1,272	Wisconsin	1,364	1,176
Mississippi	1,061	945	West Virginia	1,534	1,305
Montana	1,534	1,305	Wyoming	1,526	1,299

Appendix 7 –Adjustments to state-level 2012 baseline data

Hydro adjustment – Commenters suggested that 2012 was an outlier year for hydrological generation, and because of the predominance of hydro generation in their state, this also made it an outlier year for other generation technologies in the state. EPA assessed this concern for all states using the following filters:

1) Using EIA 2012 data, identify the percent share of total generation coming from hydro generation in each state
2) Using EIA 1990-2012 data, identify average hydro generation for a state from 1990-2012 and look at the percent difference between 2012 hydro generation levels and the average hydro generation levels
3) Estimate the increase in affected fossil generation that would occur if the difference between the average hydro year and the 2012 hydro year was replaced with generation from affected fossil generation.

EPA determined that hydro intensive states (greater than 10 percent generation from hydro), that experienced an outlier year in 2012 (greater than 5 percent increase in hydro generation relative to observed average between 1990-2012), and that would potentially have their state's affected fossil generation significantly affected when assuming average hydro generation levels (an adjustment > 5percent) had baseline values that were sensitive to fluctuations in hydro generation and thus increased the fossil generation in the state from observed 2012 levels to reflect potential generation levels in an average hydro year.[32]

Unit-outage adjustment

As explained in the Preamble Section VI, EPA did not generally view single unit-outages as problematic to its baseline for determining source-category rates or state goals. As regional load levels did not change subject to the unit outage, the decrease at a particular unit is generally offset by the increase in generation from other fossil unit(s) in the same state or region. Therefore, EPA views the regional and state-level aggregate generation totals as robust against unit-level outages. However, it did test for outlier cases where the unit-level outage (e.g., planned, unplanned, maintenance, emergency) was significant enough to potentially have a significant impact on the state goals that EPA provided in section VII. In these instances, EPA made an adjustment. EPA assess this concern for all units by identifying:

[32] See Excel file titled "Hydro Adjustment for Rate Setting" in the docket for this rule. In Washington State for example, fossil generation fluctuates sharply depending on the amount of hydro generation available in a year. The same affected 34 fossil EGUs generated nearly twice as much in 2010 (when hydro generation was below average, than they did in 2012 (a high outlier hydro year). This adjustment increased the generation and emissions in the state baseline values to be more consistent with a representative hydro year.

1) Units where the heat input in 2012 was less than 25 percent of its 2010 and 2014 totals (signaling a significant outage). EPA used 2010 and 2014 as it needed a prior and subsequent year to identify an outage. These years were chosen as they were less likely than 2011 and 2013 to have any spillover effects from the outage.[33]
2) For units meeting the step 1 criteria, EPA identified those where the heat input observed in the non-outage years of 2010 and 2014 years was greater than 10 percent of the state's total heat input (suggesting the replacement generation may be more difficult to find in state).[34]

The only unit that met this criteria was the 900 MW Sherburne County coal-fired unit 3 in Minnesota. EPA adjusted the state's coal generation level value up to reflect this unit operating in a typical year.

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[33] EPA used heat input for this analysis in place of generation data given the availability of 2014 unit-level data was more complete for the heat input metric. Changes in heat input and generation output track each other closely, and heat input serves as a reasonable variable for identifying an outage. Heat input rate is defined in Part 72.2. Hourly heat input values are required to be reported by 40 CFR 75 Subpart G (75.64(a)(6) that refers to 75.57 see 75.57(b)(5))

[34] See Excel file titled "2010, 2012, 2014 heat input used for unit outage test" in the Docket for this rule.

Appendix 8 – State Mass Goals (Short Tons)

State	Interim	Final
Alabama	62,210,288	56,880,474
Arkansas	33,683,258	30,322,632
Arizona	33,061,997	30,170,750
California	51,027,075	48,410,120
Colorado	33,387,883	29,900,397
Connecticut	7,237,865	6,941,523
Delaware	5,062,869	4,711,825
Florida	112,984,729	105,094,704
Lands of the Fort Mojave Tribe	611,103	588,519
Georgia	50,926,084	46,346,846
Iowa	28,254,411	25,018,136
Idaho	1,550,142	1,492,856
Illinois	74,800,876	66,477,157
Indiana	85,617,065	76,113,835
Kansas	24,859,333	21,990,826
Kentucky	71,312,802	63,126,121
Louisiana	39,310,314	35,427,023
Massachusetts	12,747,677	12,104,747
Maryland	16,209,396	14,347,628
Maine	2,158,184	2,073,942
Michigan	53,057,150	47,544,064
Minnesota	25,433,592	22,678,368
Missouri	62,569,433	55,462,884
Mississippi	27,338,313	25,304,337
Montana	12,791,330	11,303,107

State	Interim	Final
Lands of the Navajo Nation	24,557,793	21,700,587
North Carolina	56,986,025	51,266,234
North Dakota	23,632,821	20,883,232
Nebraska	20,661,516	18,272,739
New Hampshire	4,243,492	3,997,579
New Jersey	17,426,381	16,599,745
New Mexico	13,815,561	12,412,602
Nevada	14,344,092	13,523,584
New York	33,595,329	31,257,429
Ohio	82,526,513	73,769,806
Oklahoma	44,610,332	40,488,199
Oregon	8,643,164	8,118,654
Pennsylvania	99,330,827	89,822,308
Rhode Island	3,657,385	3,522,225
South Carolina	28,969,623	25,998,968
South Dakota	3,948,950	3,539,481
Tennessee	31,784,860	28,348,396
Texas	208,090,841	189,588,842
Lands of the Uintah and Ouray Reservation	2,561,445	2,263,431
Utah	26,566,380	23,778,193
Virginia	29,580,072	27,433,111
Washington	11,679,707	10,739,172
Wisconsin	31,258,356	27,986,988
West Virginia	58,083,089	51,325,342
Wyoming	35,780,052	31,634,412

Appendix 9- Description of 111(d) baseline data sources and development

Introduction

This section describes the methodology used by the EPA to develop 2012 unit-level data used to inform the adjusted state and region-level CO_2 emission rate baselines.

The 111(d) baseline analysis methodology is based largely on the methodology used to develop the Emissions and Generation Resource Integrated Database (eGRID)[35], with certain key differences, which are explained below. The 111(d) baseline consists of emission rates in pounds of CO_2 per megawatt-hour (MWh) of electricity generation. The baseline is constructed by matching electricity generation data reported to the Energy Information Administration (EIA) by power plants on forms EIA-860[36] and EIA-923[37] with data on CO_2 emissions submitted by power plants to the EPA under 40 CFR Part 75.[38]

The process of matching emissions data to generation data and categorizing the EGUs is described in more detail below. The differences between the 2012 unit-level data released for the Clean Power Plan Proposed Rule[39] and the Final Rule are also discussed below.

Data Sources

The key data sources used in the construction of the 111(d) baseline are listed in Table 1.

Table 1. Key data sources used to construct the 111(d) baseline.

Data Source	Key Data

[35] U.S. Environmental Protection Agency, Clean Air Markets Division, Emissions and Generation Resource Integrated Database (eGRID), available at http://www.epa.gov/cleanenergy/energy-resources/egrid/
[36] Energy Information Administration, Form EIA-860, available at http://www.eia.gov/electricity/data/eia860/
[37] Energy Information Administration, Form EIA-923, available at http://www.eia.gov/electricity/data/eia923/
[38] 40 CFR Part 75, available at http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr75_main_02.tpl
[39] The Federal Register is available at https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

EIA-860	Contains key identifying information, including nameplate capacity, summer capacity, unit operational status, prime mover type, and fuel type, as well as plant name and location.
EIA-923	Contains information on net electricity generation and fuel use at the generator level, boiler level, and/or prime mover level.
EPA Part 75 Data	Contains information on CO_2 emissions and heat input.

EPA Part 75 emissions data are presented at the unit level, where the unit is defined as the fossil fuel-fired device, which could be a turbine or boiler (including any heat recovery steam generators (HRSG), if present). EIA data on generation and fuel use are presented at the generator, boiler, prime mover, and plant levels.

The 111(d) baseline analysis methodology involves matching EPA emissions data at the unit level (i.e. emissions from boilers or turbines), with EIA generation data at the generator level. However, the data do not always match cleanly between the two data sources. While both data sources identify plants using the Office of Regulatory Information Systems PLant code (ORISPL code), the EIA data identifies generators with a generator ID, and the EPA data identifies units with a unit ID. The ORISPL code generally matches between data sources, but the generator ID from EIA must be matched to the unit ID from EPA based on ORISPL code, nameplate capacity, fuel type, prime mover type, and year of operation.

Furthermore, because there are different regulations governing which plants and units must report data to the EIA and the EPA, there may be different numbers of units at each plant between the two data sets. Additionally, existing and proposed plants are required to submit Forms 860 and 923 to the EIA if the plant's total generator nameplate capacity is 1 MW or greater and it is capable of supplying power to or drawing power from the electricity grid. Plants are required to submit emissions data to EPA under 40 CFR Part 75, generally if a unit serves a generator with a nameplate capacity of greater than 25 MW which produces electricity for sale.

Unit-level Data Construction Process

As discussed above, the construction of the 111(d) 2012 unit-level data involves matching net electricity generation data from EIA with data on CO_2 emissions from EPA. All of the existing, proposed, and retired units listed in EIA-860 serve as the foundation for the baseline, establishing the universe of units. Electricity generation and CO_2 emissions are added to this foundation using the EIA-923 and EPA Part 75 data.

Electricity Generation

For any given power plant, data on net electricity generation from the EIA-923 may be available at the unit level for some units or at the prime mover level for other units. If unit-level data are available, the data are used in the baseline. If data are only available at the prime mover level, then these data are distributed proportionally based on nameplate capacity to the units at that plant with that prime mover.

CO_2 Emissions

Part 75 emissions data from EPA are matched to the generator-level data from EIA. When units can be matched exactly between the two data sources, the unit-level emissions are used in the baseline. When one unit from the EPA data is associated with more than one generator from the EIA data (e.g. emissions from a boiler that supplies steam to more than one generator), or if units at a given plant cannot be matched exactly between the two data sources, the total emissions may be distributed to generators based on the proportion of nameplate capacity. Combined cycle units are considered a single system and emissions from all components are summed and distributed to all generators based on proportion of nameplate capacity.

Because there are different regulations governing which plants and units report data to EIA and EPA, there are more units listed in the EIA data than in the EPA data (for example, a unit under 25 MW may not be required to report emissions data under Part 75). To estimate emissions for units that are listed in the EIA data but not in the EPA data, a fuel-specific emissions factor is multiplied by unit-level fuel consumption (million British thermal units (mmBtu)).[40] This method is based on the methodology used by the Intergovernmental Panel on Climate Change (IPCC)[41] and in EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks.[42] CO_2 emissions factors for year 2012 are obtained from two sources: EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, and the emissions factors used in the Greenhouse Gas Reporting Program, which are listed in 40 CFR Part 98.[43] The emissions factors used in the 111(d) baseline analysis are listed in the Emissions Factors section below. The fuel use is based on heat input data from EPA Part 75 data, boiler-level data from the EIA-923, and prime mover level data from the EIA-923. Data are selected preferentially in that order (e.g. if heat input data are unavailable from EPA, then boiler-level data from EIA are used).

Data Corrections

When CO_2 emissions from EPA are matched with net electricity generation data from EIA, an emissions rate (lbs. CO_2 per MWh) is calculated. If the calculated emissions rate is unreasonably high (>10,000 lbs. CO_2 per MWh) or unreasonably low (<500 lbs. CO_2 per MWh) for a unit, the net electricity generation data are calculated based on gross generation data from EPA. Because the EPA data contain gross generation rather than net electricity generation, net generation must be calculated by multiplying gross generation by a unit-specific net-gross conversion factor.[44] In cases

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[40] It should be noted that most of these units not reporting to EPA are categorized as "excluded" and not factored into the baseline used for BSER quantification. However, the data are still made available in the 2012 unit-level file.

[41] IPCC, 2007: The Intergovernmental Panel on Climate Change (IPCC), "2006 IPCC Guidelines for National Greenhouse Gas Inventories", volume 2 (Energy), April 2007. http://www.ipccnggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf

[42] EPA, 2014: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, Washington, D.C., April 2014. http://epa.gov/climatechange/emissions/usinventoryreport.html

[43] See 40 CFR Part 98, Table C-1. http://www.epa.gov/ghgreporting/documents/pdf/2009/GHG-MRR-FinalRule.pdf

[44] These conversion factors were developed by Ventyx (now called ABB Enterprise Software), a consulting firm that provides information and data related to the electricity generation sector. The factors are developed using North American Reliability Corporation (NERC) Generating Availability Data System (GADS),

where a net-gross conversion factor is not available for a specific unit, the calculation uses the average of the net-gross conversion factor from plants in the same state and with the same prime mover. If the EPA data do not include gross generation for a specific unit, the calculation uses data on gross generation from EIA.[45] If this correction still results in an emissions rate greater than 10,000 lbs. CO_2/MWh or less than 500 lbs. CO_2/MWh, then the net electricity generation data are left unchanged and the original calculated rate is retained. While these out-of-bounds unit-level emission rates may not be reasonable for the specific units, generally they do not affect facility-wide, state-wide, or region-wide aggregated levels, and therefore do not disturb the subcategory rates or state goals.

In addition, for units that report negative net electricity generation (for example, the facility uses more electricity than it produces) and CO_2 emissions, the electricity generation is adjusted using gross electricity generation data as described above. This correction is intended to avoid estimating a negative emissions rate.

Limited adjustments are also made for several likely affected facilities that had reported summertime capacity significantly greater than nameplate capacity. For these units, EPA replaced the summer capacity value reported in EIA-860 with the *lower* nameplate value reported in EIA 860 or the wintertime capacity reported in EIA-860.

Inclusion Criteria

In order to calculate the state-level emission rate for coal steam units, natural gas combined cycle units, and oil and gas steam units, the individual units are categorized according to the nameplate capacity, prime mover type, fuel, and operating status, as shown in table 2.

Table 2. Criteria for inclusion of units in the 111(d) baseline as likely affected EGUs.

Category Code	Category	Inclusion criteria
COALST	Coal steam units	Steam turbine units (prime mover = ST) with coal as primary fuel source. Nameplate capacity must be greater than 25 MW.
NGCC	Natural gas combined cycle units	Combined cycle units with natural gas as primary fuel source. If all of the turbine components of the combined cycle unit (prime mover = CT) have a nameplate capacity greater than 25 MW, then all of the steam components (prime mover = CA) are included, regardless of whether they have a nameplate capacity greater than 25 MW. Otherwise, only components with a nameplate capacity greater than 25 MW are included.

which contains data on gross and net generation for units with a nameplate capacity greater than 20 MW. The data provided for this analysis are unit-level ratios of net generation to gross generation.

[45] EIA supplied the gross generation data for a subset of generators to EPA, as these data are not publicly available in the EIA-923 data.

Category Code	Category	Inclusion criteria
OGST	Oil and gas steam units	Steam turbine units with oil or gas as primary fuel source. Nameplate capacity must be greater than 25 MW.
UC Coal – Commenced in 2012	Coal steam units that commenced operations in 2012	Units that would otherwise be classified as COALST, but which commenced operations in 2012. Determination of when the unit commenced operations is based on EIA-860, public data sources, and comments on the 111(d) baseline developed for the Proposed Rule.
UC NGCC – Commenced in 2012	NGCC units that commenced operations in 2012	Units that would otherwise be classified as NGCC, but which commenced operations in 2012. Determination of when the unit commenced operations is based on EIA-860, public data sources, and public comments on the 111(d) baseline developed for the Proposed Rule.
UC-Coal	Coal steam units that are under construction in 2012 or 2013	Units that are under construction in the data year (EIA unit status = U, V, or TS), but which would likely be considered COALST units if operational. For the 111(d) baseline, units can be listed as UC-Coal if they are under construction in 2012, 2013, or before 1/08/14.
UC-NGCC	NGCC units that are under construction in 2012 or 2013	Units that are under construction in the data year (EIA unit status = U, V, or TS), but which would likely be considered NGCC units if operational. For the 111(d) baseline, units can be listed as UC-NGCC if they are under construction in 2012, 2013, or before 1/08/14.
EXCLUDE	Units excluded from the 111(d) baseline	Units may be excluded from the baseline for several reasons, including: • Internal combustion engine units and simple-cycle gas turbines; • Non-combustion prime movers, such as photovoltaics, wind turbines, and hydropower units; • Units that used less than 10 percent fossil fuel on a heat input basis in 2012; • Non-operational units, such as units that have retired prior to 2012; or • Industrial or commercial units, including CHP units and non-CHP units.

*Note also that the inclusion or exclusion of a particular unit in the 111(d) baseline analysis does not necessarily indicate that the unit will meet the applicability criteria in the Final Rule.

State-level data

The state-level data (pre adjustments) shown in the beginning columns of Appendix three is created by summing the CO_2 emissions and net generation from the generator-level baseline for units in the COALST, NGCC, and OGST categories that are not categorized as under construction. Units are also grouped by state and North American Electric Reliability Corporation (NERC) region.

NERC region data for each plant are taken from EIA-860, which lists the Independent System Operator/Regional Transmission Organization (ISO/RTO) region at the plant level.[46]

The emissions rate is calculated by converting the CO_2 emissions from tons to pounds by multiplying by 2,000 and then dividing by the net generation. Mainly due to unit-level apportionment, some unit-level emission rates may not be reasonable by themselves, however, when aggregated to the facility level, generally out-of-bound emission rates are resolved as the apportionment is no longer relevant.

Differences between 111(d) and eGRID Methodologies

The methodology used to develop the 2012 unit-level data for the 111(d) analysis is based largely on the methodology used to develop the annual editions of the Emissions and Generation Resource Integrated Database (eGRID), with certain key differences. In general, however, the methodologies are broadly similar: they both involve matching Part 75 CO_2 emissions data from the EPA Clean Air Markets Division (CAMD) with data on electricity generation from EIA. Nevertheless, there are specific criteria set forth in the Clean Power Plan that necessitate slight deviations from the eGRID methodology in the 111(d) baseline analysis.

In particular, the Clean Power Plan defines specific criteria that dictate which generating units are to be included in the baseline analysis. The eGRID methodology is altered slightly to accommodate these inclusion criteria. This section explains those methodological differences.

[46] There are at least two facilities in Texas (Tenaska Frontier Generating Station and Tenaska Gateway Generating Station) that can supply electricity either to the Eastern or ERCOT NERC regions. The region that these plants reported in EIA-860 is used as the NERC region in the 111(d) baseline analysis.

Emissions assigned to boilers

eGRID reports emissions at the boiler level and rolled up to the plant level, but the eGRID methodology does not attempt to assign emissions from boilers to individual generators. Because the 111(d) baseline is based on generators (e.g. units with a nameplate capacity greater than 25 MW), the boiler-level emissions must be assigned to the generators in the 111(d) baseline analysis.

Where possible in the 111(d) baseline analysis, the emissions data from EPA are assigned to the generator directly associated with that boiler, according to data from EIA-860. When the emissions are only available at the plant level, or if one boiler is associated with more than one generator, or if it is unclear which generator is associated with which boiler, the emissions are proportionally distributed to generators based on nameplate capacity.

Similarly, in the 111(d) baseline analysis, combined cycle units are treated as a single system, and the total emissions from the combined cycle units are distributed to the components (the steam parts and turbine parts) based on proportion of nameplate capacity.

Inclusion criteria

In order to decide which units are included as likely affected EGUs, it is necessary to evaluate if they meet the inclusion criteria based on unit size and type, operating status, fuel use, electricity sales, and capacity factor. For example, coal units with a nameplate capacity less than or equal to 25 MW or with a heat input capacity less than 250 mmBtu/hr. are excluded from the analysis, and therefore the emissions from these units are not used to calculate the state-level rates. In addition, the 111(d) baseline analysis does not include units that use less than 10 percent fossil fuel on a heat input basis in 2012 or certain commercial and industrial units that are not grid connected. However, the data files from the 111(d) baseline analysis still list all of these units, but the "Category" field for these units is listed as "EXCLUDE."

Adjustments to emissions from biomass

In eGRID, it is assumed that biomass is carbon neutral and therefore the emissions associated with biomass are adjusted to zero. While the eGRID plant file reports both the adjusted and unadjusted emissions, the summary tables are based on adjusted emissions.

This adjustment is not made in the 111(d) baseline analysis, although units that use less than 10 percent fossil fuel on a heat input basis in 2012 are excluded from the baseline of likely affected EGUs.

Tribal lands

The 111(d) analysis includes a total of 4 plants from Navajo, Ute, and Fort Mojave tribal lands and are categorized as such in the "state" field of the baseline. Therefore, their respective generation and emissions are not included in the state in which they are located, but rather are included under their own tribal lands category.

Key Differences between Proposed and Final 111(d) Baselines

This section outlines the differences between the 111(d) baseline file, created for the Proposed Rule (June 2014, hereafter "proposed file") and the version of the file created for the Final Rule (hereafter "final file"). EPA received public comment on the proposed file and made changes accordingly. Change to the methodology, based on comment, are used to create the final file are as follows:

1. Outlier emission rates.

In addition to this methodological change, EPA also made non-methodological changes to the proposed file when creating the final file, including:

2. Changes to unit characteristics;
3. Changes to the unit categorization; and
4. Changes to emissions data and generation data.

Each of these changes are described in more detail below.

Methodological Changes Based on Comment

1. Outlier emission rates

In certain cases, when EPA emissions data collected under 40 CFR Part 75 are matched with generation data from EIA, a unit can have positive emissions, but zero or negative generation. This may occur if a unit uses more power than it generates. As a result, the emission rate calculated for this unit would be negative. To correct this issue, EPA estimated the net electricity generation from these units based on their gross generation and net-gross conversion factors. Using this methodology, EPA updated the generation for 95 units with negative generation. Of these, 63 units satisfy the criteria for inclusion in the 111(d) baseline analysis. Additionally, EPA also implemented a correction for units with emission rates that are considered unreasonable, either too low or too high. For this analysis EPA used 500 lbs. CO_2/MWh as the cutoff for rates that are too low, and 10,000 lbs. CO_2/MWh as the cutoff for rates that are too high.

For these units EPA applies a correction converting the gross generation to net generation using net-gross conversion factors, as describe in the Data Corrections section above. If these corrections result in emissions rates that are still less than 500 lbs. CO_2/MWH or greater than 10,000 lbs. CO_2/MWh, EPA leaves the generation data unchanged and retains the original emissions rate.

Using this methodology, EPA updated the generation for 104 units that have "out-of-range" emission rates. Of these, 10 units satisfy the criteria for inclusion in the 111(d) baseline analysis.

Non-Methodological Changes Based on Comment

2. Changes to unit characteristics

In addition to the methodological changes described above, EPA also responded to public comments received on the 111(d) baseline developed for the Proposed Rule. These comments include updating generation data that had been misreported to EIA, changing prime movers and fuel types, and changing CHP flags. EPA also added a column to the baseline files to indicate whether a unit had commenced operations in that data year. This column is populated using a combination of public comments and data from EIA on when the unit commenced operations.

3. Changes to unit categorization

For the 2012 baseline final file, EPA made changes to the categorization for coal steam and natural gas combined cycle (NGCC) units that were under construction or commenced operations prior to 1/08/14. In the proposed file, there are 9 units listed as COALST and 46 units listed as NGCC that commenced operations in 2012. In the final file, EPA changed the category of these units to "UC Coal – commenced in 2012" or "UC NGCC – commenced in 2012", respectively. There are also 4 coal steam units and 66 NGCC units that were under construction in either 2012 or 2013 according to EIA data that are in the EXCLUDE category in the proposed file, but are now listed as "UC Coal" or "UC NGCC", respectively, in the final file appendices 1 and/or 2. Many of these "under construction" categorized units had been included in the baseline at proposal, but had received their estimated generation and emissions values when calculating state goals and were identified through the NEEDs 5.13 database rather than EIA/eGRID database. This separate categorization of "under construction – commenced in 2012" in the final file reflects that they are still included (or newly incorporated into the baseline), but that EPA estimated annual generation and emission levels for them as done in appendix 2 and 3 and suggested by commenter, instead of relying on annual 2012 data that reflected partial year operation. Those units identified as "under construction" in the file receive equal treatment as the "UC – commenced in 2012" categorized units. They are both likely affected EGUs incorporated into the baseline.

At proposal, EPA relied on NEEDS to identify under construction capacity in a state (which reflected some of these units). Commenters pointed out that EPA had omitted some under construction units and should rely on EIA data to inform its inclusion of units. Therefore, in this Final Rule, EPA used the unit's status as reported in EIA - along with comments, NEEDs v.5.15 and other publically available data - to flag under construction units.

In addition, the proposed file contained additional categories, including some simple-cycle turbines (SST), which are not included in calculations for the Final Rule. EPA changed the category for these units to EXCLUDE.

4. Changes to the EPA emissions data

EPA used an updated version of emissions data collected under 40 CFR Part 75 in the analysis. The EPA pulled the emissions data used to create the proposed file in February 2014, and the data used to create the final file in February 2015. This resulted in changes in emissions for 23 units between the proposed and final files. This update was prompted by comment pointing out some inaccuracies in the non-updated data.

Emissions Factors

The emissions factors listed in the table below are used in the 111(d) baseline analysis to estimate CO_2 emissions, if emissions for a given unit are not included in the EPA data. CO_2 emissions factors for year 2012 are obtained from two sources: EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, and the Greenhouse Gas Reporting Program (40 CFR Part 98). These emissions factors are most frequently applied for units that are categorized as "EXCLUDE", and therefore not in the EPA baseline for the quantifying BSER.

Fuel Code	Fuel Type	Prime Mover	Emissions Factors (Tons CO_2/mmBtu)
AB	Agricultural byproducts	ST	0.13027
BFG	Blast furnace gas	ST	0.05844
BG	Bagasse	ST	0.13027
BIT	Bituminous coal	ST	0.10282
BLQ	Black liquor	ST	0.10448
BU	Butane	ST	0.07182
COG	Coke oven gas	ST	0.05844
DFO	Distillate fuel oil #2	ST	0.08152
DFO	Distillate fuel oil #2	GT	0.08152
DFO	Distillate fuel oil #2	OT	0.08152
DFO	Distillate fuel oil #2	CS	0.08152
DFO	Distillate fuel oil #2	CT	0.08152
DFO	Distillate fuel oil #2	CC	0.08152
DFO	Distillate fuel oil #2	IC	0.08152
DG	Digester gas	ST	0.05739
DG	Digester gas	GT	0.05739
DG	Digester gas	OT	0.05739
DG	Digester gas	CS	0.05739
DG	Digester gas	CT	0.05739
DG	Digester gas	CC	0.05739
DG	Digester gas	IC	0.05739
DG	Digester gas	FC	0.05739
GEO	Geothermal	BT	0

Fuel Code	Fuel Type	Prime Mover	Emissions Factors (Tons CO_2/mmBtu)
GEO	Geothermal	ST	0
HY	Hydrogen	ST	0
HY	Hydrogen	GT	0
HY	Hydrogen	CT	0
HY	Hydrogen	OT	0
HY	Hydrogen	CS	0
HY	Hydrogen	CC	0
IGCC	Integrated gasification combined cycle burning BIT	IG	0.10282
JF	Jet fuel	GT	0.07962
JF	Jet fuel	IC	0.07962
JF	Jet fuel	CC	0.07962
KER	Kerosene	GT	0.08067
KER	Kerosene	IC	0.08067
LB	Liquid byproduct	ST	0.08209
LFG	Landfill gas	ST	0.05739
LFG	Landfill gas	GT	0.05739
LFG	Landfill gas	OT	0.05739
LFG	Landfill gas	CS	0.05739
LFG	Landfill gas	CT	0.05739
LFG	Landfill gas	CC	0.05739
LFG	Landfill gas	FC	0.05739
LIG	Lignite coal	ST	0.10771
MH	Methanol	ST	0.06984
MSB	MSW biomass component	ST	0.10339
NG	Natural gas	ST	0.05844
NG	Natural gas	GT	0.05844
NG	Natural gas	OT	0.05844
NG	Natural gas	CS	0.05844
NG	Natural gas	CT	0.05844

Fuel Code	Fuel Type	Prime Mover	Emissions Factors (Tons CO_2/mmBtu)
NG	Natural gas	CC	0.05844
NG	Natural gas	IC	0.05844
NG	Natural gas	FC	0.05844
OBG	Other biomass gas	CC	0.05739
OBG	Other biomass gas	GT	0.05739
OBG	Other biomass gas	ST	2.01492
OBG	Other biomass gas	FC	0.05739
OBL	Other biomass liquid	ST	0.08989
OBL	Other biomass liquid	GT	0.08989
OBL	Other biomass liquid	CT	0.08989
OBL	Other biomass liquid	OT	0.08989
OBL	Other biomass liquid	CS	0.08989
OBL	Other biomass liquid	CC	0.08989
OBS	Other biomass solid	ST	0.11632
OG	Other gas	ST	0.05844
OG	Other gas	GT	0.05844
OG	Other gas	CC	0.05844
OO	Other oil	ST	0.08152
OTL	Other liquid	ST	0.08209
OTL	Other liquid	GT	0.08209
OTL	Other liquid	OT	0.08209
OTL	Other liquid	CS	0.08209
OTL	Other liquid	CT	0.08209
OTL	Other liquid	CC	0.08209
OTS	Other solid	ST	0.11289
PC	Petroleum coke	ST	0.11256
PC	Petroleum coke	GT	0.11256
PC	Petroleum coke	CT	0.11256
PC	Petroleum coke	OT	0.11256
PC	Petroleum coke	CS	0.11256

Fuel Code	Fuel Type	Prime Mover	Emissions Factors (Tons CO_2/mmBtu)
PC	Petroleum coke	CC	0.11256
PG	Propane gas	ST	0.06774
PP	Paper pellets	ST	0.10339
PRG	Process gas	ST	0.05844
RFO	Residual fuel oil #6	ST	0.08278
RFO	Residual fuel oil	GT	0.08278
RFO	Residual fuel oil	CC	0.08278
RG	Refinery gas	ST	0.07356
SC	Synthetic coal	ST	0.10529
SLW	Sludge waste	ST	0.11632
SUB	Subbituminous coal	ST	0.10711
SUN	Sun	PV	0
TDF	Tire-derived fuel	ST	0.06376
WAT	Water	HY	0
WC	Waste coal	ST	0.10529
WDL	Wood liquid	ST	0.08989
WDS	Wood solid	ST	0.10339
WND	Wind	WS	0
WND	Wind	WT	0
WO	Waste oil	ST	0.08209
WO	Waste oil	CC	0.08209
WO	Waste oil	GT	0.08209

Data Codes

The following data codes are used by in the EIA-860 and EIA-923 forms to indicate a unit's prime mover, fuel type, and status.

Prime Mover Code	Prime Mover Description
BA	Energy Storage, Battery
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
CA	Combined Cycle Steam Part
CC	Combined Cycle Total Unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided)
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
CS	Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
CT	Combined Cycle Combustion Turbine Part
ES	Energy Storage, Other
FC	Fuel Cell
FW	Energy Storage, Flywheel
GT	Combustion (Gas) Turbine (does not include the combustion turbine part of a combined cycle; see code CT, below)
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other
HY	Hydroelectric Turbine (includes turbines associated with delivery of water by pipeline)
IC	Internal Combustion Engine (diesel, piston, reciprocating)
OT	Other
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
PV	Photovoltaic
ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)
WS	Wind Turbine, Offshore

WT	Wind Turbine, Onshore

Fuel Type Code	Energy Source Description
AB	Agricultural By-Products
ANT	Anthracite Coal
BFG	Blast Furnace Gas
BIT	Bituminous Coal
BLQ	Black Liquor
DFO	Distillate Fuel Oil (including diesel, No. 1, No. 2, and No. 4 fuel oils)
GEO	Geothermal
JF	Jet Fuel
KER	Kerosene
LFG	Landfill Gas
LIG	Lignite Coal
MSW	Municipal Solid Waste
MWH	Electricity used for energy storage
NG	Natural Gas
NUC	Nuclear (including Uranium, Plutonium, and Thorium)
OBG	Other Biomass Gas (including digester gas, methane, and other biomass gases)
OBL	Other Biomass Liquids
OBS	Other Biomass Solids
OG	Other Gas
OTH	Other
PC	Petroleum Coke
PG	Gaseous Propane
PUR	Purchased Steam
RC	Refined Coal
RFO	Residual Fuel Oil (incl. Nos. 5 & 6 fuel oils, and bunker C fuel oil)
SGC	Coal-Derived Synthesis Gas
SGP	Synthesis Gas from Petroleum Coke
SLW	Sludge Waste
SUB	Subbituminous Coal
SUN	Solar

Fuel Type Code	Energy Source Description
TDF	Tire-derived Fuels
WAT	Water at a Conventional Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology
WC	Waste/Other Coal (incl. anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
WDL	Wood Waste Liquids excluding Black Liquor (including red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
WDS	Wood/Wood Waste Solids (incl. paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
WH	Waste heat not directly attributed to a fuel source (WH should only be reported when the fuel source is undetermined, and for combined cycle steam turbines that do not have supplemental firing.)
WND	Wind
WO	Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)

Unit Status Code	Status Code Description
IP	Planned new generator canceled, indefinitely postponed, or no longer in resource plan
L	Regulatory approvals pending. Not under construction but site preparation could be underway
OA	Out of service – was not used for some or all of the reporting period but is expected to be returned to service in the next calendar year.
OP	Operating - in service (commercial operation) and producing some electricity. Includes peaking units that are run on an as needed (intermittent or seasonal) basis.
OS	Out of service – was not used for some or all of the reporting period and is NOT expected to be returned to service in the next calendar year.
OT	Other

P	Planned for installation but regulatory approvals not initiated; Not under construction
RE	Retired - no longer in service and not expected to be returned to service.
SB	Standby/Backup - available for service but not normally used (has little or no generation during the year) for this reporting period.
T	Regulatory approvals received. Not under construction but site preparation could be underway
TS	Construction complete, but not yet in commercial operation (including low power testing of nuclear units)
U	Under construction, less than or equal to 50 percent complete (based on construction time to date of operation)
V	Under construction, more than 50 percent complete (based on construction time to date of operation)

Description of Baseline Data Fields

The following table provides a description of the data fields in the 111(d) baseline file with an indication of the data sources used to populate each field.

Field	Description	Source
Category	Category based on the inclusion criteria of each generator	--
State	State in which the plant is located	EIA-860
State-Region	Combined State and NERC Region in which the plant is located	EIA-860
Plant Name	Plant name	EIA-860
ORIS Code	EIA Office of Regulatory Information Systems Plant or facility code	EIA-860
Generator ID	Generator identification code	EIA-860
Fuel type	Primary fuel type of the generator	EIA-860
Prime mover type	The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for	EIA-860

Field	Description	Source
	reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cells).	
Nameplate Capacity (MW)	The full capacity value of power output from the generator	EIA-860
Summer Capacity (MW)	The full capacity value of power output from the generator during the summer	EIA-860
Heat Input Capacity (mmBtu/hr)	The hourly heat input capacity for the unit in mmBtu	EPA Part 75
Electric Generation (MWh)	Net electricity generation of the unit	EIA-923, EPA Part 75 data
Carbon Dioxide Emissions (tons)	The annual carbon dioxide emissions from each generator in tons	EPA Part 75 data, EIA-923
UNITKEEP (CA<25 part of CC with CT>25)	If all of the turbine parts (prime mover =CT) of an NGCC system have a nameplate capacity > 25MW, then all of the steam parts (prime mover = CA) are included in the baseline, regardless of whether they have a nameplate capacity >25MW. In this case, the UNITKEEP field will be equal to 1. It will be blank otherwise.	--
Source Category	The type of industry in which the generator is located. Options include electric utility, independent power producer (IPP), industrial, or commercial.	EIA-860
Cogn Flag Y/N	Indicates the cogeneration status of each generator – yes (Y) or no (N).	EIA-860
Unit Status	The operating status of the generator	EIA-860
Unit Retirement Year	The actual or planned retirement year of the generator	EIA-860
Exclusion Description	Description of why the generator was excluded in the "Category" field	--

Field	Description	Source
Commenced Operations in Data Year	If the generator commenced operations within the data year, the field is marked "Yes." This field is left blank for all other generators.	EIA-860
NERC Interconnection	NERC region in which the plant is located	EIA-860

EXHIBIT 3

DECLARATION OF COLIN MARSHALL

I, Colin Marshall, declare as follows:

Introduction

1. My name is Colin Marshall, and I am the President and Chief Executive Officer of Cloud Peak Energy Inc. ("Cloud Peak Energy"). I have served in that capacity since Cloud Peak Energy's 2009 initial public offering. Before my appointment as President and Chief Executive Officer of Cloud Peak Energy, I was President and Chief Executive Officer of Rio Tinto Energy America, the predecessor to Cloud Peak Energy prior to its initial public offering. Cloud Peak Energy's common stock is listed on the New York Stock Exchange under the ticker symbol "CLD."

2. Cloud Peak Energy, headquartered in Wyoming, is one of the largest and safest coal producers in the United States, and it is the only U.S. coal company with mining operations exclusively in the Powder River Basin ("PRB"). Located in northeastern Wyoming and southeastern Montana, the PRB is by far the largest coal-producing region in the United States. In 2013, the PRB produced more than 400 million tons of low sulfur, subbituminous coal, representing approximately 94 percent of subbituminous coal production and approximately 41 percent of total coal production in the United States. The PRB is also the nation's lowest cost major coal producing

region. PRB coal is used by domestic and, to a lesser extent, international electric utilities for electric power generation.

3. As described further in this Declaration, the Environmental Protection Agency's ("EPA") rules under Section 111(d) of the Clean Air Act are expected to have an immediate negative impact on investment decisions of U.S. electric utilities regarding their utilization of existing coal-fired power plants and any future investments in coal-fired power plants. Due to the unprecedented and broad impact on the power sector and complexity of the EPA's Section 111(d) rule and the long-term investment decisions required to be made by utilities, I believe (1) utilities, along with state governments and regulators and grid operators, will be required to begin making decisions based on the adoption of the Section 111(d) rule well before the compliance deadlines, (2) those decisions will have near-term negative impacts on the demand and pricing for coal and the outlook for the U.S. coal industry, including specifically on Cloud Peak Energy, and (3) those decisions are unlikely to be meaningfully reversed years down the road regardless of whether a court years in the future rejects the Section 111(d) rules based on the anticipated numerous legal challenges against the rule. In fact, I believe these negative impacts on the demand, pricing and outlook for the coal industry in general and Cloud Peak Energy specifically have already started to take place based on the prior proposal of the Clean Power Plan.

Background on Cloud Peak Energy

4. Cloud Peak Energy owns and operates three surface coal mines in the PRB, namely the Antelope and Cordero Rojo mines in Wyoming and the Spring Creek mine in Montana. In 2014, Cloud Peak Energy shipped approximately 86 million tons of PRB coal from its three mines to electric utilities located primarily throughout the United States and also to international customers. Cloud Peak Energy is the fuel supplier for approximately 4 percent of the nation's electricity.

5. Cloud Peak Energy also owns rights to substantial undeveloped coal and complimentary surface assets in the Northern PRB in northern Wyoming and in Montana.

6. Cloud Peak Energy currently employs approximately 1,600 people. The number of employees depends primarily on current and expected production levels and on company financial results and cost management.

7. Cloud Peak Energy provides significant contributions to U.S., state and local economies. From taxes and royalties paid, to community contributions and goods and services purchased, the company is committed to making our communities a better place to live, work and raise a family. In 2014, Cloud Peak Energy incurred $351 million in federal and state taxes and royalties for 2014 operations and also paid

$69 million for federal coal lease payments in a year when net income for the company was only $79 million.

Impact of Clean Power Plan on Cloud Peak Energy

8. Cloud Peak Energy's ability to economically invest (for example, through purchasing rights to coal and surface access, acquiring coal assets from other companies, making capital expenditures, hiring employees, engaging contractors and procuring supplies) in the future growth of the company, the operations of its existing mines and its development projects is directly and negatively impacted by federal regulatory actions and proposals that, like EPA's Section 111(d) rule, adversely impact demand for PRB coal by U.S. electric utilities and associated pricing.

9. These proposed and adopted federal regulations have negatively impacted, and are expected to continue to negatively impact, coal-fired power plant capacity and utilization and cause electric utilities to continue to phase out or close existing coal-fired power plants, reduce or eliminate construction of any new coal-fired power plants, and reduce consumption of coal from the PRB.

10. Cloud Peak Energy's business model, like that of the entire coal mining industry, is highly capital-intensive and requires significant investments with extended lead times to plan for future mining operations. These long lead time decisions must

be made in today's environment based on current expectations and the outlook for the future.

11. For example, Cloud Peak Energy acquires a large portion of its coal through the federal Lease by Application ("LBA") process, and as a result, most of Cloud Peak Energy's coal is held under federal leases. Under this process, before a mining company can obtain a new federal coal lease, the company must nominate a coal tract for lease and then win the lease through a competitive bidding process. The LBA process can last anywhere from two to five years or more from the time the coal tract is nominated to the time a final bid is accepted by the federal Bureau of Land Management ("BLM"). After the LBA is awarded, the company begins the process to permit the coal for mining, which generally takes another two to five years. Third-party legal challenges, such as legal challenges that are now routinely filed by certain environmental groups, may result in further delays.

12. In addition, most of the coal Cloud Peak Energy leases from the U.S. comes from "split estate" lands in which one party, such as the federal government, owns the coal and a private party owns the surface. In order to mine the coal, Cloud Peak Energy must acquire rights to mine from certain owners of the surface lands overlying the coal, adding additional expense, uncertainty and delay before being able to mine and sell the coal.

13. Thus, investment decisions necessary to mine coal must be made many years in advance of when the coal is actually mined. Cloud Peak Energy paid $69 million in federal coal lease payments in 2015 and, as noted in the company's second quarter 2015 earnings release, the company is forecasting approximately $40 million to $50 million in 2015 capital expenditures in addition to the federal coal lease payments. In the last five years, Cloud Peak Energy has averaged approximately $90 million per year in federal coal lease bonus payments. The expenditure of these significant amounts of money is predominantly to support mining operations extending many years in the future.

14. The EPA's recently adopted Section 111(d) rule will significantly reduce the demand and pricing for coal throughout the United States and including from the PRB, as is shown by EPA's own figures. According to EPA's own analysis, the rule will trigger a wave of early retirements of coal-fueled electric generating stations well before the 2022 compliance date in the rule. This is because of the long lead times for electric utility planning, where utilities have to begin restructuring their operations well before the compliance deadline in order to meet the requirements of the rule. As EPA's calculations show, retirements begin as early as 2016, and many of these units retired use PRB coal and are therefore current or potential customers of Cloud Peak Energy. This is described more fully in the expert report of Seth Schwartz, President

of Energy Ventures Analysis, which is attached to the Motion for Stay of the National Mining Association.

15. Obviously, closure of these units in 2016-17 would cause Cloud Peak Energy and other PRB producers to lose the coal production now supplied to those units and to lose the opportunity to supply units that otherwise could have been customers. Given that other electric generating stations will be closing as a result of the Section 111(d) rule beyond 2016-17, and given the currently depressed market conditions caused by other EPA rules and federal regulatory actions and depressed natural gas prices, it is unlikely that all of this lost production could be sold by Cloud Peak Energy or other PRB producers to other customers at economic prices. Loss of existing production and sales opportunities for Cloud Peak Energy would cause injury not just to Cloud Peak Energy but also to its workers at the mines, contractors and suppliers who would have otherwise received revenues based on the impacted lost production, and publicly funded governmental services and investments because of the lost royalties and taxes from the impacted lost production.

16. The injury that the Section 111(d) rule will cause to Cloud Peak Energy is not limited to the lost production associated with the near-term closure of certain generating stations. Over time, as described in Mr. Schwartz's report, many more coal-fueled generations will close and the coal market will shrink dramatically.

17. This reduction in demand, and therefore pricing, for PRB coal will have a direct and immediate impact on Cloud Peak Energy's profitability and its investments and operations by forcing Cloud Peak Energy to reduce production, make associated reductions in the company's workforce, delay and curtail capital investments in its mines, seek to reduce other operating costs, decline to bid on or invest in new coal leases, and otherwise plan for reduced and uncertain future operations.

18. Even just the anticipation of depressed market conditions due to the anti-coal federal regulatory environment has affected investment decisions. For example, Cloud Peak Energy previously nominated as an LBA a large coal tract adjacent to its existing operation. The BLM divided this LBA into two tracts, Maysdorf II North and Maysdorf II South. The Maysdorf II North tract was offered in August 2013 and no bids were submitted. This was the first time ever that no bids were received on an LBA for PRB coal. Cloud Peak Energy's decision not to bid was heavily influenced by the depressed market conditions and the uncertain and adverse regulatory environment towards coal and coal-powered generation. As a result of receiving no bids, the BLM delayed any future lease sale on the Maysdorf II South tract.

19. Of course, the Section 111(d) rule is not the only EPA rule affecting the coal market, and these other rules, combined with expectations created around EPA's earlier proposal and recent adoption of the Section 111(d) rule, have already reduced coal demand and forced Cloud Peak Energy to reduce operations.

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20. Nevertheless, no other EPA rule is anticipated to have as far-reaching an impact on Cloud Peak Energy as the Section 111(d) rule because of the rule's direct and adverse impact on the existing U.S. coal-fired power generation fleet and associated reduction in the demand and pricing for PRB coal. Cloud Peak Energy thus expects additional similar mine and workforce reductions and curtailments will be inevitable given that the rule is now final. If the rule is not stayed, due to expected required decisions currently being made by electric utilities as discussed in this Declaration, Cloud Peak Energy expects to be reducing capital investments from 2016 and its workforce thereafter.

21. On the other hand, if the U.S. EPA were to withdraw the Section 111(d) rule, or if a federal court were to vacate it, Cloud Peak Energy would expect coal demand by U.S. electric utilities to stabilize at a higher level than will be the case under the rule. Cloud Peak Energy is fully able to play its part in meeting that higher level of demand. As of December 31, 2014, Cloud Peak Energy controlled approximately 1.1 billion tons of proven and probable coal reserves. If the rule were withdrawn or invalidated, and if a substantially similar rule was not expected to replace the rule, Cloud Peak Energy would revise its demand forecasts and its investment and planning decisions accordingly.

22. I, Colin Marshall, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Colin Marshall

Colin Marshall

Dated: August 19, 2015

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EXHIBIT 4

DECLARATION OF J. CLIFFORD FORREST, III

I, J. Clifford Forrest, III, declare as follows:

1. My name is J. Clifford Forrest, III, and I am the President of Rosebud Mining Company ("Rosebud").

2. Initially formed in 1979 as a single mining operation, Rosebud currently operates 22 underground bituminous coal mines in Pennsylvania and Ohio. Rosebud's mines are typically smaller mines, known as "low seam mines" that are often only 40 inches high and produce between 150,000 and 500,000 tons of coal per year. Even so, Rosebud is the 3rd largest coal producer in Pennsylvania and the 21st largest producer in the United States.

3. Rosebud's business, like that of the rest of the coal mining industry, is highly capital-intensive and requires significant investments with extended lead times. Presently it takes 2 to 4 years to explore and permit a new mine, with engineering and permitting costs in the two hundred and fifty thousand to seven hundred thousand range. A new coal refuse area often takes longer than 5 years to permit. New mines are developed at capital costs, including equipment, of ten to twenty million dollars. Given the long lead times and high capital costs, it is important to have coal sales contracts in place. However, most of our customers, due to regulatory and market uncertainty, are buying on one-year periods for contracts, versus the five year

contracts common ten or more years ago. This requires the mining company to self-fund all the engineering, permitting, and development internally. Additionally, due to having short contracts coupled with extensive cap ex, bank financing in general becomes more difficult and costly. Also, as regulatory restrictions increase, the cost of reclamation of the sites increase and the amount for which the sites must be surety bonded increases.

4. Reversing decades of growth, the market for coal has recently become precipitously depressed, which has severely impacted Rosebud's business. Regulations of the Environmental Protection Agency ("EPA"), including the expectation of EPA's now finalized Section 111(d) rule, are the leading cause of the reduction in coal demand. At its peak, Rosebud supplied roughly 9 million tons of coal and employed over 1,450 people, but recent declines in the market for coal have forced Rosebud to reduce production to 7 million tons of coal and cut its workforce by nearly 20 percent, down to 1,124 employees. Rosebud has not hired a new class of miners since June 2013 and has had layoffs since that time.

5. Because of the small size of its mines, Rosebud opens and closes mines more frequently than most coal mining companies. However, Rosebud completed its last mine opening in August 2014 and is not currently in the process of opening any new mines.

6. Finalization of EPA's Section 111(d) rule will depress the coal market even more. As shown in the declaration of Seth Schwartz attached to the Coal Industry Motion for Stay, the rule will result in dramatic reductions in nationwide coal production, particularly in the Appalachian coal region.

7. This further reduction in the coal market will have a direct and immediate impact on Rosebud's investments and operations by forcing Rosebud to delay and curtail capital investments in its mines, decline to bid on or invest in the opening of new coal mines, and otherwise plan for reduced operations. As with all economic systems, power production from coal fired utilities is our main economic driver. The reductions in coal burn that EPA forecasts the 111(d) rule will cause will have substantial impact on the burn rates, or viability, of our customers, which in turn will mean we mine less coal. The degree to which this can be forecasted for each individual coal fired power plant and trickled back to each of our individual mines is difficult to forecast, but we must plan on the basis that the significant reductions in the market for Appalachian basin coal will result in a concommitant reduction in our own customers' demand for our coal. During the time period of this economic collapse, quite often companies try and survive longer than their competitors and there is an extended period of intense competition that squeezes profitability until companies eventually succumb to the financial reality of exhaustion – bankruptcy.

This process often takes several years and is the market's way of weeding out higher cost operations.

8. For example, Rosebud is planning to significantly cut back its capital expenditures. Specifically, Rosebud has decided to delay certain infrastructure plans that it previously contemplated, such as the construction of new rail load outs and cleaning plants, including an additional $20 to $25 million cleaning plant in Indiana County. Also, as our tonnage needs to customers diminishes, we are scrutinizing and shelving new mines that otherwise would be used replenish depleting mines. With less mines to be put in, we must reduce our equipment inventory. We are not buying new equipment from vendors like Caterpillar or Joy Manufacturing. Instead, we are only rebuilding idle equipment as needed to supply our equipment needs. Each new continuous miner we were buying cost over $2 million dollars, and we do not see the need to buy any new miners in the foreseeable future and will run on rebuilt equipment.

9. In addition, the further reduction in coal demand expected in future years is currently affecting Rosebud's negotiations for new coal leases and royalty payments because Rosebud can only make highly conservative offers in light of the additional damage to the coal market expected in coming years with the 111(d) Rule in place.

10. Rosebud also intends to reduce its fleet of equipment via an auction that will occur next year. Rosebud expects that the price it will receive for its equipment will be much lower than it would be without the 111(d) Rule. Large scale surfacing mining equipment, like Caterpillar D11 dozers, are the prime example. The value of Caterpillar D11 dozers has dropped by more than half. Most road construction jobs or gas well pad development jobs are not long enough duration or require enough volume of dirt to warrant spending money on a large D11 dozer, nor can they afford to pay for the mobilization and demobilization of it, unless the job will last for a year or more. Thus, that model of dozer is primarily used in mining and the value of it has crashed, along with other large equipment like 992 loaders, 777 rock trucks, and other large equipment. In addition, we are stripping parts from dozers and using to repair dozers still in production because the core value of the worn out equipment has fallen so low as to make that the most cost-effective approach available.

11. Of course, the Section 111(d) rule is not the only EPA rule affecting the coal market, and these other rules, combined with expectations created around EPA's proposal of the Section 111(d) Rule, have already reduced coal demand and forced Rosebud to reduce operations, as noted above. However, no other EPA rule will have as far-reaching an impact on Rosebud as the Section 111(d) Rule. The Section 111(d) rule thus is a significant driver in Rosebud's decisions to cut back its future operations.

12. I, J. Clifford Forrest, III, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

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J. Clifford Forrest, III
Rosebud Mining Company

Dated: October 16, 2015

EXHIBIT 5

DECLARATION OF JOHN SIEGEL

I, John Siegel, declare as follows:

1. My name is John Siegel, and I am the Executive Chairman of Bowie Resource Partners, LLC ("Bowie").

2. Bowie has three mining operations in Utah and one in Colorado that together produce approximately 13 million tons of high-BTU, low-sulfur bituminous coal per year. Our mines include some of the most productive and longest, continuously-operating mines in the United States.

3. One of our mines, the Bowie #2 mine, is an underground mining complex in Paonia, Colorado, approximately 74 miles east of Grand Junction, Colorado, that is owned and operated by a wholly-owned subsidiary of Bowie named Bowie Resources, LLC. The Bowie #2 mine is located in the Somerset coalfield, which is in the Uinta coal-bearing region of Western Colorado. The Bowie #2 mine began production in 1998.

4. The Bowie #2 mine currently employs approximately 204 people.

5. In the last several years, the market for Colorado coal and coal in general has become severely depressed as a result of a number of regulations of the Environmental Protection Agency ("EPA"), including in particular the expectation of

EPA's recently finalized Section 111(d) Rule, and other market factors. For example, up until last year, Bowie sold substantially all of the coal it produced from its Bowie #2 mine (approximately 3 million tons per year at the time) to the Tennessee Valley Authority ("TVA") under a long-term contract originally executed in 1999. However, on September 30, 2014, TVA terminated its contract with Bowie, forcing Bowie to curtail production at the Bowie #2 mine and reduce its workforce by approximately 150 employees. Upon information and belief, TVA's desire to terminate the contract was motivated in part by its decision to close several coal-fired power plants or convert them to natural gas.

6. Bowie expects to make a decision by the end of this year as to whether it needs to further curtail production at, or idle or close, the Bowie #2 mine. The impact of EPA's Section 111(d) Rule on the coal market will be a key factor in that determination and may make it impossible to find new buyers for coal produced at the Bowie #2 mine. Given the dramatic reductions that the Rule will cause in national coal production and western coal production specifically, as shown in the declaration of Seth Schwartz attached to the Coal Industry Motion for Stay, it will be very difficult to continue mine operations if the Rule is in place.

7. Idling or closing the Bowie #2 mine will eliminate the approximately 204 remaining jobs at the mine—a total payroll of approximately $22.5 million including direct wages and benefits, with average worker consideration of over $110,000

(approximately $87,000 in direct wages and $23,000 in benefits) —in an area with few other high paying job opportunities.

8. I, John Siegel, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

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John Siegel
Executive Chairman
Bowie Resource Partners, LLC

Dated: August 13, 2015

EXHIBIT 6

DECLARATION OF JOHN D. NEUMANN

I, John D. Neumann declare as follows:

1. My name is John D. Neumann, and I am the Vice President, General Counsel and Secretary of The North American Coal Corporation ("NACoal").

2. NACoal, a subsidiary of NACCO Industries, Inc., mines and markets lignite and bituminous coal primarily as fuel for power generation and provides selected value-added mining services for other natural resources companies. Its corporate headquarters is located in Plano, Texas near Dallas. NACoal operates surface mines in North Dakota, Mississippi, Texas, and Louisiana.

3. NACoal is one of the United States' largest miners of lignite coal and among the largest coal producers in the country, producing approximately 29.3 million tons of lignite in 2014.

4. Because lignite has a higher moisture content and a lower heat content than other types of coal, and therefore cannot be transported long distances in a cost-effective manner, most lignite is sold to power plants adjacent or near to the producing mine. If a power plant served by a lignite mine closes, I am not aware of any reasonably viable new market opportunities for the lignite coal.

5. EPA's Clean Power Plan ("CPP") will cause immediate, irreparable injury to NACoal, its workers, and the communities in which it mines coal in three ways. First, according to EPA modeling, the CPP will cause the retirement of the electric generating station to which our Coyote Creek Mine in North Dakota sells all of its coal production. This will cause the mine to close, cause a layoff of the mine's workforce, and it will lead to more than $150 million in stranded investment at the mine, all of which will likely be passed through to North Dakota electric ratepayers and small municipalities. Second, according to EPA modeling, the CPP will cause the retirement of one of the electric generating units to which our Falkirk Mine in North Dakota sells coal, which in turn will cut mine production by more than 40 percent and cause a layoff of about 40 percent of the mine's work force. In any event, the rule will force us to forego a major equipment purchase in excess of $50 million at the mine. Third, it will force us to forego our plan to relocate a highway at our Red Hills Mine in Mississippi, forcing us to strand valuable coal assets and resulting in the loss of tens of millions and even hundreds of millions of dollars. NACoal believes that all of these injuries are preventable if the Court stays and ultimately overturns the rule.

<u>North Dakota—Coyote Creek Mine</u>

6. Through a wholly-owned subsidiary, Coyote Creek Mining Company, L.L.C. ("CCMC"), NACoal is developing the Coyote Creek Mine in Mercer County, North Dakota, about 70 miles northwest of Bismarck. The Coyote Creek Mine will begin making lignite deliveries to the Coyote Station, a 427 megawatt power plant, in 2016.

7. Based on the EPA's projections, Coyote Station will close in 2016 or 2017 unless the CPP is stayed. See Declaration of Seth Schwartz attached to the Coal Industry Motion for Stay ("Schwartz Declaration"). The purpose of the Coyote Creek Mine is to support, and to provide a fuel source for, Coyote Station. Thus, if the power plant closes, Coyote Creek Mine would close as well. If that were to happen, the 90-person mine workforce would be laid off, CCMC would go out of business, and the local community and the State of North Dakota would be deprived of the valuable spin-off benefits and taxes and royalties described below in paragraph 15.

8. To fund the development and construction of the Coyote Creek Mine, CCMC obtained $130 million in fixed-rate third-party financing from an institutional lender and an additional $115 million credit facility from a four bank group.

9. CCMC, to date, has spent approximately $70 million drawn down from the institutional lender. Between now and the end of 2016, as development of the Mine

progresses, CCMC plans to expend an additional $60 million in institutional lender money.

10. Closure of the Coyote Creek Mine in 2016 or 2017 would cause the entire institutional lender loan to accelerate and become due. Moreover, the acceleration will give rise to a $22 million "make whole" payment to the institutional lender.

11. Due to the cost-plus nature of the contract under which CCMC will supply fuel to the Coyote Station, CCMC's obligations to the institutional lender are passed through to the public utilities that jointly own Coyote Station—Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Company, and NorthWestern Corporation. In the end, the utilities, and more specifically their ratepayers and members, would have to pay AIG the money borrowed from AIG if the CPP is not stayed. In return, the ratepayers and members to whom the costs of the Coyote Station are passed on will not have received the benefit of the low-cost power that otherwise would be delivered by Coyote Station. Their stranded investment in the Coyote Creek Mine will be lost.

<u>North Dakota—Falkirk Mine</u>

12. NACoal, through its wholly-owned subsidiary, The Falkirk Mining Company ("Falkirk"), operates the Falkirk Mine near Underwood, North Dakota, about 50 miles north of Bismarck. The Falkirk Mine annually produces between 7 million and

9 million tons of lignite for the Coal Creek Station, a two-unit 1100 megawatt power plant owned by Great River Energy.

13. EPA modeling projects that the CPP will cause the Coal Creek Station unit 1 to close in 2018. See Schwartz Declaration. In 2014, the Falkirk Mine produced 7,985,648 tons of lignite, 43% of which (or 3,408,268 tons) was burned in unit 1. Closure of unit 1 would lead to the layoff of a similar percent of the Falkirk Mine workforce, or in other words 207 of its 482 employees.

14. A layoff at Falkirk Mine will be acute on numerous levels. According to an economic report prepared by North Dakota State University, a true and correct copy of which is attached, the "lignite energy industry (coal production and conversion) provides average wages higher than almost all other industries in North Dakota." For the two hundred plus employees that stand to lose their jobs if Coal Creek unit 1 closes, their lives, and their families' lives, will be drastically impacted.

15. Also, a shutdown would have a substantial impact across several counties and cities in North Dakota. Like all mining companies, Falkirk pays a coal severance tax of 37.5 cents on each ton of lignite mined. In 2014, Falkirk paid $3,104,886 in coal severance taxes. If production declines by 43%, Falkirk would pay 43% less in severance taxes. In 2014 dollars, that amounts to a $1,335,100 decline in tax payments. Under North Dakota law, 30% of revenue from the 37.5 cent tax is used

to fund a Constitutional Trust Fund administered by the Board of University and School Lands. The other 70% is shared among the coal producing counties in the State, which is further apportioned as follows: 40% to the county general fund; 30% to the cities within the county, and 30% to the school districts. Absent a stay of the CPP, according to EPA modeling, Coal Creek unit 1 will shut-down in 2018, which in turn will impact education, law enforcement, and social services throughout the State.

16. Even if EPA modeling is wrong and unit 1 of the Coal Creek Station does not close in 2018, the CPP is still creating an immediate impact on the operation of the mine to the detriment of the local community. At the Falkirk Mine, decisions regarding large capital expenditures must be made years in advance due to the amount of time it takes to finance, acquire, transport, assemble and test equipment. Until the CPP was announced, Great River Energy and Falkirk had intended to acquire, at a cost in excess of $50 million, a used dragline excavator in 2016 or 2017. Dragline excavators are the largest pieces of earthmoving equipment in the world and are commonly used in surface mining to remove overburden.

17. Due to their enormous size and complexity, it takes years for a used dragline to become operational at a new location. Because of its size, the dragline must be disassembled for transport (by rail and truck) to its new location. The parts and equipment constituting the dragline are transported in dozens of modular units to the new location. Upon arrival, the equipment is refurbished, re-assembled, erected, and

tested. This work is done by private contractors, including truckers, welders, electricians, mechanical and electrical engineers, and software programmers.

18. Because of this extensive and time-consuming process, Falkirk and Great River Energy did not plan on the dragline becoming operational until around 2020 or 2021. But because of the CPP, plans to purchase the used dragline for the Falkirk Mine have been postponed, which in turn delays the benefits this $50-plus million transaction would create, including more efficient mining and the, at least, delayed benefits to the private contractors and their employees who would work on the dragline project.

<u>**Mississippi**</u>

19. NACoal has operated the Red Hills Mine near Ackerman, Mississippi since 2002. On an annual basis, the Red Hills Mine produces approximately 3.4 million tons of lignite. Lignite from the Red Hills Mine is used as a fuel supply at the adjacent Red Hills Generating Facility, a 440 megawatt power plant that provides electricity to the Tennessee Valley Authority.

20. Based on current projections, NACoal believes that the CPP could lead to a closure of the Red Hills Generating Facility. If that were to happen, the Red Hills Mine would be forced to close as well.

21. NACoal provides lignite to the Red Hills Generating Facility pursuant to a supply agreement that runs through 2032. The agreement, however, also includes two ten-year extension options that, if exercised, would extend the agreement to 2052.

22. Based on NACoal's geological data, there are enough proven lignite reserves in the vicinity of the Red Hills Mine to support mining, and delivering lignite to the Red Hills Generating Facility, until at least 2052. However, in order for that to occur, approximately 6 miles of Mississippi Highway 9, which bisects the Red Hills Mine area in a north-south direction, would need to be relocated about 2 miles to the east.

23. Mining, and in particular mining at the Red Hills Mine, involves making complex operational, engineering, permitting and property acquisition decisions many years in advance. Those decisions have long-term impacts and in many instances, once they are committed to, they cannot be undone. These decisions can result in the sterilization of valuable lignite reserves, meaning recoverable reserves are bypassed in a way that makes future mining impossible or uneconomic. Relocating Highway 9 is an example of one of those decisions.

24. A highway relocation project involves a wide variety of phases and tasks, including alternate route location, environmental evaluation, surveying, right-of-way acquisition, utility coordination, permitting, contracting and bidding, and construction. Because Mississippi Highway 9 is maintained by the Mississippi Department of

Transportation ("MDOT"), MDOT must participate in the relocation project, adding lead time to the relocation project. Given the complexity of this project, the MDOT has estimated that relocating Highway 9 would take between 7 and 10 years to complete. The cost of that relocation, which would fall on NACoal and which NACoal was prepared to pay before the CPP was announced, is approximately $30 million.

25. Due to the uncertainty introduced by the CPP with respect to the continuing operation of the Red Hills Generating Facility through 2052 (or even 2032), NACoal will not proceed with the Highway 9 relocation project absent a stay and ultimate reversal of the CPP. Instead, NACoal will simply construct an underpass beneath the existing Highway. This will lead to a much more inefficient solution from a mine planning standpoint. More importantly, the underpass will enable NACoal to mine until 2037, but not for the remaining 15 years of the agreement to supply lignite.

26. If Highway 9 is going to be moved in order to facilitate future mining, NACoal is at the "point of no return." The reserves on the west side of Highway 9 will be depleted relatively soon, and NACoal must either move the Highway or go under it. Put in other words, if the Highway is going to be moved, NACoal must begin the process right now.

27. There are approximately 6.2 million tons of lignite underlying Highway 9 that NACoal will be unable to mine if the Highway is not moved. Relocating the Highway would allow NACoal to mine those 6.2 million tons, and mine them more cost-effectively that it can mine reserves if it must go under Highway 9. If the Highway is not relocated, NACoal stands to lose tens of millions of dollars in nearer-term profit on the 6.2 million tons of lignite underlying Highway 9.

28. In addition, NACoal engineers have advised that moving the Highway would enable NACoal to modify its mine plan so that it is able to continue mining until 2052. If the Highway is not relocated, NACoal stands to lose 15 years of profit (hundreds of millions in additional profit).

29. I, John D. Neumann, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct to the best of my knowledge.

John D. Neumann
The North American Coal Corporation

Dated: August 21, 2015

EXHIBIT 7

DECLARATION OF CHRIS McCOURT

I, Chris McCourt, declare as follows:

1. My name is Chris McCourt and I am the Mine Manager for the Colowyo Coal Mine for Colowyo Coal Company L.P. ("Colowyo").

2. The Colowyo Coal Mine is located about 10 miles north of Meeker, Colorado. It presently produces approximately 2.5 million tons of low sulfur, subbituminous coal annually. The mine presently employs 220 people.

3. The mine currently supplies coal to Craig Station in northwestern Colorado. It is also capable of supplying coal to other electric generating facilities and has done so in the past.

4. Operating the Colowyo Coal Mine is a highly capital-intensive activity that requires significant investments with extended lead times. For example, Colowyo has been undergoing environmental review and permitting for an 80+ million ton expansion into previously leased federal coal reserves, the "Collom" expansion, involving one or two new pits, for the past 11 years.

5. The United States Environmental Protection Agency's recently adopted Section 111(d) rule (the "Rule") will significantly reduce the market for coal throughout the United States, as is shown by EPA's own figures. See Declaration of Seth Schwartz attached to Coal Industry Motion for Stay ("Schwartz Declaration").

6. EPA's own figures also show that Western coal production will be harmed to a greater degree than the national average. See Schwartz Declaration.

7. The Rule has been promulgated at an especially sensitive time for Colowyo. Colowyo is presently mining the last reserves in the "South Taylor Pit," first permitted in 2007. At the present and necessary rate of production, Colowyo has approximately four years of production remaining at the South Taylor Pit until its reserves are exhausted. To continue to operate, Colowyo must be able to mine the Collom leases at that time.

8. There are several additional steps that must occur before Collom can become operational. Although Colowyo already holds leases and has received state permits to mine the Collom coal, Colowyo must receive approval of its Mine Plan of Operation from the Office of Surface Mining, Reclamation, and Enforcement ("OSMRE"). OSMRE is presently working on federal environmental review for the Collom expansion, with a draft Environmental Assessment expected this fall, and a decision by OSMRE this winter or in the Spring of 2016. Only after the Mine Plan of Operation is approved by OSMRE can Colowyo undertake any of the extensive preparatory construction necessary to begin mining coal. There is an approximately 24 month gap between receiving OSMRE approval of the Mine Plan of Operation and commencing actual mining of coal.

9. As proposed in the Mine Plan of Operation, Colowyo intends to both supply Craig Station for the foreseeable future and sell coal in the general market in

approximately equal shares. Colowyo Coal Mine coal can be quite competitive in the general market. Anticipated production rates drive major capital investment components of the Mine Plan of Operation, including the initial configuration of the pit, the size and capacity of the dragline and shovels, the crusher, the number of haul trucks, water trucks, graders, scrapers and the configuration of support facilities costing tens of millions of dollars.

10. As discussed, the Rule substantially threatens the western coal market, and consequently Colowyo's ability to market Collom coal to the general market. An efficient and economic mine layout and Mine Plan of Operation for Collom would look quite different if Colowyo is only able to sell to Craig Station instead of equally to Craig Station and the general market.

11. Were it not for the short remaining production life left in the South Taylor Pit, a prudent course of action in response to the Rule would be to delay finalization of Mine Plan of Operation for Collom until Colowyo could get a better sense whether EPA's unprecedented application of Section 111(d) is upheld on judicial review. Unfortunately, that is not an option given the remaining life of South Taylor and the long lead time necessary to bring Collom into production. Colowyo needs to make a firm decision on the Collom Mine Plan of Operation in the next few months. That decision will be extremely expensive, difficult, and time-consuming to revisit, given the required investments and many approvals necessary to change a permit and Mine Plan of Operation.

12. Consequently, Colowyo faces a Hobson's Choice if there is no stay of the Rule pending review. Colowyo can either now scale back the Collom Mine Plan of Operation and suffer irreparable long term injury by foregoing the opportunity to sell into the general market if the Rule is overturned, or it can proceed on its current course in anticipation that the Rule will be overturned. Even if Colowyo proceeds in the belief the Rule will be overturned, it will likely suffer regardless, because Colowyo's utility market customers face their own long lead time, capital-intensive decisions. Many of them will undoubtedly forego investments either voluntarily or under effective compulsion through the State Implementation Plan process. As with Colowyo, these decisions by utilities are extremely difficult and expensive to undo once made. If the Rule is not stayed, it is highly likely that many if not all of the market-dampening effects of the Rule will occur even if the Rule is ultimately overturned. It is thus critical to Colowyo that the Rule be stayed pending review.

13. I, Chris McCourt, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Chris McCourt
Chris McCourt
Mine Manager
Colowyo Coal Company L.P.

Dated: October 9th, 2015

EXHIBIT 8

DECLARATION OF DAVID T. LAWSON

I, David T. Lawson, declare as follows:

Introduction

1. My name is David T. Lawson and I am Vice President Coal for Norfolk Southern Corporation ("Norfolk Southern"). I joined Norfolk Southern in 1988 as a sales representative and have served in various capacities within our organization, including as a member of our automotive supply chain, as President of Modalgistics, our rail-centric logistics solutions consulting group, and as Vice President of our Industrial Products marketing group. I hold degrees from Louisiana State University and Wayne State University. In my current position as Vice President of our Coal marketing group, I am responsible for the marketing strategies for Norfolk Southern's coal transportation services. This includes the sales responsibilities as well as the forecasting of our resources relative to market demand, including the utility market; export market; domestic metallurgical market and the industrial coal market.

2. Norfolk Southern is one of the nation's premier transportation companies. We are primarily engaged in the rail transportation of raw materials, intermediate products, and finished goods mainly in the Southeast, East, and Midwest and, via interchange with rail carriers, to and from the rest of the United States. We also transport overseas freight through several Atlantic and Gulf Coast ports. We

provide comprehensive logistics services and offer the most extensive intermodal network in the eastern half of the United States.

3. Our Norfolk Southern Railway Company subsidiary is one of seven Class I freight railroads in the United States and operates approximately 20,000 route miles in 22 states and the District of Columbia. Our system reaches many individual industries, electric generating facilities, mines (in western Virginia, eastern Kentucky, southern and northern West Virginia, western Pennsylvania, and southern Illinois and Indiana), distribution centers, transload facilities, and other businesses located in our service area.

4. Finalization of EPA's Clean Power Plan already is having, and will continue to have, significant impacts on our investment decisions related to our coal franchise. Although the interim standards set by the Clean Power Plan will not go into effect until 2022, the projected overall impacts of the final rule on coal-fired generation within our service area are substantial and immediate. Many railroad assets have useful lives measured in decades, not years, meaning current investment decisions must project and incorporate expected returns well past full implementation of the rule. Unless the court issues a stay during the consideration of the legal challenges to the Clean Power Plan, the final rule will continue to be a significant factor in internal decision-making for long-term investment decisions disincenting the company against making needed further investment in our coal franchise.

Norfolk Southern's Utility Coal Franchise

5. Coal is one of the most important commodities transported by the U.S. freight railroads. In 2014, coal comprised over 38 percent of the tonnage, 20 percent of the carloads, and 18 percent of the gross revenue for U.S. Class I railroads.[1] This rail transportation is vital to the domestic power fleet. According to the U.S. Energy Information Administration ("EIA"), 67 percent of coal consumed by electric power generators was shipped either completely or in part by rail in 2013.[2]

6. Norfolk Southern's coal franchise supports the electric generation market as well as the export, metallurgical, and industrial markets, primarily through direct rail and river, lake, and coastal facilities, including various terminals on the Ohio River, Lambert's Point in Norfolk, Virginia, the Port of Baltimore, and Lake Erie. Most of our carloads in 2014 originated on our lines from major eastern coal basins, with the balance from major western coal basins received via the Memphis and Chicago gateways. Overall, 21 percent of our 2014 total railway operating revenues was generated by coal transportation.

7. Of our four major markets (utility, export, domestic metallurgical, and industrial), utility coal is by far our largest. In 2014, out of the 141 million tons of coal Norfolk Southern transported, over 93 million tons was utility coal. We serve

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1 ASSOCIATION OF AMERICAN RAILROADS, RAILROADS AND COAL, at 6 (July 2015), https://www.aar.org/BackgroundPapers/Railroads%20and%20Coal.pdf.

2 EIA, "Railroad Deliveries Continue to Provide the Majority of Coal Shipments to the Power Sector" (June 11, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=16651.

approximately 84 coal generation plants in at least twenty states: Alabama, Delaware, Florida, Georgia, Illinois, Indiana, Kentucky, Maryland, Michigan, Mississippi, North Carolina, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, and Wisconsin.

8. Our utility customers source coal from all the major coal basins in the United States. The power plants we serve in Midwest take their coal predominantly from the Power River basin and the Illinois Basin, while the Northeast plants take their coal predominantly from the Northern Appalachia regions. Plants in the Southeast source from all three of those regions as well as Central Appalachia.

Projected Impacts of the Clean Power Plan

9. All parties, including EPA, agree that the Clean Power Plan will have substantial impacts on coal consumption and production. Nationwide, EPA projects that the final rule will displace 323 to 335 thousand gigawatt hours of coal-fired electricity generation in 2030 versus the reference case if the rule was not enacted.[3] That amount represents more than a fifth of current coal-fired generation.[4] Overall, EPA projects coal-fired generation will make up just 27 percent of the U.S. generation mix in 2030, compared with 37 percent under the reference case projection.[5] We are aware that EPA understated the impacts of its final rule by including many more

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[3] EPA, REGULATORY IMPACT ANALYSIS FOR THE CLEAN POWER PLAN FINAL RULE, at 3-27, Table 3.11 – Generation Mix (Aug. 2015) [hereinafter *EPA RIA*].

[4] *See* EIA, Electric Power Monthly (July 27, 2015), http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01 (reporting net generation from coal was 1,585,697 thousand megawatt hours in 2014, or about 1,586 thousand gigawatt hours).

[5] *See EPA RIA*, *supra* note 3, at 3-27 tbl.3.11.

retirements of coal-fired generation in its "base case" than it included in its "base case" for the proposed rule and as compared with the Energy Information Administration's "business-as-usual" (without the Section 111d) rule scenario.[6] Nevertheless, even the impact that EPA itself projects are extremely large.

10. EPA further estimates that the final rule would reduce coal production 21 to 22 percent versus the 2030 reference case, depending on the method of compliance.[7] Breaking the numbers down by major coal basins, EPA projects that Appalachia will lose 23 to 25 percent of its coal production for the electric power sector even earlier, by 2025, as a result of the final Clean Power Plan.[8]

11. Published analyses of EPA's initial, less stringent proposal reached similar conclusions. EIA projected that coal plant retirements would increase from 40 gigawatts by 2040 under the reference case to 90 gigawattas under EPA's proposal, with nearly all of those additional retirements occurring by the time the proposal would have gone into effect in 2020.[9] EIA also found that all major coal-producing regions would experience negative production impacts in 2020.[10] NERA Economic Consulting produced a study reporting a similar increase in coal retirements, from 51 gigawatts by 2031 under their reference case to 97 gigawatts under EPA's initial

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6 *See* Declaration of Seth Schwartz attached to Coal Industry Motion for Stay.

7 *See id.* at 3A-7 tbl.3A-2.

8 *Id.* at 3-33 tbl.3-15.

9 EIA, ANALYSIS OF THE IMPACTS OF THE CLEAN POWER PLAN, at 16 (May 2015), available at http://www.eia.gov/analysis/requests/powerplants/cleanplan/pdf/powerplant.pdf.

10 *Id.* at 18.

proposal.[11] That projection increased to 220 gigawatts of coal plant retirements if states faced constraints in permissible methodologies to achieve emission reductions.[12] The study found that "[t]he Southeast and Central regions experience the greatest impact on coal retirements in both scenarios."[13]

12. It is almost axiomatic that any regulation that projects to dramatically reduce both domestic coal-fired electricity generation and coal production would harm Norfolk Southern's utility coal business.[14] Lower production and consumption necessarily will decrease demand for coal transportation from the freight railroads that move the overwhelming majority of coal consumed by electric power generators. The projected disproportionate impact on Southeast generation and Appalachia production particularly would affect Norfolk Southern. Although we move significant quantities of coal originating from all of the major basins across the United States, over 60 percent of the coal we transported in 2014 originated from the Appalachia region.

13. Looking at the state level, several states with significant coal-fired electricity generation within Norfolk Southern's service area face substantial reductions in CO_2 emission rates under the final rule. For example, West Virginia,

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11 *See* NERA ECONOMIC CONSULTING, POTENTIAL ENERGY IMPACTS OF THE EPA PROPOSED CLEAN POWER PLAN, at S-6 (Oct. 2014), available at http://www.nera.com/content/dam/nera/publications/2014/NERA_ACCCE_CPP_Final_10.17.2014.pdf

12 *Id.*

13 *Id.* at 22.

14 *Cf.* Norfolk Southern Corp., Annual Report (Form 10-K), at K14 (Feb. 11, 2015) (identifying climate change regulation as a corporate risk factor).

which produced over 95 percent of its electricity from coal in 2014,[15] must reduce its emission rate from 2,064 pounds of CO_2 per megawatt hour in 2012 to 1,305 pounds of CO_2 per megawatt hour by 2030.[16] Kentucky, which produced 92 percent of its electricity from coal in 2014,[17] must reduce its emission rate even further, from 2,122 pounds of CO_2 per megawatt hour in 2012 to 1,286 pounds of CO_2 per megawatt hour by 2030.[18] Such large reductions cannot be achieved without scaling back coal-fired generation, which necessarily will harm Norfolk Southern's utility coal business.

The Clean Power Plan Is a Significant Factor Influencing Norfolk Southern's Current Investment Decisions

14. Recognizing these potential impacts, Norfolk Southern has followed EPA's Clean Power Plan closely.[19] We cannot precisely quantify the impact of the final rule on our coal business at this time, due to unsettled questions about the formulation of state implementation plans and utility compliance strategies. But there is no doubt that the Clean Power Plan will substantially reduce coal-fired generation and production going forward, and thus harm Norfolk Southern's coal transportation

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15 *See* EIA, State Profile and Energy Estimates: West Virginia, http://www.eia.gov/state/?sid=WV (last visited Aug. 12, 2015).

16 EPA Connect, Clean Power Plan: Power Plant Compliance and State Goals, tbl.1 (Aug. 4, 2015), https://blog.epa.gov/blog/2015/08/clean-power-plan-power-plant-compliance-and-state-goals/ [hereinafter *EPA Connect*].

17 *See* EIA, State Profile and Energy Estimates: Kentucky, http://www.eia.gov/state/?sid=KY (last visited Aug. 12, 2015).

18 *EPA Connect*, *supra* note 15.

19 Norfolk Southern submitted comments opposing finalization of the Clean Power Plan because the proposal would result in significant costs to American consumers and the economy and exceeded the limits of EPA's authority. *See* Comments of Norfolk Southern Corp., Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, EPA Docket ID No. EPA-HQ-OAR-2013-0602 (Dec 1, 2014).

business. And even though EPA's interim emission goals do not go into effect until 2022, both the third party projections discussed above and our experience with our customers' decision-making in response to EPA's Mercury and Air Toxic Standards for power plants demonstrate that these impacts are likely to begin well before then.

15. Moreover, the Clean Power Plan is already affecting Norfolk Southern's decision-making process concerning our coal franchise. Railroad assets are longer-lived than many other industries – average rail equipment service lives are approximately 28 years, and structures range from 38 to 54 years.[20] Many of these investments are also largely sunk – they are not easily moved, sold, or used for other purposes.[21] As a result, significant changes in volumes or traffic flows of particular commodities have the potential to strand prior investments.[22] Therefore, when making investment decisions, Norfolk Southern and other railroads must project decades into the future in order to determine if the expected rate of return on a particular investment justifies current capital spending.

16. Norfolk Southern is constantly evaluating investment decisions related to our coal-related assets, including our equipment (mainly coal cars), infrastructure

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[20] Reply Comments of Association of American Railroads, Reply Verified Statement of Dr. Roger E. Brinner, at 17, *Railroad Revenue Adequacy*, Surface Transportation Board Docket No. EP 722 (filed Nov. 4, 2014) (based on data from the U.S. Department of Commerce, Bureau of Economic Analysis).

[21] *See* LAURITS R. CHRISTENSEN ASSOCIATES, INC., SUPPLEMENTAL REPORT TO THE U.S. SURFACE TRANSPORTATION BOARD ON CAPACITY AND INFRASTRUCTURE INVESTMENT, at 2-18 (Mar. 2009).

[22] *See, e.g.*, Michael W. Kahn, "BNSF Sees 'Stranded Assets' on Coal Lines," ECT.COM (June 22, 2015), http://www.ect.coop/industry/business-finance/bnsf-sees-stranded-assets-on-coal-lines/82235.

and track work, and related facilities. We carefully consider market dynamics, for example recent shifts from traditional Central Appalachia coal origins to Northern Appalachia and the Illinois Basin, when making such decisions. The final Clean Power Plan is now a significant factor in those analyses – Norfolk Southern simply cannot afford to ignore the rule's projected impact of reducing both coal-fired generation and coal production more than 20 percent. Although interim standards will not apply until 2022, and the final standards will not become effective until 2030, impacts from those limitations will be felt during the useful life of most railroad assets purchased or constructed now. As a result, the Clean Power Plan is a disincentive to current investment in our coal franchise.

17. Absent a stay, Norfolk Southern must operate under the assumption that the finalized rule will continue to be effective in its current form. And many investment decisions Norfolk Southern will make during the interim time period cannot be reversed easily or cheaply, if at all, several years from now. For example, Norfolk Southern must consider opportunities to rationalize infrastructure, such as by adjusting routing and removing lines from service, rather than investing to keep underutilized infrastructure operational. Similarly, we have a fleet of approximately 22,000 coal cars, of which more than 4,000 are used in utility service. These cars cost around $95,000 each and have an average life of around 50 years, meaning purchasing decisions require long-term volume certainty. Although our Mechanical Department has been innovative in finding new ways to retrofit existing coal cars to allow us to

defer purchasing decisions, the window of opportunity for those programs in short because of the limited quantity and age of eligible cars. As a result, finalization of the Clean Power Plan is already directly impacting our coal franchise.

Conclusion

18. There is no debate that the final Clean Power Plan will substantially reduce the amount of coal consumed by and produced for the United States electric power sector. Therefore, there can be no debate that Norfolk Southern, which serves 84 coal-fired plants and the major coal producing basins east of the Mississippi, will be harmed by the effects of EPA's rule. When evaluating current investments related to our coal franchise, Norfolk Southern is already factoring in the projected impacts of the Clean Power Plan into long-term decision-making. Due to the nature of the railroad industry and railroad assets, many coal-related investment decisions that Norfolk Southern will make now will either be expensive or impossible to reverse should the final rule ultimately be invalidated by the courts. As a result, Norfolk Southern will suffer harm if the rule is not stayed pending the outcome of legal challenges to the Clean Power Plan.

19. I, David T. Lawson, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

David T. Lawson

David T. Lawson, VP Coal
Norfolk Southern Corporation
Dated: August 20th, 2015

EXHIBIT 9

DECLARATION OF ROBERT E. MURRAY

I, Robert E. Murray, declare that the following statements made by me are true and accurate to the best of my knowledge, information and belief:

Background

1. My name is Robert E. Murray. I am the Founder, Chairman, President, and Chief Executive Officer of Murray Energy Corporation and subsidiary companies ("Murray Energy"), a group of coal mining, sales and brokerage, transloading, and coal shipment companies.

2. I am providing this Declaration in connection with finalization by the United States Environmental Protection Agency ("EPA") of the final rule entitled, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (the "Final Rule"). The Final Rule, announced in August, 2015 expressly contemplates the shifting of fuel at power plants from coal to other fossil fuels, and the shifting of energy supply from fossil fuel power plants to alternative energy sources such as wind and solar.

3. I make this Declaration based upon personal knowledge or information supplied by Murray Energy employees who report to me; my daily involvement in the coal industry over the past fifty eight (58) years; market reports, projections and analysis used in the ordinary course of Murray Energy's business; and EPA's own analysis and those of others of the

economic effects of the Final Rule.

4. I received a Bachelor of Engineering in Mining Degree from The Ohio State University, completed the Advanced Management Program at the Harvard School of Business, and am a licensed Professional Engineer.

5. Prior to founding Murray Energy, I was President and Chief Executive Officer of The North American Coal Corporation ("North American"), which is now part of Nacco Industries, Inc.

6. With North American, I served in every coal mine and preparation plan operations management and engineering position, beginning my 31-year career with North American while a student at The Ohio State University. I was elected Vice President – Operations in 1969, served as President of the Western Division and President of four subsidiaries in North Dakota from 1974 to 1983, and was named Executive Vice President – Operations in 1983. Subsequently, I was elected President and Chief Operating Officer, and then President and Chief Executive Officer, of North American and its subsidiaries.

7. I am currently serving on the boards of the National Mining Association, the American Coalition for Clean Coal Electricity, and the American Coal Foundation. I am also a member of the Energy Leadership Council of the U.S. Chamber of Commerce, and a Life Member of The Rocky Mountain Coal Mining Institute. Murray Energy belongs to the Kentucky,

Illinois, Ohio, Pennsylvania, and West Virginia Coal Associations.

8. I am also a past president of the American Institute of Mining, Metallurgical and Petroleum Engineers, Inc., the Society for Mining, Metallurgy and Exploration, Inc., and The Rocky Mountain Coal Mining Institute.

9. During my fifty-eight (58) year career in the mining industry, I have received a number of awards including the Erskine Ramsay, Howard N. Eavenson, Percy Nicholls, and Distinguished Member Awards from the Society for Mining, Metallurgy, and Exploration, Inc. I also received the Honorary Member Award from the American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc.

<u>The Business of Murray Energy Corporation</u>

10. Murray Energy began in 1988 with the purchase of a single continuous mining operation in the Ohio Valley mining region with an annual output of approximately 1.2 million tons per year.

11. In April, 2015, Murray Energy acquired a substantial interest in Foresight Energy GP LLC and Foresight Energy LP ("Foresight Energy"), a leading producer of coal in the United States that recently completed a $1.7 billion capital expenditure program constructing mining complexes and related transportation infrastructure.

12. Today, Murray Energy is the largest privately-held coal company

in the United States and the largest underground coal mine operator in the United States, with combined operations that currently produce and ship about eighty-seven (87) million tons of bituminous coal annually and employment peaking earlier this year at about 8,400 persons, but which has since declined to about 6,100 persons.

13. Together, Murray Energy and Foresight Energy currently operate seventeen (17) active mines located in three major high-Btu coal-producing regions in the United States:

a. Northern Appalachia (Ohio and West Virginia): Century Mine, Harrison County Mine, Marion County Mine, Marshall County Mine, Monongalia County Mine, Ohio County Mine, and Powhatan No. 6 Mine;

b. Illinois Basin (Illinois and Kentucky): Deer Run Mine, M-Class Mine, Mach No. 1 Mine, New Era Mine, New Future Mine, Paradise No. 9 Mine, Shay No. 1 Mine, and Viking Mine; and

c. Uintah Basin (Utah): Lila Canyon Mine and West Ridge Mine.

14. Murray Energy has other projects in various stages of coal mine development depending on market conditions for our products.

15. In the last five years, Murray Energy and Foresight Energy mines

have supplied coal directly to electric utility generating units ("EGUs") located in at least twenty-three (23) different States: Alabama, California, Delaware, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nevada, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Utah, West Virginia, and Wisconsin.

16. Murray Energy and Foresight Energy together own or control approximately 9.0 billion processable, saleable tons of coal reserves in the United States, strategically located near our customers, near favorable transportation, and high in heating value.

17. Additionally, Murray Energy and Foresight Energy own over 80 subsidiary and support companies directly or indirectly related to the domestic coal industry, including intermodal transloading facilities in Illinois, Indiana, Ohio and West Virginia (on the Ohio River); in Kentucky (on the Green River); and in Pennsylvania (on the Monongahela River). Foresight Energy also holds contractual rights to terminal capacity in the Gulf of Mexico, and Murray Energy operates twenty-seven (27) river tow boats and five hundred seventy (570) barges.

18. Murray Energy also builds the vast majority of its mining equipment at factories located in Centralia, Illinois; Clarington, Ohio; Millersburg, Kentucky; and Wheeling, West Virginia.

19. As indicated above, Murray Energy's business is coal, and that business directly touches nearly half of the States as taxpayer, employer, or coal supplier. Once electricity produced by its customers is added to the grid, Murray Energy's business touches households and businesses across an even larger swath of the United States.

The Harm to Murray Energy Corporation

20. Virtually all of the coal produced by Murray Energy and Foresight Energy is supplied to power plants, providing reliable and affordable energy to households and businesses across the country.

21. The Preamble to EPA's proposed rule stated that, ***as a result of the rule***, 24–32 gigawatts of coal-fired EGUs would retire through 2020. EPA further stated that the rule would result in a decline in coal production for use by the power sector by roughly 25 to 27 percent in 2020 from base case levels, and that the use of coal by the power sector would decrease roughly 30 to 32 percent in 2030.

22. Because the proposed rule clearly and purposefully aimed at significantly depressing the use of coal in the United States at coal-fired power plants, yet was contrary to the express authority given to EPA by Congress, Murray Energy filed two lawsuits in the United States Court of Appeals for the District of Columbia Circuit seeking to stop the rulemaking in its tracks. Murray Energy also filed comments on the proposed rule on December 1,

2014.

23. EPA has plowed forward with its so-called Clean Power Plan notwithstanding its illegality and the devastating impact it has had and will continue to have – by design – on the coal industry.

24. The Final Rule aims to reduce emissions of carbon dioxide from the power sector by 32 percent from 2005 levels by 2030. To meet this reduction target, EPA lays out three strategies, referred to as "building blocks," that States can use. Building block 1 contemplates efficiency improvements at coal-fired EGUs. Building block 2 contemplates displacing the generation of electricity from coal-fired EGUs with generation from gas-fired EGUs, and building block 3 contemplates increased generation from renewable energy resources, displacing generation from both coal- and gas-fired EGUs.

25. The end result is that the Final Rule calls for a nearly 40% across-the-board reduction in the rate of emissions from fossil fuel fired EGUs (primarily coal-fired EGUs, but also oil-fired EGUs) compared to 2012 levels.

26. Specifically, EPA calculates a fleet wide emission rate for coal- and oil-fired EGUs in 2012 of 2167 lb/MWh and requires achievement of a rate of 1305 lb/MWh by 2030, a 39.7% reduction compared to 2012. *See* Goal Computation Technical Support Document, Table 4 (Exhibit 2 to the Coal Industry Motion for Stay).

27. Applying EPA's figures for heat rate improvements to power

plants that are achievable (according to EPA) results in an emission rate of only 2087 lb/MWh, a mere 3.7% reduction compared to 2012. In other words, the Final Rule calls for nearly ten times more in emission rate reduction than EPA considers achievable by improvements in the operation of the power plants. Another 36% reduction in emission rate is still needed.

28. Clearly, building block 1 of the Final Rule is not the focus of EPA's Clean Power Plan.

29. Instead, building blocks 2 and 3 of the Final Rule are the real crux of EPA's Clean Power Plan. And these are the building blocks directly calling for displacement of coal as a fuel at EGUs.

30. Thus, the only way EPA itself found that the additional 36% reduction in emissions required by the Final Rule can occur is by curtailment of operations, retirements, and conversions of coal-fired EGUs. Significant reduction in coal for electric production in the United States is EPA's end game irrespective of any purported flexibility given to the States, and even if States are able to create a workable emissions trading program as an element of their plans.

31. Murray Energy will be immediately impacted by the closing, curtailing or converting of customers' power plants as a result of the Final Rule, even before the deadline for States to submit initial plans and certainly before completion of judicial review of the Final Rule's legality.

32. This is due in part to the long lead time needed by utilities to effect such a dramatic change in the generation mix, including time needed for planning to assure as little disruption in reliability as possible and for the permitting and construction of new facilities with associated infrastructure. Utilities also face the upcoming March, 2016 deadline for compliance with the separate Utility MACT rule, as well as other near-term deadlines under the Regional Haze Program and the Water Intake Rule.

33. For example, based on a review of a recent SNL Energy analysis, 6.5 gigawatts of Murray Energy and Foresight Energy customers reportedly have planned (or ongoing) investments in environmental controls in order to comply with EPA's Utility MACT by the upcoming 2016 deadline, including the following:

- Georgia Power Company's Bowen Plant (3 units) (Georgia)
- Big River Electric Corporation's DB Wilson Plant (1 unit) (Kentucky)
- Alabama Power Company's EC Gaston Plant (1 unit) (Alabama)
- NRG Energy Service's Homer City (2 units) (Pennsylvania)
- Louisville Gas & Electric Company's Mill Creek (4 units) (Kentucky)
- Public Service of New Hampshire's Schiller (2 units) (New Hampshire)

34. The utility sector has no choice but to make decisions immediately – within a period measured in months not years – about coal plant retirements versus investment of millions if not billions of dollars. Utilities faced with the threat of forced retirement due to the Clean Power Plan will seek to avoid investing the additional capital needed to comply with other EPA programs, and thus will retire units as soon as possible. Moreover, once the decision is made to retire a coal-fired power plant and replace it with another alternative, the decision is largely irrevocable.

35. This phenomenon already occurred in connection with the Utility MACT rule, where utilities did not await the compliance deadline (or the end of judicial review) before making decisions to retire units. *See* Schwartz Report, Section IV (attached to the Schwartz Declaration, included as Exhibit 1 to the Coal Industry Motion for Stay). The same will be true for the Clean Power Plan.

36. As utilities close coal-fired power plants, mines which supply them will be forced to close as well. Jobs will be lost, as will the value of the coal industry's investments. Additionally, like the utility sector, the coal industry is highly capital intensive and must also make investment decisions that have long lead times. For example, Foresight Energy's development of three new mines in Illinois averaged nearly 6 years to get from first permit to full production. *See* Schwartz Report, Exhibit 20. Murray Energy and others in the coal industry cannot wait another year or two to make the decisions

necessary to adjust to new market realities.

37. EPA agrees that immediate effects will occur. According to EPA's own analysis, the Final Rule will trigger a wave of early retirements of coal-fired EGUs long before the 2022 interim compliance date in the rule. This is described more fully in the expert report of Mr. Seth Schwartz, President of Energy Ventures Analysis, Inc., titled "Evaluation of the Immediate Impact of the Clean Power Plan Rule on the Coal Industry," which is attached to the Schwartz Declaration included as Exhibit 1 to the Coal Industry Motion for Stay ("Schwartz Report").

38. According to Mr. Schwartz' expert report, ***as a result of the Final Rule***, EPA's IPM model projects the retirement of approximately 5.7 gigawatts of EGUs ***in 2016-2017*** that are or within the last five (5) years have been supplied by Murray Energy's coal mines, including the following seventeen (17) units in six (6) States:

- Georgia Power Company's Bowen Plant (4 units) (Georgia)
- Gulf Power Company's James F. Crist Generating Plant (Florida) (1 out of 4 units)
- Tennessee Valley Authority's Gallatin Plant (4 units) (Tennessee)
- Alabama Power Company's Greene County Plant (1 unit) (Alabama)
- Georgia Power Company's Hammond Plant (3 units)

(Georgia)

- Louisville Gas & Electric's Mill Creek Plant (2 units) (Kentucky)
- TES Filer City Station (2 units) (Michigan)

See Schwartz Report, Exhibit 29 and accompanying discussion.

39. As explained by Mr. Schwartz, these retirements – projected by EPA using its IPM model – cannot be attributed to the impacts of the Utility MACT rule, because EPA has included those impacts in its base case.

40. Based on a review of data compiled by the Federal Regulatory Energy Commission (FERC), Murray Energy is a significant supplier of coal to the following EGUs that would close according to EPA's model, as analyzed by Mr. Schwartz.

- M-Class and New Future/New Era Mines together represented about 32% of the contracted coal to the Bowen Plant in 2014, and about 63% in the first quarter of 2015.
- M-Class Mine also represented about 25% of the contracted coal to the Crist Plant in 2014, and about 62% in the first quarter of 2015.
- M-Class and New Future/New Era Mines represented about 29% of the contracted coal to the Hammond Plant in 2012 and nearly 90% in 2014 (Hammond's total reported

coal demand dropped dramatically between 2012 and 2014, with 2014 levels at only 12.5% of 2012 levels).

- M-Class and New Future/New Era Mines represented about 13% of the contracted coal to the Mill Creek Plant in 2014.
- Mach No. 1, Shay No. 1 and New Future/New Era Mines have steadily represented between 13 and 20% of the contracted coal to the TES Filer Plant since 2010.

41. In 2014, Murray Energy coal supply contracts totaled over 3 million tons for these 17 units identified in the Schwartz Report. Even if EPA's model does not accurately predict which specific units will close, if they are not these units, they will be other units. The impact to the coal industry is the same.

42. We estimate that the current Administration has now closed 411 coal-fired EGUs, a loss of 101,000 megawatts of the lowest cost electricity in America.

43. The American Coalition for Clean Coal Electricity (ACCCE) tracks announced retirements and conversions of coal-fired EGUs. As of May 8, 2014, one month before EPA published its proposed Clean Power Plan, ACCCE identified 338 announced retirements and conversions since 2010 attributable to EPA policies and regulations. This represented over 51,000 megawatts of electric generating capacity.

44. ACCCE updated its list of retirements and conversions as of October 4, 2015 [available at http://www.americaspower.org/sites/default/files/Coal%20Unit%20Retirements%20OCTOBER%204%202015.pdf]. Comparing information collected by ACCCE as of October 2015 with its previous compilation as of May 2014, ACCCE has identified an ***additional*** 65 retirements or conversions due to EPA policies and regulations announced in the last 16 months, representing another 13,410 megawatts of electric generating capacity

45. Notably, EPA's proposed Clean Power Plan was published in June, 2014.

46. These are not modeled or theoretical retirements and conversions; these are real-world retirements and conversions that have been formally announced, in most cases by the EGU owners themselves (according to ACCCE).

47. Murray Energy is being directly and immediately impacted. An examination of the additional 65 announced retirements and conversions identified by ACCCE indicates that Murray Energy and Foresight Energy mines have supplied coal to at least thirteen of them within the last five years. Notable amongst this group, based on information obtained from ACCCE as to announced retirements/conversions and data compiled by the Federal Energy Regulatory Commission (FERC), is the following:

a. Indiana Power & Light announced in August, 2014 that it was converting the last of the coal-fired units at its Harding Street Generation Station to natural gas in 2016. Viking Mine has supplied coal to this EGU. Reportedly, this conversion is a direct result of EPA's increasingly stringent regulation following statements by the Indiana Utility Commission that future rate increases due to the Clean Power Plan and other environmental rules would ***not*** be forthcoming. In other words, future investment costs would be at the utility's risk.

b. Southern Company announced in August, 2014 that it was converting its last two coal-fired units at the Jack Watson Generating Plant in Mississippi from coal to natural gas by April, 2015. Mach No. 1 and M-Class Mines supplied 80 to 100% of the contracted coal demand at Jack Watson since 2011.

c. Tennessee Valley Authority announced in May, 2015 that it was closing Widows Creek unit 7 by October, 2015. M-Class Mine supplied nearly 20% of the contracted coal demand at Widows Creek in 2014 and about 42% in the first quarter of 2015.

d. Southern Company announced in August, 2014 that it was closing its Gorgas units 6 and 7 in Alabama in 2015. New Future and M-Class Mines supplied nearly 13% of Gorgas' coal demand in 2014.

48. Even if utilities' plans change with regard to these specific units, retirements and conversions are happening and will continue. Over time, as described in Mr. Schwartz's report, many more coal-fired units will close and the coal market will shrink dramatically. This reduction in demand, and therefore pricing, for coal will have a direct and immediate impact on profitability, investments and operations by forcing Murray Energy to reduce production, make associated reductions in the workforce, delay and curtail capital investments in its mines, seek to reduce other operating costs, decline to bid on or invest in new coal leases, and/or otherwise plan for reduced and uncertain future operations.

49. The bond credit rating agencies have taken note. On September 24, 2015, Moody's Investors Service downgraded Murray Energy's ratings, noting specifically in its announcement that, "[i]n addition to cheap natural gas, EPA's recently issued Clean Power Plan will keep the US coal industry in secular decline, and will have an impact across all US basins." Moody's made the same statement with regard to the outlook on the ratings of Foresight Energy, which was changed from positive to negative in a separate September 24, 2015 announcement. Ratings downgrades negatively affect Murray Energy's ability to refinance, obtain new financing, and do business.

50. Murray Energy and its employees depend upon the presence of a stable and continuing domestic market for coal. Every coal fired power plant that is shut down (or converted) threatens the well paid and well benefited jobs of our employees.

51. The harm and damage to Murray Energy and to the coal sector are not unintended consequences. Because regulatory success under the Final Rule is largely dependent upon depressing and suppressing the burning of coal, the harm and damage are intended, targeted goals.

52. The effect of the pendency of the EPA regulatory requirements is intended to operate, is operating, and will continue to operate, in a cascading fashion as interim and final deadlines approach. Because of the commercial advantages of continued operation of existing coal-fired units such as on-site fuel storage (a critical advantage during extreme cold), other reliability advantages, lower cost, and preservation of sunk capital costs, an immediate stay of the effectiveness of the Final Rule would reduce the rate at which irreparable harm is occurring to Murray Energy.

53. Moreover, should Murray Energy ultimately prevail on judicial review of the Final Rule, a stay would entirely prevent the threatened irreparable harm. On the other hand, in the absence of a stay, most of the harm projected to occur over the next one to two years will most assuredly happen during the normal period required for final judicial review.

I make this Declaration under penalty of perjury under the laws of the United States, and I state that the foregoing is true and correct to the best of my knowledge, information and belief.

Robert E. Murray

Robert E. Murray

Dated: October 9, 2015

EXHIBIT 10

DECLARATION OF JEREMY COTTRELL

I, Jeremy Cottrell, declare as follows:

1. My name is Jeremy Cottrell, and I am the Corporate Counsel of the Westmoreland Coal Company ("Westmoreland")

2. Westmoreland mines and markets bituminous, sub-bituminous, and lignite coal primarily as fuel for power generation. Westmoreland's United States corporate headquarters is located in Englewood, Colorado.

3. Westmoreland operates six coal mines in four states. As of December 31, 2014, Westmoreland's U.S. coal production was 28,118,000 tons, with an additional annual production of 5,598,000 tons by its affiliated company Westmoreland Master Limited Partnership. Across all of our coal company operating segments, we owned or controlled an estimated 1,256.2 million tons of total proven or provable reserves as of December 31, 2014. Westmoreland's operating companies mine coal in Wyoming, Montana, Texas, Ohio and North Dakota.

4. Westmoreland employs approximately 1,800 people in the United States. We pay significant taxes and royalties on the coal we produce to the states in which we mine coal.

5. Coal mining is a highly capital intensive business with long lead times for investment decisions. It can take ten years or more to develop a new mine. Mine planning and capital investment decisions take place on a decadal scale. Westmoreland's planning process therefore must take into consideration market and regulatory trends in the short, medium and long-term. Mining is a narrow-margin, high-volume industry. To that end, it is imperative that we are able to secure long-term contracts with our customers, a task which is increasingly difficult when our customers are unsure if they will be in business.

6. EPA's "Clean Power Plan" is the most impactful regulation that Westmoreland has ever experienced. It effectively caps the market for coal sales beginning in 2022 at a significantly reduced level and then lowers the cap through 2030. This will obviously have a highly negative effect on Westmoreland and other coal companies, all of which will be competing for a much reduced market.

7. Given the long lead times in the coal industry, Westmoreland will experience the effect of a significantly curtailed future coal market immediately. We will delay and lower capital investment in our existing mines and we will restrict investment in new mines and new coal reserves. Our valuations of our products as well as valuations of new mine acquisitions will be uncertain and inaccurate due to tiered regulations.

8. EPA analysis of the Clean Power Plan shows that Westmoreland will suffer immediate and irreparable injury at a number of our mines. First, we are informed that EPA modeling projects that the Conesville electric generating station in Ohio will retire by 2016. See declaration of Seth Schwartz, attached to Coal Industry Motion for Stay ("Schwartz Declaration"). Westmoreland supplies coal to the Conesville plant from three mines, the Oxford #3, Buckingham, and Snyder mines. All of the production of the Buckingham and Oxford mines is sold to Conesville. As a result, closure of Conesville would force the closure of these two mines. Oxford #3 was just bought by Westmoreland Master Limited Partnership in 2014. If the mine closes the partnership would be dissolved. All 359 of Buckingham's employees would be laid off, as would all 207 Oxford employees.

9. Similarly, EPA's analysis shows that Naughton electric generating station in Wyoming would close. See Schwartz Declaration. We supply coal to Naughton from our Kemmerer mine, which is adjacent to the Naughton station. About 61% of Kemmerer's total annual production of 4,399,253 tons is sold to Naughton. Loss of the Naughton contract would jeopardize our ability to keep the Kemmerer mine open. At least, it would force us to significantly cut back production and lay off workers, likely 175 workers from the mine's total work force of Kemmerer's 286 employees.

10. Also, EPA's analysis shows that the Lewis & Clark plant in Montana would close in 2016. See Schwartz Declaration. We supply that plant from our Savage Mine. In 2014, the Savage Mine produced 333,922 tons, of which 284,509 tons were sold to Lewis & Clark. Closure of the Lewis & Clark plant would therefore either force the Savage Mine to close, with the resultant lay off of all 12 employees, or at least would force us to significantly reduce production from the mine and lay off many of these employees.

11. I, Jeremy Cottrell, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Jeremy O. Cottrell

Jeremy Cottrell
Corporate Counsel, Westmoreland Coal Company

Dated: August 18, 2015

EXHIBIT 11

DECLARATION OF CHRISTOPHER P. JENKINS

I, Christopher P. Jenkins, declare that the following statements made by me are true and accurate to the best of my knowledge, information, and belief:

1. I am the Vice President of the Coal & Automotive Service Group at CSX Transportation, Incorporated ("CSXT"), the main subsidiary of CSX Corporation, which together with its other subsidiaries ("CSX"), provides rail-based transportation services including traditional rail service and the transport of intermodal containers and trailers. I am a 1980 graduate of Williams College with a major in Economics, and I earned a Masters of Business Administration from Harvard Business School in 1982. I have been employed by CSX, or its predecessor companies, since 1982, including 19 years in the CSXT Coal Department. While at CSXT, I have also led other markets including chemicals and agriculture. As head of the CSXT Coal Department, a position which I have held since 2000, I am knowledgeable about factors that impact the demand for coal used in electric generation, including federal and state environmental regulations. In addition to having lead responsibility for pricing and sales to our coal customers, my department is also responsible for the operation and maintenance of our coal export terminal at Baltimore, our lake dock at Toledo, and our river coal terminal at Maysville, Kentucky. I serve as a member of the Board of Directors of the Paducah and Louisville Railway, a CSXT affiliated coal-centric regional railroad in Kentucky, and in 2014 I completed more than a decade of service as a member of the board of directors of the Indiana Railroad, a CSXT owned shortline with a large volume of coal traffic. I also serve on the Executive Committee of the National Coal Council, a Federal Advisory Committee that provides advice and recommendations to the Secretary of Energy on general policy matters relating to coal and the coal industry.

2. CSXT traces its lineage back more than 185 years to The Baltimore and Ohio Railroad Company, the nation's first common carrier, which was chartered in 1827. Railroad mergers and consolidations have resulted in what today is CSXT, a company that provides an important link to the transportation supply chain through its approximately 21,000 route-mile rail network, serving major population centers in 23 states east of the Mississippi River and the District of Columbia. This current rail network allows CSXT to directly serve every major market in the eastern United States with safe, dependable, environmentally responsible, and fuel efficient freight transportation and intermodal service. CSXT provided these services in 2014 by employing approximately 32,000 people, including approximately 26,000 union employees, most of whom provide or support transportation services.

3. The CSXT coal network connects coal mining operations in the Appalachian mountain region and Illinois Basin with industrial areas in the Northeast and Mid-Atlantic, as well as many river, lake, and deep-water port facilities. CSXT counts among its most important customers almost all the large coal-fired electric utility companies in the Eastern U.S. In 2014, CSXT moved nearly 1.3 million carloads of coal, accounting for 22 percent of CSX's total $12.7 billion revenue and 18 percent of its transported volume. A majority of the domestic coal that CSXT transports is used for generating electricity. Coal traffic on this network helps to support our major ongoing investments in rail infrastructure. This infrastructure facilitates the transport of other commodities, removing traffic from the nation's overcrowded highways.

4. While CSXT maintains a diverse business portfolio with strong core earnings power, regulations that result in a reduction of coal consumption in the United States will impact a significant portion of the shipments that CSXT handles, potentially causing adverse effects on the company's financial condition, capital investment, and size of its service territory. As coal

volumes diminish, CSXT will be forced to discontinue service on portions of its railroad network dependent upon coal and make corresponding workforce reductions.

5. As I understand it, modeling performed by the Environmental Protection Agency ("EPA") indicates that the final Clean Power Plan ("CPP") will reduce coal consumption throughout the country. Notably, I also understand that this modeling projects that starting as soon as 2016, well before the CPP's initial 2022 compliance obligations, utilities will begin retiring coal-fired power plants in response to the regulatory burden. As such, EPA's own projections indicate that CSXT will suffer irreparable harm from the CPP before the courts have an opportunity to consider legal challenges to the regulation. These impacts will have a rippling effect, not only reducing CSXT's revenue, but limiting investments that enhance important public benefits.

6. EPA's own analysis indicates that the nation's electricity sector is likely to be substantially altered in response to the CPP. According to EPA, the CPP will result in a reduction in U.S. coal generation from the "business as usual" base case by as much as 335,000 GWh, a 23 percent drop.[1] Whereas coal generated 39 percent of U.S. electricity in 2014,[2] EPA projects that coal's share of total generation in 2030 under the CPP will drop to as low as 28 percent.[3] EPA also estimates that the CPP will have the effect of cutting U.S. coal production by as much as 186 million short tons in 2030.[4] Appalachia is projected to be hit particularly hard

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[1] EPA, REGULATORY IMPACT ANALYSIS FOR THE FINAL CLEAN POWER PLAN 3-27, Tbl. 3-11, Aug. 2015, www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-regulatory-impact-analysis.

[2] EIA, ELECTRIC POWER MONTHLY WITH DATA FOR JULY 2015 Tbl. 1-1, Sep. 2015, www.eia.gov/electricity/monthly/pdf/epm.pdf.

[3] REGULATORY IMPACT ANALYSIS, *supra* n.1 (under "2030" in the "Mass-based" column, coal generation is listed at 1,144 GWh with total generation listed at 4,110 GWh, dividing these amounts results in coal equaling to 27.8% of total generation).

[4] *Id.* at 3A-7, Tbl. 3A-2.

under EPA's modeling, with a 23 percent to 25 percent reduction in coal production by just 2025.[5]

7. EPA projects that power plant operators will begin responding early to the CPP by retiring up to 11 GW of coal-fired capacity in 2016 and as many as 15 GW by 2020,[6] with much of these projected capacity retirements[7] occurring within CSXT's operating territory.[8] Therefore, the CPP irreparably harms CSXT by reducing a substantial portion of its coal shipments due to power plant retirements.

8. Lost coal business does not simply reduce CSXT revenue, it also limits the company's ability to support investments that result in important public benefits. As a historical driver of company profitability, the revenue generated by CSXT's coal business has funded a large and significant part of the company's $21 billion worth of investments since 2003 in critical transportation infrastructure, including track improvements, bridges, tunnels, new equipment and strategic capacity projects since 2003. These investments help railroads move goods across land in an environmentally-friendly and energy-efficient manner, and support the economy as well as passenger and commuter rail availability.

9. Revenue to fund railroad infrastructure investments is important to the environment. A single CSXT freight train can carry the load of more than 280 trucks. In this

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[5] *Id.* at 3-33, Tbl. 3-15.

[6] *Compare* EPA, *EPA Base Case for the Clean Power Plan, Base Case SSR File, Summary*, http://www.epa.gov/airmarkets/documents/ipm/Base_Case.zip *with* EPA, *Mass-Based, Mass-Based SSR File, Summary*, www.epa.gov/airmarkets/documents/ipm/Mass_Based.zip.

[7] *Compare* EPA, *EPA Base Case for the Clean Power Plan, Base Case Overview File, Retired (MW)*, http://www.epa.gov/airmarkets/documents/ipm/Base_Case.zip *with* EPA, *Mass-Based, Mass-Based Overview File, Retired (MW)*, www.epa.gov/airmarkets/documents/ipm/Mass_Based.zip (EPA modeling of power plant retirements by model regions.); *see also* ENERGY VENTURES ANALYSIS, INC., *Evaluation of the Immediate Impact of the Clean Power Plan Rule on the Coal Industry* 66-68 (Oct. 2015) (listing specific coal-fired power plants projected to retire by the CPP under EPA modeling.).

[8] *See* CSX, *CSX System Map*, www.csx.com/index.cfm/customers/maps/csx-system-map.

way, CSXT services enable customers to reduce transport-related greenhouse gas emissions by approximately 60 percent to 80 percent when switching from truck to rail transport of goods.

10. Revenue to fund railroad infrastructure investments is important to the economy. Railroads account for approximately one-third of all U.S. exports, linking American manufacturers, farmers, and resource producers to international markets.[9] Rail transport reduces traffic on American highways, not only making it easier to get to work, but also saving the economy nearly $100 billion.[10]

11. Revenue to fund railroad infrastructure investments is important to rail passengers and commuters. Each day, approximately 115 intercity passenger and commuter trains run on the CSXT network. Access fees from passenger service do not fully offset its use of and impacts on the CSX network, meaning CSXT's revenue generation and capital expenditures effectively subsidize passenger rail service.

12. Under EPA's projections, the CPP will restrict the revenue available to CSXT to make near-term investments, hinder the company's ability to plan for necessary capital improvements, and compel CSXT to abandon rail lines and other infrastructure. The CPP therefore injects uncertainty into CSXT's long-term decision making, and acts as a disincentive to infrastructure investment. These impacts reverberate across society, limiting CSXT's ability to enhance services that lead to important public benefits in areas including the environment, economy, and passenger and commuter rail transportation. For these reasons, CSXT faces irreparable harm if the CPP is not stayed pending the outcome of judicial review.

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[9] ASS'N OF AM. R.R., *The Economic Impact of America's Freight Railroads*, May, 2015 *available at:* www.aar.org/BackgroundPapers/Economic%20Impact%20of%20US%20Freight%20Railroads.pdf.

[10] *Id.*

I make this Declaration under penalty of perjury pursuant to 28 U.S.C. § 1746, and I state that the facts set forth herein are true.

Christopher P. Jenkins

Dated: October 22, 2015

EXHIBIT 12

DECLARATION OF BILL BISSETT

I, Bill Bissett, declare as follows:

1. My name is Bill Bissett, and I am the President of the Kentucky Coal Association ("KCA"). KCA is a statewide trade association with a membership comprised of companies that mine coal in Kentucky as well as companies conducting a variety of related activities and support services to the Kentucky coal mining industry.

2. KCA works with the Kentucky Department for Energy Development and Independence of the Kentucky Energy and Environment Cabinet in periodically publishing a report entitled Kentucky Coal Facts. The latest edition of that report, published in 2014, is available at http://www.kentuckycoal.org/index2.cfm?pageToken=coalFacts. The report details the scope and critical importance of the coal mining industry to Kentucky's economy. I will summarize key findings of the report.

3. In 2013, Kentucky ranked as the third-highest coal-producing state in the United States at approximately 80 million tons. Coal supplies more than ninety percent of the electricity for Kentucky and is the largest source of domestic energy production in the Commonwealth.

4. More than 30 percent of the coal produced in Kentucky was consumed within the Commonwealth and, in most cases, is almost entirely for electric generation. The balance was sold to electric generators and for other uses across the United States but primarily in the southeast.

5. Coal provides enormous direct benefits to the Kentucky economy in terms of coal severance revenue, jobs, and wages to miners. These direct benefits are as follows:

- Employed an average of 11,885 miners in 2013.
- Paid wages of $850 million in 2013, resulting in an average annual wage of $72,779 per miner. Coal workers are among the highest paid blue collar workers in the Kentucky economy.
- Produced almost 80.6 million tons of coal with an approximate value of $4.96 billion dollars;
- Severance taxes on coal production in calendar year 2013 were $212,443,519.59. Severance tax revenue generated through the production of coal is distributed to several state budgetary programs including the Kentucky General Fund, the Local Government Economic Assistance Fund (LGEAF), and the Local Government Economic Development Fund (LGEDF). In FY 2014, $61.3 million in coal severance tax receipts was

returned to coal-producing counties for infrastructure improvements and economic development projects;

- In FY 2013, $24.5 Million of dollars in unmined mineral taxes was collected.

6. The importance of coal employment in Kentucky cannot be overstated. In eight Kentucky counties, direct coal employment represents at least 10 percent of all people employed. In three of those counties, direct coal employment represents more than 20 percent of all people employed. These are some of the poorest counties in Kentucky and indeed in the United States, with some of these counties having poverty rates in excess of 30% and median household incomes well below the national level and all below the Kentucky state level, as the following chart shows.[1]

	Poverty Level	Median Household Income
U.S.	14.4%	$53,046
Kentucky	18.8%	$43.036
Kentucky Counties w/10%+ coal employment		
Perry	25.3%	$33,528
Harlan	31.3%	$25,906
Martin	35.1%	$26,261
Knott	23.1%	$33,839
Leslie	22.6%	$29,293
Union	25.7%	$39,125

[1] Source: U.S. Census, State and County QuickFacts, http://quickfacts.census.gov/qfd/states/00000.html.

Ohio	19.7%	$40,830

7. Coal also provides significant indirect benefits to the Kentucky economy. Indirect benefits include new income flowing into the coal industry that is then re-spent creating a multiplier effect. Economic impact models trace the flow of these dollars for new spending in the economy. Economic impact models are not designed to calculate the impact for an existing industry. We can, however, gauge the industries that will receive the greatest impact for any new investment. Below are the top five types of industries that receive the greatest percentage of an indirect impact.[2]

- 20 percent of indirect spending would be spent in industries defined as mining coal and support activities for mining. This is essentially intra-industry trade that does show up as new revenue.
- 15 percent would be spent in the transportation industry by rail or truck.
- 14 percent would be spent in professional services industries. These are typically industries such as architectural and industrial engineering, management companies, legal services, financial institutions and other industries that provide services that might not be offered in house.
- 9 percent would be spent in the petroleum industry, natural gas and electric power transmission.

[2] Source: 2014 Kentucky Coal Facts, 14th Edition. http://www.kentuckycoal.com/documents/Kentucky%20Coal%20Facts%20-%2014th%20Edition.pdf

- 9 percent would be spent in industries that sell or maintain commercial equipment and structures used to support the coal industry.

8. Coal also provides significant induced benefits to the Kentucky economy. Induced effects occur when money that is received as income by employees and/or owners either at the direct or indirect level is spent on personal expenditures such as household goods and services.

9. I, Bill Bissett, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Bill Bissett

Bill Bissett, President

Kentucky Coal Association

Dated: August 19, 2015

EXHIBIT 13

DECLARATION OF WILLIAM B. RANEY

I, William B. Raney, declare as follows:

1. My name is William B. Raney, and I am the President of the West Virginia Coal Association ("WVCA"). The WVCA is a membership association comprised of companies that mine coal in West Virginia as well as companies providing a variety of support services to the West Virginia coal mining industry.

2. One of the functions of the WVCA is to monitor and keep statistics on the impact the coal industry has on the economy of West Virginia. We publish an annual report, Coal Facts, that provides updated material on this subject based on information from the Energy Information Administration of the U.S. Department of Energy and the West Virginia Office of Miners' Health and Safety. The information provided below is taken primarily from the latest iteration of that report, Coal Facts 2014.[1]

3. West Virginia is the second largest coal-producing State, after Wyoming. The State produced 116,900,140 tons of coal in 2014 from 205 mines located in 26 counties. More than 49,000 people are employed in the West Virginia coal industry at an average wage of $68,500, which is significantly above the average wage for blue collar workers in the State and indeed is more than 40% above the median *household*

[1] The report is available at http://www.scribd.com/doc/237454996/2014-Coal-Facts.

income for the State of $41,043.[2] The estimated aggregate value of 2014 coal sales was $7,357,830,480.

4. West Virginia has been one of a few states to maintain balanced budgets during the recent recession years.

5. Coal is absolutely critical to the West Virginia counties in which it is mined. West Virginia in general has lower median household income and higher poverty rates than the U.S. in general, and this holds true in the West Virginia counties that produce the most coal. As can be seen from the chart below, coal produces critically important income to these otherwise economically-challenged economies.[3]

	Poverty Level	Median Household Income	Estimated Direct Coal Wages
U.S.	15.4%	$53,046	?
West Virginia	17.9%	$41,043	$3,356,500,000
West Virginia counties that produced more than 7 million tons of coal in 2013			
Boone	22.5%	$42,156	$159,480,000
Kanawha	15.3%	$46,085	$121,392,000
Logan	22.1%	$36,999	$120,672,000
Marion	15.3%	$42,152	$93,384,000

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[2] Source for median household income: U.S. Census, State and County QuickFacts, http://quickfacts.census.gov/qfd/states/00000.html.

[3] Source for poverty level and median household income: U.S. Census, State and County QuickFacts, http://quickfacts.census.gov/qfd/states/00000.html. Source for estimated direct wages: West Virginia Coal Association, Coal Facts.

Marshall	16.9%	$40,681	$124,920,000
Mingo	24.9%	$35,955	$69,408,000
Monongahela	19.2%	$44,173	$89,640,000
Ohio	15.3%	$41,025	$34,776,000
Raleigh	20.2%	$40,758	$113,976,000

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6. Various coal tax collections and distributions are the vital heart of the state and county budgets in West Virginia.

	Est. Property Tax Collections	Est. Severance Tax Collections	Total Tax Collections	Severance Tax Distributions
U.S.		n/a	n/a	n/a
West Virginia	$151,333,006	$367,891,524	$3,356,500,000	$19,775,008
West Virginia counties that produced more than 7 million tons of coal in 2013				
Boone	$25,358,839	$30,975,375	$56,334,214	$2,306,038
Kanawha	$9,553,201	$28,879,950	$38,443,151	$1,101,913
Logan	$19,050,068	$27,490,834	$46,540,902	$2,109,490
Marion	$7,682,665	$37,034,345	$44,717,010	$4,200,839
Marshall	$13,061,578	$47,297,589	$60,359,167	$703,792
Mingo	$9,479,583	$19,840,842	$29,320,425	$635,730
Monongahela	$3,458,253	$25,015,054	$28,473,307	$178,256
Ohio	$3,501,988	$31,165,030	$34,667,018	$1,323,861
Raleigh	$11,154,082	$20,452,734	$31,606,816	$269,860

7. I, William Raney, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct to the best of my knowledge.

William B. Raney

William Raney

Dated: August 24, 2015

EXHIBIT 14

DECLARATION OF JONATHAN DOWNING

I, Jonathan Downing, declare as follows:

1. My name is Jonathan Downing, and I am the Executive Director of the Wyoming Mining Association (WMA). The WMA is the trade association for Wyoming's mining companies, including its coal mining companies. A part of WMA's function is to collect information on the benefits of coal mining to the State of Wyoming.

The Importance of the Coal Economy to Wyoming

2. Coal production has been a cornerstone of the modern Wyoming economy since the 1970's, and has served as Wyoming's most stable source of tax revenues over the past four decades.[1] Wyoming produces more coal than any other state in the country, principally from the Powder River Basin in the northeastern part of the state. According to statistics compiled by the National Mining Association, Wyoming produced 387,924,000 tons of coal in 2013, about 40 percent of national coal production.

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[1] The information in this declaration is taken primarily from a report entitled "Impact of the Coal Economy on Wyoming Prepared for the Wyoming Infrastructure Authority," January, 2015, prepared by Professors Robert Godby, Roger Coupal, David Taylor, and Tim Considine at the Center for Energy Economics and Public Policy, Department of Economics and Finance, University of Wyoming. The report is available at http://www.researchgate.net/publication/270568668_The_Impact_of_the_Coal_Economy_on_Wyoming_Prepared_for_the_Wyoming_Infrastructure_Authority.

3. The following table provides a high-level summary of the importance of coal mining and the coal industry in Wyoming:

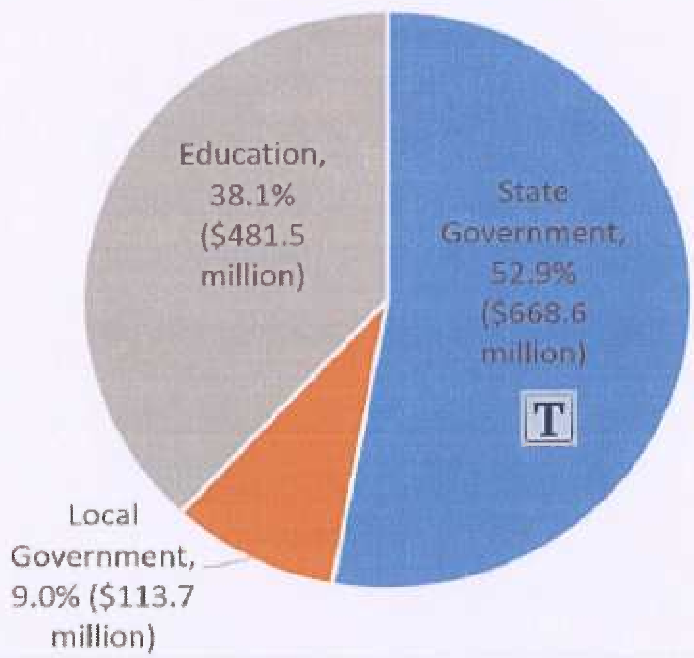
Wyoming Coal Economy Quick Facts	Coal Economy	Coal Mining
Share of gross state product	14.0%	11.3%
Share of total labor income	9.3%	4.7%
Share of total employment	5.9%	1.8%

The "coal economy" includes all activity caused by the presence of coal mining, rail-shipping and coal-fired electricity generation in Wyoming in fiscal year 2012.

4. Coal mining is directly responsible for $1.3 billion, or 11.2 percent, of all state government revenues collected in Wyoming. Of that $1.3 billion, the largest three sources of revenue (representing about two-thirds of the total) were Severance Taxes (23.5%), Federal Mineral Royalties (23.0%), and Ad Valorem Taxes on Production (20.3%). Other significant sources of state revenue included State Rents & Royalties from coal production on state lands (5.0%), Sales & Use Taxes associated with coal production (2.5%), and Ad Valorem Taxes on Property associated with coal mine facilities (2.3%). In all, coal is the second largest source of tax revenue for state and local government.

5. More than one-half of the total Wyoming state revenues from the coal industry went to fund various aspects of state government, including programs and funds

related to environmental protection, such as the Department of Environmental Quality and the Wyoming Wildlife and Natural Resource Trust Fund. A significant share of coal revenues is also used to support education in the State. Coal revenues were used to fund all aspects of education in Wyoming including K-12, Community Colleges, and the University of Wyoming, supporting both operations and capital construction. Education received about one-third of coal revenues with the remaining 9% going to local government. The following figure summarizes the distribution of Wyoming State & Local Government revenue from coal for 2012:



<u>Figure 1</u>: Distribution of Wyoming Government Revenues from Coal

6. Overall, Wyoming's gross state product, that is, the total value of production or economic activity produced in Wyoming, was $41.8 billion in 2012. Of this, the direct contribution of coal mining to state product was $4.0 billion in 2012, or 9.6% of the

state's entire value of production. Including all computed indirect and induced production created by coal mining activity only increases the impact of coal mining to 11.3% or $4.7 billion of the state's gross state product. Computation of the total impact of the coal economy on gross state product requires adding to the impact of coal mined and shipped to locations outside the state, the impacts of coal related railroad and generation sectors. Including the value added in Wyoming of railroad activity and its induced activity increases, the share of total state product rises to 12.5% ($5.2 billion). Including the impact created by coal-fired generation, the total share of gross state product due to the coal economy rises to 14%, or $5.9 billion.

7. With respect to employment, the effects of the coal economy are smaller on the state than output, in part because of the very high productivity in coal mining and associated activities, but still very significant. Of the 393,348 jobs in Wyoming in 2012, there were 6,902 direct jobs (1.8%) created from coal mining operations. Mining created an additional 9,138 indirect and induced jobs. Overall, the total impact of coal mining in the state was to create 16,040 jobs or 4.1% of total state employment. Including the associated rail and electricity generation sectors related to coal, the total direct, indirect and induced jobs estimated to be created by the total coal economy rises to 23,145 jobs or 5.9% of total state employment.

8. The coal economy not only adds significantly to the state's total employment, it also creates high-paying jobs. The estimated total share of labor income in the state

created just by coal mining was 7.0% or $1.4 billion. Including labor incomes from rail transport, electricity generation and the indirect and induced employment these sectors are estimated to create, the share of total state labor income associated with coal activity in the state rises to 9.5%. The average income in coal mining, railroading, or generation paid over $100,000 including benefits, and was $80,617 across all jobs created in the wider coal economy. As a point of comparison, the average wage per job in the State in 2012 was $45,243.

9. In summary, the coal economy generated approximately one seventh of total output, almost one tenth of total labor income, and one seventeenth of total employment in the state of Wyoming. Regionally, the coal economy is even more important to local economies.

10. I, Jonathan Downing, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Jonathan Downing

Dated: August 14, 2015