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
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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: Identify category-specific baseline emission rates for fossil steam and NGCC

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 net 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.

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

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

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.

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[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	Remainin g NGCC Gen	BB3 generation assigned to fossil steam	BB3 generatio n 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

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

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

[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
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	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:

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[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.

[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	State	Interim	Final
Alabama	62,210,288	56,880,474	Lands of the Navajo Nation	24,557,793	21,700,587
Arkansas	33,683,258	30,322,632	North Carolina	56,986,025	51,266,234
Arizona	33,061,997	30,170,750	North Dakota	23,632,821	20,883,232
California	51,027,075	48,410,120	Nebraska	20,661,516	18,272,739
Colorado	33,387,883	29,900,397	New Hampshire	4,243,492	3,997,579
Connecticut	7,237,865	6,941,523	New Jersey	17,426,381	16,599,745
Delaware	5,062,869	4,711,825	New Mexico	13,815,561	12,412,602
Florida	112,984,729	105,094,704	Nevada	14,344,092	13,523,584
Lands of the Fort Mojave Tribe	611,103	588,519	New York	33,595,329	31,257,429
Georgia	50,926,084	46,346,846	Ohio	82,526,513	73,769,806
Iowa	28,254,411	25,018,136	Oklahoma	44,610,332	40,488,199
Idaho	1,550,142	1,492,856	Oregon	8,643,164	8,118,654
Illinois	74,800,876	66,477,157	Pennsylvania	99,330,827	89,822,308
Indiana	85,617,065	76,113,835	Rhode Island	3,657,385	3,522,225
Kansas	24,859,333	21,990,826	South Carolina	28,969,623	25,998,968
Kentucky	71,312,802	63,126,121	South Dakota	3,948,950	3,539,481
Louisiana	39,310,314	35,427,023	Tennessee	31,784,860	28,348,396
Massachusetts	12,747,677	12,104,747	Texas	208,090,841	189,588,842
Maryland	16,209,396	14,347,628	Lands of the Uintah and Ouray Reservation	2,561,445	2,263,431
Maine	2,158,184	2,073,942	Utah	26,566,380	23,778,193
Michigan	53,057,150	47,544,064	Virginia	29,580,072	27,433,111
Minnesota	25,433,592	22,678,368	Washington	11,679,707	10,739,172
Missouri	62,569,433	55,462,884	Wisconsin	31,258,356	27,986,988
Mississippi	27,338,313	25,304,337	West Virginia	58,083,089	51,325,342
Montana	12,791,330	11,303,107	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.

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

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.

North Dakota—Coyote Creek Mine

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.

North Dakota—Falkirk Mine

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.

<u>The Clean Power Plan Is a Significant Factor Influencing Norfolk Southern's Current Investment Decisions</u>

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, 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.

The Business of Murray Energy Corporation

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 <u>indirect benefits</u> 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

[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:

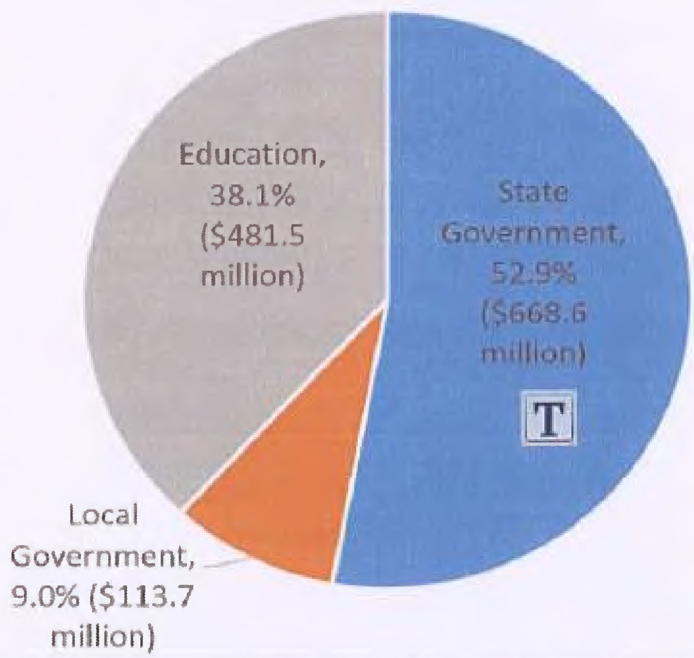

Figure 1: Distribution of Wyoming Government Revenues from Coal

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

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October 23, 2015

VIA HAND DELIVERY

Mark Langer
Clerk of the Court
United States Court of Appeals
District of Columbia Circuit
333 Constitution Avenue, NW
Washington, DC 20001

Re: Coal Industry Motion to Stay: *Murray Energy Corp. v. U.S. EPA*, Case No. 15-1366; *National Mining Ass'n v. U.S. EPA*, Case No. 15-1367; *American Coalition for Clean Coal Electricity v. U.S. EPA*, Case No. 15-1368

Dear Mr. Langer:

Please accept for filing the original and four copies of the Coal Industry Motion to Stay relating to the above-referenced cases. Kindly stamp on the extra copy provided by our messenger that the court has received these documents.

Should you have any questions, please contact me at the telephone number indicated above. Thank you for your assistance.

Sincerely,

Peter S. Glaser