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

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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

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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
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    b. Data sources for affected "under construction" units
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    - Appendix 3 – Underlying state-level data, adjustments, and region-level data
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    - Appendix 6 – State goal summary table
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    - Appendix 9 – Description of 111(d) baseline data sources and development

[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

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[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.

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[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

$$\text{NGCC} = 15{,}060{,}254 \text{ MWh} + (8784 \text{ hours} \times 2{,}165 \text{ MW} \times 55\% \text{ capacity factor}) = 25{,}519{,}802 \text{ MWh}^{11}$$

$$\text{Coal} = 50{,}572{,}372\text{MWh} + (8784 \text{ hours} \times 60\% \text{ capacity factor} \times 825 \text{ MW}) = 54{,}920{,}452 \text{ MWh}$$

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.

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

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	Remaining NGCC Gen	BB3 generation assigned to fossil steam	BB3 generation assigned to NGCC	Remaining Fossil Steam	Remaining NGCC Gen	Fossil Steam Rate	NGCC Rate
	lb/MWh	lb/MWh	GWh	GWh	lbs/MWh	lbs/MWh			GWh	GWh	GWh	GWh	GWh	GWh	GWh	lb/MWh	lb/MWh
Eastern	2,160	894	1,304,689	734,535	2,071	894	64%	36%	438,445	1,024,173	576,606	280,515	157,929	612,922	987,857	1,305	771

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

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

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

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
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.

[30] The emissions quantified through this particular mass adjustment approach could also represent a variety of source-specific and fleet-wide actions that could result if affected EGUs procure incremental RE beyond what is required to demonstrate the source category-specific performance rate.

[31] State-specific values for building block 3 generation levels not captured in the source category-specific emission performance rates are available in Appendix 5.

7. APPENDIX

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

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

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

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

Appendix 3 – Underlying state-level data, adjustments

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

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

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

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

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

Appendix 6 –State Goals (lbs/MWh)

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

Appendix 7 –Adjustments to state-level 2012 baseline data

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

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

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

Unit-outage adjustment

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

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

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

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

[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