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MJB&A Summary ■ August 6, 2015

Summary of EPA's Final Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the "111(d) rule")

On August 3, 2015, EPA released the final rule to regulate CO_2 emissions from *existing* power plants under Section 111(d) of the Clean Air Act. This rule finalizes the proposed Clean Power Plan, released on June 2, 2014. Overall, the Agency projects the final rule will achieve a 32 percent reduction in power plant CO_2 emissions from 2005 levels by 2030, which has been touted as an increase from the proposed rule. The program starts in 2022 with an eight-year interim period, and final targets in 2030. EPA requires states to submit plans by September 6, 2016, but all states can request an extension to file final plans by September 6, 2018. EPA has allowed substantial flexibility in terms of how the goals are met. This document summarizes the key aspects of the rule based on MJB&A's initial review of the final rule.

At the same time, EPA has also released a proposed federal plan for Clean Power Plan implementation that includes model rules for both mass- and rate-based programs. Comments on the federal plan will be due 90 days after publication in the Federal Register. EPA also released final Section 111(b) standards for new, modified, and reconstructed electric generating units. Please see MJB&A's forthcoming summaries of the proposed federal plan and Section 111(b) standards for more information.

Key Differences Between Proposed and Final Rule

There are several major differences between EPA's proposed Clean Power Plan and the final rule. The key changes are highlighted in Table 1 and discussed throughout the summary. In this table we include references to areas in this summary where we address issues in more detail.

Table 1. Key Differences between Draft and Final CPP

	Issue	Draft Rule	Final Rule	MJB&A Summary Page Reference
Timeline	Baseline year	2012	2012 (with corrections)	p. 6
	Compliance period	From 2020 to 2030 using a ten-year averaging period from 2020 and 2029 for states to achieve interim emission targets.	Interim period from 2022 to 2030, which is separated into three steps (2022-2024, 2025-2027, and 2028-2029), each associated with its own interim goal that states can establish and final goal in 2030.	p. 14
	State Plan Submittal	• State SIPs due in 2016 • State SIPs with 1-year extension due in 2017 • Multi-state SIPs due in 2018	• Initial plans due in September 2016 • All states can request an extension of up to 2 years to file a final plan by September 2018	p. 7
Targets	Form(s) of standard	Standards were provided in rates (lb CO_2/MWh) on a state-level basis; illustrative equivalent mass-based rates were provided separately in a TSD	Standards were provided in three forms: • National emission rate standards for both fossil steam- and combustion turbine units; • Statewide rate standards applicable	pp. 5-7

	Issue	Draft Rule	Final Rule	MJB&A Summary Page Reference
			to all affected EGUs; and • Statewide mass standards applicable to all affected EGUs (and new source complements).	
	Interim goals	State specific, average emission reductions between 9% and 65%	State-specific, average emissions reductions between -1% and 39% (from the 2012 baseline; statewide rate goals)	pp. 5-6, Appendices
	Final goals	State specific, averaging emission reductions between 11% and 72% (from the 2012 baseline)	State-specific, averaging emissions reductions between 7% and 48% (from the 2012 baseline; statewide rate goals)	pp. 5-6, Appendices
Building Blocks	Building Block 1: Increase coal plant efficiency	Power plants heat rate improvements between 4 to 6 percent	Region-specific heat rate improvements between 2.1% and 4.3%	p. 4
	Building Block 2: Increase in natural gas	• Increase use of existing NGCC to a maximum 70% capacity factor based on nameplate capacity on a state-by-state basis • Apply transition to each state in 2020	• Increase natural gas generation by 22% in 2022 and increase 5% per year at a regional level • Limit NGCC average capacity factor to 75% based on regional summer capacity	p. 4
	Building Block 3: Increase use of zero-emitting resources	• Existing and new renewable energy included in calculating state targets. Two options proposed for future renewable energy generation. • Includes 5.8% of existing nuclear capacity and nuclear plants under construction in calculating state targets.	• Incremental new renewable energy included in calculating state targets. Updated NREL/IPM analysis of technical/economic potential for renewables on a regional basis. Renewables displace existing fossil (steam and NGCC) in the building block formula. • Nuclear power is excluded from BSER	p. 5
	Building Block 4: Increase energy efficiency	Estimates a 1.5% annual incremental savings in energy efficiency	Building block 4 is eliminated from BSER	p. 5

	Issue	Draft Rule	Final Rule	MJB&A Summary Page Reference
Compliance	Interstate Trading Options	States required to submit multi-state plans and demonstrate compliance with a blended rate-based goal or aggregate mass-based goal for participating states	• States can submit individual plans that allow interstate trading of allowances in mass-based states or ERCs in rate-based states using the national performance standards for the two categories of fossil EGU (i.e, separate standards for steam and NGCC) • States can submit multi-state plans that allows trading (e.g., a joint plan that includes a blended multi-state rate-based goal for the states using the statewide rate standards applicable to all affected EGUs)	pp. 7-14
Other Topics	Reliability Safety Valve	No reliability safety valve.	• States can modify an emission standard for an affected EGU or EGUs for an initial period of up to 90 days if needed to address a reliability concern • After 90 days, states must revise plan and account for excess emissions.	pp. 17-18

	Early Action	Measures taken after the date of the proposal, or current programs and that result in CO_2 emission reductions at affected power plants during the 2020-2030 period would apply toward state's CO_2 goal.	Clean Energy Incentive Program: early action credit pool for:
			• Wind and solar projects and energy efficiency projects in low-income communities, that:
			  ○ are built after state plan submission (or after a federal plan is imposed); and
			  ○ generate or save energy in 2020 and 2021.
				pp. 16-17

	Rate to Mass Translation	Two mass-based goal options were provided in TSD: one for Existing Affected EGU only and a second for Existing and New fossil EGU.	Again, EPA has calculated two mass-based goal options, but the calculation methodology has been modified consistent with the changes to the Building Block formula. EPA provides mass-based goals for Existing Affected EGU and new source complements for new fossil EGU.	pp. 7-8, Appendices

Applicability

In the final rule, an affected source is any fossil fuel-fired electric steam generating unit (e.g., utility boiler, or integrated gasification combined cycle (IGCC) unit), or stationary combustion turbine (e.g., natural gas combined cycle (NGCC) unit) that was in operation or had commenced construction as of January 8, 2014 and that meets the following criteria: must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h heat input of fossil fuel. For the purposes of this rule, states must include stationary combustion turbines that

meet the definition of combined cycle or combined heat and power combustion turbine. Simple cycle turbines are not included within the definition of an affected EGU.

In addition to excluding simple cycle turbines, certain affected EGUs are exempt from inclusion in state plans: (1) those units that are subject to 111(b) as a result of commencing modification or reconstruction; (2) steam generating units or IGCC units that are currently and always have been subject to a federally enforceable permit limiting net-electric sales to one third or less of its potential electric output or 219,000 MWh or less on an annual basis; or (3) non-fossil units that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federal enforceable permit limiting fossil fuel use to ten percent or less of the annual capacity factor; (4) stationary combustion turbines that are not capable of combusting natural gas; and (5) combined heat and power units that are subject to a federally enforceable permit limiting, or have historically limited, annual net electric sales to a utility power distribution system to the product of the design.

Best System of Emission Reduction – Buildings Blocks

EPA's final rule includes significant revisions to EPA's determination of the Best System of Emission Reduction (BSER), which is used to establish performance goals for existing EGUs. Most significantly, EPA's final determination includes a revised approach to building blocks 1-3 and does not include building block 4, energy efficiency.

Building Block 1: Heat rate improvements at coal-fired EGUs

In the proposed rule, EPA concluded that the U.S. fleet of affected coal-fired EGUs could achieve a six percent improvement in heat rate through adoption of best practices and upgrades to equipment. Based on comments, EPA refined its approach to quantifying the emission reductions achievable through heat rate improvements and decided not to include a separate increment of emission reductions attributable to equipment upgrades. As part of this refinement, EPA also moved from a national basis for quantifying heat rate improvements to a regional basis. Through the updated regional analysis, EPA found achievable heat rates improvements for coal-fired steam EGUs of 4.3 percent for the Eastern Interconnection, 2.1 percent for the Western Interconnection, and 2.3 percent for the Texas Interconnection.

EPA identified the following examples of heat rate improvement measures that could result in this type of improvement: staff training, boiler chemical cleaning, cleaning air preheater coils, and use of various kinds of software, as well as equipment upgrades such as turbine overhauls. EPA reviewed the potential to improve the emissions rate of existing coal-fired boilers through co-firing with natural gas and the implementation of carbon capture and storage (CCS). EPA found that while these measures are technically feasible and potentially cost effective, they are more expensive than alternative measures, such as shifting to NGCC or new renewable energy generating units. EPA also evaluated the potential for heat rate improvements at oil- and gas-fired steam EGUs and NGCC units and found, consistent with the proposed rule, that the available emission reductions would be more expensive or too small to merit consideration as a component of BSER.

Building Block 2: Increased NGCC Utilization

Consistent with the proposed rule, EPA found that substantial emission reductions can be achieved at a reasonable cost by increasing generation from existing NGCC and reducing generation from steam EGUs. However, in response to comments, EPA revised its analysis to compute a target utilization based on summer capacity ratings instead of nameplate capacity ratings. Using summer capacity ratings, EPA found that a 75 percent average capacity factor is feasible.

In response to commenter concerns about the timing of the shift from steam EGUs to existing NGCC, EPA finalized a methodology that phases in the shift to natural gas. The phase-in applies a limit to the maximum building block 2 potential in each year of the interim period based on (1) an amount of generation shift to existing NGCC capacity that is feasible by 2022 and (2) how quickly that amount could grow until the maximum is reached. EPA based the first parameter on the largest annual increase in power sector gas-fired generation since 1990, which occurred between 2011 and 2012 (i.e., 22 percent). EPA based the second parameter on the average annual growth in gas-fired generation between 1990 and 2012, which was about five percent per year. As described below, EPA used these two parameters as the basis for incorporating building block 2 into regional performance rate-setting methodology.

Building Block 3: Substituting increased generation from new low- or zero-carbon generating capacity for reduced generation from affected EGUs

In the proposed rule, EPA identified renewable energy generating capacity and nuclear generating capacity as potential sources of lower- or zero-emitting generation that could replace higher-emitting generation. EPA proposed to include existing and new renewable energy generation as well as a fraction of existing nuclear capacity that EPA determined was "at risk" and generation from under-construction nuclear generating capacity. In the final rule, EPA focused solely on generation from new renewable energy capacity, which the final rule defines as capacity that commenced operation after 2012. EPA's estimate of renewable energy potential for the final rule is based on an updated technical and economic assessment.

EPA did not include existing renewable energy generation or the previously identified at risk nuclear generation on the basis that existing zero-emitting generation helps to make existing emissions lower than they would otherwise be, but will not further reduction emissions below current levels. EPA decided to exclude under-construction nuclear generation from BSER based on an evaluation of the costs of new nuclear capacity relative to new renewable energy capacity. Note that new nuclear plants, including under construction facilities, would be eligible to generate credits under a rate-based compliance program, as would uprates at existing nuclear facilities that occur after 2012. An existing nuclear facility that undergoes relicensing would not be considered a "new" facility.

Building Block 4: Increased demand-side energy efficiency

In the proposed rule, EPA included a fourth building block for demand-side energy efficiency. However, EPA no longer includes demand-side energy efficiency in the BSER analysis in the final rule.

State Goals

In contrast to the proposal, EPA established *uniform national* interim and final CO_2 emission performance standards for two subcategories of fossil fuel-fired electric generating units (EGUs), shown in Table 2.

Table 2. Interim and Final Nationwide Emission Performance Standards by EGU subcategory

Subcategory	Interim National Standards	Final National Standards
Fossil Steam Units	1,534 lb CO_2/MWh	1,305 lb CO_2/MWh.
Stationary Combustion Turbines	832 lb CO_2/MWh	771 lb CO_2/MWh

States can choose to adopt these performance standards and apply them to the two subcategories individually. Alternatively, states can choose to adopt interim and final statewide goals in one of three additional forms:

- A state-specific blended fossil rate-based state goal (based on a generation-weighted average of the nationwide standards above);
- A mass-based state goal (in CO_2 tons) for existing affected EGUs; or
- A mass-based state goal (in CO_2 tons) for both existing affected EGUs and new sources.

Derivation of the National Standards

EPA has significantly modified the structure of how the state goals are calculated relative to the proposal. The following summarizes the methodology used to calculate the performance standards for fossil steam units and NGCC:

- EPA continues to rely on a database of all the electric generating units in the U.S. and their 2012 generation and emissions as its starting point to calculate the state goals; however, corrections and adjustments have been made to

the database between the proposal and final. The adjustments include state-level changes to account for abnormally high hydroelectric production in Idaho, Maine, Montana, Oregon, South Dakota, and Washington.[1]

- EPA begins its analysis by dividing the 2012 baseline database into three regions:
  - Eastern Interconnect
  - Western Interconnect
  - Texas Interconnect
- Once the regions are established, EPA first applies a heat rate improvement to the coal-fired generating units within each region (i.e., building block #1). In the Eastern Interconnect, the average 2012 coal plant emission rate (lb/MWh) is reduced by 4.3 percent. In the Western Interconnect, the average 2012 coal plant emission rate is reduced by 2.1 percent. In Texas, the average 2012 coal plant emission rate is reduced by 2.3 percent.
- Second, EPA assumes that renewable energy generation will increase in each region by a specified amount from 2022 to 2030, displacing 2012 fossil MWhs (on a pro rata basis). For example, in the Eastern Interconnect, fossil steam units produced 1,305 million MWhs of electricity in 2012 or 64 percent of total fossil MWhs, and NGCC units produced 735 million MWhs in 2012 or 36 percent of total fossil MWhs. EPA determined that the Eastern Interconnect has the potential to add 438 million MWhs of incremental renewable MWhs by 2030. These added renewable MWhs (increasing from 2022 to 2030) displace fossil steam and NGCC MWhs, according to their pro-rata share of 2012 fossil MWhs (i.e., 64% replace fossil steam MWh and 36 percent replace NGCC MWh).
- Third, EPA assumes the increased utilization of existing NGCC capacity. NGCC generation is assumed to increase by 22 percent above 2012 levels in 2022, and then 5 percent each year thereafter. This increased NGCC generation displaces the remaining fossil steam MWhs, similar to the renewable energy MWhs (except that renewables displace both fossil steam and NGCC MWhs). EPA also limits existing NGCC utilization at a 75 percent capacity factor based on a summer capacity rating (which EPA says is similar to a 70 percent capacity factor limit based on nameplate). This limit is binding in the Eastern Interconnect by 2024 and in the Western Interconnect and Texas by 2027 (meaning this constraint determines the level of NGCC MWhs from that point forward).
- The results at this stage of the analysis (for each region) are: (1) fossil steam performance standards from 2022 to 2029 that include a blend of fossil steam MWhs, with coal heat rate improvements applied, incremental renewable MWhs factored in, and redispatch from fossil steam to NGCC; and (2) combustion turbine performance standards from 2022 to 2029 that include a blend of NGCC MWhs (after redispatch) and incremental renewable MWhs.
- EPA then selects, for each year, the highest (i.e., least stringent) fossil steam performance standard from among the three regions, as well as the highest (i.e., least stringent) NGCC performance standards from among the three regions. These standards then become the uniform national standards provided in the table above. EPA intended this approach (selecting the least stringent rate each time) to provide additional compliance headroom in the regions that did not set the rates.

Derivation of the State-Specific Rate Goals

EPA also proposes state-specific performance standards for fossil-fired EGUs based on the national performance standards presented above. EPA calculates state-specific performance standards based on the proportion of 2012 fossil MWhs generated by fossil steam units and NGCC facilities. For example, in Colorado, fossil steam MWhs accounted for 75 percent and NGCC MWhs accounted for 25 percent of total 2012 fossil MWhs. This weighting is used to calculate a single interim

[1] The baseline, unit-by-unit data have been published on EPA's website. Available at: http://www.epa.gov/airquality/cpp/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx.

and final fossil performance standard for the state from the category specific nationwide performance standards. Appendix A of this summary includes the interim and final state performance standards.

Derivation of the Mass-Based Goals

EPA has also proposed mass-based state goals expressed in tons of CO_2, as an alternative to the rate-based standards. To calculate the mass goals for affected EGUs, EPA multiplies the state emission rate goals by their 2012 affected EGU MWhs. EPA then makes a further adjustment intended to make the mass-based targets more equivalent to a rate-based standard. In short, EPA assigns additional renewable energy MWhs to each state (in the regions that failed to set the national targets) and multiplies that added generation by the state specific emission rate goals to arrive at the final mass-based targets for affected EGUs. EPA's methodology is outlined in the TSD entitled: "CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule". See Appendix B for the interim and 2030 mass-based targets for existing affected sources. These budgets are presumed to incorporate a certain degree of "growth adjustment" because of the headroom created by factoring in the renewable energy MWhs.

EPA also proposes a separate set of mass-based targets for states that intend to include both affected EGUs and new fossil fuel-fired sources within their program. (States have the option of using these targets as a means to satisfy the requirement to address potential emissions leakage to new fossil generators as discussed in the Leakage section below.) EPA refers to these added allowances as "new source complements" to the mass goals for existing affected EGUs. The methodology for calculating these additional allowances is a five step process outlined in the TSD entitled: "New Source Complements to Mass Goals Technical Support Document for CPP Final Rule". See Appendix C for the interim and 2030 mass-based targets for existing and new sources. The new source complements are relatively small compared to the existing source budgets (2.4 percent increase on average).

State Compliance Plans

State Plan Submission Timing

In the final rule, EPA requires each state to submit their plan by September 6, 2016 or request an extension and file an initial plan by September 6, 2016 and a final plan by September 6, 2018. If a state submits an initial request, it must indicate the plan types it is considering and the reason an extension is warranted. The state must then also submit a progress report by September 6, 2017, indicating a commitment to a plan approach and a roadmap of outstanding steps to complete a state plan. For states that do not submit a final or initial state plan by September 6, 2016, EPA will implement a federal plan for EGUs in that state.

State Plan Options

The final rule requires each state with affected EGUs to develop, adopt, and submit a state plan that establishes standards of performance for the affected EGUs in its jurisdiction in order to implement the BSER. States must develop and implement plans that ensure that the power plants in their state—either individually, together or in combination with other measures—achieve the interim and final rate-based goals or mass-based goals. The final rule allows states to decide whether to implement a rate-based goal or a mass-based goal. In general, there are six options for compliance plan design:

1. Mass-based: states can adopt the mass-based state goal in CO_2 tons (for existing sources only), as shown in Appendix B.
2. Mass-based: states can adopt the mass-based state goal in CO_2 tons (for both new and existing sources) as shown in Appendix C.
3. Mass-based: states can implement a "state measures" approach that is mass-based but could include measures implemented by the state that reduce emissions from affected EGUs and are not federally enforceable components of the plan. However, a state measures type plan must include a backstop of federally enforceable standards on

affected EGUs that would be triggered if the state measures fail to result in the affected EGUs achieving the required emission reductions.

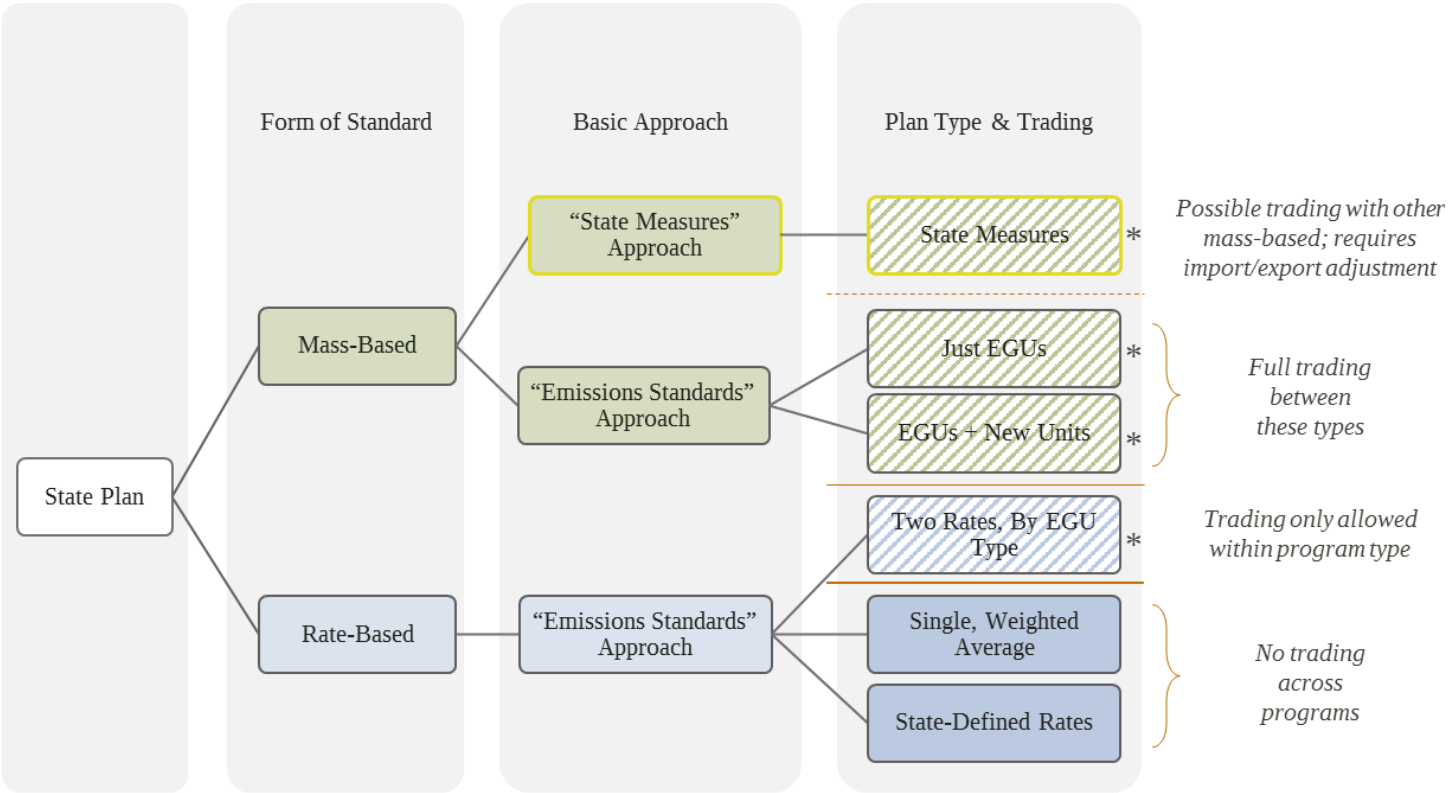
4. Rate-based: states can adopt the national performance standards for the two categories of affected fossil EGU (i.e., separate standards for fossil steam EGU and combustion turbines).
5. Rate-based: states can adopt the state specific weighted average performance standards for all affected EGUs based on the EPA-defined state performance standards.
6. Rate-based: states can adopt performance standards that apply to individual affected EGUs, or categories of EGUs (so long as the state proves the equivalency of these standards with EPA-defined standards)

For any of these options, a state may incorporate trading as part of the compliance approach. Under mass-based programs, this would be an emissions trading program within a cap. Under the rate-based options, trading would occur using the emissions performance standards combined with "emissions rate credits," or ERCs.

Both rate- and mass-based programs can also allow interstate trading with entities in other states as well, though the final rule makes clear that trading is limited within program type (i.e., rate-based programs may only trade with equivalent rate-based programs, and mass-based with mass-based). EPA has finalized two options that would allow states to trade between and among states: (1) states can submit individual plans, but still trade ERCs or allowances, using a "trading-ready" approach, or (2) states can participate in a multi-state compliance plan.

Figure 1 organizes these six primary plan types. Rate-based plans are shown in blue, mass-based in green. As discussed further below, only four of these plans—those marked with cross-hatching—can participate in interstate trading via "trading-ready" elements (i.e., without a multi-state approach). All plans can be pursued as multi-state plans. We provide more detail on each of these program types below.

Figure 1. State Plan Types



**As discussed more below, all types of plans can be used as the foundation of multi-state plans. However, only those marked with a * and cross-hatching are eligible for interstate "trading-ready" programs.*

Mass-Based Approaches: Emission Standards & State Measures Approach

When applying a mass-based approach to existing affected EGUs, total allowable CO_2 emissions from all affected EGUs must be equal to or less than the mass-based CO_2 goal. If a state elects to implement a mass-based approach, states have several design choices.

First, states must decide whether to adopt an emission standards approach, which would apply standards directly to affected EGUs (and possibly new NGCC units), or whether to adopt the state measures approach, which could incorporate measures applying to non-EGU sources.

- *Emission standards approach*: this approach applies federally enforceable mass-based standards on affected EGUs within a state. Under this approach, states must decide whether to apply the emission reduction requirements to existing EGUs or also include new units. States must also decide whether to allow trading and whether to allow EGUs in their state to submit allowances from other states to demonstrate compliance. States have discretion in allowance allocation, including the option to auction the allowances.
- *State Measures Approach*: states could also decide to include sources and measures beyond affected EGUs. This program could be used to accommodate California's AB32 or the Regional Greenhouse Gas Initiative (RGGI).

States using this approach must decide whether to allow trading with states outside of these programs. Also, to make a state measures approach federally enforceable, a state must institute a "backstop" provision.

As indicated above, both systems allow for interstate trading within the state and among states, either as part of a multi-state plan or individual, "trading-ready" plans, though the state measures approach requires additional accounting mechanisms.

Leakage & Accounting for New Sources

The final rule requires mass-based states[2] to account for leakage of emissions, which the rule defines as emissions that would not otherwise occur that result from the shift in generation from existing fossil-fired generation to new fossil units.

For states implementing a mass-based compliance approach, states can choose one of three methods to address such leakage:

1. *Include new units in the mass-based program*. States can either use EPA's established budgets that account for emissions growth, called the "new source CO_2 emissions complement," (which would be presumptively approvable) or may propose an alternative projection for a new source CO_2 emissions complement (EPA notes that such an alternate should take into account that the base mass-based goals already incorporate "significant growth in generation" compared to historical levels).
2. *Use an allowance allocation method that counteracts leakage incentives*. This could either be an updating output-based allocation or an allowance set-aside that targets incremental renewable energy and energy efficiency. EPA notes that if a state uses the exact allocation methodology described in the federal plan, this component would be presumptively approvable.
3. *Provide a supported demonstration* that leakage is unlikely to occur due to unique state characteristics or state plan design elements that mitigate leakage.

Interstate Trading Under an Emission Standards Mass-Based Approach

Under an emission standards mass-based plan, states are able to trade CO_2 allowances issued by other states for compliance. There are three approaches for mass-based states to trade CO_2 allowances: (1) retaining individual plans using EPA's trade ready program, (2) retaining individual plans that specify state partners (but without formally aggregating the individual goals); or (3) submitting a multi-state plan that combines state mass emission standards into one joint target. CO_2 emissions from affected EGUs cannot exceed total combined CO_2 emission budgets under the emission standards in the two (or more) states. Because the state budget is equivalent to the total allowable emissions under the EPA-established emission standard, and because affected EGUs emissions are limited to this budget, EPA will assess goal compliance based on an EGUs submitting one allowances for every ton of CO_2 emitted. EPA allows states to authorize EGUs to bank allowances, including across compliance periods.

1. *Trading-Ready Program*. States that choose to regulate affected EGUs and affected EGUs plus new units may indicate in their state plan to want to use the EPA administered trade-ready program. A state must institute an EPA-approved accounting program or use an EPA-administered accounting program. By using this approach, no additional EPA approval is necessary, and affected EGUs can begin trading upon plan approval. Additionally, a state does not need to make any changes to its plan in order to begin or stop trading.
2. *Individual Plan with Specified State Partners*. In order for a state to choose this pathway, it must identify the other states from which it will recognize emission allowances for compliance and must explain how allowances will be tracked (joint tracking system, interoperable tracking system, or EPA-administered system) for EPA assessment and approval. The state plan can include new states over time with EPA approval that the expanded program includes

[2] EPA notes that a rate-based plan automatically prevents these incentives. Under a rate-based trading program, new fossil-fired units cannot create ERCs, meaning that these units would be at a disadvantage compared to new renewable generation (which always generates ERCs) and, in states with rates above a natural-gas rate, existing fossil-fired units (which would also generate ERCs in this state).

states with compatible tracking systems. A state made need to revise its plan if it wishes to add new trading partners.

3. *Multi-State Plan with Joint Goal.* This plan would aggregate the mass-based CO_2 emission goals for the participating states into one joint goal. States would be held jointly responsible for meeting the joint target.

State Measures Approach – Sources and Measures Beyond EGUs

The state measures plan is a mass-based option for states that want to include a suite of state-based existing or planned programs that result in avoided generation or reduce CO_2 reductions at EGUs in their emission reductions plan. These types of measures could include renewable portfolio standards, state-administered or third party demand-side energy efficiency programs as well as market-based emission reduction programs that include components beyond emission reduction requirements for EGUs. This type of plan accommodates emission trading programs like that in California and states participating in RGGI.

In order to become an EPA approved plan, the state must demonstrate that the chosen combination of state measures and emission standards will result in achievement of the state's mass-based goal (or mass-based CO_2 goal plus new source complement). States must demonstrate their legal authority and funding to implement any state measures and that those measures are quantifiable, verifiable, enforceable, non-duplicative and permanent. In addition to the state based programs, the state measures plan can also include emission standards for affected EGUs.

In the state measures plan, the suite of state measures are not federally enforceable emission standards; therefore, the plan must also include a backstop of federally enforceable emission standards for all affected EGUs, as explained below in the corrective actions and federal backstop section.

For EPA to ensure compliance with a state measures approach, it will measure emissions from affected EGUs, and determine whether those emissions are less than the applicable state mass-based target. Under a state measures approach, a state may choose to incorporate other sources—and their emissions—under the allowance budget in order to align with existing state programs. For example, California could utilize a state measures approach to demonstrate compliance with 111(d) standards through the use of its AB 32 cap-and-trade program, which regulates emissions not only of existing power plants, but also industrial sources and commercial fuels. Therefore, even if affected EGUs in a state measures program hold allowances for their emissions, EPA cannot know that those emissions, in total, are below the 111(d) emissions goal. In this case, EPA must use actual reported emissions from affected EGUs to determine compliance.

However, states implementing state measures plans are able trade CO_2 allowances with other states, either through interstate trading or multi-state programs. Due to this trading, affected EGUs in a state measures plan may acquire allowances that allow them to exceed their state emissions target (which are offset by affected EGUs in the selling state, who are emitting less than their state emissions target). To account for this trading in demonstrating compliance, states must make adjustments to their affected EGU emissions for net "imports" and "exports" of CO_2 allowances. In this way, a state that holds a net "import" of CO_2 allowances in affected EGU compliance accounts at the end of the performance period are able to report an exceedance, in the same amount, over the state CO_2 mass goal during this performance period.

Rate-Based Approaches

States electing to implement a rate-based approach impose federally enforceable emission standards on affected EGUs in the form of lb CO_2/MWh. There are three types of rates states can impose:

1. National performance rates established for each affected source subcategory: 771 lb CO_2/MWh for stationary combustion turbines, and 1,305 lb CO_2/MWh for fossil fuel-fired utility steam generating units.
2. The applicable blended state-specific weighted average rate for affected EGUs, as calculated by EPA and listed in Appendix A.
3. State-defined rates, applied either to classes of EGUs or separate EGUs provided that the state demonstrates that their plan will meet the blended CO_2 emission performance rates.

Under each of these options, states can design plans to encourage EGUs to reduce CO_2 emissions through actions such as heat rate improvements or fuel switching, or a state may implement a market-based emission trading program to enable EGUs to generate and procure "Emissions Reduction Credits," or ERCs.

Emission Reduction Credits (ERCs)

The final rule makes clear that states using a rate-based approach may implement a market-based emission trading program, which enables EGUs to generate and procure ERCs, a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero-associated CO_2 emissions. To demonstrate compliance, an affected EGU operating above the emission performance rate would purchase ERCs (denominated in MWh) and add them to the denominator in its rate calculation. This would result in a lower reported rate (i.e., fewer tons per MWh).

ERCs can be generated and issued for: (1) affected units operating below the performance standard, (2) generation of zero-emitting energy, and (3) demand-side energy efficiency, as well as other emission measures. For a state to issue ERCs to affected EGUs, state plans must specify an accounting method and administrative process. The state would issue ERCs into a tracking system account, which could differ depending on whether a state plan includes a single rate-based standard that applies to all affected EGUs or separate rate-based emission standards that apply to individual subcategories of EGUs. In both cases, ERCs are issued in MWh based on the difference between an affected EGU's reported CO_2 emission rate and a specified CO_2 lb/MWh emission rate (the "reference rate"). In states that that choose to impose separate emission standards for subcategories of affected EGUs, the reference rate differs for affected fossil fuel-fired steam units and stationary combustion turbines. New NGCC units, because they are not affected EGUs under a rate-based plan, may not earn ERCs.

For example, assume that an affected NGCC unit operates at 900 lb/MWh in a state with a single weighted-average performance rate of 1,200 lb/MWh (the reference rate). For each MWh generated, it emits 300 fewer pounds than a unit operating at the reference rate. In order to generate one ERC, defined as an "emissions-free" MWh relative to the reference rate, this unit would have to avoid 1,200 lb. To avoid 1,200 lb, the unit would have to generate 4 MWh (4 MWh * 300 lb per MWh = 1,200 lb), so each MWh is equivalent to 0.25 ERCs.

The formula for calculating the ERCs earned for each MWh it generates is:

$$ERCs = \frac{reported\ MWh\ by\ affected\ EGU * (CO2\ emissions\ rate\ limit - affected\ EGU\ emission\ rate)}{CO2\ emission\ rate\ limit\ for\ affected\ EGUs}$$

$$ERCs = \frac{1\ MWh\ * (1{,}200 - 900)}{1{,}200}$$

$$ERCs = 0.25$$

In a state that imposes two rates, one on each subcategory, EPA allows for the state to award ERCs to NGCC generation that is equivalent to the incremental NGCC assumed to back out fossil steam units in the goal-setting methodology. These ERCs would be available for use only by fossil steam units subject to the appropriate subcategory rate (consistent with the goal computation formula in which existing NGCC MWhs displace fossil steam MWhs). EPA does not specify a methodology for calculating the value of these incremental gas ERCs in the final rule but includes methodologies for comment in the proposed Federal Plan.

States may also issue ERCs to qualifying zero-emitting energy and energy efficiency measures that are installed or implemented after January 1, 2013 for generation or energy savings in the compliance period. Since they do not contribute to emissions, these sources are awarded ERCs on an MWh basis with no adjustment. To issue ERCs to these sources, a state plan must institute a two-step process:

1. A potential ERC provider submits a form of eligibility for review including a description of project, a projection of MWh generation or energy savings anticipated, and an EM&V plan that meets state plan requirements. Projections must be verified by an independent verifier.

2. The provider must submit an EM&V report to the state to show results, following the implementation of a renewable energy or energy efficiency project. The results are verified and the number of ERCs that should be issued are determined based on the report. The ERCs are issued to the tracking system account held by the program or project provider. State plan requirements must ensure that only one ERC is issued for each verified MWh.

ERCs issued in 2022 or later may be banked and used for demonstrating compliance in a future year.

Interstate Trading Under a Rate-Based Approach

A state with a rate-based plan may wish to interact with other states for compliance purposes. This could take three forms:

1. Retaining individual programs but trading ERCs with other rate-based programs;
2. Forming a multi-state plan; or
3. Claiming credit for emissions-reducing activities occurring in other states.

To facilitate trading with other rate-based programs, a state must either adopt the two rate approach (i.e., imposing the national performance rates for stationary combustion turbines and fossil fuel-fired utility steam generating units) or it must develop a multi-state plan with another state (or states) and develop a blended rate (weighting individual rate emission standards by states' affected EGU 2012 generation). Such plans must indicate how ERCs would be tracked, from issuance to use for compliance, either through a joint tracking system, an EPA-administered system, or an individual state system with components allowing for linkage with other states. Plans must also demonstrate that any ERC issued by another state were issued by a state with an approved state plan, and that the ERCs being generated are unique across state plans. Rate-based states can only trade ERCs with states that adopt a similar structure. For example, states that adopts EPA's state-specific rate or other state-specified rates may not trade ERCs with states that adopt the two rate approach.

Separate from a trading program, a state or EGUs operating in a state that adopts a rate-based standard may wish to claim credit for zero-emitting energy and energy efficiency that the state has incentivized or caused to happen, but that happens in another state. If the out-of-state emissions reductions occurred in another state with a rate-based program, the state or EGU may claim the associated ERCs as long as there are tracking mechanisms to protect against double counting.

For qualifying renewable energy that is deployed in a mass-based state, EPA has included provisions to recognize that states or EGUs may take actions that result in renewable development outside its boundaries, and may wish to apply the credit for associated emissions reductions to its state rates. EPA specifies that an affected EGU in a rate-based state can only procure credits from renewable energy projects in a mass-based state if the electricity generated is "delivered with the intention to meet load in a state with a rate-based plan" and the generation resource was used to serve regional load that included the rate-based state. EPA notes that states can demonstrate this latter requirement through, for example, a power purchase agreement (PPA) in which an entity in the rate-based state contracts for the supply of the renewable energy located in the mass-based state. Measures other than renewable energy that may reduce emissions in a mass-based state, such as energy efficiency or nuclear power, may not be used to adjust rate-based plan targets.

Additional Considerations for Multi-State Plans

As discussed above, states may develop multi-state plans that combine goals across two or more states. Multi-state plans achieve an "aggregated joint CO_2 emission goal" for the participating states, and may be in the form of either a mass-based program (under a state measures plan or an emission standards plan) or rate-based program.

States may participate in more than one multi-state plan, or one (or more) multi-state plans in addition to an individual plan. EPA is creating this option to reflect the ways in which jurisdictions in the electric system cross state lines, for instance through utilities that operate across state lines, or states that participate in multiple markets or grid regions. A state must identify in each relevant plan which EGUs are subject to which plan.

Because multi-state plans require joint goals based on a blend (of rate standards) or sum (of mass standards) of individual state targets, entry or exit of a state to or from a multi-state plan would require the recalculation of the multi-state goal. Due

to this complexity, EPA requires that modification to multi-state plans only take effect at the beginning of a new interim step or final plan performance period.

Compliance Timing

All state plans must impose requirements that begin compliance in 2022. The final rule establishes an interim period, ranging from 2020 through December 31, 2029. Final targets take effect in 2030. State plans must demonstrate that affected EGUs will meet both interim emissions performance standards on average over the interim period and final emissions standards in 2030 and beyond.

A state must show progress toward meeting the interim emission performance standard by establishing no less than three "interim steps." Each interim step can be no longer than three years, and the final step must be no longer than two years. These step periods are the basis for interim "checks" on compliance. In a state plan, a state must establish interim step emissions performance standards that, on average, result in compliance over the entire interim period. A state will have to monitor and report compliance during each of these step periods; corrective measures, as discussed in more detail below, may apply if a report shows that a state has not met an interim step goal.

EPA has proposed an interim step schedule that states may use, though no state is required to follow this schedule as long as it establishes its own steps following the above requirements.[3] EPA's proposed interim schedule is:

- Interim step 1 period: 2022 to 2024;
- Interim step 2 period: 2025 to 2027; and
- Interim step 3 period: 2028 to 2029.

As noted above, EGUs participating in trading systems may bank allowances or ERCs for use across compliance periods. Borrowing is not allowed; however, states do have the flexibility to determine their interim step goals, which provides flexibility similar to borrowing.

Starting in 2030, the rule provides for two-year "final plan performance periods," starting with 2030-2031 (and followed by every subsequent two-year period). Over this period, a state must continue to monitor and report emissions and maintain compliance with the final emission performance standard established in the state plan.

Federal Enforceability, Backstop, and Corrective Measures

If a state under any type of plan does not meet its emissions standard requirements, corrective measures would be triggered, which vary based on the compliance period:

- Interim step 1 (2022-2024) or step 2 (2025-2027) period: if actual emissions performance is 10 percent or more deficient compared to levels specified in the state plan, or a state has not met programmatic milestones for the reporting period, corrective measures would be triggered.
- Total 8-year interim performance period *and* final plan performance period (2030-2031, and every subsequent 2-year period): if actual emission performance does not meet exact emissions performance specified in the plan, corrective measures would be triggered.

In other words, a state may be deficient by up to 10 percent during one of the two initial interim step periods, but must meet and maintain overall interim and final targets.

If a state has chosen to adopt and implement the emissions standards plan, the requirements on affected EGUs are federally enforceable emissions standards. However, if a state with this plan triggers corrective measures, it must submit to EPA a

[3] The exception to this flexibility is states who have designed "state measures" plans; these states must utilize EPA's proposed three interim steps.

plan revision that adjusts requirements or adds new measures and explains how any shortfall that occurred during a performance period will be made up "expeditiously." Such a revision must be made within 24 months of the first state report noting the shortfall.

By comparison, the procedures for corrective measures under a state measures plan are more extensive. Under this type of plan, the suite of measures a state chooses to adopt and implement are enforceable only under state law. Therefore, a state plan must also include a mandatory contingent backstop of federal enforceable emission standards for affected EGUs that would apply in the event that the plan does not achieve its anticipated level of emission performance. EPA notes that this inclusion is legally necessary for a state plan to meet the terms of 111(d), which specifically require a state to submit standards of performance. Thus, the backstop will serve as the corrective measure in the case of any shortfall. As part of a state measures plan, a state must specify the exact trigger and schedule for any possible future backstop, including state administrative and technical procedure for its implementation. If a backstop is triggered, the state is required to notify EPA, and compliance with a federally enforceable emissions standard must begin no later than 18 months after the trigger. The final rule requires that any backstop emissions standards make up for any shortfall in previous emissions performance, which may require adjusting ongoing emissions standards to account for prior shortfall.

State Plan Components and Approvability Criteria

While the content of a state plan submittal will vary depending on the type of approach that the state chooses to adopt, and whether that state plans to participate in a multi-state plan. EPA finalized the following components for all types of state plans to include:

1. *Description of the plan approach and geographic scope*. The description must include whether the state will have an individual or joint plan and the plan type (emissions standards or state measures). Multi-state plans must identify all participating states and the geographic boundaries applicable. If a state plans to implement an individual plan in coordination with other states to allow for interstate transfer of ERCs or emission allowances, the links must be identified.
2. *Applicability of state plans to affected EGUs.* This includes listing individual affected EGUs and an inventory of CO_2 emissions from those affected EGUs from the most recent calendar years prior to plan submission.
3. *Demonstration that a state plan will achieve the CO_2 emission performance rates or state CO_2 emission goal.* State plans must demonstrate that the measures taken in the plan are sufficient to meet the state's goal for both the interim and final performance period.
4. *Monitoring, reporting and recordkeeping requirements for affected EGUs.* Each state plan must specify how each emission standard is quantifiable and verifiable by describing the CO_2 monitoring, reporting, and recording requirements for affected EGUs.
5. *State reporting and recordkeeping requirements.* A state plan must include the process, content, and schedule for state reporting to EPA on plan implementation and process toward meeting the state goal including an annual report due to EPA by July 1 following the end of each reporting period. States must submit a report to EPA in 2021 that demonstrates that the state has met the milestone steps it indicated it would take from the submittal of the final plan through the end of 2020.
6. *Public participation and certification of hearing on state plan*. States must show meaningful public engagement as a part of the plan development process including public hearings. EPA notes a special interest in low-income and some communities of color as they are often disproportionately affected by certain climate change related impacts.
7. *Supporting documentation including*:
    a. Legal authority and funding
    b. Technical documentation
    c. Programmatic milestones and timeline

d. Reliability considerations during plan development

State Plan Modifications

EPA notes that 111(d) does not specifically mention a process for revising state plans, but believes it is reasonable to offer such a process in order for a state to continue to provide for a pathway to meeting state targets. In all cases, a state plan revision must still ensure that affected EGUs meet the emissions performance requirements laid out in the final rule.

EPA does not establish any limitations on what a state may request to modify so long as emissions performance requirements are maintained. However, the final rule does specify some acceptable reasons that a state could modify its plan:

- to adjust the state interim and final CO_2 emission goals for affected EGUs in a state, though only to address changes within a state's fleet of affected EGUs;
- to update a plan to correct for failure to meet emissions targets;
- to enter or exit a multi-state plan through a plan modification, with certain limitations described in the multi-state plan section above; or,
- in response to a reliability issues that cannot be addressed within the range of actions already included in a plan.

A state may receive expedited review of a plan revision request to address a reliability concern. To receive this treatment, it must provide with its request a separate analysis of the reliability risk from the relevant ISO, RTO, or other planning authority, which must include a statement that there are no practicable alternate resolutions to the reliability risk.

In non-reliability cases, EPA will review a plan revision per the implementing regulation requirements of 40 CFR part 60.28. Consistent with the timing for final plan submittals originally submitted by states, EPA commits to act on state plan revisions within 12 months of a complete submittal. EPA indicates in the final rule that it expects that the long plan performance timeframes in this final rule and flexibility provided to states in developing state plans will lessen the need for modifications to approved state plans.

Early Action/Clean Energy Incentive Program for 2020 and 2021

EPA had proposed that measures taken by a state or its sources after the date of the proposal, or programs already in place, and that result in CO_2 emission reductions at affected power plants during the 2020 to 2030 period would apply toward achievement of the state's CO_2 goal. However, in the final rule, EPA introduces an incentive program, called the Clean Energy Incentive Program (CEIP), that will allow states to incentivize new wind, solar, and energy efficiency, if they choose to participate. The basic requirements for eligible projects are:

- *Wind and solar*: a wind or solar facility must start construction after a state plan is submitted (or after September 6, 2018, for states that do not submit a final plan), and must generate energy in 2020 or 2021.
- *Energy efficiency*: a project must commence operation after a state plan is submitted (or after September 6, 2018, for states that do not submit a final plan), and must reduce demand in a low income community in 2020 or 2021.

Projects do not need to be "additional" or surplus relative to business as usual. For such eligible renewable generation or savings, a state may allocate allowances (under a mass-based program) or "early action ERCs" (under a rate-based program) to these projects from its existing budget or compliance pool. EPA will then match the state's award from a pool of 300 million short tons of CO_2 emissions, and EPA is taking comment on the size of the reserve.

The amount of ERCs or allowances allocated to a project depends on the type. Eligible energy efficiency savings are awarded double the amount of credits that are awarded to wind and solar:

- Eligible wind and solar: for every *two* MWh generated, the project receives *two* ERCs (or the equivalent number of allowances) – one from the state, and one from EPA's pool (i.e., effectively qualifying RE receives one credit for each eligible MWh generated).
- Eligible energy efficiency: for every *two* MWh generated, the projected receives *four* ERCs (or the equivalent number of allowances) – two from the state, and two from EPA's pool (i.e., effectively qualifying EE receives two credits for each eligible MWh generated).

In order for a state to receive allowances from EPA's pool, it must have a program in its state plan to award early action credits in a way that maintains the stringency of the state's goal (not including "matching" grants from EPA's pool, which can be incremental to the targets). For example, a state that wished to distribute allowances for early action credit under a mass-based program would have to draw those allowances from under the cap in later years of the program. States also must verify all generation and/or reductions and ensure that no actions are counted twice. States that are subject to the federal plan would automatically participate in the CEIP program and have access to the early action credits.

States will only be able to draw their pro-rata share of allowances from the 300 million ton pool, determined based on the amount of reductions from 2012 levels that affected EGUs in the state are required to achieve, relative to other states. This means that states with steeper required reductions are eligible for more early action than states with less stringent targets. In the federal plan, EPA proposes that if any states elect not to establish a CEIP program, its portion of allowances will be reallocated among states that do have programs. EPA also proposes in the federal plan that it will retire any tons from the EPA pool that are unused at the end of 2022.

EPA is also taking comment on the CEIP program in the federal plan, on several additional aspects including:

- How to identify "low income communities";
- How to translate from MWh generated or saved to tons; and
- How to allocate the pool between renewable energy and energy efficiency programs.

In addition to the CEIP, EPA notes that states implementing mass-based approaches could, through their allowance allocation methodology, create a set-aside of allowances that could be provided to entities who take action to reduce emissions prior to 2022. These allowances would have to be drawn from the total mass budget for the interim period (i.e., would not be incremental to the existing budgets) and would not be subject to matching by EPA. However, this set aside could also apply to a broader set of actions than credited under the CEIP.

Reliability Considerations and a Reliability Safety Valve

EPA notes that the Clean Power Plan's inherent flexibility minimizes the chance of reliability concerns. It also notes that changes to the final rule, especially moving the start of interim compliance to 2022 and making the interim goals more gradual, further reduce this risk by providing sufficient time to plan for system reliability. However, EPA has incorporated three additional changes that are specifically focused on incorporating reliability considerations into the final rule:

1. *State plan revisions.* As discussed in more detail above, a state may submit a revision to its state plan in order to address changes in circumstances that could have reliability impacts if not accommodated by a revision to the plan. Reliability-related requests may be eligible for expedited review by EPA.
2. *Reliability demonstration.* Each state must demonstrate as part of its final state plan submission that it considered reliability issues. EPA notes that a "particularly effective" way to make this demonstration is through consultation with the appropriate ISO, RTO, or other planning authority; if a state chooses this method of demonstration, EPA recommends that the state request that the planning authority review the state plan at least once during plan development state, and maintain a continuing dialogue during development of a plan. States may provide other comparable support for a demonstration as well, which could involve working with state utility regulators or state energy offices.

3. *Limited Reliability Safety Valve.* EPA believes that it is "highly unlikely" that there would be a conflict between the activities required under a state plan and maintaining reliable operation of the electric grid. However, EPA notes that EGUs operating under some inflexible state plans may need to temporarily operate under a modified emissions standard in order to respond to a reliability concern. EPA indicates that this circumstance would likely have to meet the following criteria:

    a. The event creating the emergency would be unforeseeable;

    b. Without the relief to a specific EGU provided by the safety valve, the electricity grid would face some sort of failure; and

    c. The plan under which the EGU operations imposes emissions constraints that, without relief, would be violated in order to maintain reliability.

    EPA notes that any EGU operating under any plan that permits trading would likely *not* meet these criteria. If, however, a situation arises that does meet the criteria, a state may then submit a request to EPA, which, if accepted, would result in the following relief:

    a. A 90-day period during which the EGU would not have to meet the emissions standard under the state plan, but instead meet an alternative standard (excess emissions during this time *do not* have to be made up by this or other EGUs at any time); and

    b. A period after this initial 90 days, if necessary, during which the EGU could continue to operate under the alternate emissions standard, but during which any emissions in excess of the applicable state goals *must be accounted for and offset* through changes to the state's plan.

    The submission from the state in the case of a reliability concern would need to include the following:

    a. *Initial notice*: within 48 hours of an emergency situation, the state must submit to its regional EPA office a notification that it is necessary to modify emissions standards for a specified reliability-critical EGU, what state what the modified standard should be.

    b. *Detailed notice*: within seven days of the initial notification, the state must submit a second notification that includes a full description of the emergency situation, why it was unforeseen, and how it is coordination with relevant reliability coordinators to alleviate the problem. This notice must include a written concurrence from the reliability coordinator.

    c. *Extension request*: at least seven days before the end of the initial 90-day period, a state may request that the short-term modification period be extended. This must be accompanied by a second written concurrence from the reliability coordinator. In this case, EPA will work with the state on a case-by-case basis to identify an appropriate emission standard. As noted above, any excess emissions during this extended period, if granted, must be made up by other units or later in the program.

In addition, if a state submits more than one request under the reliability safety valve, EPA requires that, upon the second request, the state undertake a plan revision to address the issue in the plan leading to reliability restrictions.

While operating under an alternate or modified emissions rate, an EGU must still monitor and report emissions and generation pursuant to the final rule requirements. EPA also notes in the final rule that it is maintaining an ongoing relationship with FERC and DOE in order to monitor and manage reliability impacts.

Appendix A: Interim and Final State Goals

	2012 Historic Rate[1] (lb/ Net MWh)	Interim Target Rate-Based	Final Target Rate-Based
Alabama	1,518	1,157	1,018
Arizona	1,552	1,173	1,031
Arkansas	1,779	1,304	1,130
California	963	907	828
Colorado	1,973	1,362	1,174
Connecticut	846	852	786
Delaware	1,254	1,023	916
Florida	1,247	1,026	919
Georgia	1,600	1,198	1,049
Idaho	858	832	771
Illinois	2,208	1,456	1,245
Indiana	2,021	1,451	1,242
Iowa	2,195	1,505	1,283
Kansas	2,319	1,519	1,293
Kentucky	2,166	1,509	1,286
Louisiana	1,618	1,293	1,121
Maine	873	842	779
Maryland	2,031	1,510	1,287
Massachusetts	1,003	902	824
Michigan	1,928	1,355	1,169
Minnesota	2,033	1,414	1,213
Mississippi	1,185	1,061	945
Missouri	2,008	1,490	1,272
Montana	2,481	1,534	1,305
Nebraska	2,161	1,522	1,296

	2012 Historic Rate[1] (lb/ Net MWh)	Interim Target Rate-Based	Final Target Rate-Based
Nevada	1,102	942	855
New Hampshire	1,119	947	858
New Jersey	1,091	855	812
New Mexico	1,798	1,325	1,146
New York	1,140	1,025	918
North Carolina	1,780	1,311	1,136
North Dakota	2,368	1,534	1,305
Ohio	1,900	1,383	1,190
Oklahoma	1,565	1,223	1,068
Oregon	1,089	964	871
Pennsylvania	1,682	1,258	1,095
Rhode Island	918	832	771
South Carolina	1,791	1,338	1,156
South Dakota	2,229	1,352	1,167
Tennessee	2,015	1,411	1,211
Texas	1,566	1,188	1,042
Utah	1,874	1,368	1,179
Virginia	1,477	1,047	934
Washington	1,566	1,111	983
West Virginia	2,064	1,534	1,305
Wisconsin	1,996	1,364	1,176
Wyoming	2,331	1,526	1,299

1. EPA made some targeted baseline adjustments at the state level to address commenter concerns about the representativeness of baseline-year data. These are highlighted in the CO_2 Emission Performance Rate and Goal Computation TSD.

Appendix B: Interim and Final State Goals – Annual Average; Affected EGUs Only

	2012 Historic Emissions[1] (short tons)	Interim Target Mass-Based	Final Target Mass-Based
Alabama	75,571,781	62,210,288	56,880,474
Arizona	40,465,035	33,061,997	30,170,750
Arkansas	39,935,335	33,683,258	30,322,632
California	46,100,664	51,027,075	48,410,120
Colorado	41,759,882	33,387,883	29,900,397
Connecticut	6,659,803	7,237,865	6,941,523
Delaware	4,809,281	5,062,869	4,711,825
Florida	118,395,844	112,984,729	105,094,704
Georgia	62,851,752	50,926,084	46,346,846
Idaho	703,517	1,550,142	1,492,856
Illinois	96,106,169	74,800,876	66,477,157
Indiana	107,299,591	85,617,065	76,113,835
Iowa	38,135,386	28,254,411	25,018,136
Kansas	34,353,105	24,859,333	21,990,826
Kentucky	91,372,076	71,312,802	63,126,121
Louisiana	43,028,425	39,310,314	35,427,023
Maine	1,795,630	2,158,184	2,073,942
Maryland	20,171,027	16,209,396	14,347,628
Massachusetts	13,125,248	12,747,677	12,104,747
Michigan	69,860,454	53,057,150	47,544,064
Minnesota	28,263,179	25,433,592	22,678,368
Mississippi	25,903,886	27,338,313	25,304,337
Missouri	78,039,449	62,569,433	55,462,884
Montana	17,924,535	12,791,330	11,303,107
Nebraska	27,142,728	20,661,516	18,272,739

	2012 Historic Emissions[1] (short tons)	Interim Target Mass-Based	Final Target Mass-Based
Nevada	15,536,730	14,344,092	13,523,584
New Hampshire	4,642,898	4,243,492	3,997,579
New Jersey	15,207,143	17,426,381	16,599,745
New Mexico	17,339,683	13,815,561	12,412,602
New York	34,596,456	33,595,329	31,257,429
North Carolina	58,566,353	56,986,025	51,266,234
North Dakota	33,370,886	23,632,821	20,883,232
Ohio	102,239,220	82,526,513	73,769,806
Oklahoma	52,862,077	44,610,332	40,488,199
Oregon	7,659,775	8,643,164	8,118,654
Pennsylvania	116,657,632	99,330,827	89,822,308
Rhode Island	3,735,786	3,657,385	3,522,225
South Carolina	35,893,265	28,969,623	25,998,968
South Dakota	3,184,962	3,948,950	3,539,481
Tennessee	41,222,026	31,784,860	28,348,396
Texas	240,730,037	208,090,841	189,588,842
Utah	30,822,343	26,566,380	23,778,193
Virginia	27,365,439	29,580,072	27,433,111
Washington	7,360,183	11,679,707	10,739,172
West Virginia	72,318,917	58,083,089	51,325,342
Wisconsin	42,317,602	31,258,356	27,986,988
Wyoming	49,998,736	35,780,052	31,634,412

1. EPA made some targeted baseline adjustments at the state level to address commenter concerns about the representativeness of baseline-year data. These are highlighted in the CO_2 Emission Performance Rate and Goal Computation TSD.

Appendix C: Interim and Final State Goals – Annual Average; Affected EGUs & New Source Complements

	2012 Historic Emissions[1] (short tons)	Interim Target Mass-Based	Final Target Mass-Based
Alabama	75,571,781	63,066,812	57,636,174
Arizona	40,465,035	34,486,994	32,380,196
Arkansas	39,935,335	34,094,572	30,685,529
California	46,100,664	53,873,603	52,823,635
Colorado	41,759,882	34,627,799	31,822,874
Connecticut	6,659,803	7,373,274	7,060,993
Delaware	4,809,281	5,141,711	4,781,386
Florida	118,395,844	114,738,005	106,641,595
Georgia	62,851,752	51,603,368	46,944,404
Idaho	703,517	1,644,407	1,639,013
Illinois	96,106,169	75,619,224	67,199,174
Indiana	107,299,591	86,556,407	76,942,604
Iowa	38,135,386	28,553,345	25,281,881
Kansas	34,353,105	25,120,015	22,220,822
Kentucky	91,372,076	72,065,256	63,790,001
Louisiana	43,028,425	39,794,622	35,854,321
Maine	1,795,630	2,199,016	2,109,968
Maryland	20,171,027	16,380,325	14,498,436
Massachusetts	13,125,248	12,972,803	12,303,372
Michigan	69,860,454	53,680,801	48,094,302
Minnesota	28,263,179	25,720,126	22,931,173
Mississippi	25,903,886	27,748,753	25,666,463
Missouri	78,039,449	63,238,070	56,052,813
Montana	17,924,535	13,213,003	11,956,908

	2012 Historic Emissions[1] (short tons)	Interim Target Mass-Based	Final Target Mass-Based
Nebraska	27,142,728	20,877,665	18,463,444
Nevada	15,536,730	15,114,508	14,718,107
New Hampshire	4,642,898	4,314,910	4,060,591
New Jersey	15,207,143	17,739,906	16,876,364
New Mexico	17,339,683	14,342,699	13,229,925
New York	34,596,456	34,117,555	31,718,182
North Carolina	58,566,353	57,678,116	51,876,856
North Dakota	33,370,886	23,878,144	21,099,677
Ohio	102,239,220	83,476,510	74,607,975
Oklahoma	52,862,077	45,191,382	41,000,852
Oregon	7,659,775	9,096,826	8,822,053
Pennsylvania	116,657,632	100,588,162	90,931,637
Rhode Island	3,735,786	3,727,420	3,584,016
South Carolina	35,893,265	29,314,508	26,303,255
South Dakota	3,184,962	3,995,462	3,580,518
Tennessee	41,222,026	32,143,698	28,664,994
Texas	240,730,037	213,419,599	198,105,249
Utah	30,822,343	27,548,327	25,300,693
Virginia	27,365,439	30,030,110	27,830,174
Washington	7,360,183	12,211,467	11,563,662
West Virginia	72,318,917	58,686,029	51,857,307
Wisconsin	42,317,602	31,623,197	28,308,882
Wyoming	49,998,736	36,965,606	33,472,602

1. EPA made some targeted baseline adjustments at the state level to address commenter concerns about the representativeness of baseline-year data. These are highlighted in the CO_2 Emission Performance Rate and Goal Computation TSD.

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