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Preliminary Summary of Proposed Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

On June 2, 2014, EPA released its long-awaited proposal to regulate CO_2 emissions from existing power plants—the 111(d) rule. In the rule, EPA proposes enforceable state-by-state CO_2 performance goals, expressed in pounds of CO_2 per megawatt hour (lbs/MWh). Unlike the 111(b) rule for new fossil-fired power plants, the state performance goals are not directly applicable to fossil generating units. The goals are based on a bottom-up, multi-factor analysis that reflects a "system-wide" approach, including natural gas redispatch, renewable energy deployment, and demand-side energy efficiency. Overall, the Agency projects the rule will achieve a 30 percent reduction in power plant CO_2 emissions (from 2005 levels) by 2030 and a 25 percent reduction by 2020. EPA will allow broad flexibility in terms of how the goals are met.

At the heart of the rule proposal is EPA's determination of the Best System of Emissions Reduction (BSER), which is used to establish the state-by-state performance goals. The factors (or building blocks) used in calculating the performance goals include:

1. **Heat rate improvements at existing coal-fired power plants.** EPA calculates the impact of a six percent heat rate improvement, relative to 2012 average rates, at existing coal-fired power plants.

2. **Increased utilization of existing natural gas combined cycle (NGCC) units.** EPA calculates a potential emission rate improvement for each state assuming all existing and under construction NGCC (as of the proposal) have a capacity factor of 70 percent. The calculated increase in NGCC generation is used to back out megawatt hours from fossil fuel-fired steam boilers using 2012 generation data.

3. **Continued and increased operation of zero-emitting generation.** EPA calculates the generation (in MWh) of electricity associated with existing and projected renewable energy as well as "at risk" and under construction nuclear capacity. The calculated generation by zero-emitting sources in 2030 is added to the denominator of the goal, resulting in a lower emission rate.

    a. The energy efficiency component is based on 2012 non-hydro renewable energy and projected 2030 generation based on an analysis of regional potential by EPA.

    b. The nuclear generation component is based on a percentage credit (5.8 percent) for continued operation of existing nuclear units and full credit for new nuclear capacity—assuming a 90 percent average capacity factor.

4. **Increased demand-side energy efficiency**. Based on its analysis of existing energy efficiency program savings, EPA estimates that 1.5 percent annual incremental savings is

achievable by all states, given adequate time. Estimated cumulative savings for each state in 2030 is added to the denominator of the goal, resulting in a lower emission rate.

The proposed rule for existing power plants is expected to drive increased natural gas demand within the electric power sector; EPA projects a 10 percent to 14 percent increase by 2020 (above projected Base Case levels). EPA projects an additional 30 to 49 gigawatts (GW) of coal plant retirements by 2020 (beyond the Base Case). The rule is also expected to drive significant nitrogen oxide (NOx) and sulfur dioxide (SO_2) reductions. These outcomes are based on EPA's modeling of the proposed emission goals. However, given the flexibility afforded states in developing their compliance plans, the benefits, cost, and economic impacts published by EPA are not definitive projections, but are illustrative of compliance actions states may take. Subject to EPA approval, states will ultimately define the approaches available to affected sources to comply with the goals established in this regulatory action.

EPA is proposing a BSER goal-setting approach referred to as Option 1 and requesting comment on a second approach referred to as Option 2. Each of these goal-setting approaches use the four building blocks at different levels of ambition. Option 1 is based on more aggressive deployment of the four building blocks but allows a longer timeframe to comply (2030) whereas Option 2 has a slightly lower deployment over a shorter timeframe (2025).

Applicability

EPA proposes to have this rule apply to any fossil fuel-fired electric generating units (EGU) that was in operation or had commenced construction as of January 8, 2014 and is therefore an "existing source" for purposes of section 111 of the Clean Air Act and otherwise meet the applicability criteria under the proposed standards for new fossil fuel-fired EGUs under 111(b). In other words the rule applies to any boiler, IGCC unit, or combustion turbine that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input during any 3 consecutive calendar years; (3) sells the greater of 219,000 MWh per year and 1/3 of its potential electrical output to a utility distribution system; and (4) was in operation or under construction as of January 8, 2014. Natural gas stationary combustion units may average over three years to reach the one-third output requirement, while fossil fuel boilers must meet the requirement annually.

Best System of Emission Reduction

In its BSER determination, EPA identified the four building blocks outlined above. For each building block, EPA assessed the technical potential of the building block and the reasonableness of its cost. EPA uses the building blocks and the technical potential to develop the state performance goals discussed in more detail below and included in Appendix A.

Building Block 1: Heat rate improvements

Building block 1 applies to existing (in 2012) coal-fired steam EGUs. EPA completed an analysis of data reported to EPA and concluded that affected coal-fired EGUs could achieve a four percent improvement in heat rate through adoption of best practices to reduce hourly heat rate variability. In addition, EPA reviewed the potential for equipment upgrades across the fleet and found opportunities for a two percent improvement. Based on these findings, EPA proposes a six percent heat rate improvement as BSER across affected coal-fired sources (Option 2 assumes a 4% improvement). EPA flags "rebound effects" where generation increases in response to efficiency improvements at a site but concludes such effects would only be an issue if BSER was solely based on building block 1.

EPA finds that the heat rate improvements would result in fuel savings that would largely offset the cost of the heat rate improvements, resulting in an average CO_2 reduction cost of $7.75 per metric ton of CO_2.

Building Block 2: Increased NGCC utilization

EPA's second building block is based on the increased utilization of existing and under construction NGCC units to displace fossil-fired steam units (coal, oil, and gas units). To demonstrate technical feasibility, EPA cites examples of re-dispatch as a compliance strategy in regions where EGUs are subject to market-based emission limitation programs such as under Title IV of the CAA Amendments of 1990 and the Regional Greenhouse Gas Initiative. EPA also cites the use of limits on utilization or emissions through permitting mechanisms.

In its evaluation of the potential magnitude of re-dispatch, EPA reviewed the design capabilities and average annual availability of existing NGCC units in the U.S. Citing a NERC report and *Power Engineering* article, EPA found that the average annual availability of NGCC units in the U.S. generally exceeds 85 percent. In a review of historical operations, EPA found a range of examples of NGCC units operating at a 70 percent capacity factor or above for sustained periods and concludes that "increasing the utilization rates of existing NGCC units to 70 percent, not in every individual instance but on average, as part of a comprehensive approach to reducing CO_2 emissions from existing high carbon-intensity EGUs, would be technically feasible." (Page 178) Option 2 assumes a 65 percent average capacity factor for NGCC.

EPA also reviewed natural gas pipeline adequacy and supply. EPA found that it was reasonable to conclude that the natural gas pipeline system can deliver sufficient natural gas to increase average NGCC unit utilization to 70 percent. This conclusion was based on the time before states have to demonstrate compliance, which should allow for necessary expansion, combined with the flexibility of the emission guidelines and the fact that pipelines have already delivered gas to allow average monthly fleet-wide NGCC utilization rates of up to 65 percent. Citing EIA data, EPA found no concerns with natural gas supply. As a part of the NGCC utilization consideration, EPA completed an analysis of upstream methane emissions and found that the net impacts from methane emissions are likely to be small compared to the CO_2 emission reduction impacts of shifting power generation from coal-fired steam EGUs to NGCC units.

EPA tested its conclusions using the Integrated Planning Model (IPM) and found that IPM could solve for scenarios reflecting 65, 70, and 75 percent average NGCC capacity factors within defined areas. EPA used IPM to estimate costs of compliance and found costs associated with 70 percent NGCC utilization to be $30 to $33 per metric ton of CO_2.

Building Block 3: Continued and expanded use of zero-carbon generation

EPA uses the third BSER building block to factor renewable electricity (RE) and nuclear capacity into the goal. To estimate CO_2 emission reductions based on RE generation, EPA developed a best practices scenario for RE generation based on existing renewable portfolio standard (RPS) requirements. Recognizing that RE potential varies by region, EPA grouped states into six regions and developed annual RE growth factors and maximum RE generation targets for each region. Table 1 shows the regional groupings and the RE generation targets for 2030. EPA developed the generation targets by averaging 2020 renewable portfolio standard (RPS) targets for states within each region that had RPS requirements. The annual RE growth factors were based on a linear increase in renewable energy from the regional 2012 generation to the 2030 target level, assuming a 2017 starting point.

Table 1. Regions for Development of Best Practices RPS Scenario

Region	States	2030 Target
East Central	DE, DC, MD, NJ, OH, PA, VA, WV	16%
North Central	IL, IN, IA, MI, MN, MO, ND, SD, WI	15%
Northeast	CT, ME, MA, NH, NY, RI, VT	25%
South Central	AR, KS, LA, NE, OK, TX	20%
Southeast	AL, FL, GA, KY, MS, NC, SC, TN	10%
West	AZ, CA, CO, ID, MT, NV, NM, OR, UT, WA, WY	21%

For the states in each region, EPA developed annual RE generation goals by applying the regional RE growth factor to each state's initial generation level, starting in 2017, and stopping at the RE generation target. In some states, the RE generation targets are less than reported RE generation in 2012. EPA requests comment on whether the approach should be modified to include a floor based on 2012 RE generation in each state.

EPA also requests comment on an alternative approach to quantifying RE generation using a state-by-state assessment of RE technical and market potential combined with IPM modeling of RE deployment.

Using EIA data on levelized costs, EPA estimates that the cost to reduce emissions through RE ranges from $10 to $40 per metric ton of CO_2 under the proposed approach.

In addition to the expanded use of renewables, EPA recognizes that increasing the amount of nuclear capacity that is available to operate is a technically viable approach to reducing CO_2 emissions from affected fossil fuel-fired units. As a result, EPA also includes new nuclear generation (assuming a 90% capacity factor) in the denominator of a state goal, including Watts Bar in TN, Vogtle in GA, and Summer in SC. EPA requests comment on the appropriateness of including nuclear sources under construction in the development of the state goal because of the large impact the associated generation has on the goal.

EPA also recognized the importance of continued operation of existing nuclear generation to meet the environmental goals of the program. To estimate the nuclear capacity that is vulnerable to retirement, EPA relies on EIA's estimate in the 2014 Annual Energy Outlook that there is the potential for 5.7 gigawatts (GW) of capacity reductions to the nuclear fleet in response to continued economic challenges. The 5.7 GW represents 5.8 percent of current nuclear capacity. EPA uses the six percent estimate to calculate a share of nuclear capacity at risk for retirement. The MWh associated with continued operation of that capacity is included in the state goals established by EPA. EPA finds that the cost associated with offsetting the revenue losses at at-risk units is $12 to $17 per metric ton of CO_2.

Building Block 4: Increased demand-side energy efficiency

EPA's fourth BSER building block is demand-side energy efficiency (EE). EPA found that 12 states have achieved or have established requirements to achieve annual incremental savings rates of at least 1.5 percent of the electricity demand that would have otherwise occurred, annually. Using 1.5 percent as a reasonable level of annual savings, EPA develops estimates of best-practices levels of performance for each state. Recognizing that some states need time to develop the systems and expertise to advance EE programs, EPA estimates a 2012 annual savings rate for each state and develops scenarios where the savings level increases by 0.2 percent per year starting in 2017 until it reaches 1.5 percent. Option 2 assumes a 1.0 percent annual savings target.

EPA assumes that EE savings are cumulative across the life of the energy efficiency program portfolio (~10 years). For the purposes of goal setting, EPA has projected the cumulative annual savings for each state from 2020 to 2029.

Using IPM, EPA found the average cost of the CO_2 reductions achieved through EE to be $16 to $24 per metric ton of CO_2.

Potential Emission Reduction Measures Not Used to Set Proposed Goals

EPA considered four additional potential sources of reductions but did not propose them as part of the BSER building blocks. EPA requests comment on each of these potential sources of reductions:

- Fuel switching at individual units (including natural gas co-firing at coal units);
- Carbon capture and storage;
- New NGCC capacity; and
- Heat rate improvement opportunities at other fossil sources.

BSER Legal Defensibility

EPA notes in the preamble that because of the integrated nature of the electricity system, states and industry have "long pursued a wide variety of strategies for ensuring that the demand for electricity services is met reliably, at reasonable costs, and in a manner consistent with evolving constraints, including environmental objectives." (page 255) EPA explains that it believes that states and industry will consider all four building blocks when developing state plans and strategies for reducing CO_2, and thus, the combination of all four is appropriate for establishing BSER.

EPA proposes two formulations for BSER. The first approach defines BSER as comprising all four building blocks on the basis that they will result in substantial CO_2 reductions while maintaining fuel diversity and a reliable and affordable electricity supply. The second approach consists of building block 1 with reduced utilization from high-emitting affected EGUs. Under this second approach, the measures under building blocks 2, 3, and 4 justify the quantity of reduced utilization. For example, the amount of generation from the increased utilization of NGCC units would determine the portion of the amount of generation reduction component of BSER for affected EGUs.

To explain EPA's legal justification for BSER, EPA notes that under case law, it must: (1) ensure that the system must be technically feasible, (2) consider the amount of emission reductions the system would generate, (3) ensure that the costs are reasonable, and (4) consider that section 111 is designed to promote the development and implementation of technology. EPA may also consider energy impacts over time, but has discretion on how to weigh each of these factors.

The preamble also explains how the electric sector's interconnected and integrated nature supports the BSER determination, and EPA examines how each building block meets the criteria for BSER. In the legal discussion, EPA also notes:

- It was concerned about the potential "rebound effect" if building block 1 were applied in isolation. In other words, absent other incentives to reduce generation, heat rate improvements and variable cost reductions at coal-fired EGUs could cause such units to become more competitive compared to other EGUs and increase their generation, which would lead to smaller overall reductions in CO_2.

- It considered whether a combination of building blocks 1 and 2 would constitute BSER. While EPA notes such a combination would be a valid system of emission reductions, it would not achieve the same level of emission reductions as all four building blocks could achieve.

- States can encourage the current trend of shifting generation toward NGCC using a variety of strategies. Specifically, EPA notes states could use its permitting authority to impose limits on the hours of operation of individual units or change the relative costs of generation for more carbon-intensive and less carbon-intensive generating units through market-based systems.

- It is seeking comment on whether combining the category of steam EGUs and combustion turbines into a single category for fossil fuel-fired EGUs is a prerequisite for allowing re-dispatch or averaging between the two categories.

- It considers the proposed BSER findings to be servable. That is, in the event a court invalidates a particular building block, EPA would find that the remaining building blocks constitute BSER.

State Goals

EPA applies the BSER building blocks to each state, starting with 2012 generation and emissions data to establish state goals for 2030. Table 2 provides an overview of the methodology EPA used to calculate the 2030 goals using Ohio as an example. In addition to the 2030 goals, EPA proposes interim goals that are calculated as the simple average of the annual rates computed for each of the years from 2020 to 2029. Those annual rates are based on increased generation of RE and EE across the time period.

States have the opportunity to comment on the proposed BSER, the proposed methodology for calculating the state goals, and the state-specific data. Once finalized, EPA considers the state goals binding. As indicated above, EPA proposes, for comment, a set of alternative goals (Option 2) with a final goal in 2025 based on four percent heat rate improvements at coal-fired units, a 65 percent capacity factor for NGCC, and a one percent ceiling for annual energy efficiency.

Table 2. Methodology for Calculating 2030 State Goals (Ohio Example)

Methodology	Formula	Example (Ohio)	Result
Building Block 1: Heat rate improvements			
Apply a 6% heat rate improvement to existing state coal fleet	2012 Coal Emissions Rate * (1 – 0.06)	2,126 lb/MWh * (1-0.06)	**1,999 lb/MWh**
Building Block 2: Increased NGCC Utilization			
Step 2a: Estimate generation associated with increasing existing and under construction NGCC capacity to a 70% capacity factor to replace fossil steam units[a]	(2012 Existing NGCC Capacity + Under Construction NGCC Capacity) * 8784 hours[b] * 0.7	(4,343 MW + 539 MW) * 8784 hours * 0.7	30,015,367 MWh
Step 2b: Calculate incremental increase in NGCC generation available for redispatch	Step 2a Generation – (2012 Existing NGCC Generation + Under Construction NGCC Capacity * 8784 hours * 0.55[c])	30,015,367 MWh – (20,907,183 MWh + 539 MW * 8784 hours * 0.55)	6,504,167 MWh
Step 2c: Proportionally back out 2012 fossil steam generation	2012 Coal Steam Generation - Share of Step 2b Generation 2012 O&G Steam Generation - Share of Step 2b Generation	86,473,075 MWh - 6,480,067 MWh 321,602 MWh - 24,100 MWh	79,993,008 MWh 297,502 MWh
Step 2d: Calculate emissions associated with re-dispatch	(2012 NGCC Generation + Step 2b Generation) * NGCC Emissions Rate + Step 2c Coal Generation * Improved Coal Emissions Rate + Step 2c O&G Generation * O&G Emissions Rate + Other Emissions[d]	(20,907,183 MWh + 6,504,167 MWh) * 963 lb/MWh + 79,993,008 MWh * 1,999 lb/MWh + 297,502 MWh * 1,332 lb/MWh + 2,791,474,084 lb	189,473,298,879 lb
Step 2e: Divide by 2012 fossil generation	Step 2d Emissions / (2012 Fossil Generation + Expected Under Construction NGCC Generation)	189,473,298,879 lb / (107,916,038 MWh + 2,604,017 MWh)	**1,714 lb/MWh**
Building Block 3: Continued and expanded use of zero-carbon generation			
Step 3a: Based on regional assessment and growth from 2012 existing installed renewable energy, estimate 2029 existing and incremental renewable energy and add to the MWh calculated in Step 2e	Step 2d Emissions / (2012 Fossil Generation + Expected Under Construction NGCC Generation + 2029 Existing and Incremental RE Generation)	189,473,298,879 lb / (107,916,038 MWh + 2,604,017 MWh + 13,775,594 MWh)	1,524 lb/MWh
Step 3b: Calculate "at risk" nuclear generation as 6% of 2012 capacity operating at 90% capacity factor	2012 Nuclear Capacity * 0.06 * 0.90 * 8784 hours	2,094 MW * 0.06 * 0.90 * 8784 hours	993,077 MWh

Methodology	Formula	Example (Ohio)	Result
Step 3c: Add at risk nuclear generation to the MWh calculated in Step 3a	Step 2d Emissions / (2012 Fossil Generation + Expected Under Construction NGCC Generation + 2029 Existing and Incremental RE Generation + At Risk Nuclear Generation)	189,473,298,879 lb / (107,916,038 MWh + 2,604,017 MWh + 13,775,594 MWh + 993,077 MWh)	**1,512 lb/MWh**
Building Block 4: Increased demand-side energy efficiency			
Based on assessment of energy efficiency potential, estimate 2029 cumulative energy efficiency (accounting for line losses and in-state generation[e]) and add to the MWh calculated in Step 3c	Step 2d Emissions / (2012 Fossil Generation + Expected Under Construction NGCC Generation + 2029 Existing and Incremental RE Generation + At Risk Nuclear Generation + 2029 EE Potential)	189,473,298,879 lb / (107,916,038 MWh + 2,604,017 MWh + 13,775,594 MWh + 993,077 MWh + 16,284,584 MWh)	**1,338 lb/MWh**

Notes

a. EPA considered NGCC units that were in operation or had commenced construction as of January 8, 2014. While 70 percent utilization is the target for all NGCC, that level of utilization is only reached in 29 states as there is insufficient fossil steam generation to back out. The average utilization rate reflected in the state goals is 64 percent.
b. 2012 was a leap year, EPA uses 366 days * 24 hours = 8784 hours to calculate total generation
c. EPA assumes new generation would have an average capacity factor of 55%, here we are calculating the incremental increase in generation
d. EPA includes emissions from other affected sources (e.g., CTs >25 MW and >33% utilization, IGCC, etc) and emissions associated with the expected generation of NGCC that are under construction (calculated as 55% of expected capacity)
e. Potential EE is based on a percentage of 2012 sales. To correct for transmission losses, EPA multiples 2012 sales by 1.0751, reflecting losses of 7.51% between the generator and the customer. In cases where a state imports generation (as is the case in Ohio), EPA multiplies the state's sales by the percent of sales that could be met by in-state generation (in the Ohio example, 85.97%) before estimating the potential EE.

State Plans

After finalization of state goals, each state is required to develop, adopt, and submit a state plan (or sign on to a multi-state plan).[1] EPA notes that "each state has the discretion to adopt emission reduction measures other than the measures found by the EPA to comprise the BSER, or to place greater or lesser emphasis than EPA on certain measures, provided that the state's plan achieves the required level of emission performance for affected sources." (page 262) Thus, states can include other reduction measures beyond what EPA includes in defining BSER, but states will need to demonstrate that the plan will achieve the same performance level for affected EGUs.

A first step for states (or multi-state region) will be deciding whether to implement the emission performance level as a rate or translating it to a mass-based level. EPA notes that states may later switch from a mass-based plan to a rate-based plan and vice-versa, through approved plan modifications.

EPA proposes four general plan approvability criteria and 12 required components, discussed below, for a plan to be approvable. These criteria and components are equally applicable to individual and multi-state plans. EPA identifies three threshold issues for the design of state plans on which it is taking comment:

[1] EPA will develop plan(s) for affected sources on tribal lands, unless affected tribes seeks such authority.

1) Whether the plan should require the affected EGUs to be subject to emission limits that ensure that the emission performance level is achieved, or instead, whether the plan could rely on measures, such as RE or demand-side EE, to achieve part of the emission performance level;

2) Whether the responsibility for all of the measures other than emission limits should fall on the affected EGUs, or, instead, could fall on entities other than affected EGUs through mechanisms such as renewable energy and demand-side energy efficiency measures; and

3) Whether the fact that requiring all measures relied on to achieve the emission performance level to be included in the state plan renders those measures federally-enforceable.

In order to ensure the integrity of 111(d) plans, EPA proposes that affected sources must remain subject to 111(d) while in operation. EPA proposes that sources subject to 111(d) remain subject to their state's (or region's) 111(d) plan even after a modification or reconstruction. In this scenario, such units would be subject to both emission rates under 111(b) as well as applicable state (or regional) requirements under 111(d), once both rules are final.

Timing

In accordance with the President's Climate Action Plan, initial plan submittals are due June 30, 2016, 13 months after expected finalization of the goals. EPA proposes that all states must submit basic requirements by this date; however, extensions of one year are broadly available and states participating in a multi-state compliance plan may take until June 30, 2018 to submit a complete plan. If a state does not submit a plan, or EPA cannot approve the plan as complete, then EPA will establish a plan. EPA solicits comment on whether, similar to SIPs under section 110, the Agency may partially approve/disapprove and/or conditionally approve a state's 111(d) plan.

State plans must demonstrate achievement of emission performance levels equivalent to or better than the interim and final goals established by EPA. EPA proposes that interim goals begin January 1, 2020, with annual milestones to ensure attainment of the 2030 goals. Beginning July 1, 2022, each annual evaluation would cover the preceding two-year period, although states may propose and EPA may finalize alternative milestones or lookback periods (e.g., RGGI's one- and three-year cycles). States will have the flexibility to determine the trajectory of emissions performance between 2020 and 2029, as long as the interim emissions performance level is met on the 10-year average (or cumulative basis) and that the 2030 performance level is achieved and maintained. State plans do not need to include post-2030 projections as long as required provisions do not sunset or otherwise endanger ongoing compliance with the final state goals. Starting at the end of 2032, emission performance must be compared to the final goal on a three-year rolling average basis.

Early Action

EPA is proposing 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 2020-2030 period would apply toward achievement of the state's CO_2 goal. EPA contends that states with existing programs and policies will be better positioned to achieve the goals.

Enforceability

EPA proposes to authorize states either to submit plans that hold the affected EGUs solely responsible for achieving the emission performance level or to submit plans that rely in part on measures imposed on entities other than affected EGUs. EPA refers to the latter as the "portfolio approach" whereby the plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures. EPA solicits comment on whether it can interpret the Act as allowing states to adopt plans that require EGUs and other entities to be legally responsible for actions under the plan that, in aggregate, will achieve the emission performance level.

One concern EPA recognizes with this approach is whether RE and demand-side EE measures in state plans would make such programs federally enforceable. EPA proposes that all measures relied on to achieve the emission performance level would become federally enforceable. EPA notes that some stakeholders suggested that states should be allowed to rely on these measures to reduce costs and facilitate EGU emission limits but not be required to include them in the state plans. Thus, EPA solicits comment on whether 111(d)(1) allows states to adopt plans that hold EGUs as well as other entities responsible for required emissions reductions.

EPA also notes that states could submit plans that would include an enforceable commitment by the state to implement state-enforceable measures that would achieve a specific portion of the emission performance level on behalf of an affected EGU. EPA does not propose this approach, but is requesting comment on it as well as its potential implications.

Corrective Measures

As one component of enforceability and to ensure state goals are reached, EPA proposes several options by which states may guarantee plans will be effective. EPA describes some plans as "self-correcting" because they ensure achievement of interim and final goals through requirements enforceable against EGUs. As one example, a state plan with a rate-based emission performance level that requires affected EGUs collectively to meet an emission rate consistent with the state's required emission performance level could allow EGUs to comply through an emission rate averaging system. Another example is a plan that includes measures or actions (e.g., emission limits) that take effect automatically if the plan's required emission performance level is not met by a specified milestone. EPA would consider these types of plans "self-correcting" and proposes that they would not need interim milestones. Annual reporting would remain required.

Plans without self-correcting mechanisms must include periodic program implementation milestones (e.g., retirement of an affected EGU or start of an end-use energy efficiency program) and specify corrective measures that will be implemented if the state's level of performance falls short. EPA proposes that if an interim check showed that actual emission performance was not within 10 percent of the performance projected in the state plan, the state would be required to explain reasons for the deviation and specify the corrective measures that will be taken to ensure that the required level of emission performance in the plan will be met. The state would be required to implement corrective measures as expeditiously as practical. In addition to seeking comment on how the corrective measure mechanism would work in practice, EPA requests comment on the appropriateness and feasibility of a mechanism similar to the SIP Call, in which EPA would have the authority to replace a state plan if it is not achieving state goals.

Criteria for Approving State Plans

EPA proposes four general plan approvability criteria:

1. <u>Enforceable measures</u>. To be enforceable, a plan must be quantifiable, verifiable, straightforward, and calculated over as short a term as reasonable.
2. <u>Emission performance</u>. State plans must be equivalent to, or better than, the required CO_2 emission performance level of the state goal.

3. Quantifiable and verifiable emission performance. EPA proposes that all plans must specify how CO_2 emissions from affected EGUs are monitored and reported. EPA is proposing to measure useful energy output as net rather than gross.
4. Reporting and corrective actions. A state plan must (i) specify a process for annual reporting to the EPA of overall plan performance and implementation (including compliance of affected entities with applicable emission standards) during the plan performance periods, and (ii) include a process and schedule for implementing corrective measures if reporting shows that the plan is not achieving the projected level of emissions performance.

Elements of State Plans

State plans must include the following 12 components.

1. Identification of affected entities. Plans must list the individual affected EGUs subject to the plan and provide a CO_2 inventory, as well as identify any other affected entities with responsibilities for implementation and enforceable obligations under the plan.
2. Description of plan approach and geographic scope. Plans must specify whether the state will achieve its requirements on an individual state basis or jointly through a multi-state demonstration.
3. Identification of state emission performance level. Plans must state whether the state will implement the rate-based CO_2 emission guidelines or a mass-based translation. If the plan adopts a mass-based goal, the plan must include a description of the analytic process, tools, methods, and assumptions used to translate from the rate-based goal to the mass-based goal. EPA is seeking comment on whether the final rule should translate the rate-based goal into a mass-based goal to assist states for all states, for those who request it, and/or for multi-state regions. Alternatively, EPA could provide guidance for states to use in translating a rate-based goal to a mass-based goal for states and multi-state regions. For multi-state approaches, states would demonstrate emission performance by affected EGUs in aggregate with partner states. EPA is seeking comment on options for calculating a weighted average for multiple states.
4. Demonstration that the plan is projected to achieve the state's emission performance level. Plans must demonstrate that the actions taken pursuant to the plan are, when taken together, projected to achieve emission performance that, on average, will meet both the initial and final emission performance levels.
5. Milestones. State plans must include periodic programmatic milestones to show progress in program implementation if the plan is not self-correcting (i.e., does not inherently require both interim progress and the full level of required emission performance in a manner that is federally-enforceable against affected EGUs).
6. Corrective measures. Plans without self-correcting mechanisms must specify corrective measures that will be implemented if the state's level of performance falls short. EPA is soliciting comment on several levels at which corrective measures would be required (for example, a 10 percent deviation from interim goals).
7. Identification of emission standards and any other measures. Plans must identify the affected entities to which each emission standard applies (e.g., individual affected EGUs, groups of affected EGUs, all the state's affected EGUs in aggregate, other affected entities that are not EGUs), as well as any implementing and enforcing measures for such standards. Plans must also describe compliance measures and timelines. As in the new source proposal, EPA proposes that the appropriate averaging time for any rate-based

emission standard is no longer than 12 months and no longer than three years for a mass-based standard.

8. Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated and non-duplicative if it is not already incorporated in another state plan.[2] An emission standard is permanent if the standard must be met for each applicable compliance year or period, or replaced by another emission standard in a plan revision, or the state demonstrates in a plan revision that the emission standard is no longer necessary for the state to meet its required emission performance level for affected EGUs. An emission standard is verifiable if adequate monitoring, recordkeeping, and reporting requirements are in place to enable independent evaluation, measurement, and verification. An emission standard is enforceable if: (1) it represents a technically accurate limitation or requirement and the time period is specified, (2) compliance requirements are clearly defined, (3) the affected entities responsible for compliance and liable for violations can be identified, (4) each compliance activity or measure is practically enforceable and the Administrator and the state maintain the ability to enforce against violations and secure appropriate corrective actions.
9. Identification of monitoring, reporting, and recordkeeping requirements. Plans must include provisions for CO_2 emission monitoring, reporting, and recordkeeping. A state plan that contains other emission standards, in addition to emission limits applicable to affected EGUs, must include additional reporting and recordkeeping requirements related to these other measures, such as RECs. EPA is proposing a record retention requirement of ten years.
10. Description of state reporting. Plan must provide that the state will submit reports to EPA detailing plan implementation and progress. EPA is proposing that an annual report is due no later than the July 1 following the end of the reporting year.
11. Certification of state plan hearing. Plans must certify that a hearing on the state plan was held, provide a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and provide a brief written summary of each presentation or written submission pursuant to the requirements of the EPA framework regulations at 40 CFR 60.23-60.29.
12. Supporting material. Plans must provide all necessary supporting material and technical documentation to enable EPA evaluation and approval. For example, a state plan must provide analytical materials used in translating a rate-based goal to a mass-based goal if a translation is chosen.

EPA is also seeking comment on two additional options for multi-state plan submittals:

1. Whether states participating in a multi-state plan should also be given the option of providing a single submittal that addresses common plan elements, with individual participating states required to provide individual submittals where state-specific elements are needed.

[2] EPA intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans.

2. Whether all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan, and where all common plan elements would be materially consistent.

Interstate Crediting

As described above, EPA recognizes the interstate nature of the electricity grid and that programs and measures in a state plan, including RE and demand-side EE, any affect the performance of the electricity system beyond a state border. EPA recognizes the complexity for accounting for these interstate effects, the need to allow states to take into account the CO_2 emission reductions resulting from these programs, and the need to minimize the likelihood of double counting. Thus, EPA is seeking comment on several options:

- For demand-side EE, EPA proposes that a state can only take into account those CO_2 emission reductions occurring or projected to occur in the state that result from demand-side EE measures implemented in the state. For states that participate in multi-state plans, the states have the flexibility to distribute the emission reductions among states in that multi-state area provide the emission reductions claimed are equal to the total of each state's in-state emissions reduction from the measures implemented in those states. EPA also requests comment on whether states should take credit for emission reductions out of state due to in-state demand-side EE if the state can demonstrate that the reductions will not be double-counted when the relevant states report on their achieved plan performance.
- For renewable energy measures, EPA proposes that a state can take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state regardless of whether they occur in the state or other states. The preamble acknowledges that there are existing REC programs that allow for interstate trading of RE attributes and many state RPS programs often allow for the use of qualifying RE located in another state to be used to comply with that state's RPS. EPA is seeking comment on how to avoid double counting emission reductions using this proposed approach. For states that participate in multi-state plans, EPA proposes that states could distribute the CO_2 emission reductions among states in the multi-state area as long as the total emission reductions are equal to the total of each state's in-state emission reductions from RE measures. EPA is also seeking comment on the option of allowing states to take into account only those CO_2 emission reductions occurring in its state. EPA also requests comment on whether states should take credit for emission reductions out of state due to in-state demand-side EE if the state can demonstrate that the reductions will not be double-counted when the relevant states report on their achieved plan performance.

Other Areas of Interest

There are a number areas EPA discussed in the preamble. The following briefly describes a few of note.

New Source Review

EPA notes that for GHGs, a modifying major stationary source triggers PSD permitting requirements for GHGs if it emits GHGs in excess of 100,000 tons per year (tpy) of CO_2e and it undertakes a change or change in the method of operation resulting in an emissions increase of 75,000 tpy CO_2 as well as an increase on a mass basis. As part of a state's compliance plan under 111(d), a state may impose requirements that require an affected EGU to undertake a physical or operational change that improves the unit's efficiency and that results in an increase in the unit's dispatch and unit's annual emissions. If the increase exceeds the PSD thresholds, then NSR would be triggered. However, EPA notes that it expects these instances to be few. EPA also states that states can establish their plans in ways to avoid triggering NSR. For example, EPA explains that a state could decide to adjust its demand side measures or increase reliance on renewable energy as a way to reduce emissions from affected EGUs. The state could also develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch (effectively establishing a synthetic minor limit). EPA is requesting comment on whether a state plan could include such provisions to avoid triggering NSR as well as the level of analysis that would be needed to support such a determination by a state.

Title V Fees

Title V fee collection was a concern in the new source proposal. However, EPA notes in this proposal that that Title V fee issue was a one-time occurrence resulting from the promulgation of the first section 111 standard to regulate GHGs (the EGU NSPS for new sources). Thus, it is not an issue for any other subsequent section 111 regulations, and EPA does not foresee Title V fee issues in this proposal. EPA is not proposing revisions to any Title V regulations as part of this proposal.

Comments

Comments are due 120 days after the rule is published in the Federal Register.

EPA has announced a public hearing in Atlanta, GA; Denver, CO; Pittsburgh, PA; and Washington, DC the week of July 28, 2014.

Key Resources

- Proposed rule and fact sheets: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

- Interactive map summarizing climate impacts, state action, and EPA's proposal for that state: http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/.

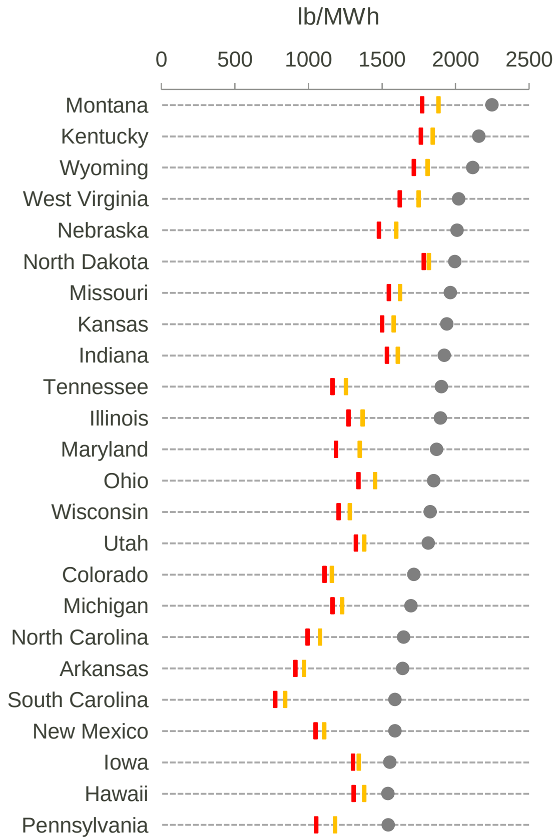
- Legal Memorandum: http://www2.epa.gov/sites/production/files/2014-05/documents/20140602tsd-legal-memorandum.pdf.

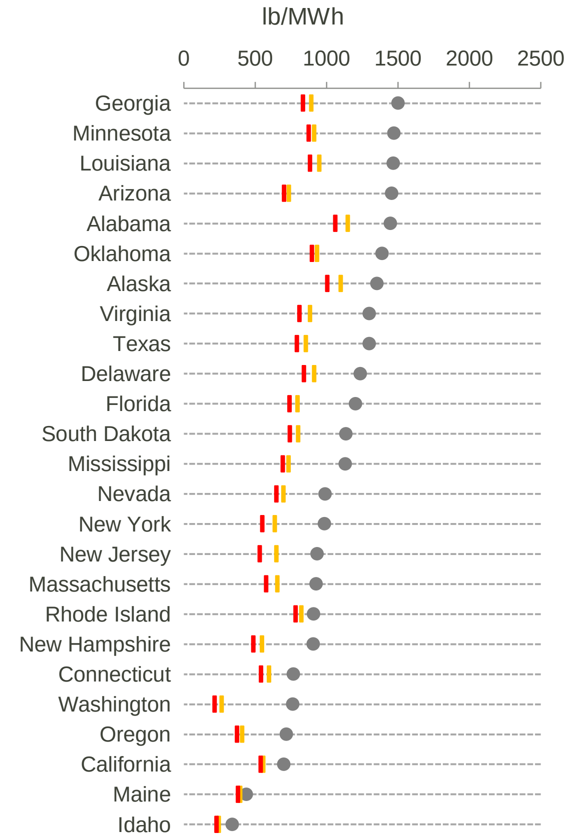
Appendix A: Proposed Preferred Option Interim and 2030 Goals

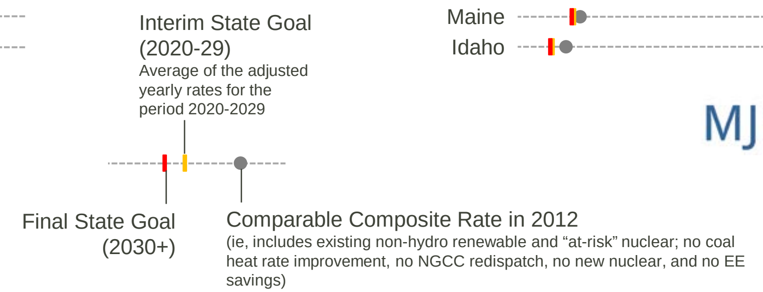
State*	Interim Goal (2020 - 2029 average, lb/MWh)	Final Goal (2030 and thereafter, lb/MWh)	State	Interim Goal (2020 - 2029 average, lb/MWh)	Final Goal (2030 and thereafter, lb/MWh)
Alabama	1,147	1,059	**Montana**	1,882	1,771
Alaska	1,097	1,003	**Nebraska**	1,596	1,479
Arizona	735	702	**Nevada**	697	647
Arkansas	968	910	**New Hampshire**	546	486
California	556	537	**New Jersey**	647	531
Colorado	1,159	1,108	**New Mexico**	1,107	1,048
Connecticut	597	540	**New York**	635	549
Delaware	913	841	**North Carolina**	1,077	992
Florida	794	740	**North Dakota**	1,817	1,783
Georgia	891	834	**Ohio**	1,452	1,338
Hawaii	1,378	1,306	**Oklahoma**	931	895
Idaho	244	228	**Oregon**	407	372
Illinois	1,366	1,271	**Pennsylvania**	1,179	1,052
Indiana	1,607	1,531	**Rhode Island**	822	782
Iowa	1,341	1,301	**South Carolina**	840	772
Kansas	1,578	1,499	**South Dakota**	800	741
Kentucky	1,844	1,763	**Tennessee**	1,254	1,163
Louisiana	948	883	**Texas**	853	791
Maine	393	378	**Utah**	1,378	1,322
Maryland	1,347	1,187	**Virginia**	884	810
Massachusetts	655	576	**Washington**	264	215
Michigan	1,227	1,161	**West Virginia**	1,748	1,620
Minnesota	911	873	**Wisconsin**	1,281	1,203
Mississippi	732	692	**Wyoming**	1,808	1,714
Missouri	1,621	1,544			

*Vermont and the District of Columbia have no 111(d) sources and, therefore, no state goals.

Final (2030+) and Interim (2020-2029) State Goals and Comparable Composite Rates in 2012

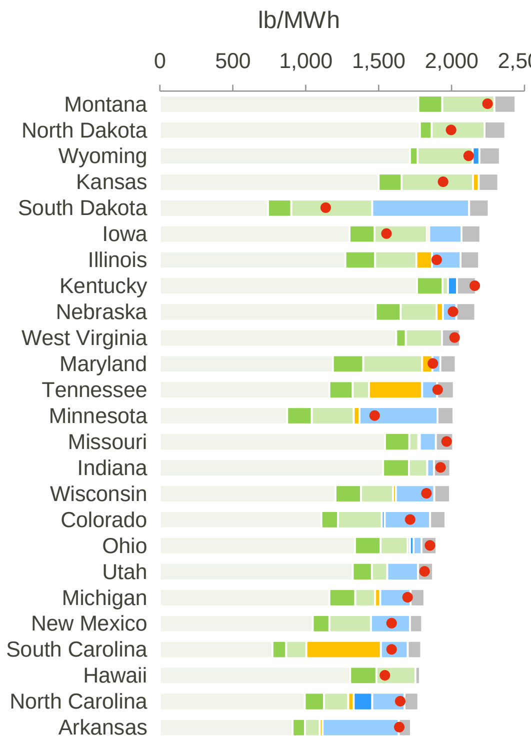






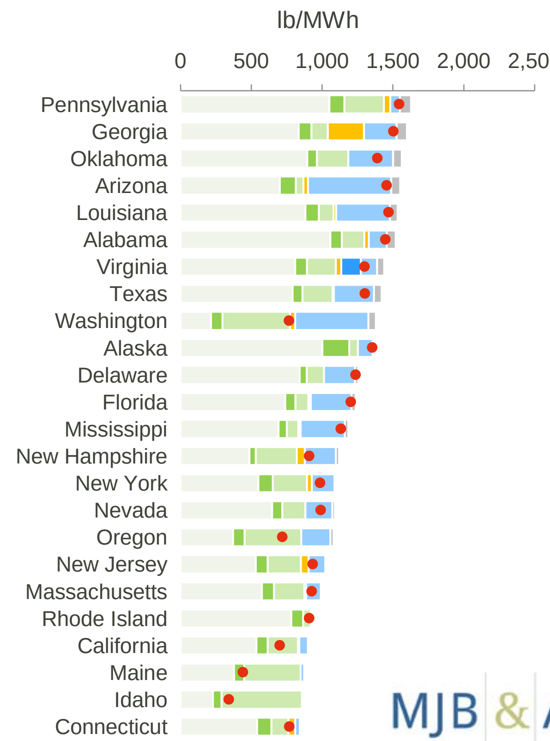
Getting from 2012 to 2030 – BSER Building Blocks

Note: EPA derived the state goals using the following assumptions about what is feasible at the state level. This is not a compliance plan. Each state has the discretion to adopt emission reduction measures other than the measures found by the EPA to comprise the BSER, or to place greater or lesser emphasis than EPA on certain measures, provided that the state's plan achieves the required level of emission performance for affected sources.



● Comparable Composite Rate in 2012

(ie, includes existing renewable and "at-risk" nuclear; no coal heat rate improvement, no NGCC redispatch, no new nuclear, and no EE)



MJB & A

BSER BUILDING BLOCKS

2029+ State Goal

This is the emission rate that becomes the state goal for 2030 and thereafter

Energy Efficiency

State- and year-specific % value multiplied by 2012 retail sales scaled by a factor of 7.5% to account for losses (adj. for net importers)

Renewable

Combination of existing in-state renewable generation + target RE levels informed by existing RPS in the region

Nuclear

Total under-construction and "at risk" (~5.8% of the existing fleet) nuclear is incorporated into the state goal @90% capacity factor

New NGCC

Includes NGCC capacity that came online in 2013 or under construction by Jan 8, 2014. Incorporated @70% capacity factor (15% for redispatch of fossil steam)

NGCC

Existing NGCC ramped up to 70% capacity factor; incremental output redispatches existing fossil steam proportionally by fuel

Coal HRI

Assumes a 6% heat rate improvement at existing coal plants.

Key BSER Building Block Assumptions by State

Note: EPA derived the state goals using the following assumptions about what is feasible at the state level. This is not a compliance plan. Each state has the discretion to adopt emission reduction measures other than the measures found by the EPA to comprise the BSER, or to place greater or lesser emphasis than EPA on certain measures, provided that the state's plan achieves the required level of emission performance for affected sources.

MJB & A

	Coal Generation (MWh)			NGCC (Redispatched; MWh)			Renewable (MWh)			Nuclear (MWh)		Demand Side EE	Rates (lb/MWh)	
State	2012	2029	Change	2012	2029	Change	2012	2029	Change	2012 At-Risk	2029 New Nuclear	2029 avoided MWh sales (%)	2012 Comparable	2030 Final State Goal
Alabama	46,045,176	36,001,107	-22%	53,492,096	63,536,165	19%	2,776,554	14,292,801	415%	2,329,528	0	9.5%	1,444	1,059
Alaska	215,407	0	-100%	2,204,942	2,420,349	10%	39,958	163,089	308%	0	0	9.4%	1,351	1,003
Arizona	24,335,930	0	-100%	26,782,325	52,152,127	95%	1,697,652	3,663,325	116%	1,818,486	0	11.4%	1,453	702
Arkansas	28,378,831	10,218,693	-64%	15,651,185	34,361,954	120%	1,660,370	4,708,823	184%	842,037	0	9.7%	1,640	910
California	933,157	0	-100%	81,298,989	92,636,067	14%	29,966,846	41,150,704	37%	1,034,648	0	11.6%	698	537
Colorado	34,385,542	22,548,824	-34%	8,811,706	20,648,637	134%	6,192,082	10,839,820	75%	0	0	11.0%	1,714	1,108
Connecticut	99,461	0	-100%	15,299,704	15,734,432	3%	666,525	3,114,375	367%	971,137	0	11.9%	765	540
Delaware	1,406,502	184,879	-87%	5,179,270	7,335,518	42%	131,051	1,038,351	692%	0	0	9.5%	1,234	841
Florida	44,537,196	4,131,158	-91%	133,320,419	182,822,446	37%	4,523,798	22,109,614	389%	1,623,104	0	10.0%	1,200	740
Georgia	40,972,090	27,190,604	-34%	37,591,123	51,372,609	37%	3,278,536	12,230,636	273%	1,876,000	17,344,561	9.8%	1,500	834
Hawaii	1,502,308	1,502,308	0%	0	0	0%	924,815	1,046,927	13%	0	0	9.5%	1,540	1,306
Idaho	0	0	0%	1,639,922	1,639,922	0%	2,514,502	3,196,687	27%	0	0	11.1%	339	228
Illinois	79,166,165	66,157,723	-16%	7,870,423	20,878,865	165%	8,372,660	17,818,004	113%	5,305,342	0	11.6%	1,895	1,271
Indiana	87,213,268	83,034,543	-5%	12,839,309	17,018,034	33%	3,546,367	7,547,086	113%	0	0	11.1%	1,923	1,531
Iowa	33,055,156	26,779,114	-19%	1,437,496	7,771,468	441%	14,183,424	8,565,921	0%	277,784	0	11.7%	1,552	1,301
Kansas	27,979,593	27,979,593	0%	0	0	0%	5,252,653	8,884,938	69%	542,728	0	9.5%	1,940	1,499
Kentucky	84,358,283	83,515,019	-1%	0	843,264	0%	332,879	1,713,556	415%	0	0	10.0%	2,158	1,763
Louisiana	24,300,393	11,538,767	-53%	19,771,182	40,018,850	102%	2,430,042	6,891,619	184%	985,225	0	9.3%	1,466	883
Maine	0	0	0%	4,053,378	4,112,445	1%	4,098,795	3,611,728	0%	0	0	12.1%	437	378
Maryland	16,297,835	15,364,292	-6%	676,556	1,775,773	162%	898,152	5,982,069	566%	787,533	0	11.5%	1,870	1,187
Massachusetts	2,268,133	0	-100%	23,603,160	26,201,176	11%	1,843,419	8,613,477	367%	316,260	0	11.8%	925	576
Michigan	53,210,780	41,091,564	-23%	18,499,951	30,795,650	66%	3,785,439	8,055,859	113%	1,827,909	0	11.8%	1,696	1,161
Minnesota	21,989,584	10,699,001	-51%	5,715,510	17,021,108	198%	9,453,871	7,888,544	0%	840,190	0	11.7%	1,470	873
Mississippi	7,503,114	0	-100%	31,813,677	43,719,569	37%	1,509,190	5,458,430	262%	631,874	0	9.6%	1,130	692

Key BSER Building Block Assumptions by State

Note: EPA derived the state goals using the following assumptions about what is feasible at the state level. This is not a compliance plan. Each state has the discretion to adopt emission reduction measures other than the measures found by the EPA to comprise the BSER, or to place greater or lesser emphasis than EPA on certain measures, provided that the state's plan achieves the required level of emission performance for affected sources.

State	Coal Generation (MWh)			NGCC (Redispatched; MWh)			Renewable (MWh)			Nuclear (MWh)		Demand Side EE	Rates (lb/MWh)	
	2012	2029	Change	2012	2029	Change	2012	2029	Change	2012 At-Risk	2029 New Nuclear	2029 avoided MWh sales (%)	2012 Comparable	2030 Final State Goal
Missouri	72,939,512	65,012,570	-11%	4,854,569	12,781,511	163%	1,298,579	2,763,528	113%	549,657	0	9.9%	1,963	1,544
Montana	14,447,406	14,447,406	0%	0	0	0%	1,261,752	2,722,706	116%	0	0	10.9%	2,245	1,771
Nebraska	24,660,983	22,208,869	-10%	423,638	2,879,483	580%	1,346,762	3,819,427	184%	574,830	0	10.4%	2,009	1,479
Nevada	4,133,662	0	-100%	23,783,256	28,196,901	19%	2,968,630	6,405,939	116%	0	0	10.7%	988	647
New Hampshire	1,281,341	0	-100%	6,946,869	8,300,824	19%	1,381,285	4,822,223	249%	575,615	0	11.0%	905	486
New Jersey	2,602,990	0	-100%	20,015,730	22,792,692	14%	1,280,715	10,147,466	692%	1,616,037	0	9.6%	932	531
New Mexico	11,353,987	7,594,319	-33%	5,730,957	10,221,765	78%	2,573,851	4,721,996	83%	0	0	10.6%	1,586	1,048
New York	4,156,143	27,582	-99%	44,002,777	60,550,923	38%	5,192,427	24,261,905	367%	2,410,637	0	11.8%	983	549
North Carolina	50,607,838	33,884,577	-33%	15,195,335	31,918,596	110%	2,703,919	11,668,176	332%	2,295,625	0	10.3%	1,646	992
North Dakota	28,186,691	28,186,691	0%	0	0	0%	5,280,052	5,459,957	3%	0	0	9.7%	1,994	1,783
Ohio	86,473,075	79,993,008	-7%	20,907,183	27,411,350	31%	1,738,622	13,775,594	692%	993,077	0	11.6%	1,850	1,338
Oklahoma	29,102,160	14,034,401	-52%	29,943,376	49,406,223	65%	8,520,724	15,579,318	83%	0	0	10.0%	1,387	895
Oregon	2,640,259	0	-100%	11,424,291	14,064,550	23%	7,207,229	12,567,372	74%	0	0	11.4%	717	372
Pennsylvania	87,052,562	78,328,894	-10%	50,028,719	58,916,572	18%	4,459,118	35,330,855	692%	4,480,395	0	11.7%	1,540	1,052
Rhode Island	0	0	0%	8,140,017	8,140,017	0%	101,895	476,110	367%	0	0	11.6%	907	782
South Carolina	28,460,318	22,299,838	-22%	11,209,394	17,457,673	56%	2,143,473	9,675,568	351%	2,996,000	17,344,660	10.2%	1,587	772
South Dakota	2,923,161	958,046	-67%	27,096	1,992,211	7252%	2,914,666	1,818,850	0%	0	0	9.9%	1,135	741
Tennessee	34,373,696	31,076,520	-10%	6,548,897	9,846,073	50%	836,458	4,305,814	415%	1,571,000	8,845,619	10.3%	1,903	1,163
Texas	138,705,138	66,698,233	-52%	148,010,278	230,873,298	56%	34,016,697	85,962,502	153%	2,291,006	0	9.9%	1,298	791
Utah	27,332,140	20,797,210	-24%	5,447,362	12,011,066	120%	1,099,724	2,373,069	116%	0	0	11.0%	1,813	1,322
Virginia	13,641,552	7,600,565	-44%	23,070,350	29,263,632	27%	2,358,444	11,192,008	375%	1,645,275	0	9.3%	1,297	810
Washington	3,735,730	0	-100%	5,665,045	9,400,775	66%	8,214,350	17,725,558	116%	506,700	0	11.3%	763	215
West Virginia	70,074,636	70,074,636	0%	0	0	0%	1,296,563	10,273,036	692%	0	0	10.1%	2,019	1,620
Wisconsin	32,112,721	24,062,122	-25%	10,244,273	18,306,822	79%	3,223,178	6,859,301	113%	546,885	0	11.8%	1,827	1,203
Wyoming	42,907,427	42,617,555	-1%	0	289,872	0%	4,369,107	9,427,996	116%	0	0	9.7%	2,115	1,714