EPA’s Proposed Carbon Pollution Standard

Summary of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

Alejandra Núñez

Andres Restrepo

Elena Saxonhouse

Joanne Spalding

**Contents**

[I. Summary of Proposed Carbon Pollution Standard 4](#_Toc389687715)

[A. Overview of Section 111(d) of the Clean Air Act 4](#_Toc389687716)

[B. Building Blocks for Setting State Goals and the Best System of Emission Reduction 4](#_Toc389687717)

[C. State Goals 5](#_Toc389687718)

[D. State Plans 6](#_Toc389687719)

[II. What Does the Proposed Rule Mean? 8](#_Toc389687720)

[A. Preliminary Observations 8](#_Toc389687721)

[III. Affected Sources and Treatment of Categories 10](#_Toc389687722)

[A. Affected Sources 10](#_Toc389687723)

[B. Categorization 11](#_Toc389687724)

[IV. Building Blocks for Setting State Goals and the Best System of Emission Reduction 12](#_Toc389687725)

[A. Building Blocks 12](#_Toc389687726)

[**1.** **Building Block 1: Heat Rate Improvements** 12](#_Toc389687727)

[**2.** **Building Block 2: Re-dispatch from Affected Steam EGUs to NGCC Units (including NGCC units under construction as of January 8, 2014)** 13](#_Toc389687728)

[**3.** **Building Block 3: Expanded Use of Low or Zero Carbon Generating Capacity** 14](#_Toc389687729)

[**4.** **Building Block 4: Reducing Emissions from Affected EGUs through Demand-Side Energy Efficiency** 16](#_Toc389687730)

[B. Potential Combinations of the Building Blocks as Components of BSER 17](#_Toc389687731)

[C. BSER Formulations 18](#_Toc389687732)

[D. Evaluation of Individual Building Blocks Against the BSER Criteria 18](#_Toc389687733)

[E. Potential Emission Reduction Measures Not Used to Set Proposed Goals 19](#_Toc389687734)

[**1.** **Fuel-Switching at Individual Units (Switching to or Co-Firing with Gas)** 19](#_Toc389687735)

[**2.** **Carbon Capture and Storage (CCS)** 19](#_Toc389687736)

[**3.** **New NGCC Capacity** 20](#_Toc389687737)

[**4.** **Heat Rate Improvements at Other Steam EGUs (Oil-Fired, Gas-Fired, NGCC Units, and Simple-Cycle Combustion Turbine Units)** 20](#_Toc389687738)

[F. Severability 20](#_Toc389687739)

[V. State Goals 21](#_Toc389687740)

[A. Overview 21](#_Toc389687741)

[B. Form of the Goals 21](#_Toc389687742)

[C. Proposed State Goals 22](#_Toc389687743)

[D. Computation Procedure 24](#_Toc389687744)

[E. Flexibility 26](#_Toc389687745)

[F. Reliability and Affordability of Electricity 27](#_Toc389687746)

[VI. State Plans 28](#_Toc389687747)

[A. Timing and Process for State Submittal, EPA Review, and Federal Plan 28](#_Toc389687748)

[B. Required Elements for an Approvable State Plan 28](#_Toc389687749)

[C. More on Enforceability of Reductions from RE and EE Measures 30](#_Toc389687750)

[D. Other Topics 31](#_Toc389687751)

[**1.** **Double Counting** 31](#_Toc389687752)

[**2.** **Emission Reductions Prior to 2020** 31](#_Toc389687753)

[**3.** **Emission Reductions from Methods Not Proposed to be Part of BSER** 32](#_Toc389687754)

[**4.** **Remaining Useful Life** 32](#_Toc389687755)

[**5.** **Section 111(h) – Design, Equipment, Work Practice, or Operational Standards** 32](#_Toc389687756)

[VII. Implications for Other EPA Programs and Rules 34](#_Toc389687757)

# Summary of Proposed Carbon Pollution Standard

EPA proposes emission guidelines for each state to use in developing their plans to address carbon pollution from existing electrical generating units (“EGUs”). The emission guidelines are based on EPA’s determination of the best system of emission reduction (“BSER”), and include state-specific goals, requirements for state plan components, general approvability criteria for state plans, and requirements for the process and timing for state plan submittal and compliance.

## A. Overview of Section 111(d) of the Clean Air Act

Under section 111(d) of the Clean Air Act (“CAA”) and its implementing regulations, EPA must issue an emissions guideline that reflects the application of BSER that, taking into account costs, environmental impacts, and energy requirements, EPA determines has been adequately demonstrated. Each state must then adopt and submit to EPA a plan establishing standards of performance that incorporate equally or more stringent standards than those set forth in EPA’s emission guideline, as well as implementation and enforcement measures required to achieve them. EPA must approve the states’ plans, or issue a federal implementation plan (“FIP”) in the event that a state fails to submit a satisfactory plan or fails to enforce the provisions of an approved plan.

## B. Building Blocks for Setting State Goals and the Best System of Emission Reduction

EPA’s proposed BSER determination is based on a combination of emission rate improvements and reductions in overall emissions at affected EGUs through a combination of measures, which EPA divided into four main categories, or “building blocks”:

* **Building Block 1:** Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements;
  1. Proposed – A 6% heat rate improvement in the state’s coal fleet
  2. Alternative – A 4% heat rate improvement in the state’s coal fleet
* **Building Block 2:** Reducing emissions from the most carbon-intensive affected EGUs by substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction);
  1. Proposed – a 70% capacity factor[[1]](#footnote-1) (CF) ceiling for the state’s natural gas combined-cycle (“NGCC”) fleet
  2. Alternative – a 65% capacity factor ceiling for the state’s NGCC fleet
* **Building Block 3:** Reducing emissions from affected EGUs by substituting generation at those EGUs with expanded low- or zero-carbon generation;
  1. Proposed – renewable energy (“RE”) at 13% by start of 2030 and thereafter
  2. Alternative – RE at 9.4% by start of 2025 and thereafter
  3. Both Proposed and Alternative state goals include under construction (5.5 GW) and at risk nuclear capacity (~5.8% of nuclear capacity)
* **Building Block 4:** Reducing emissions from affected EGUs through demand-side energy efficiency (“EE”).[[2]](#footnote-2)
  1. Proposed – 10.7% cumulative savings by start of 2030 and each year thereafter
  2. Alternative – 5.2% cumulative savings by start of 2025 and thereafter

The technology assumptions described above are used to determine an emission rate (lb/MWh) for each state that constitutes the state goal. As these building blocks comprise both fossil and non-fossil measures, the corresponding state goal reflects a composite emission rate including fossil and zero emitting non-fossil technologies. EPA is not mandating that the states use a specific combination of these building blocks to reach these goals--it will be up to each state to decide how it will use the four building blocks to reach the goal. For example, a state could use more EE than natural gas and reach the same proposed state goal.

## C. State Goals

* **Interim and Final Goals:** EPA proposes to establish state-specific goals expressed as average emission rates for fossil fuel-fired EGUs. EPA proposes, for each state, an interim goal for the phase-in period 2020-2029 and a final goal that applies beginning in 2030.[[3]](#footnote-3) If a state takes any measures after the date of this proposal that result in CO2 emissions reductions during the plan period, these reductions would apply toward the achievement of the state’s goal.
* **Equivalency:** Each state’s emissions standard would be equivalent to the state-specific goals in EPA’s emission guidelines. EPA’s proposed emission guideline allows states the option of translating EPA’s rate-based goal into a mass-based goal. For states participating in a multi-state approach, the state-specific performance goals in the emission guideline would be replaced with an equivalent multi-state performance goal. EPA’s proposal provides that states may not adjust the stringency of the goals set by EPA in their plans, whether single state or multi-state.

## D. State Plans

* **Who is Required to Submit a Plan?** Not every state is required to submit a plan. A state that has no affected EGUs must document this in a formal letter to EPA by June 30, 2016. A tribe that has one or more affected EGUs in its area of Indian country would have the opportunity, but not the obligation, to establish a section 111(d) plan for its area of Indian country.
* **Performance Level:** EPA proposes to authorize each state to include in their plans either of two types of measures to achieve the performance level: (1) “portfolio” measures, which include a combination of emission limitations that apply directly to the affected sources and other measures that have the effect of limiting generation by, and therefore emissions from, the affected sources; or (2) only emission limitations that apply directly to the affected sources.
* **Components:** EPA proposes that a state plan include the following components: (1) identification of affected entities; (2) description of plan approach and geographic scope; (3) identification of state emission performance level; (4) demonstration that plan is projected to achieve emission performance level; (5) identification of emissions standards; (6) demonstration that each emissions standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable; (7) identification of monitoring, reporting, and recordkeeping requirements; (8) description of state reporting; (9) identification of milestones; (10) identification of backstop measures; (11) certification of hearing on state plan; and (12) supporting material.
* **Timetables for Submission:** EPA’s proposed emission guideline sets timetables for states to submit their plans. EPA proposes to require each state to submit its plan to EPA by June 30, 2016. If a state needs additional time to submit a complete plan, the state must, no later than April 1, 2016, notify EPA by a letter that adequately explains why it needs more time to submit a complete plan, the actions that it is taking to develop it, and a commitment to meet the requirements for submittal of an initial plan by June 30, 2016. A state that submits an initial plan with the proper components will receive an extension to submit a complete plan. For states developing a plan limited to the individual state, the deadline to submit a complete plan would be June 30, 2017. States developing a plan that includes a multi-state approach may request up to a two-year extension, to June 30, 2018, to submit a complete plan.
* **Approvability Criteria:** EPA proposes the following general criteria for approvability of state plans: (1) enforceable measures that reduce EGU CO2 emissions; (2) projected achievement of emission performance equivalent to EPA’s goals on a timeline equivalent to that set forth in the emission guidelines; (3) quantifiable and verifiable emission reductions; and (4) a process for reporting on plan implementation, progress toward achieving CO2 goals, and implementation of corrective actions, if necessary.
* **Compliance Milestones:** EPA proposes performance and emission milestones that follow its proposed state goals. The emission guideline provides for an initial, phase-in compliance period of up to 10 years, from 2020 to 2029, for each state and other responsible parties to comply with the interim 2020-2029 CO2 performance level, and a final compliance deadline to achieve its ultimate CO2 emission performance level by 2030, and maintain it thereafter.

# What Does the Proposed Rule Mean?

## Preliminary Observations

* EPA set each state’s goals by determining the average emissions rate from covered EGUs that could be achieved by implementing all of the building blocks in that state.
* EPA has proposed two different levels of onsite efficiency improvements for coal-fired power plants—4% and 6%. EPA has determined that onsite efficiency improvements are the least cost approach for reducing GHG emissions.
* EPA has also proposed “dispatch constraints” that reduce dispatch of existing coal units to the extent that new and existing NGCC units can accommodate demand. EPA sets the state’s emission rate by assuming that existing NGCCs can accommodate up to a 70% capacity factor, and that new NGCCs will operate at a 15% capacity factor over what would otherwise be expected, as the proposed default value for what existing and new NGCCs can accommodate. Otherwise, new source generation and emissions are not included in determining compliance with the guideline.
  + These dispatch constraints could be characterized as the “next least cost approach” and would involve no additional capital cost. This approach is, in several aspects, relatively unsophisticated in that it does not look at age or efficiency of the coal unit subject to reduced generation or of the gas units that replace that generation. In some states, this approach leads to a very aggressive dispatch constraint; in others, much less.
* EPA has also proposed renewable energy and energy efficiency goals that it believes are reasonable given state renewable portfolio standards (“RPS”) and EE programs. EPA credits the reductions from those goals towards compliance with the emission rates and factored those goals into the proposed BSER emission rates.
* At several points EPA uses electricity demand increases at or slightly below 1% per year (0.8%, without EE programs). This seems generally consistent with EIA and other projections. Thus far, we have not isolated projections on a state basis, but ISO sub-regional data do not show large variations in demand growth.
* EPA’s determination of BSER includes measures for facilities to directly reduce their CO2 emissions by improving plant efficiency through operational and equipment upgrades that would reduce emissions from coal-fired units by 6% without reducing the amount of electricity produced. EPA also relies on shifting some generation from existing coal-fired generation to underutilized, lower-emitting, natural gas combined cycle plants (“NGCCs,” also known as combined-cycle gas turbines or “CCGTs”). To ensure continued reliability of delivery, EPA proposes to limit the amount of this re-dispatch of available resources so that existing CCGTs are not assumed to operate at greater than 70% of their annual capacity. In addition, the BSER goals include estimates, based on the current status of state programs, for renewable energy and energy efficiency programs that can further reduce the CO2 emissions from existing units. EPA’s proposed emission rates include reductions reflecting assumptions for each of these four elements.
* A preliminary review suggests that EPA’s 2025 target is meaningful, although 2022/2023 would seem to be achievable. The additional reductions from 2025-2030 are much smaller, but may be essential in encouraging/forcing states to adopt EE programs that take time to implement. EPA can and should be encouraged to factor in additional retirements of both coal and gas-fired units, heat rate improvements at gas-fired units, and more renewables and demand side energy efficiency, but the coal capacity restrictions in EPA’s proposal are significant.

# Affected Sources and Treatment of Categories

## Affected Sources

The proposal covers three basic types of plants:

* **Steam EGUs** (i.e., utility boilers): these are mostly coal plants, but could include oil- or gas-fired boilers as well.
* **Integrated gasification combined cycle plants (“IGCCs”)**: these are defined as combined-cycle units that burn at least 50% or more solid-derived fuel that does not meet the regulatory definition of natural gas.
* **Stationary combustion turbines (“CTs”)**: either simple-cycle units or non-IGCC combined-cycle units that burn either gaseous or liquid fuel.[[4]](#footnote-4)

The following units are considered **“affected facilities:”**

* **Steam EGUs and IGCCs**:
  + The plant’s maximum heat input must exceed 73 MW based on fossil fuel combustion—either alone or in combination with other fuels.
  + The plant must be designed to supply at least one-third of its potential electric output and over 219,000 MWh to the grid annually.
  + Notably, there is no requirement that the unit burn at least 10% fossil fuel. This omission may be inadvertent.
* **Stationary combustion turbines:**
  + The plant’s maximum heat input must exceed 73 MW. For combined cycle units, this figure only includes the heat input at the combustion turbine—any additional heat input from duct burners is not included.
  + The plant must be designed to supply, *and must actually supply*, at least one-third of its potential electric output and over 219,000 MWh annually to the grid on a three-year rolling average basis.
  + The plant must combust over 10% fossil fuel on a three-year rolling average basis.
  + The plant must combust over 90% natural gas on a three-year rolling average basis.[[5]](#footnote-5)

Accordingly, the following units are **exempt from regulation**:

* **Any plant** smaller than 73 MW. For IGCCs and CCGTs, this figure excludes any additional heat input from duct burners.
* **Any steam EGU/IGCC** that was not designed to supply at least one-third of its potential output and over 219,000 MWh annually to the grid.
* **Any stationary combustion turbine** (CT or non-IGCC CCGT) that was *either* not designed to supply *or* does not *actually* supply at least one-third of its potential output and over 219,000 MWh annually to the grid on a three-year rolling average basis.
* **Any stationary combustion turbine** (CT or non-IGCC CCGT) that burns 10% or less fossil fuel on a three-year rolling average basis.
  + As currently written, the rule does not include a minimum fossil fuel threshold for steam EGUs or IGCCs. Hence, it would theoretically cover (for instance) a steam EGU that burns biomass along with a small amount of fossil fuel (less than 10%) for flame stabilization purposes. However, because the 111(b) rule included an explicit 10% fossil fuel requirement for such units, it seems likely that EPA’s omission of that provision here was inadvertent, and that it will be included in the final rule.
* **Any stationary combustion turbine** (CT or non-IGCC CCGT) that burns 90% or less natural gas on a three-year rolling average basis.
  + For example, a CCGT that burned 89% natural gas and 11% blast furnace gas, or 11% coke oven gas, would not be covered.
* **Any IGCC unit** that burns less than 50% syngas (defined as any solid-derived fuel not meeting the regulatory definition of natural gas).
  + For example, a CCGT that burned 49% syngas and 51% natural gas would not be covered.

## Categorization

In its primary 111(b) proposal, EPA retained separate categories for the two kinds of plants subject to the rule: steam EGUs/IGCCs (covered under subpart Da) and stationary combustion turbines (covered under subpart KKKK). The agency also co-proposed grouping all regulated sources into a single category under a new subpart TTTT, which would cover only GHG emissions from such sources.

EPA’s 111(d) proposal follows the latter approach and includes all regulated sources in a single category (codified under a new subpart UUUU) for the purposes of GHG regulation. The agency has chosen this approach “for purposes of facilitating emission trading among sources in both categories.” As such, EPA solicits comments on whether the combined category “would offer additional flexibility, for example, by facilitating implementation of CO2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from boilers to NGCC units) or facilitating emissions trading among sources.” Because this category does not include any sources that have not been previously regulated under section 111, EPA asserts that it is not “listing” a new source category under section 111(b)(1)(A), and hence need not issue a new endangerment finding.

# IV. Building Blocks for Setting State Goals and the Best System of Emission Reduction

## Building Blocks

The proposed BSER is based on a range of measures that are already being implemented by many utilities and in many states. EPA divided these measures into four main categories, or **“building blocks”**:

* **Building Block 1:** Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements;
* **Building Block 2:** Reducing emissions from the most carbon-intensive affected EGUs by substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction);
* **Building Block 3:** Reducing emissions from affected EGUs by substituting generation at those EGUs with expanded low- or zero-carbon generation; and
* **Building Block 4:** Reducing emissions from affected EGUs through demand-side energy efficiency.

EPA provides, for each building block, an assessment of technical potential, reasonableness of costs as part of the BSER determination, a description of data inputs for the proposed state goals,[[6]](#footnote-6) and alternate goals offered for comment.

### **Building Block 1: Heat Rate Improvements**

* EPA proposes that the BSER should include heat rate improvements at **coal-fired EGUs** only.
* **Best practices:** EPA estimates that the adoption of best practices (e.g. turning off unneeded pumps at reduced loads, installing digital control systems, more frequent tuning of existing control systems) to reduce hourly heat rate variability could achieve between 1.3% and 6.7% in technical improvements in the average heat rate of the entire fleet of coal-fired EGUs. Based on this figure, the agency believes that a reasonable estimate for state-specific goals is that affected coal-fired steam EGUs on average could achieve a 4% improvement in heat rate through best practices. EPA solicits comment on the use of estimates up to 6%.
* **Equipment upgrades:** EPA also estimated that implementation of equipment upgrades (upgrades to boilers, steam turbines, and control systems) could result in an aggregate heat rate improvement of 4%. Recognizing that this number may overstate the average equipment upgrade opportunity because some EGUs may already have implemented upgrades, EPA proposes an estimate of 2% as data input for developing state goals, and solicits comment on increasing it to 4%.
  + The **total of the estimated potential heat rate improvements** from adoption of best practices to reduce heat rate variability and implementation of equipment upgrades as discussed above is 6%. This total is used as the data input for heat rate improvements in the computation of proposed state goals. A 6% heat rate improvement would be associated with a 6% reduction in CO2 emissions.
  + For the **alternate set of goals** on which it requests comment, EPA has used a more conservative 4% heat rate improvement.
* This analysis of technical potential to reduce heat rate variability is based on **gross heat rate** data because the hourly generation data reported to the EPA represent gross generation. EPA states that it has less data available to analyze potential **net heat rate** improvements, and thus has not included separate estimates of **parasitic load** reductions through best practices (even though it recognizes that it would increase opportunities for reducing carbon intensity at affected EGUs).
* **Costs:** based on an average cost of $100 per kW and using a 6% heat rate improvement, EPA estimates the average cost of CO2 reductions from heat rate improvements at approximately $7.75 per metric ton of CO2 (or $11.63 per metric ton under the alternate 4% proposal). Heat rate improvements would achieve CO2 emission reductions at low cost, but they are limited when compared to other measures.
* **Concerns:** EPA is concerned about the potential for **rebound effects** from improvements in heat rates at individual EGUs (if this was the only approach being considered for BSER), but believes that the effect can be addressed by a combination of approaches.
* **Specific requests for comment:** EPA requests comment on increasing the estimates of the amount of heat rate improvement to 6% and 4%, representing a total of 10%, and on the quantitative impacts on the neat heat rates of operation at loads less than the maximum unit loads.

### **Building Block 2: Re-dispatch from Affected Steam EGUs to NGCC Units (including NGCC units under construction as of January 8, 2014)**

* **NGCC utilization rate:** EPA analyzed historical data reported to EPA to determine NGCCs’ utilization rates, and found that in 2012 only roughly 10% of existing NGCCs operated at annual utilization rates of 70% or higher. Based on this, EPA estimates that increasing the **annual utilization rate for NGCC units up to 70%**, on average (not in every individual plant) across all the NGCC units in the state, would be technically feasible.
  + For the **alternate proposal**, EPA seeks comment on a target of a 65% average utilization rate for NGCC units. EPA has also performed preliminary analysis of the impacts of using a target utilization rate of 75%, and invites comment on whether it should consider options for a target utilization rate greater than 70%.
* To establish state goals, after the application of NGCC re-dispatch toward a 70% target utilization rate, total generation from these existing sources is projected to be 1,390 TWh per year. Adding in the NGCC units that had commenced construction before January 8, 2014 increases the projected total generation 1,443 TWh per year.
* **Costs:** EPA estimated the cost of CO2 reductions achievable by substituting electricity from an existing NGCC unit for electricity from an average coal-fired steam EGU at approximately $30 per metric ton. Under the alternate proposal, the NGCC utilization rate could be achieved at a cost of $21 per metric ton.
* **Economic impacts:** EPAalso assessed the economic impacts of extending re-dispatch, concluding that these are not significant. In the 70% utilization rate scenario, delivered natural gas prices are projected to increase by no more than 10% over the 2020-2029 period, and projected wholesale electricity price increases are projected to be less than 7% during the same period.
* **Methane emissions:** EPA analyzed the potential upstream net methane emissions impact from natural gas and coal for the impacts analysis. This analysis indicated that any net impacts from methane emissions are likely to be small compared to the CO2 emissions reduction impacts of shifting power generation from coal-fired steam EGUs to NGCC units.
* **Natural gas and electricity transmission infrastructure:** EPA also examined the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system to accommodate shifting generation patterns, concluding that these systems would be capable of supporting the degree of increased NGCC utilization to achieve the proposed goals (as indicated by a 20% increase in natural gas consumption for electricity generation from 2011 to 2012). In addition, the proposal’s compliance schedule provides flexibility and time for investment in additional natural gas and electric industry infrastructure.
* **Request for comment:** EPA invites comment on whether the regional or state scenarios should be given greater weight in establishing the appropriate degree of re-dispatch to incorporate into the state goals for CO2 emission reductions, and in assessing costs.

### **Building Block 3: Expanded Use of Low or Zero Carbon Generating Capacity**

* More than half the states already have some form of state-level renewable energy requirements (RPS), with targets of on average 20% of 2020 generation to be supplied from renewable sources. As for nuclear units, 30 states already have nuclear EGUs (with five units under construction) and the generation from these units is currently helping to avoid CO2.
* **Best practices scenario:** To estimate the CO2 emission reductions from affected EGUs achievable based on increases in renewable generation, EPA has developed a “best practices” scenario for renewable energy generation based on the RPS requirements already established by a majority of states. EPA grouped the states into six regions in order to take regional variations into account.
  + The best practices scenario for each state consists of increasing annual levels of RE generation based on the application of an annual RE growth factor to the states’ historical RE generation (calculated by region), subject to a maximum RE generation target.
  + To determine the **baseline**, EPA first quantified the amount of renewable generation in 2012 in each state, and then summed these amounts for all states in each region. The baseline excludes **hydropower generation**, but this does not prevent states from considering incremental hydropower generation from existing (or later-built) facilities as a compliance option. EPA requests comment on whether to include 2012 hydropower generation from each state in the calculation.
  + EPA estimated the aggregate target level of RE generation in each of the six regions assuming that all states within each region can achieve the RE performance represented by an average of RPS requirements in states within that region that have adopted such requirements.
  + For each region, EPA computed the regional growth factor necessary to increase regional RE generation from the baseline to the regional target through investment in new RE capacity, assuming that the new investment begins in 2017 (the year following the initial state plan submission deadline), and continues through 2029.
  + EPA then developed the annual RE generation levels for each state, by applying the appropriate regional growth factor to that state’s initial RE generation level, starting in 2017, but stopping at the point when additional growth would cause total RE generation for the state to exceed the state’s maximum RE generation target.
  + For computation of the proposed state goals, EPA used the annual amounts for 2020 through 2029. For computation of the alternate state goals EPA used the annual amounts for 2020 through 2024.
  + This approach to quantification of a state’s RE generation target does not account for the amount of fossil fuel-fired generation in that state. Without such an accounting, the application of this approach could yield, for a given state, an increase in RE generation that exceeds the state’s reported 2012 fossil fuel-fired generation. EPA seeks comment on whether this approach should be modified so that the difference between a state’s RE generation target and its 2012 level of corresponding RE generation does not exceed the state’s reported 2012 fossil fuel-fired generation.
* **Costs:** RE generation at the levels represented in the best practices scenario can be achieved at reasonable costs. According to an EPA analysis based on EIA levelized costs, the cost to reduce emissions through RE ranges from $10 to $40 per metric ton of CO2.
* **Request for comment:** EPA makes three specific requests for comment with respect to the proposed quantification approach: (1) the possibility of a floor based on 2012 RE generation, (2) the possibility of a limitation based on 2012 fossil fuel-fired generation and, (3) the treatment of hydropower generation (for both main and alternate proposals).
* **Nuclear—new capacity:** increasing the amount of nuclear capacity is a technically viable approach to support reducing CO2 emissions from affected fossil fuel-fired EGUs. Five nuclear EGUs at three plants are currently under construction (Watts Bar 2 in Tennessee, Vogtle 3-4 in Georgia, and Summer 2-3 in South Carolina). Since the decisions to construct these units were made prior to this proposal, EPA considers it reasonable to view the incremental cost associated with the CO2 emission reductions available from the completion of these units as zero for purposes of setting states’ CO2 reduction goals. Thus, the emission reductions achievable at affected sources based on the generation from these nuclear units currently under construction should be factored into the state goals.
* **Nuclear—preserving existing capacity:** another way to increase nuclear capacity is to preserve existing nuclear EGUs that might otherwise be retired. EPA is aware of six nuclear EGUs at five plants that have retired or whose retirements have been announced since 2012 (San Onofre Units 2-3 in California, Crystal River 3 in Florida, Kewaunee in Wisconsin, Vermont Yankee in Vermont, and Oyster Creek in New Jersey). EPA proposes that the emission reductions supported by retaining in operation 6% of each state’s historical nuclear capacity be factored into the state goals for the respective states.
* **Costs:** retaining the estimated 6% of nuclear capacity that is at risk for retirement could support avoiding 200 to 300 million metric tons of CO2 over an initial compliance phase-in period of ten years. Nuclear units may be experiencing up to a $6/MWh shortfall in covering their operating costs with electricity sales. Assuming that such a revenue shortfall is representative of the incentive to retire at-risk nuclear capacity, the value of offsetting the revenue loss at these at-risk nuclear units is estimated to be approximately $12 to $17 per metric ton of CO2.

### **Building Block 4: Reducing Emissions from Affected EGUs through Demand-Side Energy Efficiency**

* More than 40 states already have established some form of demand-side energy efficiency policies, and individual states have avoided up to 13% of their electricity demand. In 2011, state demand-side EE programs are estimated to have reduced CO2 emissions by 75 million metric tons.
* **Benefits:** EE avoids GHG emissions associated with electricity generation. Because fossil fuel-fired EGUs typically have higher variable costs than other EGUs (such as nuclear and renewable EGUs), their generation is typically the first to be replaced when demand is reduced.
* **Best practices scenario:** To estimate the potential CO2 reductions at affected EGUs that could be supported by implementation of demand-side energy efficiency policies as a part of state goals, EPA developed a “best practices” demand-side energy efficiency scenario. EPA has not assumed any particular type of demand-side energy efficiency policy.
  + For the best practices scenario, EPA has estimated a rate of 1.5% annual incremental savings rate starting in 2017 (based on level of performance that 12 states have already achieved or will achieve). The pace at which states are estimated to increase their savings rate level is 0.2% per year.
  + Under the alternate proposal, EPA estimates a rate of 1.0% annual incremental savings (based on level of performance that 20 states have already achieved or will achieve). The pace at which incremental savings levels are increased from their historical levels is relaxed slightly to 0.15% per year.
* **Reasonable costs:** EPA analyzed a scenario incorporating the resulting reduction in electricity demand and compared the results with the business-as-usual scenario, using the IPM model. EPA found that the average cost of the CO2 reductions achieved ranged from $16 to $24 per metric ton of CO2, which the agency views as reasonable.
* **Request for comment:** EPA specifically requests comment on: (1) increasing the annual incremental savings rate to 2.0% and the pace of improvement to 0.25% per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5% rate and the 0.20% per year pace of improvement, such as building energy codes and state appliance standards, (2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for determining each state’s current level of annual incremental electricity savings, and (3) alternative approaches and/or data sources for evaluating costs.

## Potential Combinations of the Building Blocks as Components of BSER

* EPA compared the merits of a potential BSER that comprises only building blocks 1 and 2 against the merits of a BSER that comprises all four building blocks - the preferred option in this proposal.
* **Combination of building blocks 1 and 2:**  This combination involves only affected EGUs and generation from affected EGUs. While EPA believes that this combination would be a system of emissions reduction capable of achieving significant reductions in CO2 emissions from affected EGUs at a reasonable cost, it is not proposing this combination as the BSER but requests comment on it.
* **Combination of all 4 building blocks:** EPA’s BSER proposal is a combination of all four building blocks. EPA states that this proposal satisfies the legal criteria to be considered the BSER, and can achieve greater overall CO2 emission reductions from affected EGUs at a lower cost per unit of CO2 eliminated, mainly because of the potential of building blocks 3 and 4 to achieve additional CO2 reductions at reasonable costs. In addition, building block 3 would help to reduce reliance on fossil fuels and improve fuel diversity. Further, building block 4 would help to reduce the amount of electricity that would need to be delivered over the electric grid, generally reducing pressure on the grid and thereby improving system reliability.
* **Regional organizations:** Building blocks 2, 3, and 4 can be accommodated through the existing regional components of the electricity system (ISO/RTOs or applicable regional groups). Grid operators already factor environmental costs into their economic dispatch through a variety of mechanisms, including allowance costs, variable costs associated with operating environmental controls, and operating limits for high-emitting units.
* **Concerns/request for comment:** Some stakeholders have argued that the CAA does not authorize outside the fence measures as components of the BSER. EPA’s view is that Section 111 of the CAA does not by its terms preclude the BSER from including those types of measures, and welcomes comments on this issue.

## BSER Formulations

* EPA proposes and requests comment on two alternative formulations for the BSER, each of which are based on, although in different ways, the four building blocks.
  + **First approach:** emission rate improvements and mass emission reductions at affected EGUs facilitated through the adoption of the four building blocks meet the criteria for the BSER because they will amount to substantial reductions in CO2 emissions achieved while maintaining fuel diversity and a reliable, affordable electricity supply.
  + **Second approach:** the BSER consists of building block 1 coupled with reduced utilization in specified amounts from higher-emitting affected EGUs. The measures in building blocks 2, 3, and 4 would not be BSER components, but would serve to quantify the reduced generation at affected EGUs because these measures are used for the purpose of reducing CO2 emissions from affected EGUs.

## Evaluation of Individual Building Blocks Against the BSER Criteria

EPA evaluated and concluded that the individual building blocks meet the criteria to qualify as components of the BSER. For all building blocks, EPA explains that they are technically feasible; do not jeopardize grid reliability; entail reasonable costs; and promote technological innovation. Other reasons specific to each building block are the following:

* **Building block 1:** heat rate improvements are a BSER component because fuel is used more efficiently, reducing the volumes of and therefore the adverse impacts associated with disposal of coal combustion solid waste products.
* **Building block 2:** re-dispatch is a BSER component because (1) there has been a long-term trend in the industry away from coal-fired generation and toward NGCC generation; (2) natural gas combustion does not produce the large volumes of solid waste associated with coal combustion for electricity generation; and (3) NGCC units require less cooling water than steam EGUs.
* **Building block 3:** the use of expanded low-and zero-carbon generating capacity is a BSER component because (1) markets for renewable energy certificates, which facilitate renewable energy investment, are already well-established; (2) wind generation does not produce solid waste of require cooling water; and (3) the potential disadvantage of nuclear generation (waste disposal issues) relative to fossil fuel-fired generation does not outweigh its other advantages.
* **Building block 4:** increased demand-side energy efficiency is a BSER component because (1) it avoids the non-air health and environmental effects of the fossil fuel-fired generation for which it substitutes; and (2) relieves stress on the grid, thereby increasing system reliability.

## E. Potential Emission Reduction Measures Not Used to Set Proposed Goals

The following measures are not part of the BSER, but EPA discusses them and requests comment as to whether they should be part of the BSER:

### **Fuel-Switching at Individual Units (Switching to or Co-Firing with Gas)**

* **Costs:** the most significant cost change associated with switching from coal to gas in a coal-fired boiler is the difference in fuel cost (switching a steam EGU’s fuel from coal to gas typically would more than double the EGU’s fuel cost per MWh of generation). For a typical base-load coal-fired EGU, and reflecting EIA’s projected future natural gas and coal prices, the average cost of CO2 reductions achieved through gas conversion or co-firing ranges from $83 per metric ton to $150 per metric ton.
* EPA’s economic analysis suggests that there are more cost-effective opportunities for coal-fired utility boilers to reduce their CO2 emissions than through natural gas conversion or co-firing. As a result, EPA has not proposed at this time to include this option in the BSER. However, the agency solicits comments on whether the option should be included because a number of utilities have reworked some of their coal-fired units to allow for some level of natural gas co-firing and for other reasons beyond CO2 reductions (e.g. the capability to burn natural gas in a coal-fired boiler can improve economics because it allows the boiler to operate more effectively at lower loads; there are significant health co-benefits associated with burning natural gas instead of coal, etc.).

### **Carbon Capture and Storage (CCS)**

* Partial CCS has been demonstrated at existing EGUs (EPA refers to Southern Company’s Plant Barry, NRG’s W.A. Parish facility, and SaskPower’s Boundary Dam plant in Canada).
* However, EPA expects that the costs of integrating a retrofit CCS system into an existing facility would be substantial. Some existing sources have a limited footprint and may not have the land available to add a CCS system. Moreover, because there are a large number of existing fossil-fired EGUs, the overall costs of requiring CCS would affect the nationwide cost and supply of electricity on a national basis.
* EPA solicits comments on all aspects of applying CCS to existing fossil fuel-fired EGUs (in either full or partial configurations), but does not expect to finalize CCS as a component of the BSER in this rulemaking. However, in light of the fact that several existing fossil-fired EGUs are currently being retrofitted with CCS, emission reductions achieved through partial CCS could be used to help meet the emission performance level required under a state plan.

### **New NGCC Capacity**

* The analysis regarding the feasibility of policies to increase utilization rates of existing NGCC units on average to 70% applies equally to new NGCC units.
* However, compared to reduction of CO2 emissions at affected EGUs through re-dispatch to existing NGCC capacity, an option involving new NGCC capacity would be more costly for several reasons: (1) additional costs associated with additional usage of natural gas; (2) capital investment costs; and (3) costs of pipeline infrastructure expansion, in particular the unevenly distributed nature of those costs by states.
* While not proposing it, EPA seeks comment on whether to consider construction and use of new NGCC capacity as part of the basis supporting the BSER because there are a number of new NGCC units being proposed and many modeling efforts suggest that development of new NGCC capacity would likely be used as a CO2 emission mitigation strategy. EPA also seeks comment on ways to define appropriate state-level goals based on consideration of new NGCC capacity.

### **Heat Rate Improvements at Other Steam EGUs (Oil-Fired, Gas-Fired, NGCC Units, and Simple-Cycle Combustion Turbine Units)**

* For these non-coal technologies, the total additional potential CO2 reductions achievable through heat rate improvements appear relatively small compared to the potential CO2 reductions achievable through heat rate improvements at coal-fired steam EGUs.
* However, because the proportion of total generation provided from these EGUs varies by location, and may be relatively large in geographically isolated areas such as islands, EPA seeks comment on whether heat rate improvements for some of the EGU types discussed above should be identified as a basis for supporting the BSER, with particular reference to U.S. territories.

## F. Severability

EPA considers its proposed findings of the BSER with respect to the various building blocks to be severable, so that if a court were to invalidate a finding with respect to any particular building block, BSER would consist of the remaining building blocks.

# State Goals

## Overview

* EPA sets out proposed state-specific CO2 emission performance goals for state plans that considered the unique circumstances of each state. EPA quantified each state’s average emission rate from affected EGUs that could be achieved by 2030 through implementation of BSER based on all four building blocks, with interim goals that would apply over a 2020-2029 phase-in period. EPA is also taking comment on a less stringent set of goals that would be achieved by 2025, with interim goals that would apply over a 2020-2024 phase-in period.
* The goals are expressed as average CO2 emission rates for affected EGUs, but states can translate the goal to a mass-based form. Measures currently in place or measures taken after the date of this proposal that would reduce CO2 emissions from affected EGUs during 2020-2030 would count towards achievement of the goal.
* EPA proposes goals that it considers a reasonable level of emissions reduction, not the maximum possible. To persuade EPA to adjust a state goal to be less stringent, the state must not only demonstrate that EPA overestimated the emissions reductions achievable by one or more of the building blocks, but must also demonstrate that those reductions cannot be achieved through the other building blocks or other measures. EPA expects that emissions reductions at the states’ affected EGUs from the application of other building blocks will be available, so that the agency will be able to finalize the goals as proposed. This approach would mean that overall, the same nationwide level of emissions reductions proposed would be achieved. EPA seeks comment on this point.
* EPA is not proposing goals for Indian country or U.S. territories but plans to do so in the future.

## Form of the Goals

The goals are expressed as average CO2 emission rates that the affected EGUs in each state could achieve through the measures comprising the BSER (or alternative control methods). EPA discusses five aspects of the proposed form of goal: (1) a rate-based form, with the opportunity for states to translate it to a mass-based form; (2) average state emission rates; (3) adjustments to accommodate measures that reduce CO2 emissions by reducing the quantity of fossil fuel-fired generation rather than reducing the CO2 emission rate of affected sources; (4) emission rates expressed in terms of net energy output; and (5) adjustability of the goals based on the severability of the building blocks.

* **Rate-based goal, with opportunity to translate to mass-based goal:** Both approaches have advantages: (1) a rate-based form allows accommodating changes in the overall quantities of electricity generated in response to increases in electricity demand; (2) a mass-based form provides certainty as to the absolute emission levels that would be achieved and allows accommodating and accounting for the emission impacts of a wide variety of emission reduction strategies.
* **Average state emission rates (instead of uniform national emission rates):** EPA’s main consideration was to ensure that the proposed state goals reflect the possibility of shifting generation among different types of affected EGUs (from coal-fired EGUs to NGCC units) which, according to EPA, offers an opportunity to achieve large amounts of CO2 reductions at reasonable costs.
* **Adjustments to average emission rate accommodating reduced utilization of affected EGUs through low and zero carbon generation and demand-side energy efficiency:** These measures support reduced overall CO2 emissions from affected EGUs through reductions in the quantity of generation from affected EGUs, but not through reductions in their emission rates. The proposed state goals have been constructed in a manner that is intended to account for these generation quantity-reducing measures by adjusting the values used in the emission rate computations.[[7]](#footnote-7)
* **Emission rates expressed in terms of net (rather than gross) output:** EPA proposes to express the goals in net output (i.e. output encompassing MWh of generation measured at the point of delivery to the transmission grid) rather than gross output terms (i.e. MWh of generation measured at the EGU’s generator). The difference between net and gross is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. EPA proposes this approach because efficiency improvements in these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh.
  + EPA, however, recognizes that EGUs report gross rather than net load under 40 CFR Part 75, and that the proposed carbon pollution standards for new sources are expressed in gross output terms (although EPA requested comment on the use of net output). EPA seeks comment on whether the goals and reporting requirements for existing EGUs should be expressed in gross output terms for consistency with those requirements.
* **Severability of the building blocks:** If any of the building blocks is found to be invalid as a basis for the BSER, EPA would adjust the goals to reflect the emissions reductions from the remaining building blocks.

## Proposed State Goals

* EPA quantified each state’s average emission rate from affected EGUs that could be achieved by 2030 through implementation of BSER based on all four building blocks, with interim goals that would apply over a 2020-2029 phase-in period.
* In response to some stakeholders who suggested that it is the states who should set the goals or, if EPA establishes the goals, these should be considered advisory rather than binding (so that states would be able to adjust them), EPA made clear that, under section 111(d) regulations, it is EPA who sets the goals. Because the state goals are an integral part of the emission guidelines, the goals are binding, and the states, in their plans, must meet those goals and may not make them less stringent.
* EPA is also taking comment on a less stringent set of state goals that would be achieved by 2025, with interim goals that would apply over a 2020-2024 phase-in period. The shorter period reflects an expectation that less stringent goals could be achieved in less time. These alternate goals reflect different data inputs from those used in the proposed goals.

Table 1 below shows EPA’s proposed and alternate state goals:

**Table 1. Proposed State Goals (Adjusted MWh-Weighted-Average Pounds of CO Per Net MWh from all Affected Fossil Fuel-Fired EGUs) For Option 1 and 2**

| **State** | **Option 1** | | **Option 2** | |
| --- | --- | --- | --- | --- |
| **Interim Goal (2020-2029)** | **Final Goal (2030 Forward)** | **Interim Goal (2020-2024)** | **Interim Goal (2025-Forward)** |
| Alabama | 1,147 | 1,059 | 1,270 | 1,237 |
| Alaska | 1,097 | 1,003 | 1,170 | 1,131 |
| Arizona\* | 735 | 702 | 779 | 763 |
| Arkansas | 968 | 910 | 1,083 | 1,058 |
| California | 556 | 537 | 582 | 571 |
| Colorado | 1,159 | 1,108 | 1,265 | 1,227 |
| Connecticut | 597 | 540 | 651 | 627 |
| Delaware | 913 | 841 | 1,007 | 983 |
| Florida | 794 | 740 | 907 | 884 |
| Georgia | 891 | 834 | 997 | 964 |
| Hawaii | 1,378 | 1,306 | 1,446 | 1,417 |
| Idaho | 244 | 228 | 261 | 254 |
| Illinois | 1,366 | 1,271 | 1,501 | 1,457 |
| Indiana | 1,607 | 1,531 | 1,715 | 1,683 |
| Iowa | 1,341 | 1,301 | 1,436 | 1,417 |
| Kansas | 1,578 | 1,499 | 1,678 | 1,625 |
| Kentucky | 1,844 | 1,763 | 1,951 | 1,918 |
| Louisiana | 948 | 883 | 1,052 | 1,025 |
| Maine | 393 | 378 | 418 | 410 |
| Maryland | 1,347 | 1,187 | 1,518 | 1,440 |
| Massachusetts | 655 | 576 | 715 | 683 |
| Michigan | 1,227 | 1,161 | 1,349 | 1,319 |
| Minnesota | 911 | 873 | 1,018 | 999 |
| Mississippi | 732 | 692 | 765 | 743 |
| Missouri | 1,621 | 1,544 | 1,726 | 1,694 |
| Montana | 1,882 | 1,771 | 2,007 | 1,960 |
| Nebraska | 1,596 | 1,479 | 1,721 | 1,671 |
| Nevada | 697 | 647 | 734 | 713 |
| New Hampshire | 546 | 486 | 598 | 557 |
| New Jersey | 647 | 531 | 722 | 676 |
| New Mexico\* | 1,107 | 1,048 | 1,214 | 1,176 |
| New York | 635 | 549 | 736 | 697 |
| North Carolina | 1,077 | 992 | 1,199 | 1,156 |
| North Dakota | 1,817 | 1,783 | 1,882 | 1,870 |
| Ohio | 1,452 | 1,338 | 1,588 | 1,545 |
| Oklahoma | 931 | 895 | 1,019 | 986 |
| Oregon | 407 | 372 | 450 | 420 |
| Pennsylvania | 1,179 | 1,052 | 1,316 | 1,270 |
| Rhode Island | 822 | 782 | 855 | 840 |
| South Carolina | 840 | 772 | 930 | 897 |
| South Dakota | 800 | 741 | 888 | 861 |
| Tennessee | 1,254 | 1,163 | 1,363 | 1,326 |
| Texas | 853 | 791 | 957 | 924 |
| Utah \* | 1,378 | 1,322 | 1,478 | 1,453 |
| Virginia | 884 | 810 | 1,016 | 962 |
| Washington | 264 | 215 | 312 | 284 |
| West Virginia | 1,748 | 1,620 | 1,858 | 1,817 |
| Wisconsin | 1,281 | 1,203 | 1,417 | 1,380 |
| Wyoming | 1,808 | 1,714 | 1,907 | 1,869 |

## Computation Procedure

EPA used the following procedure to compute the proposed state goals.[[8]](#footnote-8) EPA requests comment on all aspects of this procedure, as well as on whether emission reductions associated with other measures that are not included in the four building blocks should be included in the states’ goals.

* **Step 1—Compilation of baseline data:** On a state-by-state basis, EPA obtained total annual quantities of CO2 emissions, net generation (MWh), and capacity (MW) from reported 2012 data for all affected EGUs. For each state, EPA aggregated the 2012 data for all coal-fired steam EGUs (first group), all oil- and gas-fired steam EGUs (second group), all NGCC units (third group) and all remaining affected EGUs (IGCC units and any covered simple-cycle combustion turbines), (forth, “other” group).[[9]](#footnote-9)
  + EPA added to these totals estimates for other EGUs not yet in operation in 2012 that are affected EGUs under this emission guideline (i.e. if they had commenced construction by January 8, 2014), estimating generation data inputs based on the average 2012 utilization rates for recently constructed EGUs of the same types.
* **Step 2—Application of building block 1:**  The total CO2 emissions amount for the coal-fired steam EGU group in each state from Step 1 was reduced by 6% to reflect EPA’s heat rate improvements proposal.
* **Step 3—Application of building block 2:** If the generation data for the NGCC group (step 1) showed average annual utilization below 70%, and the generation data for step 1 also included generation from the coal-fired and oil/gas-fired steam EGUs in that state, the generation and emissions figures for the NGCC were increased, and the generation and emissions figures for the coal-fired and oil/gas-fired steam EGU group were proportionately decreased to reflect a potential increase in utilization of the NGCC group to a maximum of 70%.
* **Step 4—Application of building block 3:** EPA estimated total generation from renewable and from covered nuclear capacity for each state. Separate estimates of renewable generation were computed for each year of the plan period for each state based on the state’s 2012 renewable generation and regional growth factor. Nuclear generation was estimated as the amount of under construction and preserved capacity for each state operated at a 90% utilization rate, consistent with industry-wide average utilization rates for nuclear units.
* **Step 5—Application of building block 4:** EPA estimated the total MWh amount of generation from each state’s affected EGUs cumulatively reduced in each year of the plan period from implementation of demand-side energy efficiency programs resulting in reductions in the state’s electricity usage of 1.5% per year.
* **Step 6—Computation of annual rates:** EPA computed adjusted output-weighted-average CO2 emission rates for each state by dividing (1) the total CO2 emissions for all four groups (coal-fired steam EGUs, oil- and gas-fired steam EGUs, NGCC units, and “other” EGUs) by (2) the total of (a) the total net energy MWh output for the four groups plus (b) the estimated annual net generation from renewable and nuclear generating capacity plus (c) the estimated cumulative annual MWh amount saved through demand-side energy efficiency. EPA made these computations separately for each year from 2020 to 2029.
* **Step 7—Computation of interim and final goals:** The final 2030 goal for each state is the annual rate computed for 2029 (step 6). The 2020-2029 interim goal for each state is the simple average of the annual rates computed for each of the years from 2020 to 2029 (step 6).

For the **alternate goals**, EPA used the following data inputs:

* A value of 4% (instead of 6%) was used for the potential improvement in carbon intensity of coal-fired EGUs (step 2);
* A value of 65% (instead of 70%) was used for the annual utilization rate of NGCC units (step 3);
* A value of 1% (instead of 1.5%) was used for the annual incremental electricity savings achievable through EE programs (step 5).
* Steps 5, 6, and 7 of the computation procedure were performed for years 2020 to 2024 (instead of 2020 to 2029).

EPA requests comment on the alternate goals, particularly with respect to whether any one or all of the building blocks in the alternate goals can be applied at a greater level of stringency. EPA also considered whether goals should be set (1) on a multi-state basis to reflect the scope of existing regional transmission control areas, or (2) on a state-specific basis, but using regional rather than state-specific evaluations to assess the opportunities for reduced emissions from re-dispatch. EPA requests comment on whether, and if so, how to incorporate greater consideration of multi-state approaches into the goal-setting process.

## Flexibility

As promulgated in the final rule, the state-specific goals will be binding emission guidelines. States have different types of “flexibility” to achieve emission performance levels consistent with the binding goals: (i) choices as to the measures employed, including the timing of their implementation; (ii) the ability to translate a rate-based into a mass-based form of goal; and (iii) the opportunity to pursue multi-state plan approaches.

* **Choice of measures:** States have flexibility to pursue some building blocks more extensively and others less extensively than the degree reflected in EPA’s data inputs, while meeting the overall goals. States can also choose to include in their plans other measures that reduce CO2 emissions at affected EGUs but that are not included in the building blocks.
* **Timing of implementation:** by allowing states to demonstrate compliance over a multi-year interim plan period of as long as ten years, states have flexibility to choose among alternative plan measures (e.g. a state could choose to rely more heavily on EE measures, whose effectiveness tends to grow over time) and to address concerns about stranded assets (e.g. a state could defer imposition of EGU requirements that may be scheduled to retire after 2020 but before 2029).
* **Ability to translate a rate-based into a mass-based goal:** EPA would allow translating the proposed rate-based goal into a mass-based goal to accommodate states’ potential interest in having emission performance requirements measured in absolute tons. This would allow RGGI states to develop state plans (or a multi-state plan) that sets mass-based emission performance levels designed to be met, at least in part, through performance standards based on RGGI’s trading program. Because a mass-based goal simplifies the process of accounting for the CO2 reduction impacts of a variety of measures, this could also facilitate the development of state plans.
* **Ability to submit multi-state plans:** This option could reduce the cost of achieving the state goals. RGGI states could choose to submit a multi-state plan that demonstrates emission performance by affected EGUs on a multi-state basis. Other states could also join a multi-state plan.

## Reliability and Affordability of Electricity

* In response to stakeholders’ concerns that this regulation may affect grid reliability, EPA held numerous meetings with DOE, FERC, state PUCs, and ISO/RTOs, to discuss how to address reliability concerns. The ISO/RTO Council specifically suggested EPA to ask states to consult with the applicable ISO/RTO in developing their state plans to ensure they are consistent with region-wide system reliability. EPA agrees with this suggestion and encourages states with borders that fall within one or more ISO or RTO footprints to consult with the relevant ISOs/RTOs. EPA has also met with the Department of Agriculture to discuss how to address the concerns of rural electric cooperatives.
* In determining the BSER, EPA considered the reasonableness of costs of the different options in part to ensure that the options would not have a negative effect on system reliability. In addition, each state has the flexibility to choose the most cost-effective measures given that state’s energy profile and economy, as long as the state achieves the reductions necessary to meet its goal. In addition, EPA’s proposed 10-year period over which to achieve the full required CO2 reductions gives states a relatively long period to plan how to further relieve any pressure on grid reliability.
* EPA’s supporting analysis for this rule concluded that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. Any remaining local issues can be managed through standard reliability planning processes.

# State Plans

## Timing and Process for State Submittal, EPA Review, and Federal Plan

## 

* **Deadline for submittal:** States must submit complete plans by June 30, 2016 or, alternatively, request an extension and submit an “initial” plan by that date. Individual states may receive a one-year extension if justified. States working on multi-state plans may receive a two-year extension if justified. EPA is proposing a narrow set of permissible justifications, and rigorous requirements for the initial plan that ensure the state is diligently working towards completing a plan but is facing genuine delays (for instance, the need to enact legislative changes).
* After receipt of complete plan submittal, EPA will review the plan and approve or disapprove through notice-and-comment rulemaking within 12 months (similar to the Section 110 process, though EPA takes care to note these are not Section 110 plans). EPA is taking comment on whether it can use the Section 110 methods of partial disapproval or conditional approval here.
* States may submit **multi-state plans**, with EPA taking comment on whether each state should have to submit a separate plan that contains that state’s individual components as well as any common multi-state components, or whether there can be one submittal on behalf of all the states. This may have implications for whether parts of the plan get implemented even if the whole thing is not approvable.
* **Plan revisions:** States may submit plan revisions, but EPA will not allow “backsliding.”
* Although it is not discussed in the preamble, EPA notes in the regulatory language that if a state fails to submit an approvable plan, EPA will develop a FIP for the state. Section 111(d) implementing regulations (40 C.F.R. § 60.27(c)) require that EPA “promptly prepare and publish proposed regulations setting forth a plan, or portion thereof, for a State” if the state does not submit a plan within the time prescribed or EPA disapproves the plan as unsatisfactory. EPA is supposed to prepare the federal plan by 6 months after the date required for submission of the state plan unless the state submits an approvable plan in the meantime (40 C.F.R. §60.27(d)).
* **Request for comment:** EPA is requesting comment on the implications for 111(d) from the agency’s review of the corresponding BSER for 111(b) every 8 years, but does not take a position on this issue. EPA is not proposing any future revisions of the emission performance levels at this time.

## Required Elements for an Approvable State Plan

EPA describes the required contents in the state plan in terms of four general criteria:

* The plan must include enforceable measures that reduce EGU emissions.
* Those measures must be projected to achieve emissions performance equivalent to or better than applicable state-specific CO2 goal on a timeline equivalent to that in EPA’s emissions guidelines.
* The EGU CO2 emission performance under the state plan must be quantifiable and verifiable.
* The plan must include a process for state reporting of plan implementation at the level of affected entity, and CO2 emission performance outcomes, and must provide for implementation of corrective measures if necessary.

These criteria are fleshed out by 12 required **plan components**, summarized below:

* A state must demonstrate that the plan’s measures are enforceable and that those measures will attain the emissions performance levels equivalent to or better than those set by EPA for (a) the “final” emissions performance level in 2030, and (b) the 10-year average between 2020 and 2029 (the “interim goal”). States must also project emission levels for each year within the planning period (2020-2030). EPA does not set any interim performance levels for individual years prior to 2030, relying only on state projections and the required performance level for the 10-year average. States do not have to ensure any further reductions after 2030 but must provide that the measures that attain the required 2030 level will remain in force and not sunset.
* In describing the emissions performance levels, states may choose whether they will use a mass-based (total CO2 emissions) or rate-based (lb CO2/MWh) emission standard, but need to rigorously justify their conversion of EPA’s rate-based guidelines to mass-based numbers if they choose to go that route. States may choose one method for the 2020-29 period and another for the 2030 final level if they so desire.
* States may also choose whether to impose emission standards on affected EGUs only, or on other entities over which the state has regulatory authority. EPA is proposing a “portfolio approach” in which the state does *not* have to obtain all needed CO2 reductions from affected EGUs themselves, but could rely on other state programs, such as RE and EE measures or trading programs, so long as those programs are included in the federally enforceable state plan. If the state includes affected entities other than EGUs in its plan, it must demonstrate it has the legal authority to regulate those entities. Alternatively, the state could include only EGUs as affected entities, but then credit the EGUs with enforceable, quantifiable, and verified RE and EE actions as an adjustment to the EGU’s CO2 emissions rate.
* EPA is also considering whether to allow states to rely on RE/EE programs even without including them as federally enforceable elements of the state plan; EPA would instead require states to commit to implement state-enforceable measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs. The requirement to achieve emission reductions would then be enforceable against the state (including by citizen groups). A few other variations are described in the preamble.
* Regardless of the emission standards chosen by the state and to which entities they apply, the state must demonstrate that each standard is
  + Quantifiable
  + Verifiable
  + Non-Duplicative
  + Permanent
  + Enforceable
* A measure is considered enforceable only if, among other requirements, “the affected entities responsible for compliance and liable for violations can be identified.”
* The plan must include reporting measures such that the state is reporting annually on its implementation efforts. Starting in 2022, the state’s annual report must also compare actual CO2 emissions from affected entities for the preceding two-year period to the projected emissions for that period.
* Unless the plan relies only upon federally enforceable emissions standards at affected EGUs to achieve both the interim and final goals, the plan must also include corrective measures to be triggered if reporting shows that actual levels are deviating from the state’s projections of emission reductions for each two-year interim period, the interim goal, or the final level, by 10% or more. EPA is not currently requiring that states have the legal authority to implement the corrective measures at the time of their plan submission, but if states do not have such authority, a lower threshold would trigger the corrective measures (8% deviation, compared with 10% for states that do have legal authority).
* EPA does not set a deadline for implementation of the corrective measures once triggered, merely requiring that they be implemented “as expeditiously as practical.” EPA is taking comment on whether there should be a deadline, and whether corrective measures should have to include additional emission reductions to make up for the deficiency during the compliance period. EPA is also taking comment on whether it should promulgate a SIP-call mechanism under 111(d) such that EPA could require a state to cure a plan deficiency within a specified time period if the state isn’t meeting its emissions performance levels. If the state still lacked an approved plan by the end of that time period, EPA would have the authority to promulgate a federal plan under CAA 111(d)(2)(A).
* Starting at the end of 2032, the emission performance of affected EGUs must be compared against the 2030 performance level on a 3-year rolling average basis to ensure emissions do not exceed it.
* Unless the plan achieves all its reductions through federally enforceable emissions standards at affected EGUs, the plan must also include implementation milestones. If reporting shows that the state has not implemented a milestone on schedule, the state must describe the steps it will take to accelerate subsequent implementation to achieve the planned reductions.
* The above reporting and verification timeline will work slightly differently for states that choose the alternative 5-year plan option described in Section VII of the proposal.

## C. More on Enforceability of Reductions from RE and EE Measures

* Whatever emission standards states choose to implement, they must describe the process for demonstrating compliance with the standard pursuant to state regulations or another legal instrument, including a schedule of compliance for each affected entity, whether an EGU or not. Further, as mentioned above, a measure is considered enforceable only if, among other requirements, “the affected entities responsible for compliance and liable for violations can be identified.”
* Any state plan that includes enforceable RE and EE measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of these measures will be determined in the course of plan implementation. Currently, there is a lack of cross-state comparability of claimed energy savings values for similar energy efficiency measures and EPA recognizes the need for common evaluation approaches. EPA intends to develop guidance for EM&V of renewable energy and demand-side EE programs and measures incorporated in state plans. EPA is seeking comment on critical features of such guidance. EPA is intending to allow any type of RE/EE program to qualify for approval into a state plan so long as it is verifiable, etc., but is taking comment on whether only certain well-established programs should be considered.
* A state must include additional reporting requirements in its plan if it contains emission standards other than those applicable to EGU. For instance, if the state is relying upon renewable energy purchased or by a distribution utility, the utility must be required to report on those purchases.

## D. Other Topics

### **1. Double Counting**

* EPA recognizes that double-counting is a potential issue where an affected entity operates across state lines and both states want to take credit for the entity’s avoided CO2 emissions, say by developing a wind farm, or implementing EE measures. For individual state plans, EPA is currently proposing that a state could take into account in its plan only those CO2 emissions occurring, or projected to occur, in the state that result from demand-side EE measures *implemented* *in the state*.
* EPA is also considering whether a state should be allowed to take credit for only those CO2 emission reductions occurring in its state or whether it could also take credit for emission reductions out of state due to renewable energy measures (e.g., purchase of RECs out of state), if the state can demonstrate that the reductions will not be double-counted by that other state.

### **2. Emission Reductions Prior to 2020**

EPA recognizes that some early actor states may feel as if they are not being credited for CO2 reductions that have already taken place. EPA is therefore taking comment on whether actions taken since some other trigger point besides 2020 (e.g., end of 2005) should receive credit. EPA recognizes that overall emissions likely would be higher if it takes this approach, and that it may not be consistent with the way that it set BSER in the first place.

### **3. Emission Reductions from Methods Not Proposed to be Part of BSER**

EPA is taking comment on whether any of the following are appropriate to include in state plan to achieve CO2 emission reductions from affected EGUs, even though they were not used to set proposed goals. For example:

* Electricity transmission and distribution efficiency improvements
* Partial CCS at affected EGUs
* Use of biomass at affected EGUs
* Use of new NGCC units
  + EPA Notes coal-to-gas substitution would automatically be reflected under mass-based plan where emission limits on affected EGU is what assures achievement with performance level, so a state would not need to include enforceable provisions for new NGCC. However, for a “portfolio plan”, it might need to include new NGCC in enforceable IRP.
  + EPA requests comments on whether emissions performance demonstration should include new emissions from new NGCC or just reductions from existing EGUs because only existing EGUs are affected units under 111(d).
* Co-firing of natural gas
* Credits for superior performance (i.e., better than required by 111(b)) at new EGUs)
* Use of integrated renewable technology (concentrating solar installation for some of steam for steam turbine)
* Additional nuclear generation or uprating of existing nuclear units
* Industrial combined heat and power
* Carbon sinks (forests/wetlands)

### **4. Remaining Useful Life**

* EPA is proposing that the flexibility provided in the state plan development process adequately allows for consideration of the remaining useful life of the affected facilities. Therefore states do not need to separately apply the remaining useful life provision in developing their plans.
* States are free to specify requirements for individual EGUs that are appropriate considering remaining useful life and other facility specific factors. Any adjustments based on remaining useful life must be included in the plan submission.
* States have flexibility to avoid requiring plants nearing the end of their useful life to make large capital investments (can rely on non-heat-rate related building blocks).

### **5. Section 111(h) – Design, Equipment, Work Practice, or Operational Standards**

EPA is taking comment on whether/when state plans can include such standards.

**6. Emissions averaging and trading**

EPA provides a legal justification for why 111(d) plans can include standards of performance that authorize emissions averaging and trading. Two other 111(d) rulemakings have (Clean Air Mercury Rule & Municipal Waste Combustors).

# Implications for Other EPA Programs and Rules

EPA notes various recent or forthcoming rules that will affect the sources covered by the 111(d) rule. These include MATS, CSAPR, the 316(b) rule for cooling water intake structures, the forthcoming effluent limitation guidelines and coal combustion residuals (CCR) rules for steam EGUs, as well as final implementation guidelines for the 2008 ozone and 2012 PM2.5 NAAQS, SO2 designations, and SIP revisions for the regional haze rule. Without providing much in the way of detail, EPA simply notes that the flexibility the 111(d) rule affords states in terms of timing and approach will allow them to coordinate their efforts and adopt an integrated approach to the various rules that will affect fossil fuel-fired EGUs in the coming years. EPA also notes that it believes the 111(d) rule will “tend to contribute to overall air quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.”

1. These capacity factor values represent ceilings for NGCC utilization. EPA used these ceilings while calculating state goal adjustments related to re-dispatching coal and/or oil and gas (O/G) steam generation to the state’s NGCC capacity. [↑](#footnote-ref-1)
2. The above RE values and EE saving rates are nationwide averages. Each state’s CO2 emission rate goal is informed by state-specific RE and EE values that relate to its pre-existing RE generation and EE savings rates respectively as described in the GHG Abatement Measures TSD. Also, the RE estimates do not count existing hydropower generation. [↑](#footnote-ref-2)
3. Table 1 (Section V.E, page 23) shows EPA’s proposed and alternate state goals. [↑](#footnote-ref-3)
4. Any units that burn solid fuel directly qualify as steam EGUs. [↑](#footnote-ref-4)
5. This requirement would appear to obviate the 10% fossil fuel requirement, but both are included. [↑](#footnote-ref-5)
6. In developing the data inputs to be used in computing state goals, EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more extensively, and others less extensively. [↑](#footnote-ref-6)
7. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying new low or zero carbon generation capacity, as well as the annual avoided generation associated with an achievable portfolio of demand-side energy efficiency measures, and adding those MWh amounts to the output from affected units that would have been used in an unadjusted output-weighted-average emission rate computation. [↑](#footnote-ref-7)
8. EPA emphasized that the particular data inputs used in this computation procedure are not intended to represent specific requirements for individual EGUs or the collection of EGUs in any state—those requirements would be based on the standards of performance established by states in their plans. [↑](#footnote-ref-8)
9. The emission and generation totals for the “other” group also reflect affected cogeneration units’ total CO2 emissions and total energy output corresponding to those units’ useful thermal output. [↑](#footnote-ref-9)