EPA Clean Power Plan - 111 (d) Proposal
June 2, 2014
Initial Review and Outline

I. Goals

A. 30% reduction in carbon emissions from 2005 levels by 2030 (nationwide); *alternate goals would yield 23% reduction from 2005 levels by 2025*

1. Proposed MI reductions – 31.5% from 2012 levels or 1,161 lbs/MWh

a. TSD appears to show MI's goal as 36%; RIA goal is 45%

2. Proposed alternate (for comment) of 1,319 lbs/MWh with reduced timeframe for compliance of 2025

B. *Interim goals to be* achieved on average between the years of 2020 and 2029

1. Michigan's proposed interim goal – ~ 27.6% from 2012 levels or 1,227 lbs/MWh

2. Proposed alternate (for comment) of 1,349 lbs/MWh with average being achieved between the years of 2020 and 2024

II. Rule Timeline and Important Dates

A. **January 8, 2014 – cut-off date for determining "affected EGUs"**

B. June 2, 2014 – Draft Proposal

C. **June 18, 2014 – published in Federal Register; Start 120-day comment period**

D. Public hearings:

1. Atlanta- July 29 and 30th
2. Denver- July 29 and 30th
3. Washington D.C. - July 29 and 30th
4. Pittsburgh - July 31st and August 1st

E. **October 16, 2014 – End comment period**

1. Request extension of the comment period; how much extra time to request and when to submit request (September)?

F. June 1, 2015 – deadline for final rule

G. June 30, 2016 – deadline for state plan/extension request submittal

1. June 30, 2017 – 1 year extension, individual plan submittal

2. June 30, 2018 – 2 year extension, multi-state plan submittal

a. Other mechanisms/incentives for fostering multi-state collaboration

III. BSER "adequately demonstrated" as determined by EPA – applied on state-wide basis consistent with interconnected nature of the electricity system. EPA solicits comment on the following regarding BSER:

1. *Proposed methodology for computing the State goals based on application of BSER*
2. *State specific data used in computing BSER*
3. *Application of only the first two building blocks as basis for BSER*
4. *Different combinations of building blocks and different levels of stringency for each block*
5. *Inclusion of trading programs (like RGGI) or emissions averaging approaches as BSER?*
6. *Gas conversion or co-firing considered as part of BSER?*
    a. *Co-benefits of natural gas co-firing considered in making that determination?*
7. *Interpretation of BSER (using all four building blocks) utilized?*
    a. *1st approach – emission rate improvements and mass emission reductions as facilitated through adoption of 4 building blocks, meet criteria for BSER because amount to substantial reductions in CO_2 emissions achieved while maintaining fuel diversity, reliability and affordability*
    b. *2nd approach - BSER consists of building block 1 coupled w/ reduced utilization in specified amounts from higher-emitting affected EGUs. With this approach, measures in building blocks 2, 3, and 4 justify those amounts and the "adequate demonstration" because they are proven measures already being pursued to reducing CO_2 from affected EGUs.*
        i. *Additional measures aside from building blocks 2, 3, and 4 that could support showing that reduced utilization is "adequately demonstrated" (including additional NGCC built in future)?*
8. *Specific considerations affecting rural cooperative, municipal utilities, or IPPs that might merit adjustments?*
    a. *What adjustments should be considered?*
9. *Potential measures (other than building blocks 1-4) that warrant consideration as components of BSER*
10. *Legal, technical, and economic conclusions with regard to BSER*
11. *If measures may be relied on in the state plan to achieve emissions reductions, they cannot be excluded from the scope of the BSER solely because they involve actions by entities or at locations other than affected sources*

12. *Application of BSER to affected EGUs in territories (Puerto Rico, U.S. Virgin Islands, Guam, American Samoa, or Northern Mariana Islands)*
    a. *Potential alternatives for those territories with no access to natural gas*

A. Building Block I – Heat rate improvements at (individual) existing coal plants, reducing carbon intensity (assumes a total of 6% reduction overall; alternative scenario assumes 4% total)

1. Heat rate improvements through reducing heat rate variability at individual plants through operation of best practices and O & M
    a. A 4% heat rate improvement is assumed through these means; *seeking comment on increasing up to 6% heat rate improvement by this means*
    b. *Alternative scenario for comment assumes improvements made to a lesser degree; 1-2% heat rate improvement by through this means*
2. Further equipment upgrades
    a. An additional 2% (on average) heat rate improvement through these means is assumed; *seeking comment on increasing that figure up to 4%*
    b. *Alternative scenario for comment assumes equipment upgrades to a lesser degree (or not at all); an additional 1-2% heat rate improvement through this means*
3. *Quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads?*

B. Building Block II – Dispatch changes among affected EGUs

1. Replacement of fossil fuel fired steam EGUs with generation at less carbon intensive affected fossil fuel EGUs, specifically NGCC.

    a. An affected NGCC unit was in operation or had commenced construction prior to January 8, 2014.

    b. *70% utilization across the board for NGCC is assumed; seeking comment on considering option of greater than 70% utilization for NGCC*
    c. *Alternative Scenario for comment assumes less stringent dispatch change of 65% among affected EGUs*

2. Cost of re-dispatch analysis completed utilizing IPM to understand and demonstrate to what extent existing NGCC units could increase their dispatch at reasonable costs and without significant impacts on other economic variables such as the prices of natural gas and electricity; *which of the below scenarios should be given more weight in establishing the*

appropriate degree of re-dispatch to incorporate into the state goals for CO_2 emission reductions, and in assessing costs?

a. 1st dispatch only analysis, explored the magnitude and cost of potential opportunities to shift generation from existing coal-fired EGUs to existing NGCC units within defined areas (region's existing fleet).

b. 2nd dispatch only analysis, shifting of generation was limited to only within the State's boundary.

C. Building Block III – Utilization of less carbon intensive generation capacity, renewables

1. Best practice scenario used for RE generation estimates based on RPS requirements already established by majority of states (no specific type of RE generation assumed):
   a. Rational for "best practice scenario":
      i) In establishing requirements, states already assessed those requirements against a range of policy objectives including both feasibility and costs
      ii) RE development varies by region; RPS requirements developed by states "necessarily reflect consideration of the states' own respective regional contexts"
   b. States grouped into one of six regions accounting for similar power system characteristics as well as geographic similarities in RE potential
      i) Michigan grouped into the "North Central" region with Illinois, Indiana, Iowa, Minnesota, Missouri, North and South Dakota, and Wisconsin.
      ii) Alaska and Hawaii, treated as separate regions, their RE targets based on the lowest regional RE target among the continental U.S. and growth factors are based on historical growth rates in their own RE generation, EPA seeks comment on their treatment as part of this method.
   c. Increased annual RE generation based on application of an annual RE growth factor to the state's historical RE generation (Summarized in GHG abatement TSD)
      i) Subject to a maximum RE generation target

2. Method for RE quantification

a. Quantified amount of RE in 2012 for each state and summed for region (excluded hydropower)

b. Averaged existing RPS % requirements that will be applicable in 2020 and multiplied that average percentage by the total 2012 generation for the region

c. Computed regional growth factor necessary to increase regional RE generation from the regional starting level to the regional target through investment in new RE capacity, assuming new investment begins in 2017 and continues through 2029

d. Final goals developed applying regional growth factor to that state's initial RE generation level, starting in 2017; stopping at point when additional growth causes total RE generation to exceed the state's max RE generation target

i) MI's RE numbers utilized for final goal computation, using annual amounts from 2020 to 2029; 2012 – 3%, interim – 6%, final - ~7.4%; 6% annual growth factor used for calculation

ii) MI's Alternate RE numbers utilized for final goal computation, using annual amounts from 2020 to 2024; Interim – 5%, final 6%

e. Calculation does not include a "floor" based on reported 2012 generation; seeking comment on modification of goal to include a "floor"

f. Calculation does not account for fossil-fuel generation in state; seeking comment on whether approach should be modified so difference between a state's RE generation target and its 2012 level of corresponding RE generation does not exceed the state's 2012 fossil fuel-fired generation

g. Hydropower from each state in 2012 was not included in RE goal computation; seeking comment on whether to include in a state's best practices

i) Whether and how variability year to year in hydropower should be considered if included in RE targets as part of BSER?

3. Alternate method for quantification of RE to support BSER relying on a state-by-state assessment of RE technical and market potential based on:

a. A metric representing the degree to which the technical potential of states to develop RE generation has already been realized

b. IPM modeling of RE deployment at the state level under a scenario that reflects a reduced cost of building new renewable generating capacity

c. EPA seeks comment on other techno-economic approaches

4. *Nuclear Capacity Quantification*

a. New Plants – Projected construction of 5 new nuclear plants currently; should completion of these units be included in the state goals and alternative ways of considering these units when setting state goals?

b. Plant retirements – Assumed 6% "at risk" capacity across the board based on known retirements nationally at the time of proposal preparation; 6% "at risk" nuclear was applied to each state's goal

c. Request comment on including in the state goals an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting. According to EGU owners' announcements?

ii) Issuance of permits?

iii) Projections of new construction by EPA or other government agency or commercial projection?

iv) Data sources to consider for permits or projections?

D. Building Block IV - Increased demand-side energy efficiency (EE)

1. Best practice scenario developed to provide an estimate of potential for implementing policies to increase investment in demand-side EE at reasonable cost (no specific type of demand-side EE assumed)

a. State's annual incremental savings rate increases from its 2012 annual saving rate to a rate of 1.5 % over a period of years starting in 2017

b. Pace states are estimated to increase their savings rate is 0.2 % per year

i) MI's savings target in 2020 is set at 4.6% with final cumulative goal of 11.8%

2. Alternative goal for comment is annual incremental savings rate of 1.0% from 2012 over a period of years starting in 2017

a. *In alternative scenario pace for increase is relaxed to 0.15% per year*

i) MI's savings target in 2020 is set at 3.6% with final cumulative goal of 6.2%

3. Additional items for comment related to EE:

a. *Increasing of incremental savings from 2012 to 2% with a pace of improvement of 0.25% per year*

b. *Alternative approaches and/or data sources (other than EIA form 861) for determining state's current level of annual incremental electricity savings*

c. *Alternative approaches and/or data sources for evaluating costs associated with implementing state demand-side EE policies.*

IV Potential Emission Reductions NOT used to set Individual Goals; seeking comment on (inclusion)

A. Fuel switching at individual units – an EGU designed for coal-fired generation is to substitute natural gas for some or all of the coal.
B. Natural gas co-firing or conversion
C. Carbon Capture and storage
   1. Application of CCS to existing EGUs in either full or partial configurations
D. New Natural Gas
   1. Consider construction and use of new NGCC capacity as part of the basis supporting the BSER?

2. *How to define appropriate state-level goals based on consideration of new NGCC capacity?*

E. *Heat rate improvements at affected EGUs other than coal-fired steam units – (reductions appear to be relatively small compared to potential CO_2 reductions achievable through heat rate improvements at coal-fired steam EGUs; however EPA asks for comment on inclusion of the following as the basis for BSER with particular reference to U.S. territories)*
   1. *Oil-fired steam EGUs*
   2. *Gas-fired steam EGUs*
   3. *NGCC units*
   4. *Simple cycle combustion units*

V Timing of Compliance

A. States must begin to make reductions by 2020, full compliance achieved by 2030

1. Interim CO_2 emission performance level met on average between 2020-2029; states define the trajectory of emission performance between 2020-2029, as long as the interim emission performance level is met on a 10-year average or cumulative basis and the 2030 emission performance level is achieved

   a. *January 1, 2020 start of interim goal plan performance period; however EPA solicits comment on the appropriate start date and rational*

   b. *Interim goal actual plan performance check in* 2030, the emission performance of affected EGUs during the period 2020-2029 must be compared against the interim goal. Additional interim emission performance checks will occur during the 10-year period

2. Achieve and maintain final emission performance level – 2030; 3-year average

   a. *Alternative 5 year period (by 2025) for compliance with less stringent CO_2 emission performance standard*

   b. *Interim goals apply over 2020-2024 phase in period*

   c. *Final goal actual plan performance check – In 2032 emission performance of affected EGUs must be compared against the final goal on a three-year rolling average basis*

B. State plans provide for tracking of emissions after 2030 and for corrective measures if the emission performance did not continue to meet the 2030 final goal during any three-year performance period

4. Second option for comment – States provide second plan in 2025 showing whether plan measures would maintain the final-goal level of emission performance over time. Solicit comment on whether 2025 or an earlier or later year is optimal for second plan submittal?

VI. Key Stakeholder Proposals – Elements key stakeholders proposed, not reflected in the proposal

A. Model Rule on interstate emissions credit trading and price ceiling; adoptable by states

1. Model rule w/ provision to allow state to compensate merchant generators and retail rate payers

2. Model rule w/ ceiling-price called "alternative compliance payment" to fund state directed clean technology investment

B. Equivalency Tests/Equivalency demonstrations via:

1. Rate-based; demonstration that state program achieves equivalent or better carbon intensity for regulated sector

2. Mass-based; demonstration that state program achieves equivalent or greater emissions reductions relative to what would be achieved by federal approach

3. Market price-based; demonstration that program reflects a carbon price comparable to or greater than cost-effectiveness benchmark used by EPA

C. Power plan specific

1. Inside the fence/unit specific assessments linked to availability of control at source such as heat rate improvements

a. *Inside the fence improvements done; then flexibility to look outside fence line to achieve the goal by emissions trading, averaging, etc.*

VII. Legal Interpretations/Issues for comment

A. CAA Section 111 limits BSER to measures taken at individual units "inside fenceline" approach

B. Is combining of the two categories prerequisite for:

1. Re-dispatch between sources in the 2 categories (ex: re-dispatch between steam EGUs and NGCC units) identified as component of BSER

2. Facilitating averaging or trading systems that include sources in both categories (which states may want to adopt)

C. Obligations on affected EGUs

1. Interpretation of CAA Section 111, that allows states to adopt plans that require EGUs and other entities to be legally responsible for actions required under the plan to achieve the emission performance level

D. Whether "standards of performance for [affected sources]" is reasonably read to include the emission performance level/state goal on grounds that the level is "a standard for emissions" because it is in the nature of a requirement that concerns emissions and it is "for" the affected sources because it helps determine their obligations under the plan

E. RE and EE - extent to which measures such as RE and EE may be considered "implement[ing]" measures in state plans if not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources?

F. Alternate interpretation of CAA Section 111 (d) (1)

1. Suggests that responsibility to achieve the state's required emission performance level must be assigned solely to affected EGUs. Must EPA adopt this alternative interpretation? If so, is there a way, nonetheless, to allow states to rely on the portfolio approach to some extent and/or for some period of time?

VIII. Indian Country – affected EGUs w/in Indian Country would not be encompassed in State's 111 (d) plan (this applies to potentially four plants according to EPA); EPA would like comment on:

A. Whether a tribe wishing to develop and implement a CAA plan should have the option of including EGUs located in its area of Indian territory in a multi-jurisdictional plan with one or more states

B. If EPA develops a CAA federal plan for areas of Indian country with affected EGUs, EPA considering doing so with multi-jurisdictional basis in coordination with other states.

C. How EGUs in Indian Country should be regulated, how BSER should be applied, and data sources for setting RE and EE within Indian Country?

D. Setting goals specific to Indian Country, EPA proposes to base goals on collection of affected EGUs located within that area of Indian Country.

IX. Combined Categories- EPA requesting comment on:

A. Combining two existing categories (steam EGUs and combustion turbines) into one for affected EGUs (no new category created)

1. Allows for emissions trading among sources in both categories

2. Offer additional flexibility by facilitating implementation of CO_2 mitigation measures (shifting from higher to lower intensity generation among existing sources?

3. Combining of existing sources necessitate combining categories for new sources?

X. Individual State Goals – Based on single state plans. Comment requested should EPA incorporate greater consideration of multi-state approaches into the goal-setting process, and if so how, the potential cost savings associated with multi-state approaches should be considered in assessing the reasonableness of the costs of state-specific goals?

A. Requirements for consideration of goal adjustment

1. Demonstration during the comment period that application of one of the building blocks would not be expected to produce the level of emission reduction quantified by the EPA because:

a. Implementation of the block using EPA assumptions is technically infeasible

b. Costs of doing so would be significantly higher than EPA projection; **AND**

2. Discussion of whether a similar state goal could still be achieved through more aggressive implementation of one or more of the measures encompassed in the other building blocks or through other comparable measures.

B. Form of State specific goals

1. Emission rate-based (EPA proposed)

a. *Flexibility – allows for changes in the overall quantities of electricity generated in response to increases in electricity demand*

2. Emission mass-based (states can convert goal to)

a. *Provides relative certainty as to absolute emission levels that would be achieved*

b. *Relative simplicity in accommodating and accounting for the emission impacts of a wide variety of emission reduction strategies*

C. Emission Rates

1. State-specific output-weighted-average emission rate for all affected EGUs in each state (EPA proposed)

a. Ensures proposed goals reflect opportunity to manage CO_2 emissions by shifting generation among different types of affected EGUs

i) Shift generation from higher carbon intensity to lower carbon intensive generation source

2. Nationally uniform emission rates for particular types of affected EGUs

D. Emission rate adjustments

1. Output-weighted-average emission rates adjusted to accommodate reduced utilization of affected EGUs due to measures like increases in RE and EE

E. Goal Computation

1. Step 1 - Compilation of data

a. Obtained total annual quantities of CO_2 emissions, net generation (MWh), and capacity (MW) from 2012 data for affected EGUs

b. Aggregated 2012 data for all coal-fired steam EGUs (one group), all oil- and gas-fired steam EGUs (second group), and all NGCC units (third group)

c. Aggregated 2012 data for all remaining affected EGUs (i.e., integrated gasification combined-cycle (IGCC) units and any simple-cycle combustion turbines satisfying relevant thresholds for qualification as affected EGUs) (fourth, “other” group)

d. To these totals for affected EGUs operating in 2012, added estimates for other EGUs not yet in operation in 2012 that are affected EGUs for purposes of this emission guideline

2. Step 2 – Application of Building Block I

a. Amount for the coal-fired steam EGU group in each state *from Step 1 reduced by 6%, reflecting the average opportunity to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements*

3. Step 3 – Application of Building Block II

a. Generation and emissions figures for the NGCC group were increased, and the generation and emissions figures for the coal-fired and oil/gas-fired steam EGU groups were proportionately decreased, to reflect an estimated potential increase in utilization of the NGCC group to a max of 70%

b. *Alternative Method: Decrease generation from the state's coal-fired steam group first, then decrease generation from the state's oil/gas-fired steam group (instead of decreasing generation from the coal-fired steam and oil/gas-fired steam groups proportionately) to account for increased NGCC described above*

4. Step 4 – Application of Building Block III

a. Estimated total quantities of generation from RE and under-construction or preserved nuclear capacity (6%) for each state

i) Nuclear generation estimated as the amount of under-construction and preserved nuclear capacity for each state operated at a utilization rate of 90 %

b. Separate estimates of RE were computed for each year of the plan period for each state based on the state's 2012 RE generation and a regional growth factor

5. Step 5 – Application of Building Block IV

a. Estimated total MWh amount by which generation from each state's affected EGUs would be cumulatively reduced in each year of the plan period associated with implementation in that state of EE programs

i) Resulted in annual incremental reductions in the state's electricity usage of 1.5% each year

b. *Alternative Method: Scaling up the estimated reduction in the generation by affected EGUs in net electricity-exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the EE efforts of other, net electricity-importing states would occur at those EGUs;* ***OR***

c. *Alternative Method: No adjustment made for either net electricity-importing or net electricity-exporting states*

6. Step 6 – Computation of Annual Rates

a. Computed adjusted output-weighted-average CO_2 emission rates for each state

7. Step 7 – Computation of interim and final goals

a. Final 2030 goal for each state - annual rate computed for 2029

b. 2020-2029 interim goal for each state as average of annual rates computed for each of the years from 2020 to 2029

F. Inclusion of emission reductions associated with other measures not currently included in any of the four proposed building blocks

G. Alternate Goals (for comment)

1. Alternate final goals - emission performance achievable by 2025, after a 2020-2024 phase-in period, interim goals apply during the 2020-2024 period on a cumulative or average basis

2. Amount for the coal-fired steam EGU group in each state from Step 1 (above) reduced by 4% (instead of 6%), reflecting the average opportunity to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements. Can heat rate improvement in alternate be set above 4%?

3. Generation and emissions figures for the NGCC group were increased, and the generation and emissions figures for the coal-fired and oil/gas-fired steam EGU groups were proportionately decreased, to reflect an estimated potential increase in utilization of the NGCC group to a max of 65%. Could NGCC utilization be set above 65% in alternate example?

4. Estimated total MWh amount by which generation from each state's affected EGUs would be cumulatively reduced in each year of the plan period associated with implementation in that state of EE programs

a. *Resulted in annual incremental reductions in the state's electricity usage of 1.0% each year. Can annual incremental electricity savings be increased above 1.0% in alternate goal?*

H. Reliability – EPA requests comment on assumption that reliability will not be an issue under the proposed rule

XI. State Plans/State Approach – *EPA assumes all measures relied on to achieve the emission performance level should be included in the state plan, and that inclusion in the state plan renders those measures federally enforceable*

A. State plan design considerations overview**:**

1. Should plan require the affected EGUs to be subject to emission limits that assure that the emission performance level is achieved, or instead, could the plan rely on measures like RE or EE, to assure the achievement of part of the emission performance level

a. Should responsibility for all measures other than emission limits fall on the affected EGUs, or, instead, could fall on entities other than affected EGUs; and

b. 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

2. State Plan Approach

a. *Submitted plan holds the affected EGUs fully and solely responsible for achieving the emission performance level;* ***OR***

b. *Submitted plans rely in part on measures imposed on entities other than affected EGUs to achieve at least part of that level, as well as on measures imposed on affected EGUs to achieve the balance of that level*

3. Portfolio Approach - plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and EE measures

a. *All measures combined that would be designed to achieve the required emission performance level for affected EGUs as expressed in the state goal*

b. *Emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level*

c. *Could be used for plans that establish the emission performance level on either emission rate basis or a mass basis*

d. *Utility Driven Approach*

i) *Example plan may include; measures implemented consistent with a utility IRP, including both measures that directly apply to affected EGUs (repowering or retirement) as well as RE and EE measures*

e. *State Driven Approach*

i) Measures include emission standards for affected EGUs and requirements that apply to entities other than affected EGUs, for example, RPS or EE resource standards

4. State Commitment Approach - state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally enforceable

a. *Plan would include enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs*

b. *State programs upon which the state bases its commitment may rely on compliance by third parties, and if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges for violating CAA requirements and could be held liable for CAA penalties*

c. *Variation of this approach for comment: State plan would imposes full responsibility for achieving the emission performance level on the affected EGUs, but the state would credit the EGUs with the amount of emission reductions expected to be achieved from RE or EE measures.*

i) State would assume responsibility for that credited amount of emission reductions in the same manner as the state commitment plan approach described above. Would this type of state plan meet the requirement in 111 (d) that necessitates state plans include standards of performance applicable to affected EGUs that achieve the emission performance while also assuring those EGUs an important measure of support?

5. Self-correcting state plans

1. Inherently assure interim performance and full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs. EPA requests comment on other plans that could be considered self-correcting

a. Could be a plan with rate-based emission performance levels that requires affected EGUs collectively to meet an emission rate consistent with the state's required emission performance level and allows EGUs to comply through an emission rate averaging system

b. Could be a plan that includes measures for actions that take effect automatically if the plan's required emission performance level is not met in accordance with a specified milestone.

c. Do not require interim milestones consisting of program implementation steps because the plan requires interim progress and achievement of the full required emission performance in a federally enforceable manner against affected EGUs.

6. Non Self-correcting state plans

a. State must identify periodic program implementation milestones appropriate to the programs and measures included in the plan.

i) If milestones missed, delay must be reported to EPA, explain the cause of the delay, and describe steps that will be taken to accelerate subsequent implementation to achieve planned emissions reductions.

b. State and EPA would track emission performance on an ongoing basis, reporting data annually by July 1st.

i) Interim performance period (beginning 2022), required to include comparison of emission performance achieved to performance projected in plan (comparison to preceding two-year period).

ii) Allowed for approval of regular, periodic emissions comparison checks of different frequency or comparison period depending on a state's program

c. Interim emissions not within 10% of performance projected

i) Report explaining the deviation and specification of the corrective measures that will be taken to meet plan performance.

7. Corrective Measures – EPA proposes State should be given a choice regarding when to adopt into regulation the corrective measures identified in the state plan

a. State could adopt corrective measure into regulation prior to plan submittal such that it enables the state to implement measures administratively w/out further rule making if deficiency occurs

b. State could wait to adopt into regulation the corrective measures until after a plan performance deficiency is noted.

8. Alternative for comment:

a. *States should be required to create legal authority and/or adopt regulations providing for corrective measures in developing plan.*

b. *In general, what conditions should trigger corrective measures requirements.*
c. Appropriate trigger emission performance inferior to project performance – 10% for requirement of reporting deficiency and implementation of corrective measures?

i) Range of 5-15% potential trigger instead of 10%

ii) For plans without corrective measures adopted into regulation prior to complete plan submittal, proposing 8% emission performance deviation trigger. Asking for comment on 5 to 10% as well
iii) Milestone approach and emissions performance checks outlined in context of alternative 5-year performance period and planning approach

7. Consequences if Emission Performance doesn't meet goal

a. Emission guidelines to specify consequences in the event that actual emission performance under plan does not meet the applicable interim or final goals [CAA section 111 (d) not specific here]

i) Consequences vary depending on reasons for deficiency in performance.
i. Consequences to include the triggering of corrective measures included in the plan or plan revisions to adjust requirements or add new measures.
ii. Should corrective measures, in addition to ensuring future achievement of the state

goal, be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal

b. *Process for invoking requirements for implementation of corrective measures in response to a plan performance deficiency?*

c. *Promulgate a mechanism under CAA 111 (d) similar to SIP call mechanism in CAA Section 110?*

i) After agency makes FOF to achieve the goal during performance period, EPA requires state to cure deficiency within a set time frame (ex: 18 months)

ii) If deficiency remains after the time frame, and plan still lacked approval after, EPA would institute FIP under 111 (d) (2) (A)

8. Maintaining or Improving Level of Emission Performance Required by the Final Goal (maintenance of emissions performance *or further improved performance once goal is met in 2030*)

a. State plans must:

i) Demonstrate plan measures are projected to achieve the final goal by 2030.

ii) Identify requirements that apply after 2030 and are likely to maintain emission performance meeting the final goal (quantitative emissions performance past 2030 not required).

iii) After implemented, state required to compare actual plan performance against final goal on rolling 3-year average basis starting in 2030 and implement corrective measures as necessary.

b. *State Plan Alternative Option must:*

i) Include projections demonstrating emissions performance would continue to meet final goal for up to 10 years beyond 2030. In general comment requested on *appropriate requirements to maintain emissions performance of affected EGUs after 2030.*

ii) Implemented through a second round of state plan analysis and submittals in 2025 to make demonstration and strengthen or add measures as necessary.

c. *BSER-based state emissions performance goals that extend beyond proposed planning period*

i) EPA would apply goal setting methodology based on application of BSER in 2030 and beyond to specified time period and final date; requesting comment on:

i. Appropriate time period?

ii. Final year for calculation of state goals that reflect application of BSER under this approach

iii. CAA Section 111 (b)(I)(B) calls for EPA to review every 8 years (at least) and revise standards of performance for new sources, implications, if any for CAA section 111 (d)?

9. Flexibility in choosing mass-based or rate-based goals after 2029

a. State that used mass-based performance level for 2020-2029 period, may still use rate-based performance level for final goal performance period (or vice versa)

b. State adopting mass-based performance level for 2020-2029 would have options for addressing need for emissions flexibility in light of anticipated electricity demand growth after 2029:

i) Adopt a rate-based performance level consistent with final goal; **OR**

ii) Adopt a mass-based performance level based on translation of rate-based final goal to mass-based goal

10. Planning Approach for Alternative State Goals

a. *Plan performance periods*

i) State plan must demonstrate that the required interim emission performance level will be met on average by affected EGUs during interim period 2020-2024; alternative final goal to be met by 2025

b. *Actual emission performance compared with alternative final goal on 3-yr rolling average starting with 2025-2027*

c. *State plan provide for emission performance after 2025*

i) *Solely through post-implementation emission checks that don't require another plan submittal;* ***OR***

ii) *Requirement to make second submittal prior to 2025 to demonstrate that program measures are sufficient to maintain performance meeting the final goal for 10 years (at least). If second plan submittal, what date?*

XII. Criteria for approval of State Plans – EPA to evaluate plans on 4 general criteria

A. Enforceable Measures; state must ensure their plan is enforceable and in conformance with the CAA. EPA seeking comment on:

1. *Appropriateness of existing EPA guidance on enforceability in context of state plans under CAA section 111 (d)*

2. *Whether agency should provide guidance on enforceability considerations related to requirements in state plan for entities other than affected EGUs*

3. State plan to include enforceable CO_2 emissions limits (rate or mass-based). *Request comment on all aspects associated with enforceability of a state plan and how to ensure compliance*

4. Portfolio approach – includes enforceable CO_2 emission limits that apply to affected EGUs as well as RE and EE measures to avoid emissions that are implemented by the state or by another entity made responsible by the State

5. State plans where emissions limits are applicable to EGUs alone and would not assure full achievement of required level of emission performance, plan must include:

a. *Additional measures that apply if any of the other portfolio of measures in the plan are not fully implemented, or if they are, but the plan fails to achieve the required level of emission performance.*

B. Emission Performance – projected CO_2 emission performance must be equivalent or better than the required CO_2 emission performance level in the State plan

1. Demonstration can be on individual or multi-state basis

2. Out-of-sector GHG offsets cannot be applied to demonstrate CO_2 performance

3. Emission limits included in state plans could contain provisions that provide ability to use GHG offsets for compliance with emissions limits, provided limits achieve required reductions; however limits wouldn't be considered self-correcting

4. Current state emission budget trading programs for GHGs include out-of-sector, project-based emission offsets which can be used to cover some of the compliance obligations of affected sources; this approach is suggested

5. SOs and RTOs could play facilitative role in developing and implementing region-wide, multi-state or coordinated individual plan; provide structure for achieving efficiencies by coordinating plan approaches throughout grid region

a. States would implement multi-state plan and jointly demonstrate emission performance by EGUs across ISO/RTO footprint

b. States that cross boundary of one or more ISO/RTO footprint need to include multiple plan components that address EGUs in each ISO/RTO.

c. States outside footprint of ISO/RTO may benefit from consulting with other planning authorities when completing state plan

C. Quantifiable and Verifiable Emission Performance – state plan must specify how each plan measure will be quantified and verified.

1. Plan must specify how emissions are monitored and reported

2. Mass and rate-based programs must include emission monitoring, reporting, and recordkeeping specified in emissions guidelines

3. Rate-based to also include requirements for useful energy output from affected EGUs as specified in emission guideline (useful energy output to be measured in terms of net output rather than gross)

4. Plans with RE and EE must include quantification, monitoring, and verification provisions for these measures (ex: RE and EE energy savings under rate-based approach)

D. Reporting and Corrective Actions

1. Must specify process for annual reporting of plan performance and implementation during performance period

2. Process and schedule for implementing corrective measures if reporting shows plan not achieving level of performance projected (not required for plans with self-correcting mechanisms)

a. *Include the adoption of new plan measures and subsequent resubmission of plan for review and approval;* ***OR***

b. *Process specifies implementation of measures already included in approved plan in event that projected level of performance not achieved*

c. *Point at which process and schedule described above should be triggered*

i) *End of multi-year plan performance period if emission performance not met;* ***OR***

ii) *At specified interim stages within multi-year plan performance period*

d. Periodic reporting requirements for each affected entity

i) *Reported annually (at a minimum), electronically, and disclosed on state database accessible by public and EPA*

ii) *Should affected entities also have to submit directly to EPA and the State*

XIII State Plan Components – EPA to evaluate plans on twelve required components

A. Plan Submittal

1. Multi-state plan – one joint submittal on behalf of all participating states, signed and authorized by officials from each of states participating

a. Addresses all components (described below) that apply jointly for all participating states and for each individual state in multi-state plan including legal authorities to implement plan (state regulations and statutes)

2. *Additional options for multi-state submittal*

a. *Provide one single submittal, signed by authorized officials from each participating state, and individual states required to provide individual submittals including state-specific elements of the multi-state plan*. *Combined common submittal and each individual submittal would be "multi-state" plan reviewed;* **OR**

b. *All states submit individual plans that address all elements of multi-state plan; submittal needs to be materially consistent for all comment elements and would also address individual state-specific aspects*

B. Twelve Components required (excepting some cases for self-correcting plans)

1. Identification of Affected Entities; plan must include:

a. List of individual affected EGUs subject to the plan

b. Inventory of CO_2 emissions from affected EGUs for most recent calendar year prior to plan submittal

c. Identification of any other affected entities in plan with responsibilities for implementation and enforceable obligations under plan

2. Description of Plan Approach and Geographic Scope - to include whether state will achieve required emission performance individually or jointly through multi-state demonstration

3. Identification of State Emission Performance Level – identification of emission performance goal as either rate or mass-based

a. If mass-based, state must describe process for rate to mass conversion and must include:

i) Analytic process

ii) Tools

iii) Methods

iv) Assumptions used to translate goal

b. Multi-state approach – individual state performance goals replaced with equivalent multi-state goal

i) Rate-based – demonstrate all affected EGUs subject to multi-state plan achieve weighted average emission rate consistent (in aggregate) with an aggregation of state-specific rate-based CO_2 emission performance goal

ii) Mass-based – states demonstrate all affected EGUs subject to multi-state plan emit total tonnage of CO_2 emissions consistent with translated mass-based goal

c. Calculation of weighted average rate-based emission goal for multiple states:

i) *First option – weighted average goal for group is computed using each state's emission rate goal from guildelines and quantity of electricity generation by EGUs in each state during 2012 base year used by EPA. Different levels computed for interim and final goals*

ii) *Second option – weighted average goal for group is computed using each state-specific emission rate goal and quantity of projected electricity generation by affected EGUs in each state, performed for the 2020 through 2029 period to produce interim goal and for 2030 to determine final goal*

d. *Translation of rate-based goals to mass-based goal; EPA seeking comment on whether they should assist states (for both individual and multi-state plans)*

i) Could provide a presumptive translation of rate-based to mass-based goals for all that request it; ***OR***

ii) Could provide guidance for use in translating goals. Guidance to include information regarding acceptable analytical methods and tool, default input assumptions for key parameters that may influence projections like electricity load forecasts and projected fossil fuel prices. Could also provide a coordinating function in addressing assumptions applied by multiple states within a grid region

e. Technical considerations for rate to mass-based translations – summarized in TSD Projecting EGU CO_2 Emission Performance in State Plans

4. Demonstration that Plan is Projected to Achieve State's Emission Performance Level – plan must demonstrate that actions taken, when taken together, will meet the state's required emission performance level during interim timeframe and for final goal

a. Demonstration to include detailed description of analytic process, tools, and assumptions used to project future emission performance by affected EGUs; considerations discussed in the Projecting EGU CO_2 Emission Performance in State Plans TSD

5. Milestones – Periodic programmatic milestones to indicate progress in program implementation if plan is not self-correcting

a. Specific dates for achievement – should be appropriate to programs and measures included in the plan

b. Intended trajectory of emission performance improvement beginning in 2022

i) State must compare collective emission performance achieved in the state during the previous two-year period with projected performance in the state plan

ii) If emission performance not within 10% of projections, submittal of report by July 1st following end of two-year period is required to explain deviation and indicate corrective measures to be taken

6. Corrective Measures – for a plan that is not "self-correcting", specifications must be made as to the corrective measures that will be implemented if state's progress falls short of what is projected in plan

a. Emission rate improvements – *amount of emission rate improvement or reduction that the corrective measures included in the plan must be designed to achieve (ex: sufficient to address a 10% performance deficiency)*

b. Deadlines – should emissions guidelines establish a deadline for implementation of corrective measures (ex: 2 years from July 1 deadline described above for reporting a deficiency as part of state's annual report on plan performance)

7. Identification of Emission Standards and Any Other Measures

a. Plan must:

i) Identify affected entities to which each standard applies (ex: individual EGUs, groups of EGUs, all EGUs aggregated)

ii) Identify implementing and enforcing measures for standards

8. Describe each of emission standards and the process for demonstrating compliance with it
9. Include schedule for compliance for each affected entity

    a. Averaging time

        i) Rate-based emission standards – no longer than 12 months within plan performance period; *comment on shorter or longer averaging times*

        ii) Mass-based emission standards – no longer than 3 years, *comment on shorter or longer averaging times*

10. Demonstration that Each Emission Standard is Quantifiable, Non-duplicative, Permanent, Verifiable, and Enforceable – state's plan must be enforceable and in conformance with the CAA

    a. *EPA guidance – appropriateness on enforceability in context of state plans under 111 (d) considering types of entities that could be included*

        i) *Guidance provided on enforceability related to requirements in plans for entities other than affected EGUs? If so, what types of entities?*

    b. Emissions standards must be reliably measured, using technically sound methods, in a way that can be replicated (in other words, quantifiable)

        i) Must be quantifiable, non-duplicative, permanent, verifiable, and enforceable with regard to the affected entity, further described in the State Plan Considerations TSD

    c. Non-duplicative – emission standard is not incorporated in another state plan (except where part of multi-state plan)

        i) Can take credit for avoided emissions from a wind farm that is also being used to generate RECs to comply with a State RPS

        ii) Single affected entity can be subject to similar emission standards in different state plans (ex: electric distribution utility with service territory across state lines)

d. Duplicative – *recognition of avoided emissions applied in more than one state's plan (except in the case of multi-state plan where recognition assigned among states)*

e. Enforceability Criteria:

i) Represents technically accurate limitation or requirement and time period for limitation/requirement is specified

ii) Compliance requirements are clearly defined

11. Affected entities responsible for compliance and liable for violations can be identified

12. Compliance activity or measure is practically enforceable in accordance with EPA guidance

13. Identification of Monitoring, Reporting, and Recordkeeping Requirements

a. Monitoring – most EGUs already monitor CO_2 emissions under CFR Part 75 and report data using ECMPS (will generally satisfy reporting requirements under proposed guidelines)

b. *RATA adjustments for steam EGU stack gas flow monitors, discussed further in the Part 75 Monitoring and Reporting Considerations TSD*

i) Require use of most accurate RATA reference method for specific stack configurations; ***OR***

ii) Require a computation adjustment when EGU changes RATA reference methods

c. Net energy output reporting requirement

i) Affected facilities with multiple generators, required to report electric output from all generators

ii) Default apportionment procedure for multi-EGU facilities – net generation of each EGU at the facility would be determined as net generation of the facility x the ratio of the EGU's gross generation to the sum of the gross generation for all EGUs at that facility

d. *Specifically seeking comment on:*

i) Should EGUs producing electric energy and useful thermal output be required to report both?

ii) Reporting of net rather than gross energy output

iii) Any existing protocols for reporting net output (FERC, NERC, etc.), electricity meter specifications, electricity meter QA testing and reporting procedures, apportionment procedures for parasitic load and multi-unit facilities, treatment of externally provided electricity, and monitoring and QA testing and reporting for non-electric energy output at CHP units.

iv Range of two-thirds to 100% credit for useful thermal output in final rule, or other alternatives to better align incentives with avoided emissions

e Records retention – 10 years

14. Description of State Reporting - must provide for the submission of reports to the EPA detailing plan implementation and progress

a. Components of state plan:

i) Description of the process, timing, and content of reports

ii) List of facilities and their compliance status

b. *Elements for comment:*

i) Frequency of reporting of various elements – including whether full reports containing all report elements should only be required every 2-years

ii) Method of submittal – electronic to streamline transmission?

15. Certification of State Plan Hearing must provide:

a. List of witnesses and their organizational affiliations and brief written summary of each presentation or written submission pursuant to requirements of EPA framework regulations

16. Supporting Material – state must provide material and technical documentation related to applicable components of plan including:

a. Demonstration of legal authority for each implementation and enforcement component that has included in its plan as part of federally enforceable emission standard

i) Provide supporting material related to legal authority used to implement and enforce each component of plan including; statutes, regulations, public utility commission orders, and applicable legal instruments

ii) Any analytical methods used including rate to mass based goal translation, analytical materials used in projecting emissions performance that will be achieved through the plan, etc.

XIV Process for State Plan Submittal and Review

A. Timeline for submittal

1. Complete plan - 13 months after finalization of emissions guidelines (June 30, 2016)

2. Initial plan only for extension (if justified by the below elements) – 13 months after finalization of emissions guidelines (June 30, 2016)

a. Documents the state's progress in preparing a complete plan

b. Demonstrates that state is on track to develop a complete plan and includes meaningful steps that commit a state to a complete approvable plan

c. Required schedule for legislative approval and administrative rulemaking

d. Need for multi-state coordination in development of individual plan

e. Process and coordination to develop a multi-state plan

f. Other circumstances for which more time is necessary; and whether some justifications should not be allowed

3. Approved extensions

a. One-year extension for single state plans that meet justification requirements (June 30, 2017)

b. Two-year extension for multi-state plans (due June 30, 2018)

i) Update required on June 30, 2017 with progress toward milestones and schedules in initial plan for developing and submitting a complete plan

B. "Initial" State Plan Submittal and Approvability Criteria

1. Must include all the components of a complete plan and identify which components are not complete

a. Incomplete components – must contain roadmap outlining path to completion including milestones and dates

2. Public Comment period – on a substantial draft of initial submittal

a. Not governed by procedural requirements of framework regulations that apply to state's complete plan such as holding a public hearing

3. Elements of approvable initial plan:

a. Description of plan approach and progress toward developing the complete plan

b. Quantification of level of emission performance that the plan will achieve

c. Commitment to maintain existing measures to limit or avoid emissions, at a minimum until the plan in approved (ex: RE standards)

e. Roadmap for completing a final plan including the process, analytical methods and schedule with milestones indicating when all plan components will be complete

f. Identification of any existing programs the state intends to rely on to meets its emission performance level

g. Identification of executed agreements with other states if a multi-state approach is being pursued (ex: MOUs)

h. Commitment to submit the complete final plan by the required extended deadline and explanation of actions state will take to show progress in addressing incomplete plan portions

i. Description of steps already taken in furthering actions to finalize a complete plan (ex: copies of draft regulations, etc.)

j. Evidence of opportunity for public comment and response to any significant comments received on issues related to approvability of initial plan.

k. Other elements that a state must include in initial submittal to qualify for extension

l. Guidelines require state to have taken significant, concrete steps toward adopting a complete plan for initial plan to be approvable

m. For multi-state program, initial submittal should include executed agreements among all participating states and road-map for the design of the multi-state program and its implementation at the state level (ex: RGGI state MOU signed December 20, 2005)

4. Process for EPA review of State Plans – EPA proposes that the agency will review the plan and approve or disprove through notice and comment rule-making process (similar to SIP process under CAA 110) within 12-months of submittal

a. Approval mechanisms for comment:

i) Partial approval/disapproval – 111 (d) includes severable provisions, some approvable, some not. Should EPA interpret CAA as providing flexibility to approve those elements that meet requirements of the guideline, while disapproving the elements that do not? Partial approval would make federally enforceable the elements of the plan that comply with these guidelines

ii) Conditional approval – plan is substantially approvable and requires only minor amendments to fully meet requirements of guidelines. Should EPA interpret CAA as providing flexibility to approve the plan on condition that the state commits to fixing the deficiencies within one year? During the year following the conditional approval, the plan would be federally enforceable

5. Failure to submit a complete plan – EPA will notify state by letter of failure to submit by deadline and will publish a Federal Register notice

6. Modification of an Approved State Plan – EPA will allow state plan revisions, provided revision does not result in reducing required emission performance specified in original plan (no backsliding)

    a. Criteria for submitting revisions:

        i) Submittal of revised enforceable measures and a demonstration that revised measures will result in emission performance equivalent or better than what was in original plan

        ii) Projection methods, tools, and assumptions used should match those in the original demonstration of the plan *OR should plan be updated to reflect the latest data and assumptions (current and future economic conditions and technology cost and performance)*

7. Templates and electronic Submittal – *Seeking comment on creation of a template for the initial and complete state plan submittals, or whether template is more appropriate for initial submittal and not complete plan*

    a. Electronic Submittals – provide for or require electronic submittal of initial and complete plans

        i) EPA workgroup currently working on an electronic submittal process for SIPs under CAA section 110 and question suitability of this approach for submittal of state plans under 111 (d)

XV State plan Considerations – EPA giving states broad discretion to develop plans that best suit their individual circumstances; however, they identify key decision points and factors that they should consider in developing their plans.

A. Affected Entities other than affected EGUs – a state needs to Identify each affected entity responsible for meeting compliance obligations under its plan and how obligation will be met including a demonstration of their legal authority. Affected entities may include:

1. Owner or operator of affected EGU

2. Other affected entities with responsibilities assigned by the state (ex: entity regulated by the state, electric distribution utility or private or public third-party entity)

3. State agency, authority, or entity

4. Other appropriate examples of entities beyond affected EGUs

5. Guidance provided on enforceability considerations related to requirements in state plan for affected entities other than EGUs and if so, which? State Plan Considerations TSD provides examples.

B. Treatment of Existing State Programs

1. Proposed approach – existing state programs, requirements, and measures may qualify for use in demonstrating that plan will achieve the required level of emission performance provided they meet approvability requirements in emissions guidelines and requirements for plan parts

a. Emissions reductions that existing state programs/measures achieve during a plan performance period as a result of actions taken after the date of the proposal may apply toward required emission performance level; however, EPA requests comment on:

i) Start date of initial plan performance period, date of promulgation of emissions guidelines, and end of base period for EPA's BSER-based goals analysis, the end of 2005 or another date.

ii) Point in time after which such actions should be able to qualify for use during a plan performance period, considering method used to set state goals

iii) Rational basis for choosing a date that predates base period from which EPA used historical data to derive goals, What is appropriate date to select?

b. *Emissions reductions that existing state requirements, programs, measures achieved starting from a specified date prior to initial plan performance period, as well as reductions achieved during plan performance period would be recognized.*

i) Enables states to count emission reductions achieved by state programs prior to 2020 toward interim goal, which allows for a more gradual emission improvement trajectory during interim period (2020-2029)

c. For general comment under this heading:

i) Alternative dates listed above related to this option

ii) Whether option is inconsistent with forward-looking method proposed for establishing goals based on BSER *iii) Whether some variation of approach could be justified as consistent with goal-setting approach as well as general concept of BSER in application and setting of goals*

iv) Whether emissions effects of actions taken after proposal or promulgations of guidelines or approval of state plan, but occur prior to beginning of initial performance period could be applied toward meeting required level of emission performance

2. Application of options under rate and mass-based plan approaches

a. Rate-based – options described above would address eligibility date for qualifying EE measures that avoid emissions through MWh savings

i) Measures installed after eligibility date (date of proposed emission guidelines) could generate MWh savings/avoided emissions during plan performance period.

ii) New EE measures installed in 2015 or later would be qualifying measure; however, only MWh savings/avoided emissions could apply toward goal

b. Mass-based – options described above would be applied when establishing reference case scenario projection used to translate rate-based to mass-based goal. Discussed in further detail in Projecting CO_2 Emission Performance in State Plans TSD

C. Incorporating RE and EE measures under Rate-based Approach – measures may be incorporated into rate-based system through adjustment or tradable credit system applied to EGUs emission rate

1. Crediting and Compliance

a. Quantified and verified end-use energy savings and RE generation credited toward demonstration emission rate for EGU compliance purposes, or used to administratively adjust average emission rate of affected EGUs when demonstrating achievement of rate-based emission performance level

b. EGU could comply with emission rate limit in part through use of credits for actions that avoid CO_2 emissions.

c. Under portfolio approach – state could administratively adjust average CO_2 emission rate of affected EGUs through similar process (as long as measures are enforceable through the plan)

2. Credits or adjustments

a. Avoided MWh of electric generation - added to the denominator when determining adjusted CO_2/MWh emission rate

i) Assumes avoided CO2 emissions come directly from particular affected EGU(s) to which credits applied

ii) Assumes that an additional emission free MWh is being generated by that EGU(s) and RE or EE measures reduces CO_2 emissions from that EGU or group of EGUs

b. Avoided tons of CO_2 emissions – subtracted from numerator when determining an adjusted lb. CO_2/MWh emission rate

i) Assumes that avoided CO2 emissions come from electric power pool or other identified region as a whole, rather than an individual EGU.

ii) Could be based on average or marginal emission rate in power pool or region, or could be based on emission rate that represents the required rate-based emission performance level in the plan

3. Avoided emissions from non-affected EGUs – some emissions avoided may fall into this category (how might these be addressed in plan)

D. Quantification, Monitoring, and Verification of RE and EE Measures

1. Evaluation, measurement and verification (EM&V) plan

a. Specify analytical methods, assumptions, and data that will be used to determine energy savings and energy generation related to RE and EE

b. Due to differences among states on EM&V, EPA seeking comment on:

i) Harmonization of state approaches, or supplemental actions and procedures should be required

ii) Plan to establish guidance on acceptable quantification, monitoring, and verification of RE and EE and seeking comment on critical features of this guidance including scope, applicability, and minimum criteria as well as the technical resources that should be used to establish it. Should guidance limit consideration to well-established programs like those in State Plan Considerations TSD

E. Reporting and Recordkeeping for Affected Entities Implementing RE and EE Measures – *measures, reporting, and recordkeeping requirements for approvable plan would differ from those applicable to affected EGUs; See State Plan Considerations TSD for suitability of potential approaches*

F. Treatment of Interstate Effects – EPA recognizes that programs and measures in a state plan may affect the performance of the interconnected electricity system beyond a state border.

1. For EE measures, consistent with approach used in determining BSER:

    a. *State could take into account only CO_2 emission reductions that occur (or are projected to occur) that result from EE measures implemented in the state*

    b. In multi-state plans, participating states would have the flexibility to distribute CO2 emissions reductions among states in multi-state area, as long as reductions claimed are equal to total of each state's in-state emissions reductions that result from EE measures implemented in those states

    c. States could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in contiguous electric grid region (attribution of emission reductions from EE would not be necessary)

    d. Credit for emissions reductions out of state due to in-state EE measures if state can demonstrate that reductions will not be double-counted when relevant states report achieved plan performance (and what the demonstration should entail)

    e. Any additional measures/approaches for taking into account emission reductions from EE in state plans

2. For RE measures consistent with existing state RPS policies:

    a. State could take into account all of CO_2 emissions reductions from RE measures implemented by the state whether they take place in the state or other states, which allows for the recognition of RECs that allow for interstate trading of RE attributes. *How can double counting be avoided*?

    b. Participating in multi-state plans can distribute CO_2 emissions reductions among states in multi-state area as long as total reductions claimed are equal to the total of each state's in-state emissions reductions from RE

c. *Allowing state to take into account only those emissions reductions occurring in state*

d. States could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in contiguous electric grid region (attribution of emission reductions from RE would not be necessary)

e. Credit for emissions reductions out of state due to in-state EE measures if state can demonstrate that reductions will not be double-counted when relevant states report achieved plan performance (and what the demonstration should entail)

G Projecting Emission Performance – all plans will include a projection of CO_2 emission performance by affected EGUs under the plan (will include either projection of average CO_2 emission rate achieved by affected EGUs or total CO_2 emissions from affected EGUs)

1. Plans using mass-based goal:

a. Must include a translation of rate-based to mass-based goal

i) Translation involves projection of emissions from affected EGUs during initial plan period (2020-2029) and in 2030, under scenario that assumes rate-based goal met

2. Considerations for projecting emissions performance – in general, any component of state requirement or program included in state plan that could affect emission performance by affected EGUs should be represented accurately in emission projections in state plan. *Considerations discussed in more detail in*

a. Mass-based emission budget trading program – include compliance flexibility mechanisms that might impact emission performance achieved by affected EGUs like:

i) Multi-year compliance periods

ii) Ability to bank allowances issued in a previous compliance period for use in subsequent period

iii) Use of out of sector project-based emission offsets

v) Cost-containment allowance reserves that make additional allowances available to market if pre-established allowance price thresholds are achieved.

b. Projections used to determine mass-based goal could be:

i) Conducted using historical data and parameters for estimating future impact of individual state programs

ii) Based on modeling like a capacity planning and dispatch model which would be able to capture dynamic interactions within the electricity sector.

3. *Projecting EGU CO_2 Emission Performance in State Plans TSD elements for comment:*

a. How projections might be conducted in approvable state plan

b. How different types of state plan approaches are represented in these projections

c. Whether EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in approvable plan and technical resources for completing projections

i) ISO/RTO Council has indicated that ISOs and RTOs could provide analytic support to help states both develop and implement plan

H. Potential Emission Reduction Measures not used to set Proposed Goals

1. EPA had identified other means for emissions reductions that were not included in BSER (soliciting comment on appropriateness of including these in a state plan to achieve CO_2 reductions):

a. Electricity transmission and distribution efficiency improvements

b. Retrofitting affected EGUs with partial CCS

c. Use of biomass-derived fuels at affected EGUs

d. New NGCC units

i) Not included as a component of BSER, but requests comment on its inclusion

ii) How emissions changes under rate-based plan resulting from substitution of generation by new NGCC should be calculated toward required emission performance level for affected EGUs.

iii) Considering legal structure of 111 (d), should emissions calculation consider only emissions reductions at affected EGUs, or should calculation also consider new *emissions added by a new NGCC [not affected under 111 (d)]*

iv) Should emissions from new NGCC included as an enforceable measure in mass-based state plan also be considered?

e. Other measures that would be appropriate for inclusion; and whether EPA should provide specific guidance on inclusion of these measures in plan

f. Any additional new nuclear generating units or uprating of existing nuclear relative to the baseline of capacity at the date of the proposal of emission guidelines. EPA requests comment on:

i) Alternative nuclear capacity baselines, including whether date for recognizing additional non-BSER nuclear capacity should be the end of the base year used in BSER analysis of potential nuclear capacity

g. New fossil fuel-fired EGUs

i) Concept of providing credit toward state's required 111 (d) performance level for emission performance at new 111 (b) affected units that, through application of CCS is superior to standards of performance for new EGUs

h. Incremental emission reductions from new fossil fuel-fired boilers, IGCC units with CCS, and new NGCC units that outperform standards for such units under 111 (b) based on use of CCS should be allowed as a compliance option to help meet requirements under a 111 (d) plan

i. Combined heat and power

j. Other areas beyond above that would be useful for EPA to provide guidance

k. Biomass derived fuel – contribution of these to atmospheric CO_2 is dependent/sensitive to the type of biomass feedstock used (including the way the feedstock is grown, processed, and combusted)

l Consideration of a Facility's "Remaining Useful Life" - EPA proposes that flexibility provided in the plan development process adequately allows for consideration of remaining useful life of facility and other source-specific factors;

should regulatory text be included in preamble discussion about how provisions in existing implementing regulations relate to this guideline?

1. Legal – EPA's 1975 implementing regulations address remaining useful life and other facility-specific factors that could affect requirements for existing source under 111 (d)

2. Implications for implementation of emission guidelines – EPA proposing to establish state emission performance goals for the collective group of affected EGUs in state, allowing the state to design the specific requirements

    a) To extent that performance standard that a state may adopt raises facility-specific issues, state is free to make adjustments to particular facility's requirements on specific grounds, as long as adjustments are included in 111 (d) plan submission

3. Relationship to State Emission performance goals and timing of achievement – EPA proposes that remaining useful life of affected EGUs and other facility specific factors should not be considered basis for adjustment of state emission performance goal or relieving state of obligation to complete an approvable state plan

J. Design, Equipment, Work Practice, or Operational Standards – CAA Section 111 (d) does not indicate whether states may include design, equipment, work practice, or operational standards or may include those types of standards, but only under limited circumstances described in section 111 (h) EPA invites comments on the following with regard to 111 (d) and (h)

1. Do provisions of 111 (d) preclude state plans from including design, equipment, work practice, or operational standards" unless they can be considered "standards of performance" or as providing for implementation and enforcement of such standards?

2. Are state plans authorized to include those design, equipment, work practice, or operational standards, but only under limited circumstances described in 111 (h)?

3. Are state plans authorized to include design, equipment, work practice, or operational standards under all circumstances so that limits of 111 (h) do not apply?

4. Should EPA authorize state plans to include them to the extent that there is legal uncertainty over whether, and under what circumstances state plans may include those standards?

K. Emissions Averaging and Trading – CAA 111 (d) authorizes state plans to include "standards of performance" and measures to implement and enforce them; EPA interprets that language as broad enough to incorporate emissions averaging and trading provisions

L. Resources for States to Consider in developing plans – EPA has developed a toolbox of resources that are available at http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox. For the final rule resources will be organized into two categories:

1. *State plan guidance section:*

   a. Serve has repository for final emissions guidelines, regulatory impact analysis, technical support documents, and other supporting material

2. State plan decision support section:

   a. Will include information to help states evaluate different approaches and measures they may consider in developing a plan

   b. Summary of current climate and EE/RE plans/programs, National Action Plan for EE, information on electric utility actions that reduce CO_2, and tools and information to assist with translating energy savings into emissions reductions

XVI Implications for other EPA Programs and Rules

1. New Source Review Program – a 111 (d) plan may impose requirements that require an affected EGU to undertake a physical or operational change to improve unit's efficiency that results in an increase in unit's dispatch and an increase in unit's annual emissions, which could trigger NSR if the threshold is exceeded.

   1. Flexibility

      a. State has ability to establish a standard of performance in their 111 (d) plan so that its sources when in compliance with the standard, would not have emissions increases that trigger NSR

      b. State could adjust EE or RE as a means of reducing the future emissions of an affected source initially predicted to increase emissions as a result of a 111 (d) plan requirement (reduced demand for operation).

c. Could develop conditions for a source expected to trigger NSR that would limit unit's ability to move up in dispatch enough to result in significant net emissions increase that would trigger NSR (establishment of synthetic minor limit)

2. *Seeking comment on:*

a. State plan could include a provision (with adequate record support), based on analysis, stating that affected source that complies with applicable standard would be treated as not increasing its emissions, and if so whether that provision means that as a matter of law, the source's actions to comply with the standard would not trigger NSR

b. Level of analysis required to support a state's determination that sources will not trigger NSR when complying with standards of performance included in state's 111 (d) plan, and type of plan requirements that would need to be included in state's plan

2. Implications for Title V Program

1. Re-proposed EGU NSPS (fees)

a. Proposed to exempt GHGs from the fee rates in effect for other fee pollutants, while

b. Proposing an alternative fee that would be much lower than the fee charged to other fee pollutants (but sufficient to cover the costs of addressing GHGs in operating permits)

2. Re-proposed EGU NSPS (regulations) – require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with applicable requirements

a. Requirements resulting from this rule imposed on affected EGUs that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into source's title V permit

b. Permit with remaining life of 3 years or more, a permit re-opening to incorporate newly applicable requirements must be completed no later than 18 months after promulgation of applicable requirement.

c. Permit with remaining life less than 3 years, newly applicable requirement must be incorporated at permit renewal

3. Interactions with Other EPA Rules – existing fossil-fuel fired EGUs are or will be impacted by other recently finalized or proposed EPA rules

1. MATS rule – reducing emissions of heavy metals, including mercury, arsenic, chromium, and nickel, and acid gases from new and existing coal and oil-fired EGUs. It will also reduce fine particulates.

2. In May 2014 EPA issued final rule under Section 316 (b) of Clean Water Act that establishes new standards to reduce injury and death of fish and other aquatic species from cooling water intake structures at exiting power plants and manufacturing facilities

3. Steam electric effluent limitation guidelines (SE ELG) to strengthen controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for steam electric power generating source category.

4. Coal Combustion Residuals rule (CCR), co-proposed two approaches to regulating the disposal of coal combustion residuals generated by electric utilities and independent power producers.

5. Development of SIPs for criteria pollutants, $PM_{2.5}$ and SO_2 and regional haze may want to have implications for existing fossil-fired EGUs

D. Ongoing Applicability of 111 (d)

a. Existing source subject to requirements under 111(d) will continue to be subject to those requirements even after a modification or reconstruction

a. Modified or reconstructed source would be subject to 111 (d) and 111 (b) simultaneously

XVII Impacts of the Proposed Action

A. Air Impacts

1. Option 1 – Four Building Block Approach

   a. CO_2 emissions projected to be reduced by 26-27% in 2020 and 30% in 2030 (compared to 2005 emissions)

2. Option 2 – Building Block 1&2 Approach

   a. CO_2 emissions projected to be reduced by 23% in 2020 and 23-24% in 2025 (compared to 2005 emissions)

3. Co-benefits – substantial co-benefits are expected through reductions in of SO_2, $PM_{2.5}$, and NO_x that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Reductions in HAPs may also happen as a result of this rule.

B. Comparison of Building Block Approaches

1. Four building block approach

   a. CO_2 emissions reductions of 27% in 2020

   b. 46-49 GW of additional coal-fired EGU retirements in 2020

   c. 16 GW in oil/gas steam EGU retirements in 2020

   d. 25-27% decrease in coal production

   e. 16-18% decrease in coal prices

   f. Increase of 12-14% in natural gas production

   g. Increase of 9-12% in natural gas prices

   h. 20-22 GW of new NGCC capacity

   i. 32-35 GW less NGCC capacity in 2030 relative to base case due to increase use of RE sources and decreased demand from EE

   j. Annual incremental cost excluding monitoring, reporting, and record keeping of $5.4-7.4 billion in 2020 and $7.3-8.8 billion in 2030

   k. Combined climate and health co-benefits of $33-57 billion in 2020 and $55-93 billion in 2030.

   l. Net benefits are estimated to be $27-50 billion in 2020, and $48-84 billion in 2030.

2. Combination of just building blocks 1 and 2

a. CO_2 emissions reductions of 22% in 2020

b. 24-32 GW of additional coal-fired EGU retirements in 2020

c. 3-4 GW in oil/gas steam EGU retirements in 2020

d. 20-23% decrease in coal production

e. 12% decrease in coal prices

f. Increase of 19-22% in natural gas production

g. Increase of 10-11% in natural gas prices

h. 11-18 GW of new NGCC capacity

i. 5-17 GW new NGCC capacity in 2030 relative to base case

j. Annual incremental cost excluding monitoring, reporting, and record keeping of $3.2-4.4 billion in 2020 and $6.8-9.8 billion in 2030

k. Combined climate and health co-benefits of $21-40 billion in 2020 and $32-63 billion in 2030.

l. Net benefits are estimated to be $18-36 billion in 2020, and $25-53 billion in 2030.

C Endangered Species Act – EPA has determined that projected environmental effects of this proposal are positive amounting to reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (So_x and No_x) and does not believe that such reductions trigger ESA consultation requirements under section 7(a)(2).

D. Energy Impacts – additional impacts (other than below are discussed more extensively in the Regulatory Impact Analysis

1. Option 1 – Four Building Block Approach

a. Average nationwide retail electricity prices are projected to increase by roughly 6-7% in 2020 (relative to the base case) in contiguous U.S.

b. Average monthly electricity bills are expected to increase by about 3% in 2030, but decline by approximately 9% by 2030 due to the increasing penetration of EE programs that offset increased prices to end users by expected savings from reduced electricity use.

c. Delivered coal price to the power sector is projected to decrease by 16-17% in 2020, and about 18% in 2030.

d. Electric power sector delivered natural gas prices will increase by 9-12% in 2020, with negligible changes in 2030.

e. Natural gas use for electricity generation is projected to increase by as much as 1.2 trillion cubic feet in 2020 relative to the base case and then decline over time.

f. Use of coal by the power sector will decrease roughly 30-32% in 2030.

g. Renewable energy capacity anticipated to increase by about 12 GW in 2020, and by 9 GW in 2030.

E. Compliance Costs

1. Option 1 – Four Building Block Approach

a. Annual incremental compliance cost estimated between $5.5-7.5 billion in 2020, and $7.3-8.8 billion (2011$) in 2030 including costs associated with monitoring, reporting, and recordkeeping (MRR)

i) MRR costs are estimated to be $68.3 million (2011$) in 2020 and $8.9 million in 2025 and 2030.

2. Option 2 – Building Block 1&2 only approach

a. Annual incremental compliance cost estimated between $4.3-5.5 billion in 2020 including MRR costs. In 2025, the estimated cost is between $4.5-5.5 billion (with assumed levels of end-use efficiency)

i) MRR costs are estimated to be $68.3 million in 2020, and $8.9 million in 2025

F. Economic and employment impacts

1. Option 1 – Four Building Block Approach

a. In electricity, coal, and natural gas sectors, EPA estimates guidelines could have an employment impact of roughly 25,900 to 29,800 job per year increase in 2020.

b. 44478,800 jobs in 2020.

2. Option 2 – Building Block 1&2 Approach

a. EE employment impacts are anticipated to increase by 57,000 jobs in 2020.

F. Benefits of the proposed goals - EPA used the social cost of carbon estimates presented in the 2013 Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 to analyze CO_2 climate impacts of this rulemaking.

1. Option 1 – Four Building Block Approach (regional compliance approach)

a. Total combined climate benefits and health co-benefits are expected to be $33-54 billion in 2020, and $55-89 billion in 2030

2. Option 1 – Four Building Block Approach (state-specific compliance approach)

a. Total combined climate benefits and health co-benefits are expected to be $35-57 billion in 2020, and $57-93 billion in 2030

3. Option 2 – Building Block 1&2 Approach (regional compliance approach)

a. Total combined climate benefits and health co-benefits are expected to be $26-44 billion in 2020 and $36-59 billion in 2025

4. Option 2 – Building Block 1&2 Approach (state-specific compliance approach)

a. Total combined climate benefits and health co-benefits are expected to be $27-45 billion in 2020 and $36-60 billion in 2025.