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EPA Docket Center
U.S. Environmental Protection Agency
Mail Code: 28221T
1200 Pennsylvania Ave., NW
Washington, DC 20460
ATTN: Docket ID No. EPA-HQ-OAR-2013-0602

Re: *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* EPA-HQ-OAR-2103-0602; Proposed Rule 79 Fed. Reg. 34829 (June 18, 2014)

American Electric Power (AEP) appreciates the opportunity to submit the attached comments on the Environmental Protection Agency (EPA)'s proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* 79 Fed. Reg. 34,829 (June 18, 2014), under § 111 of the Clean Air Act (CAA or the Act). AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP affiliates that own and operate electric generating units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

Re: *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* EPA-HQ-OAR-2103-0602; Proposed Rule 79 Fed. Reg. 34829 (June 18, 2014)

AEP's comments cover a wide range of issues, including EPA's interpretation of the scope of its legal authority to control all aspects of the generation, transmission, distribution and use of electric energy, as well as a detailed examination of the technical information underlying EPA's calculation of individual state emission rate "goals," the proposed schedule for development and submission of state plans, and the challenges of demonstrating compliance with the interim and final goals. Based on these concerns, AEP recommends that EPA withdraw the current proposal, address the significant legal, technical, and practical flaws that exist, and re-propose the guidelines for public comment. A summary of our comments and key recommendations are provided in the executive summary that follows below.

In addition to these comments, AEP is a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), the Electric Power Research Institute (EPRI), and other industry organizations. Except as otherwise set forth herein, AEP incorporates by reference the comments submitted by these groups.

We appreciate the opportunity to submit these comments, and hope to continue the dialog the agency has conducted during the development of this proposal. These issues have vast energy, economic, and environmental implications, and deserve thoughtful consideration.

Should you have any questions or need clarification regarding these comments, please direct them to me at 614-716-1268 or Frank Blake at 614-716-1240.

Respectfully submitted,

John M. McManus

John M. McManus
Vice President - Environmental Services
American Electric Power

c: Acting Assistant Administrator Janet McCabe, U.S. EPA (by email)
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American Electric Power

Comments to EPA Regarding the

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Proposed Rule
EPA-HQ-OAR-2103-0602
79 Federal Register 34829
(June 18, 2014)

Submitted December 1, 2014

Executive Summary and Recommendations:

EPA states that the proposed Clean Power Plan ("CPP") is "*an important step toward achieving the GHG emission reductions needed to address the serious threat of climate change*."[1] However, in taking that step, EPA has overstepped its statutory authority, and ignored the legal, technical, and practical limitations that govern the production, delivery, and use of electricity in the United States. Efforts have already been made, and continue to be made, by AEP and others to reduce greenhouse gas emissions from fossil-fueled electric generating units ("EGUs"). Additional dramatic changes in the nation's portfolio of generation resources and their associated emissions will continue in the near-term due a number of regulatory, market, and other drivers. For example, implementation of the Mercury and Air Toxics Standards.[2] and Regional Haze requirements[3] will result in AEP alone permanently removing over 6,000 megawatts ("MW") of coal-fired generating capacity from service and converting an additional 730 MW from coal- to gas-firing. Others are taking similar steps. Yet EPA provides no comprehensive assessment of the emission reductions resulting from these actions in order to determine whether, and if so, how much more reduction can and should be achieved, consistent with the requirements of section 111 of the Clean Air Act.

In its fact sheet released with the CPP, EPA claimed that the proposal would result in a 30 percent reduction in CO_2 emissions from 2005 levels for the power sector by 2030.[4] However, based on the guidance released on November 13, 2014, the actual reduction in CO_2 emissions from the existing fossil fleet required by this proposal on a mass basis is 30 percent *from 2012 levels* by 2030.[5] For the AEP fleet, this means that the 20 percent reduction in emissions already achieved from 2005 levels is completely disregarded, and deep additional cuts will be required to satisfy the goals established by EPA.

Section II of these comments provides a brief overview of the CPP, and a description of EPA's statutory authority under section 111(d) is provided in Section III. In the detailed sections that follow, AEP discusses the legal flaws in EPA's interpretation of the phrase "best system of

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[1] 79 Fed. Reg. 34,833.
[2] 40 CFR Part 63, Subpart UUUUU.
[3] 40 CFR §51.308.
[4] http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-overview.
[5] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice, Additional information regarding the translation of emission rate-based CO_2 goals to mass-based equivalents*, 79 Fed. Reg. 67,406 (November 13, 2014).

emission reduction" ("BSER"), and the legal and technical deficiencies in EPA's development of each of the building blocks. A brief summary of the balance of AEP's comments follows.

Summary of Section IV – EPA's Interpretation of "BSER" is Fatally Flawed

This proposal is wholly different from any prior emission limitation, standard, or guideline developed by EPA under the CAA. If adopted, the CPP would establish an expansive and unprecedented program to regulate the production, delivery, and use of electricity in the United States. The assumptions that EPA uses to develop state goals supersede the authority granted to the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, contain significant and fundamental technical flaws regarding the nature and operation of electricity generators and the electricity grid, and intrude upon authority reserved to the states. The proposal also is contrary to the express requirements of section 111 of the CAA, and EPA's own regulations, in several significant respects.

A fatal defect in EPA's CPP is the proposal's dependence upon an abstract, out-of-context interpretation of "system" in the phrase "best system of emission reduction" in the section 111 definition of "standard of performance." EPA's unprecedented interpretation of the word "system" in the "standard of performance" definition is disassociated from, and in conflict with, the interlinked CAA definitions of "stationary source," "existing source," "emission limitation," and "performance standard," and with the legislative history of Section 111. It is also in conflict with EPA's existing regulations that implement section 111, and at odds with EPA's interpretation and application of section 111 throughout its 44-year history. Rather than reflecting the degree of emission limitation achievable by applying a demonstrated technology-based (or work practice) system of emission reduction to the affected EGU, as the statute plainly directs, the proposal requires a reduction in the hours of operation and/or rate of production (or complete shutdown) of affected EGUs, a result contrary to the text and structure of the statute, and that could not have been imaginable to the Congresses that enacted and amended the CAA in 1970, 1977, and 1990.

Never before has EPA claimed the authority to limit productive capacity or control the rate of customer usage of a particular product, and the assertion of authority to do so here has no foundation in the CAA. Because EPA's interpretation would purport to give EPA broad power to regulate human behavior, EPA's interpretation of "system of emission reduction" must be rejected.

Summary of Section V - Building Block 1 Comments

EPA mischaracterizes observed variability in heat rate at coal units as being "evidence" that existing coal-based generating units are not being adequately operated or maintained.[6] Heat rate performance is influenced by a variety of known and unknown, controllable and uncontrollable factors, whose interaction is unit-specific and varies throughout the life of the unit. Moreover, EPA's examination of opportunities to improve heat rate either ignores or does not fully consider the following factors:

- the availability, technical viability, and economic feasibility of potential improvement opportunities at individual units;
- heat rate improvement measures that have already been implemented;
- unit-specific factors that influence the magnitude and sustainability of potential heat rate improvements; and
- other environmental regulatory requirements that may mask or eliminate opportunities for potential heat rate improvements.

There is also a long history of successful advancement and adaptation of new technologies, operating procedures, materials, and equipment upgrades that have allowed units within the existing fleet (both coal-fired and non-coal units) to maintain and improve efficiency through adoption of best practices. Had EPA fully considered these factors, the agency would have correctly concluded that both the proposed 6% and alternative 4% targets for heat rate improvements are overly aggressive, and cannot feasibly be implemented by the majority of existing coal-based generating units because:

- There is a wide range of inherent limitations on the potential for heat rate improvements, including original design, geographic location, availability of space, emission controls, and prior improvement efforts;
- Unit efficiency naturally degrades over time;
- There is no accurate method to measure heat rate in real time;
- Heat rate improvements may be masked by control technology installations or changes in duty cycle; and
- Remaining useful life will affect the economic feasibility of continued efficiency investments.

There is no single emission standard or limitation that is achievable or adequately demonstrated for all regulated sources. Instead, EPA should rely on Section 111(h)(1) of the

[6] "GHG Abatement Measures TSD". U.S. EPA. June 10, 2014. p. 2-1

CAA, which authorizes the Administrator to identify design, equipment, work practice, or operational standards, or a combination thereof, when it is not feasible to establish a standard of performance, and develop a work practice standard for EGUs. Such a standard would assure that cost-effective changes are routinely made at existing units, consistent with the criteria contained in section 111(d).

Summary of Section VI - Building Block 2 Comments

Building block 2 is based on EPA's generalized assumption that *all* existing NGCC units can be redispatched to sustainably achieve a 70% capacity factor, and that the additional generation provided by the existing NGCC units will *exclusively* offset generation from other, higher-emitting, existing fossil-fueled units. The underlying analysis that supports this assumption relies on inaccurate data, and generally represents a poor understanding and application of the basic concepts and operating metrics used to assess historic and future unit performance. The result is an assumed level of performance that simply has not been adequately demonstrated to be achievable across the fleet of existing NGCC units.

Further, EPA fails to explain how this building block is consistent with section 310 of the Clean Air Act,[7] which specifically preserves the authority of all other federal agencies, when such requirements for "environmental dispatch" would effectively override the system of security constrained economic dispatch created by the Federal Energy Regulatory Commission ("FERC") and implemented through regional transmission organizations ("RTOs"), independent system operators, and other balancing authorities, as required by the Federal Power Act.[8]

Even if such a concept could be incorporated into a section 111(d) standard, the level of operation assumed by EPA in calculating the state goals contains fundamental errors, such as: (1) relying on nameplate capacity instead of net demonstrated capacity (which results in about a 10% increase in the goals that cannot reasonably be achieved); (2) including units that are not designated facilities; (3) failing to accurately and consistently account for units that operated for only a portion of 2012, or were not yet operating; and (4) failing to adequately evaluate the availability of gas pipeline capacity to deliver fuel and transmission capacity to deliver power, and the time and cost necessary to increase capacity if it is not already available. EPA's own

[7] 42 U.S.C. § 7610(a).
[8] 42 U.S.C. § 824(b).

policy case modeling does not achieve the level of operation assumed by EPA in calculating the state goals.

EPA must present a proposal that, at a minimum, is grounded in accurate, complete data and that reflects the actual operation of the electricity grid. Given the egregious nature and scope of concerns to be resolved in building block 2 *alone*, EPA should withdraw the current proposal and publish a new proposed rule for public comment.

Summary of Section VII - Building Block 3 Comments

EPA has not cited, and AEP has not discovered, any statutory basis for the inclusion of generation from new and existing non-emitting nuclear and renewable resources in its calculation of state goals to regulate emissions of fossil-fueled EGUs. Such units are not "affected facilities" in the listed source categories for which these guidelines are proposed, nor would they be subject to any standards under section 111 if they were "new." EPA's expansion of its regulatory grasp far exceeds the scope specifically authorized by Congress, and invades the reserved powers of the States under the Tenth Amendment to the U.S. Constitution.

Moreover, EPA's use of individual state renewable portfolio standards to establish "regional goals" that each state must achieve is ill-informed, and overlooks distinctions among these state standards that either significantly reduce the absolute value of those standards, or rob the states of flexibility in implementing the goals, or both. EPA has also insufficiently evaluated the technical potential and cost of renewable resources across the states, and ignored significant questions related to the expansion of both intrastate and interstate transmission resources, regulatory processes, cost allocation, and timing.

Any goals established by EPA in the final rule cannot rely on nuclear or renewable resources. However, EPA should prescribe procedures for the development of state plans that allow states to determine if or how renewable resources may be included in their compliance plans.

Summary of Section VIII - Building Block 4 Comments

EPA also does not have clear authority from Congress to dictate energy policies that control customer demand, including the degree to which energy efficiency ("EE") measures should be adopted by individual customers.[9] Even if such authority existed, EPA has failed to demonstrate that the level of EE used to calculate the state goals is achievable or has been adequately demonstrated. Specifically, EPA ignores the expert evaluations of the majority of states regarding a reasonably achievable level of EE, the pace of increase in EE achievement, and a reasonable level of costs to achieve those proposed EE levels. Further, the data and methodology that the agency used in establishing these levels for all states in a one-size-fits-all manner ignores many fundamental differences between the states that affect the nature and scope of achievable EE measures and rates of growth. EPA did not use a transparent process in estimating the costs of the proposed EE levels, did not consider all cost elements of EE, and did not give adequate consideration to the ways such costs will affect customers. EPA's failure to specifically identify the evaluation, measurement and validation ("EM&V") methods required for a satisfactory state plan, and its failure to assess whether such EM&V measures are currently applied in the programs identified as "best practice standards," provide an inadequate basis for commenters to determine the actual impact of the proposed guidelines. Accordingly, EPA should not assume specific levels of EE achievement in developing any state-specific goals, but states should retain the flexibility to determine if or how EE measures may be included in their compliance plans.

Summary of Section IX – Implementation Concerns

The flaws identified within each of the building blocks collectively lead to serious concerns related to the practical implementation of the CPP. Because the errors identified in the development of each building block lead to a significant overstatement of its potential contribution to reductions in emissions from existing fossil-fueled EGUs, the combined whole represented in the state goals has not been adequately demonstrated and is not achievable. All

[9] Indeed, in the context of EPA's authority under Section 169 of the CAA to specify what is the "best available technology" for regulated pollutants in a new source review ("NSR") permit, the Supreme Court noted with approval that, "BACT may not be used to require 'reductions in a facility's demand for energy from the electric grid,'" and that "BACT should not require every conceivable change that could result in minor improvements in energy efficiency, such as the aforementioned light bulbs." Rather, the Court confirmed that BACT can only be required for pollutants that the source itself emits, and that permitting authorities should consider whether the proposed regulatory burden outweighs any emission reductions that can be achieved. *UARG v. EPA*, 134 S.Ct. 2427, 2448 (2014). These same principles should apply to the BSER, which is based on technology that can be applied to emissions from the regulated source, and must satisfy the statutory balancing of costs, other environmental affects, and the emission reductions actually achieved.

flexibility that would have been present had EPA accurately assessed each building block evaporates.

Moreover, EPA's proposal to extend compliance responsibilities to entities other than the "designated facilities" exceeds EPA's and states' authorities under the CAA, creates uncertainty regarding the ultimate enforceability of the state goals, and raises procedural and substantive due process concerns for sources within the regulated source categories if states elect to follow EPA's advice and reduce their plan requirements to goals enforceable only against those sources. EPA has ignored the requirement under section 111(d) to provide states with the flexibility to adjust the stringency of the final performance standard or the timing of the ultimate compliance schedule based on the remaining useful life of the regulated sources. And the timeline to achieve compliance is unreasonable, particularly for building blocks 1 and 2, both of which are proposed to be fully implemented by 2020. EPA has no authority to dictate the timing of implementation or to establish interim goals, and these are issues that should be reserved to the states as they develop final performance standards.

Summary of Section X – Transmission and Reliability Issues

The reliability and resource adequacy analysis performed by EPA is incomplete and inaccurate. It asks the wrong questions and provides answers developed using the wrong tools. Any analysis of the achievability of the CPP must be based on the tools used by reliability organizations to assess power flows under the conditions projected to occur as the CPP is implemented. Because EPA assumes that there will be dramatic changes in the composition, location, and characteristics of the generation fleet as a result of the CPP, such an analysis must be performed iteratively by organizations with the expertise and knowledge to analyze the dynamic nature of the impacts of these changes.

The North American Electric Reliability Corporation ("NERC") recently released a preliminary assessment of the stability and reliability of the grid if the changes envisioned in EPA's modeled outputs for its cost-benefit analysis actually occurred in 2020.[10] These changes will strain reliability and essential services, require expansion of the transmission grid, and are inconsistent with the planning horizons used to implement transmission reliability enhancements. The Southwest Power Pool ("SPP") has performed a similar analysis of the potential reliability

[10]http://www.nerc.com/pa/RAPA/ra/Reliaiblity%20Assessment%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

impacts within the SPP region. SPP found that: "1) the CPP will impact the reliability of the bulk electric system; 2) the timing proposed by EPA for compliance is infeasible; and 3) the proposed CPP will have material impacts on the market-based dispatch of electric generating units within the SPP region."[11] AEP's own internal analysis of the SPP and PJM regions within which it operates yielded similar results. Any future proposals must be accompanied by a comprehensive analysis that demonstrates that the security and reliability of the bulk power system will not be compromised.

Summary of Section XI – Assessment of EPA's Regulatory Impact Analysis ("RIA")

EPA's RIA lacks information on the full range of issues that should inform its assessment of the costs and benefits of the proposed CPP. There are startling inconsistencies between the assumptions used to calculate individual state goals and the results of EPA's modeled implementation that suggest that the assumptions underlying the individual building blocks are unreasonable, or that practical and economic constraints would produce results that vary significantly from those assumptions. EPA failed to include in its base case the existing and planned levels of EE based on current state program requirements, thus overstating the "benefits" of the CPP.

Further, the RIA has substantially underestimated the costs and the negative macroeconomic impacts (e.g. large job losses) of the CPP. This includes data errors and flaws in methodologies, which results in significant overstatement of the reduction capabilities of each of the four EPA building blocks and at the same time understates the actual costs of achieving these building block reductions. The RIA also fails to consider serious reliability constraints, which will require major electricity transmission investments as well as new natural gas pipelines and infrastructure. Not only will these investments result in significantly higher costs, they will also make achievement of the CPP interim reduction goal requirements infeasible in a number of states. EPA's analysis also improperly uses the "social cost of carbon" and collateral reductions of criteria air emissions to justify increases in the cost of electricity that will be disproportionately borne by those of low or fixed incomes.

[11] http://www.spp.org/publications/CPP %20Reliability%20Analysis%20Results%20Final%20Version.pdf

Summary of Section XII – Miscellaneous

There are important additional issues concerning EPA's lack of authority to regulate EGUs given its prior regulation of this source category in the MATS rule, the unlawful takings that would arise if the rule is implemented and enforced to require reduced utilization or retirement of existing units with remaining useful lives, the illegality of EPA's proposal to regulate modified and reconstructed units as both "new" and "existing" units, EPA's failure to clearly delineate the Title V requirements that will apply to area sources as a result of this proposal, the lack of coordination between this proposal and the anticipated issuance of a proposed ambient standard for ozone, and its failure to provide a reasonable opportunity for comment on the many additional issues raised for the first time in the notice of data availability ("NODA") released on October 30, 2014. Several of these issues are discussed at length in the comments of others, and those comments are incorporated by reference in this section.

Recommendations (Section XIII)

Electricity serves as the foundation of our nation's safety, security, and prosperity. EPA must take the time to carefully consider all of the comments submitted, and to issue guidelines that strike the appropriate balance between environmental protection and economic well-being. EPA should develop and issue for comment a proposal that includes the following elements:

(1) Heat rate improvements can be cost-effective ways to reduce CO_2 emissions, or to mitigate increases in CO_2 emissions, over the life of a fossil-fueled generating unit, regardless of fuel type or unit design. However, given the inherent variability in heat rate due to duty cycles and other uncontrollable factors, and the lack of an effective real-time heat rate measurement technique, it is infeasible to establish traditional emission limitations or standards based on improved heat rates. EPA should collect sufficient information about the techniques that could potentially be adopted to varying degrees at existing units (considering costs, lack of physical space, degree of prior adoption, remaining useful life, and other factors) and formulate a proposed guideline for a work practice standard that would allow for periodic evaluation of cost-effective heat rate improvement opportunities on a unit-specific basis, that can then be integrated into regularly planned outages across the existing fleet. Such a measure would ensure sustained adoption of available efficiency improvements within the existing fleet, which is the "best system of emission reduction" for these designated facilities.

(2) Encouraging reduced utilization of certain existing units and increased utilization of others is not authorized as a "means of emission limitation" under Section 302, and is inconsistent with the authorities granted to the Federal Energy Regulatory Commission (FERC) and the regional reliability organizations under the Federal Power Act (FPA). Section 310 of the Clean Air Act clearly states that EPA's authorities cannot be interpreted in such a way as to intrude upon the implementation of security constrained economic dispatch of the bulk electric system through the mechanisms FERC has developed under the FPA. However,

future emission reductions will occur through the natural aging of the existing fleet, and plans could be established based on the remaining useful life of existing units consistent with the express language of section 111(d). EPA should allow states to examine the emission reductions that will occur within the existing fleet as units near and reach the ends of their useful lives, and establish a glide path to lower total mass emissions from the existing fossil fleet. EPA should allow states to calculate the "degree of emission reduction" achieved through such a procedure, and to develop the path for reductions that is consistent with the energy and economic needs of the states. EPA has no authority to dictate arbitrary "interim" goals that the states must meet.

(3) Nothing in the Clean Air Act gives EPA the authority to specify the types of new generation resources that should be constructed to fulfill a utility's obligation to serve. This authority has been specifically reserved to the states under the FPA, and no Congress has yet passed laws to establish national renewable portfolio standards. However, EPA should allow states to examine the planned additions of renewable and other low- or non-emitting resources under existing integrated resource plans and other siting or certification requirements, and use any approved, cost-effective resource additions as creditable emission reductions, to facilitate the transition of the existing fleet to a cleaner, more modern system.

(4) Energy efficiency targets and goals have also been used by state utility regulators and state energy resource planning agencies as a means to delay the need for additional capital-intensive base-load generating resources, and to manage peak loads. States should be given the option to take credit for these efforts if they prove to be cost-effective, and as new technologies develop. However, EPA is not an energy planning expert or rate regulator, and these measures can only be developed consistent with the reserved power of the states for retail energy rate regulation. There is no single "best practice" that can be established for all states. Each state should be allowed to incorporate its energy planning strategy into a plan under section 111(d) to the extent it determines is appropriate.

Like the Clean Power Plan, the four recommendations listed above are not mandatory or federally enforceable requirements; they are merely guidelines to be used by the states as one of many factors that will contribute to the development of final state and regional plans. States would be free to identify other measures in their plans, if they are more cost-effective or better suited to individual state policies and resources. EPA's backstop authority under Section 111(d) would permit it to develop a federal implementation plan if a state fails to submit a satisfactory plan, but it could be based on only the first two recommendations, which directly control emissions from the regulated sources. Additional measures based on recommendations three and four would help states accommodate needs for increased flexibility, such as allowing the states to address units that have no cost-effective options for heat rate improvements due to site-specific factors, or where replacement of existing resources will require a longer compliance time frame due to the need for transmission mitigation or reinforcement, or other infrastructure additions.

COMMENTS OF THE OPERATING COMPANIES OF THE AMERICAN ELECTRIC POWER SYSTEM ON THE CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS; PROPOSED RULE, 79 Fed. Reg. 34829 (June 18, 2014) EPA-HQ-OAR-2013-0602

<u>OUTLINE:</u>

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document that "reflects the best system of emission reduction ... for *designated facilities*."

E. EPA's broad interpretation of "system of emission reduction" conflicts with its more limited interpretation of "system" in Subpart B and its current interpretations of "system" in other rulemakings.

F. EPA's emission guidelines permit states to apply emission standards to both "designated facilities" and other entities, but Subpart B permits the application of emissions standards only to "designated facilities."

V. The Emission Reductions Required by Building Block 1 Are Not Achievable

A. EPA should objectively and holistically consider the full range of issues that influence heat rate performance
    1. Heat rate improvement opportunities are unique to each unit
    2. Actual heat rate performance varies due to a number of known and unknown, controllable and uncontrollable factors
    3. EPA has overstated the potential heat rate improvements related to operating practices
        a. The design of EPA's statistical analysis is fundamentally flawed
        b. EPA's dataset contains inherent sources of variability
        c. EPA failed to account for physical and operational changes at existing units that affect potential heat rate improvement opportunities

B. EPA has overstated heat rate improvements related to equipment upgrades
    1. EPA's use of a 2009 Sargent & Lundy study does not support the BSER determination on heat rate improvements from equipment upgrades
    2. EPA's review of other documents discussing heat rate improvements does not support the BSER determination on heat rate improvements from equipment upgrades
    3. The unit-specific examples identified by EPA do not demonstrate that its heat rate improvement targets are achievable or adequately demonstrated.
    4. EPA fails to adequately address NSR related issues that challenge the efficacy of heat rate improvement opportunities

C. EPA fails to evaluate whether the 2012 heat rate data is representative of typical unit operations or if the application of a 6% improvement is feasible given prior improvement efforts and historic unit trends

D. EPA failed to examine heat rate improvement opportunities at other designated facilities

E. EPA should develop a work practice standard for heat rate improvements at designated facilities

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VI. Building Block 2 Exceeds EPA's Authority and Is Based on Flawed Data and Methods

A. EPA lacks the statutory and regulatory authority to redispatch EGUs

B. EPA has not demonstrated that a 70% capacity factor is achievable by all existing NGCC units

C. The criteria used by EPA to evaluate NGCC performance and to determine a redispatch capacity factor as the BSER is flawed

D. EPA provides no legitimate rationale for determining that a 70% capacity factor is achievable by the entire NGCC fleet

E. EPA has not fully evaluated the transmission and gas supply infrastructure issues that may significantly impact the feasibility and amount of potential redispatch
   1. EPA should thoroughly evaluate natural gas supply issues
   2. EPA should thoroughly evaluate electric transmission issues

F. EPA failed to evaluate existing air permit conditions that may significantly impact the feasibility and amount of potential redispatch

G. EPA should exclude combined heat and power facilities from the building block two calculations for NGCC units
   1. CHP units should be considered separately from NGCC units
   2. EPA should evaluate whether individual CHP units are affected sources subject to the 111(d) guidelines
   3. EPA incorrectly applies the electric output associated with useful thermal output from CHP units in the building block two calculations

H. EPA has significantly overestimated the amount of NGCC capacity available for redispatch due to egregious methodological issues and data quality errors
   1. EPA incorrectly uses "nameplate" capacity in the block 2 calculations
   2. EPA incorrectly includes simple-cycle and gas boiler units in their calculation of "existing" NGCC capacity
   3. Building block two incorrectly and inconsistently includes NGCC units that were constructed after 2011
      a. In the calculation of existing NGCC capacity available in 2012, EPA incorrectly included units that had/have not yet been commissioned
      b. EPA has incorrectly calculated the post-2012 "under construction" NGCC capacity for <u>all states</u> where the agency determined it applied
      c. EPA fails to consider certain existing NGCC units that were commissioned during or after 2012
      d. EPA incorrectly accounts for NGCC units commissioned during 2012 in their calculation of potential redispatch amounts
   4. EPA must resolve significant data quality issues
   5. Building block two calculations are incorrect for all states identified by EPA as having applicable NGCC units

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6. EPA must revise all aspects of the proposed rule that are impacted by the data quality and methodological issues identified for building block 2

I. Building Block 2 Comments related to EPA's NODA
    1. Phased Implementation of Building Block 2
    2. Consideration of Minimal NGCC Utilization in the BSER
    3. Regional Approach to Building Block 2

VII. Building Block 3 is unachievable

A. Renewable resources must be excluded from the determination of the best system of emission reductions for existing fossil fuel electric generating units
    1. Renewable resources are not affected sources under 111(b) and therefore cannot be regulated under 111(d)
    2. EPA has infringed upon States Tenth Amendment Rights

B. EPA's use of existing renewable portfolio standards to determine state renewable energy targets is fundamentally flawed
    1. EPA has mischaracterized and overstated the renewable energy development associated with existing renewable portfolio standards
    2. EPA's methodology for calculating renewable energy goals is flawed
    3. The state renewable goals calculated by EPA are flawed and inconsistent with the assessment and experience of individual states
    4. EPA should more robust data as the baseline for building block 3

C. EPA's alternative approach for calculating renewable energy goals is fundamentally flawed
    1. EPA overstates the technical potential of state renewable resources and calculates growth rates for renewable energy development that are flawed
    2. EPA uses unsubstantiated assumptions on future costs to estimate the market-based potential for state renewable energy development
    3. The alternative methodology produces absurd results as applied to state emission rate goal

D. Building Block 3 Comments related to EPA's NODA
    1. The alternative approach proposed in NODA is flawed
    2. State goal calculation method for Building Blocks 3 and 4

E. EPA did not fully consider transmission issues that impact the feasibility, cost, and timing for developing renewable resources

F. EPA does not fully consider the technical, cost, regulatory, and practical challenges of increasing renewable resources

G. EPA should exclude nuclear energy from state goal calculations

H. Recommendations regarding building block 3.

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VIII. Building Block 4 Comments

A. Flaws in EPA's EE Achievability Analysis

1. Base Data Inconsistencies
2. Invalid extrapolations
    a. Relative size of customer classes not comparable
    b. Commercial and industrial opt-out provisions not considered
    c. Customers subject to section 111 of the CAA should be excluded
    d. Average temperatures and electricity consuming devices are not comparable
    e. Temporal considerations
    f. Other options
3. Customer economic challenges
4. Market potential studies
5. States uses as proxies
6. Illustrated example
7. EE growth estimates

B. Cost Estimates

C. Measurement and Accounting

1. Attribution
2. Evaluation, Measurement, and Validation
3. Impacts

D. Ancillary Issues

1. Municipal and Co-operative utilities
2. C&I opt-out / Self-direct provisions
3. Variety of EE sources
4. Cost-effective EE not included in base case
5. Beneficial use
6. Timing

IX. EPA has failed to describe the mechanisms states can use to develop and implement a plan that will reliably demonstrate compliance.

A. Errors and uncertainties in EPA's state goal calculations creates significant uncertainty regarding the actual goal to be met and viability of available compliance options

B. Issues within each building block make implementation unworkable

1. Improvements made through building block 1 cannot be reliably projected or enforced
2. Building block 2 cannot require states to interfere with the economic dispatch or reliable operation of the grid
3. Building blocks 3 and 4 are not enforceable against designated facilities

C. Uncertainties with the state plan development process and design options must be resolved before states can propose implementation plans to EPA

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1. EPA's Proposal to Allow State Plans to Include Federally Enforceable Obligations on "Affected Entities" Exceeds EPA's Statutory Authority.
2. EPA's Proposal to Regulate States or State Agencies as "Compliance Entities" Is Inconsistent with the Clean Air Act's Premise of Cooperative Federalism and Raises Serious Enforceability Concerns
3. Uncertainties Affect Plan Development Due to Reliability Issues
4. Uncertainties Regarding Multi-State Plans

D. EPA has overstated the degree of implementation "flexibility" available to states
   1. Significant compliance flexibility will be eliminated if EPA corrects the technical errors associated with building blocks one and two
   2. Potential compliance options referenced by EPA outside of the building blocks do not provide additional "flexibility"
   3. EPA's proposed alternative mass-based program does not provide additional compliance flexibility

E. EPA must not infringe on the statutory authority granted state plan development, including consideration of the remaining useful life of the existing source

F. EPA cannot regulate affected sources under both 111(b) and 111(d)

G. EPA's proposed implementation timeline is unachievable

X. EPA Failed to Conduct An Adequate Reliability Analysis, and Does Not Provide Adequate Time in Its Implementation Schedule to Address Electric Infrastructure Needs

A. EPA Lacks the Tools and Expertise to Assess Transmission Reliability

B. AEP and Industry Analyses Demonstrate Real Reliability Concerns

C. CPP Compliance Plans Are Not Viable without a Regional Transmission Analysis

D. Interim Goals Incompatible with Transmission Infrastructure Requirements

E. Assumptions for Renewable Expansion Must Also Consider Transmission Requirements

F. Transmission Recommendations

XI. Assessment of Regulatory Impact Analysis

A. Lack of Information on State Compliance Actions

B. Conflicts Between Results and Purported BSER elements

C. Incomplete and Improper Assessment of Compliance Actions, Infrastructure Timing and Costs

D. Incomplete Assessment of Employment Impacts

E. Improper Treatment of Energy Efficiency

F. Improper Use of Social Cost of Carbon

I. Introduction

On June 2, 2014, the United States Environmental Protection Agency ("EPA") issued a proposal entitled *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule,*[1] (also referred to as the Clean Power Plan or "CPP"). If adopted, the CPP would establish an expansive and unprecedented program to regulate the production, delivery, and use of electricity in the United States. Based on the legal analysis and principles laid out in the proposed CPP, EPA is claiming authority to regulate the electric grid and the use of electricity, in pursuit of greenhouse gas emission reductions, that is virtually unlimited. If upheld by the courts, there is no reason to believe that EPA would be reluctant to extend these legal theories and principles to other source categories, leading to an unprecedented degree of control over the productive capacity of those sources and consumer choices about the use of those products.

However, the Supreme Court has recently stated, in the context of another EPA rulemaking for greenhouse gases, that "When an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' … we typically greet its announcement with a measure of skepticism."[2] Such skepticism is warranted here as well. The statutory authority for this proposal is claimed to reside in a section of the Clean Air Act ("CAA") that has rarely been used and that does not support the breadth of this regulatory proposal. Instead of identifying the degree of emission reduction that can be achieved by "existing sources" that are "designated facilities" within a "source category," as authorized by Congress, EPA instead has identified an "emission rate" that cannot be achieved by the "designated facilities" alone, and that presumes implementation of a multitude of electricity-related activities throughout each individual state, including activities to reduce electricity usage by individual electricity customers. The emission rate is based on an equation that includes not only the generation and emissions from "designated facilities" to which a section 111 standard would apply if those facilities were "new," but also the production of electricity from emitting and non-emitting sources outside the designated source category, and avoided generation attributed to customer end-use efficiency measures. All of these activities are identified as part

[1] 79 Fed. Reg. 34,829 (June 18, 2014).
[2] *UARG v. EPA*, 134 U.S. 2444 (2014) (citations omitted).

of an overall "best system of emission reduction" ("BSER") that is inconsistent with the statute, EPA's own regulations, and its historic implementation of this CAA provision.

EPA uses this equation to establish emission rate targets for individual states to meet through the development of individual state or regional plans. States will not be able to alter the emission rate once EPA finalizes the CPP, and EPA will judge the adequacy of each state's plan against the targets ("state goals") once the proposed rule is finalized. The targets include both "interim" and "final" goals, but the "interim" goals represent 50-90 percent of the required reductions in most states, and average over 60 percent of the final goals. States must complete substantial actions toward a final approved plan within one year after the guidelines are final, and there could be as little as 6 - 18 months between the federal approval of a state plan and the beginning of the first compliance year.

The operating companies of the American Electric Power (AEP) System appreciate the opportunity to submit the attached comments on the CPP. AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states, and will be directly affected by the requirements of the final rule. AEP companies also own the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

AEP is a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), and other industry organizations. Except as otherwise set forth herein, AEP incorporates by reference the comments submitted by these groups.

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II. Overview of the CPP

On June 23, 2013, President Obama announced a "Climate Action Plan" to address greenhouse gas ("GHG") emissions from a number of different sectors of the economy, which included a specific schedule for the EPA to propose and finalize a GHG program for electric generating units ("EGUs"). The President's plan called for EPA to issue its proposal for EGUs on June 1, 2014. The anticipated time frame for finalizing and implementing the CPP is as follows:

- Proposed CPP published in the *Federal Register* June 18, 2014;
- Public comment period on the proposed CPP ends December 1, 2014;
- Final CPP to be issued by June 1, 2015;
- Individual plans to be submitted by the states by June 30, 2016, but EPA may grant one-year extensions for state plan submittals and two-year extensions for states that commit to develop multi-state regional plans;
- EPA has up to one year to approve state plans, which could occur as early as June 2017, or as late as June 2019 or beyond;
- Under the proposed CPP, the initial compliance period begins January 1, 2020.

The proposed CPP is based on four "building blocks" which EPA uses to calculate proposed state goals that focus on reducing carbon dioxide ("CO_2") emission intensity from this sector. The state goals are expressed as pounds of CO_2 emissions per net megawatt-hour of electricity ("lbs./MWh net"). The four building blocks and the assumptions used in the calculations in the proposed CPP are as follows:

- Building Block 1: All existing coal plants are assumed to improve their collective average heat rate by 6%, resulting in a corresponding reduction of 6% in the CO_2 emission rates for these units.
- Building Block 2: All existing natural gas combined cycle ("NGCC") units (including those currently under construction) are assumed to increase their collective average utilization to at least a 70% capacity factor. The increased energy produced by NGCC units is assumed to displace higher CO_2-emitting generation (from coal-, gas-, and oil-fired steam units).
- Building Block 3: All states will implement regionally identified "best practices" to incorporate increasing amounts of renewable energy ("RE") into their generation portfolios, achieving in effect a 13% national renewable portfolio standard ("RPS") by 2030. EPA also assumes the continued operation of existing nuclear units (including nuclear units currently under construction) at a 90% or better capacity factor, and that no additional nuclear units will retire. The goal calculation for states with existing nuclear capacity assumes 6% of the nuclear capacity in the state

displaces carbon-emitting generation. EPA also includes the full amount of any new nuclear capacity currently under construction in the calculation of the emission rate for those affected states.

- Building Block 4: States will implement "best practices" to encourage customers to use energy efficiently ("EE"), achieving incremental savings, presumed to displace up to 1.5% of electricity sales annually and up to 10% by 2030 and thereafter.

EPA also requests comment on a set of alternate less stringent state goals that would require final compliance by 2025 instead of 2030. For the alternate goals, the 'building blocks" assume the following activities:

- Building Block 1: achieve a 4% improvement in heat rate at existing coal units
- Building Block 2: increase utilization of existing NGCC capacity to 65%
- Building Block 3: increase renewable energy to 9.4% of energy sales; and
- Building Block 4: increase EE to 5.2% cumulative energy savings by 2025 and thereafter

EPA relies on all four of these "building blocks" to establish the overall targets for each state. The state goals can generally be expressed by the following formula:

$$\frac{CO_2 \text{ emissions from all affected fossil EGUs (in pounds) + other emissions}}{\text{Generation from (fossil EGUs + 6\% nuclear + renewables}^{3}\text{) + UTO}^{4}\text{ + EE savings (in MWh)}}$$

Using this calculation and output from its Integrated Planning Model (IPM), EPA established an "interim" goal for each state based on full implementation of the changes required under building blocks 1 and 2, and a glide path of incrementally more stringent annual goals based on gradual implementation of the measures required under building blocks 3 and 4, until the "final" goal is achieved in 2030, and maintained in each year thereafter (on a three-year average basis). EPA proposes that the "interim" goals can be met on a 10-year average basis, with annual reporting and corrective measures if states fall behind in their implementation. Because the amount of electricity and emissions from fossil generation in each state vary significantly, as do the capacity and performance of renewable resources, and the applicability and penetration of energy efficiency measures, the goals calculated for each state have a very wide range.

In the 1975 rulemaking finalizing EPA's implementing regulations for §111(d), EPA explained that, "[a]lthough the general principle (application of best adequately demonstrated

[3] Renewable resources do not include existing hydroelectric generation resources. In addition, EPA is unclear on how biomass will be treated under the program.
[4] UTO = Useful Thermal Output associated with combined heat and power facilities.

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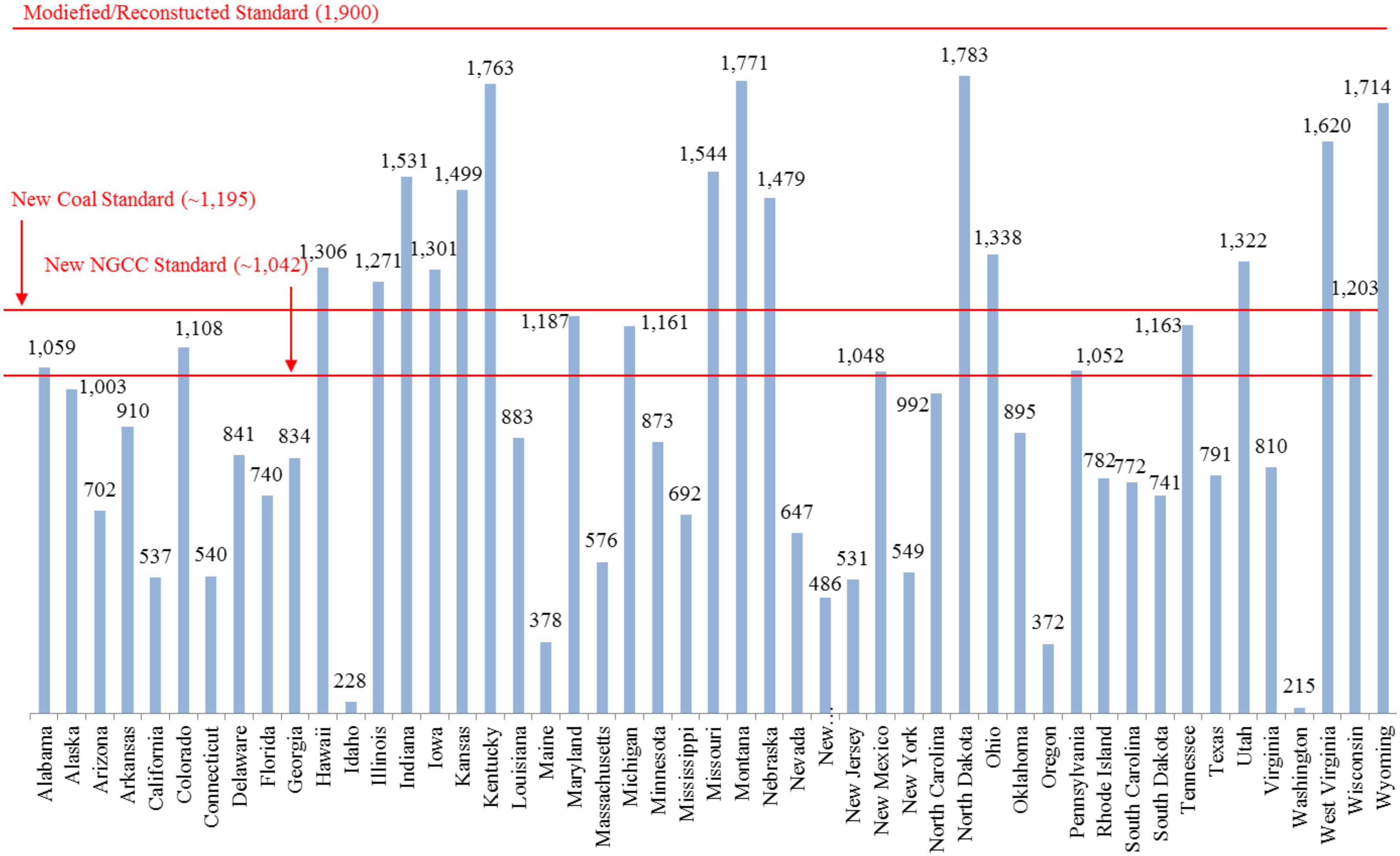
control technology, considering costs) will be the same [under sections 111(b) and 111(d)], the degrees of control represented by EPA's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources."[5] In EPA's Clean Power Plan, in comparison, approximately half of the states' CO_2 emission performance goals are less than the standards for new electric utility boilers.[6] While these state goals are not, themselves, standards of performance, EPA has said that "each state will determine, and include in its plan, emission performance levels for its affected EGUs that are equivalent to the state-specific CO_2 goal in the emission guidelines, as well as the measures needed to achieve those levels and the overall goal."[7] Consequently, for over half of the United States, EPA's Clean Power Plan would impose more stringent emission reduction requirements for existing EGUs than the performance standards EPA is proposing for new EGUs. A comparison of the final state goals to the standards EPA has proposed for "new" fossil-fueled electric generating units is shown below.

5 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975).
6 *See* Proposed Subpart UUUU, Table 1.
7 79 Fed. Reg. at 34,837.

Proposed Existing Source 111(d) Final Goals vs. New Source 111(b) Standards (lb CO2/MWh net)



For the states in which the AEP companies operate, the interim and final goals, and the relative contribution of each building block to the ultimate reductions are summarized in the table below.

State Goals and Relative Reductions Contributed by Each Building Block

	2012 Average State Coal Emission Rate	2012 Average State NGCC Emission Rate	Interim Goal	Final Goal	Block 1	Block 2	Block 3	Block 4
	(lb. CO_2 / MWh net)				% of 2030 Rate Reduction			
Arkansas	2,276	827	968	910	9%	60%	14%	17%
Indiana	2,158	914	1,607	1,531	24%	11%	17%	48%
Kentucky	2,166	n/a	1,844	1,763	29%	15%	8%	48%
Louisiana	2,323	766	948	883	7%	54%	16%	22%
Michigan	2,255	810	1,227	1,161	13%	32%	19%	37%
Ohio	2,216	963	1,452	1,338	16%	14%	32%	38%
Oklahoma	2,305	891	931	895	9%	50%	21%	20%
Tennessee	2,244	813	1,254	1,163	10%	10%	51%	29%
Texas	2,239	837	853	791	8%	44%	28%	20%
Virginia	2,268	903	884	810	6%	33%	31%	24%
West Virginia	2,056	n/a	1,748	1,620	27%	0%	52%	21%

The CPP proposal is wholly different from any prior emission limitation, standard, or guideline developed by EPA under the CAA. The assumptions that EPA uses to develop state goals supersede the authority granted to the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, contain significant and fundamental technical flaws regarding the nature and operation of electricity generators and the electricity grid, and intrude upon authority reserved to the states. The proposal also is contrary to the express requirements of Section 111 of the CAA, and EPA's own regulations, in several significant respects.

The following comments outline the requirements for rulemaking under section 111(d), and the principles that in the past have guided, and should in this case guide, EPA's determination of the "best system of emission reduction" ("BSER") for existing fossil fuel-fired steam electric- and combustion turbine-based generating units. They then examine the individual building blocks and point out ways in which EPA's determinations are inconsistent with the physical and practical limitations that affect the electricity system, are based on inaccurate information, contain fundamental errors in methodology, or are otherwise arbitrary and capricious. Finally, the comments examine the challenges states will face in attempting to implement the requirements of the proposal, address the reliability concerns raised by the proposal, and analyze the shortcomings in EPA's cost-benefit analysis. The comments conclude with suggestions for implementing a practical program to achieve CO_2 emission reductions from existing fossil fuel-fired electric generating units that is consistent with the CAA and acknowledges the primacy of the states in implementing such programs.

III. Basis for Rulemaking Under Section 111(d)

Ultimately, EPA's proposed CPP must be evaluated based on the authority granted to the agency by Congress. Under section 111(d) of the CAA, the Administrator of EPA is authorized to "prescribe regulations which shall establish a *procedure* similar to that provided by section [110] of this title."[8] Section 110 is the section under which each state develops its state implementation plan ("SIP") to assure attainment and maintenance of the national ambient air quality standards ("NAAQS"). Unlike section 110, however, section 111 does not contain any specific timelines for the development of EPA's guidelines, the submission of state plans, or the time within which EPA must review and approve or disapprove a state plan. In 1975 EPA adopted a set of regulations setting forth procedures to govern how each state develops a plan that establishes standards of performance for existing sources covering certain air pollutants that would be subject to standards under section 111(b) of the CAA if such existing sources were "new sources" as defined in section 111(a)(2) of the CAA.[9] Those regulations are set forth in 40 CFR Part 60, Subpart B, and are called the section 111(d) "implementing regulations" by EPA. EPA's implementing regulations provide certain default time periods for submission, review, and approval of state plans, but EPA has proposed alternate time periods for these activities in the CPP.

The implementing regulations require the Administrator to publish a draft guideline document, at the same time or after she proposes standards of performance for new sources in the category under section 111(b). The guideline document must contain "information pertinent to control of the designated pollutant from designated facilities." After EPA receives public comments and issues the new source standards in final form, EPA issues the final guideline document along with other information the Administrator thinks may contribute to the

[8] 42 U.S.C §7411(d) emphasis added.
[9] 42 U.S.C. §7411(d).

development of state plans.[10] States then develop and submit their plans for review by the Administrator.

The Administrator issued proposed standards for new EGUs in January of 2014, and in June 2014 issued a proposed standard for modified and reconstructed EGUs (which are considered "new sources" under section 111(a)(2) of the CAA) concurrently with the proposed existing source guideline document. The standards for new, modified, and reconstructed sources are specified emission rates for specific types of individual generating units, the "designated facilities" mentioned in 40 CFR § 60.22. In contrast, EPA's proposal for existing sources under section 111(d) goes far beyond the sources covered under its proposed "new source" standards, and fails to acknowledge the governing law that assigns states the responsibility for developing plans and grants states substantial discretion to vary from the guidelines under appropriate circumstances. In particular, EPA's interpretation of the phrase "best system of emission reduction" for purposes of this proposal departs in several significant respects from the plain language of section 111 of the CAA.

IV. EPA's Interpretation of the "Best System of Emission Reduction" Is Fatally Flawed

A fatal defect in EPA's CPP is the proposal's dependence upon an abstract, out-of-context interpretation of "system" in the phrase "best system of emission reduction" in the section 111 definition of "standard of performance." EPA's unprecedented interpretation of the word "system" in the "standard of performance" definition is disassociated from, and in conflict with, the interlinked CAA definitions of "stationary source," "existing source," "emission limitation," and "performance standard," and with the legislative history of section 111. It is also in conflict with EPA regulations that implement section 111, and at odds with EPA's interpretation and application of section 111 throughout its 44-year history.

Another fatal defect in EPA's proposal is the dubious way it attempts to ignore the phrase "standards of performance for any existing source" in section 111(d), by reinterpreting the word "for." In Humpty Dumpty fashion,[11] EPA concludes that a performance standard "for" an existing source may apply to "other entities whose actions would reduce generation, and thus

[10] 40 CFR §60.22.
[11] "When *I* use a word, Humpty Dumpty said, in a rather scornful tone, "it means just what I choose it to mean – neither more nor less."
"The question is," said Alice, "whether you *can* make words mean so many different things." *Through the Looking Glass, available at* www.gutenberg.org/files/12/12-h/12-h.htm.

emissions" from the existing source. "For any existing source" is not the same thing as "for other entities." If it were, the resulting authority to mandate reduced production from existing sources and replace that production with actions by "other entities," heretofore hidden in section 111(d), would greatly expand EPA's powers over the American economy.

EPA's flawed, out-of-context interpretations of "system" and "for" lead to proposed "emission guidelines" and "state goals" that necessitate command and control of the performance of "entities" that are outside the affected EGU source category, and contrary to the plain language of the statute. EPA's proposed emission guidelines rely on restrictions that would affect the behavior and obligations of electricity consumers, balancing authorities, electricity distribution companies with no generating capacity, natural gas pipeline suppliers, and the states themselves. Rather than reflecting the degree of emission limitation achievable by applying a demonstrated technology-based (or work practice) system of emission reduction to the affected EGU, as the statute plainly directs, the proposal requires a reduction in the hours of operation and/or rate of production (or complete shutdown) of affected EGUs, a result contrary to the text and structure of the statute, and that could not have been imaginable to the Congresses that enacted and amended the CAA in 1970, 1977, and 1990. For all of these reasons, as explained below, EPA's Proposed CPP is contrary to statute, contrary to EPA's own regulations, unworkable, and unlawful.

A. EPA's Proposed Action Is Unlawful and Not Entitled To Deference, Because It Conflicts In Multiple Ways With The CAA's Unambiguous Text

It is axiomatic that an administrative agency may not write, or re-write, its own enabling legislation. EPA is "a creature of statute," and has "only those authorities conferred upon it by Congress."[12] Since Congress is the source of an agency's powers, the absence of express Congressional constraint does not imply a delegation of legislative rulemaking authority to the agency. Congress does not delegate to an agency every authority that it does not explicitly withhold or prohibit.

In construing an agency's enabling legislation, when "Congress has directly spoken to the precise question at issue[,]" and "the intent of Congress is clear, that is the end of the matter; for

[12] *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001); *see also Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988) ("It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress.").

the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress."[13] As the Supreme Court held in its most recent CAA decision, it is a "core administrative-law principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate."[14] Also, "[a] court's prior judicial construction of a statute trumps an agency construction ... if the prior court decision holds that its construction follows from the unambiguous terms of the statute and thus leaves no room for agency discretion."[15]

It is for the reviewing court to determine, "employing the traditional tools of statutory construction," whether or not the intent of Congress is clear.[16] Determining whether a given word or phrase is ambiguous, moreover, typically requires a court to review more than just the word or phrase itself. "In making the threshold determination under *Chevron*, 'a reviewing court should not confine itself to examining a particular statutory provision in isolation.'"[17] Instead, the court must review the phrase "in context,"[18] with an eye to its "'place in the overall statutory scheme.'"[19] "Thus, an agency interpretation that is 'inconsisten[t] with the design and structure of the statute as a whole[ ]' ... does not merit deference."[20]

1. EPA's broad interpretation of "best system of emission reduction" conflicts with the narrower definitions Congress gave related terms in the Act.

EPA's BSER determination is based on the mistaken presumption that "the CAA does not define the term 'system,'" and that "the context in which 'standard of performance' ... is found does not add additional constraints."[21] In fact, the CAA contains several relevant definitions that require EPA to construe "system of emission reduction" in a more narrow and specific fashion.

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[13] *Chevron, U.S.A., Inc. v. NRDC, Inc.*, 467 U.S. 837, 842-843, 104 S.Ct. 2778 (1984).
[14] *Util. Air Regulatory Grp. v. EPA*, 134 S.Ct. 2427, 2446 (2014).
[15] *Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 982, 125 S.Ct. 2688, 2700 (2005).
[16] *Chevron*, 467 U.S. at 843 n. 9.
[17] *Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 666, 127 S.Ct. 2518, 2534 (2007), quoting *FDA* v. *Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 132, 120 S. Ct. 1291 (2000).
[18] *Brown & Williamson Tobacco Corp.*, 529 U.S. at 132 (citation omitted).
[19] *Id.* at 133, *quoting Davis v. Michigan Dept. of Treasury*, 489 U.S. 803, 809, 109 S. Ct. 1500 (1989). *See also Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 471, 121 S.Ct. 903 (2001) (indicating that a provision of the CAA must be "interpreted in its statutory and historical context and with appreciation for its importance to the CAA as a whole").
[20] *Util. Air Regulatory Grp.*, 134 S.Ct. at 2442, *quoting University of Tex. Southwestern Medical Center v. Nassar*, 570 U.S. ___, ___, 133 S. Ct. 2517, 186 L. Ed. 2d 503 (2013).
[21] Legal Memorandum at 51-52.

Under section 111(d)(1), EPA is required to prescribe by regulation procedures under which states will develop and submit plans that establish "standards of performance" for certain existing sources.[22] "Standard of performance" is defined to mean "a standard for emissions of air pollutants which reflects the degree of *emission limitation* achievable through the application of the best *system* of *emission reduction* which the Administrator determines has been adequately demonstrated."[23] It is also defined, in section 302, to mean "a requirement of continuous emission reduction ...."[24] "Emission limitation" is not defined in section 111. But it is defined in section 302 to mean "a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous *emission reduction*, and any design, equipment, work practice or operational standard promulgated under this chapter."[25] Congress directed that the CAA's section 302 definitions apply whenever "used in this chapter," including when they are part of the more specific definitions in section 111. Together, these definitions require any "emission limitation" or "standard of performance" to limit emissions on a "continuous" basis. These definitions make two more things clear:

- Congress understood an "emission limitation" to be the means to accomplish "emission reduction."

and

- Congress understood "emission limitation" to mean a continuous quantity-, rate-, or concentration-based limit on a relevant pollutant emitted by a stationary source; or a design standard, equipment standard, work practice standard, or operational standard for control of emissions from a stationary source.

The general provisions in section 302 also contain a definition for a term closely related to "system of emission reduction." The CAA defines "means of emission limitation" to mean "a system of continuous emission reduction (including *the use of specific technology* or *fuels with specified pollution characteristics*)."[26] And, section 111 includes a definition for "technological system of continuous emission reduction," which it defines as:

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[22] 42 U.S.C. § 7411(d)(1).
[23] 42 U.S.C. § 7411(a)(1) (emphasis added).
[24] 42 U.S.C. § 7602(l).
[25] 42 U.S.C. § 7602(k) (emphasis added).
[26] 42 U.S.C. § 7601(m) (emphasis added).

- a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or
- a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.[27]

As shown above, there is no meaningful difference between the phrases "system of emission reduction" and "system of continuous emission reduction." Based on the clear language of the CAA, then, there is no doubt about the kinds of things that Congress considered to be "systems of emission reduction." Importantly, they are all measures that would be taken at individual units and directly reduce emissions from those units on a continuous basis.[28]

Given the clear direction provided by Congress, EPA may not simply pick a broad definition out of the dictionary and say that its choice is entitled to deference; the agency also has to look to "contextual indications" to determine whether that definition is a "permissible interpretation."[29] EPA's second, third, and fourth building blocks, which would collectively reduce utilization of certain affected EGUs, but increase utilization of others, are nothing like the systems of emission reduction listed in the CAA or discussed in the legislative history. Rather than changing a regulated source's fuel, production process, or method of operation, or installing pollution controls at the source, EPA's building blocks would require the use of a different *source* altogether. Nothing in the CAA's definitions of "system of continuous emission reduction" or "technological system of continuous emission reduction" supports an interpretation of "system" that includes creating a preference for the operation of one type of source over another, or dictates that wholly unregulated sources should be encouraged not to retire or to be constructed in order to replace the output from sources EPA has listed within a section 111 source category. Indeed, section 111(d)'s requirement that EPA allow states to adjust compliance obligations and schedules in order to take into consideration, among other factors, the remaining useful life of existing source, is a clear indication that Congress did not mean for EPA to require wholesale changes in capital stock as a means of reducing emissions. The goals of the CAA incorporate both protecting and enhancing air quality, and promoting the productive

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[27] 42 U.S.C. § 7411(a)(7) (emphasis added).
[28] Section 111 provides additional flexibility by allowing the Administrator and the states, in appropriate circumstances, to establish work practice standards in lieu of specific emission limitations, or to adopt market-based emission allowance programs. 42 U.S.C. § 7411(a)(1), (k).
[29] *MCI Telecomms. Corp. v. AT&T Co.*, 512 U.S. 218, 226, 114 S.Ct. 2223, 2229 (1994).

capacity of the Nation's population.[30] Because the proposed interpretation of "system of emission reduction" that underlies EPA's Clean Power Plan is inconsistent with Congress's intentions for that term, as illuminated by Congress's definitions of related terms in the Act, EPA's interpretation is unreasonable and unlawful.

2. EPA's interpretation of "system of emission reduction" to include reduced utilization is incongruous with the Act's requirement that any such system be "adequately demonstrated."

EPA's assertion that "system of emission reduction" can be interpreted to include reduced utilization is also contrary to the CAA's requirement that any such system be "adequately demonstrated." Section 111(a)(1) defines "standard of performance" to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which … the Administrator determines has been *adequately demonstrated*."[31] The D.C. Circuit Court of Appeals has explained that Congress added the requirement that any "best system of emission reduction" be "adequately demonstrated" in order to ensure that the chosen emission control technology would be commercially available:

> The language in section 111 was the result of a Conference Committee compromise, and did not incorporate the language of either the House or Senate bills. The House bill would have provided that "the Secretary ... [give] appropriate consideration to technological and economic feasibility," while the Senate would have required that standards reflect "the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.
>
> The Senate Report made clear that it did not intend that the technology "must be in actual routine use somewhere." The essential question was rather whether the technology would be available for installation in new plants. The House Report also refers to "available" technology. Its caution that "in order to be considered 'available' the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution" merely reflects the final language adopted, that it must be "adequately demonstrated" that there will be "available technology.[32]

The court has explained that "where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated … on mere speculation or

[30] 42 U.S.C. §7401(b)(1).
[31] 42 U.S.C. §7411(a)(1).
[32] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

conjecture, but EPA may compensate for a shortage of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries."[33] In 1973, the D.C. Circuit also held that "[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[34]

These 1973 and 1999 opinions reflect the D.C. Circuit's assumption that a "best system of emission reduction" would be a technological system of emission reduction, even though section 111 of the 1970 CAA and the 1990 CAA did not include the word "technological" at the times the court issued those opinions. Equally importantly, however, they are incompatible with the concept of reduced utilization as a "system of emission reduction." Reduced utilization does not need to be purchased. EPA would not need to determine whether reduced utilization was "reliable" or "efficient." EPA would never need to determine whether reduced utilization had performed well in other industries. In short, EPA would never need to determine whether reduced utilization was "adequately demonstrated." Interpreting "system of emission reduction" to include reduced utilization would render the requirement to determine whether a potential BSER was "adequately demonstrated" a nullity. Thus, that interpretation must be rejected; courts are " 'reluctant to treat statutory terms as surplusage' …[,] [and] especially unwilling to do so when the term occupies so pivotal a place in the statutory scheme … ."[35]

The Act's requirement that any "best system of emission reduction" be "adequately demonstrated" conclusively proves that reduced utilization was not within Congress's conception of a "system of emission reduction." EPA's proposal to accept reduced utilization as a "building block" of BSER is contrary to the statute and, therefore, is unreasonable and unlawful.

3. EPA's broad interpretation of "best system of emission reduction" conflicts with Congressional intent, as illuminated by legislative history

A more narrow and specific understanding of "system of emission reduction" is not only evident from the language and structure of the CAA; it is, unsurprisingly, reflected in the legislative history as well. The committee reports for the bills that ultimately became the 1970

[33] *Lignite Energy Council v. U.S. E.P.A.*, 198 F.3d 930, 933-934 (D.C. Cir. 1999).
[34] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-434 (D.C. Cir. 1973).
[35] *Duncan v. Walker*, 533 U.S. 167, 174, 121 S.Ct. 2120, 2125 (2001).

CAA Amendments suggest that Congress understood a "system of emission reduction" to be something that would be installed in, or otherwise designed into, new sources at the time of construction. The House Committee on Interstate and Foreign Commerce, reporting H.R. 17255, described its proposed Section 112 as requiring that sources be "designed and equipped to prevent and control ... emissions to the fullest extent compatible with the available *technology* and economic feasibility as determined by the Secretary."[36] And, the Senate Committee on Public Works' report for the Senate bill, S. 4358, explained that "'standards of performance' ... refers to the degree of emission control which can be achieved through *process changes, operation changes, direct emission control*, or other methods."[37] Ultimately, these proposals were combined in conference committee to form section 111. A "Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970," inserted into the Congressional Record, described the NSPS regulations as requiring "new major industry plants ... [to] achieve a standard of emission performance based on the *latest available control technology, processes, operating methods*, and other alternatives"[38] – a list of "systems of emission reduction" substantially similar to that currently found in the Act. Although this legislative history refers to section 111(b), and notes 111(d), both sections rely on the same definition of "standard of performance" set forth in section 111(a)(1).

In 1990, Congress amended the definition of "standard of performance" once more to return it to something closely resembling its original 1970 form.[39] The Report of the Committee on Energy and Commerce of the U.S. House of Representatives explained that the purpose of the amendment was to "repeal[ ] the 'percent reduction' requirement" added in the 1977 CAA amendments, which EPA had interpreted to require new coal-fired power plants to "reduce emissions by a fixed percentage" and "effectively require[ ] the installation of scrubbers on all new plants."[40] Congress instead ordered EPA to "promulgate revised NSPS within three years" that would result in the same emissions, but "give units the flexibility to meet the emission rates established under the new standards through whatever combination of *fuels and emission*

[36] H.R. Rep. No. 91-1146, at 9 (1970) (emphasis added).
[37] S. Rep. No. 91-1196, at 16 (1970) (emphasis added).
[38] 116 Cong. Rec. 42,383 (1970) (emphasis added).
[39] *See* CAA Amendments of 1990, Pub. L. 101-549, 104 Stat. 2399, § 402 (1990).
[40] H.R. Rep. 101-490 at 3413 (1990).

controls the units choose."[41] Thus, a review of the legislative history for the 1977 and 1990 Clean Air Amendments reinforces that Congress intended "standard of performance" to mean an emission limitation that would be accomplished at individual units through the use of low-emitting fuels, process changes, operation changes, or direct emission controls. EPA's proposed, broad interpretation of "system" – "[a] set of things working together as part of a mechanism or interconnecting network"[42] – is inconsistent with both the examples of "systems of emission reduction" found in the Act and the examples of "systems" found in the legislative history.

EPA argues that "Congress has recognized reduced utilization in several contexts as a method to reduce air pollution."[43] More to the point, EPA argues that Congress has recognized "closing plants [as] a method of reduction pollution," and that the difference between closing plants and reduced utilization is just a matter of degree.[44] But, the only example EPA provides that is directly on point is a provision in the 1970 version of section 110 that *explicitly* authorized the imposition of "transportation controls."[45] That provision, which is no longer in the statute, does not support EPA's position, because nothing in section 111 explicitly authorizes the use of reduced utilization as a system of emission reduction. EPA's other examples – a provision in section 110 allowing for temporary emergency suspensions to prevent plant closures,[46] and one Senator's statement (in the legislative history for the 1970 amendments) that section 112 emission limitations may be set at a level that some plants cannot meet[47] – are simply not analogous. Congress's acknowledgment that the imposition of emission limitations under sections 110 or 112 could lead to the closing of some sources is far from a "recognition that closing plants is a method of reducing pollution"[48] or authorization to require reduced utilization of any existing sources as a section 111 performance standard. In other words, the fact that Congress acknowledged the possibility that some CAA requirements could *result* in plant closures does not demonstrate that Congress authorized EPA to *pursue* plant closures as a method of pollution control for existing sources under section 111. To the contrary – section 111 explicitly requires EPA (if it crafts a federal implementation plan for a state) and authorizes the

[41] *Id.* (emphasis added).
[42] 79 Fed. Reg. at 34,885 (quoting Oxford Dictionary of English (3rd ed.)).
[43] Legal Memorandum at 82.
[44] *See* Legal Memorandum at 84.
[45] Legal Memorandum at 83 n. 64.
[46] *See* 42 U.S.C. § 7410.(g)(1).
[47] *See* Legal Memorandum at 84 n. 66.
[48] Legal Memorandum at 84.

states (if they craft their own implementation plans) "to take into consideration ... the remaining useful life of the existing source to which [a standard of performance] applies."[49] The fact that some sources have *chosen* to reduce their generation to comply with the requirements of various cap-and-trade programs, including the CAA's Acid Rain program, EPA's NOx SIP Call, or EPA's Clean Air Interstate Rule,[50] does not mean that Congress intended EPA to select reduced utilization as a form of section 111, technology-based pollution control, particularly in light of the command that the Administrator allow states to consider the remaining useful life of a source in developing a section 111(d) plan.[51] As is demonstrated below, in each prior determination under section 111 for new or existing sources, including EPA's recent proposals to regulate CO_2 from new EGUs, EPA's analysis has focused on technologies and operating practices that can be applied at the source and reduce emissions while the source is operating at its maximum capacity. Not once in the history of the CAA has EPA determined that emission reductions should be based on limiting production or prematurely retiring units with substantial remaining useful life. Such action is not authorized by section 111, and EPA's attempt to compel such actions here should be rejected.

4. If EPA's BSER building blocks are a "system," they cannot be severable.

In EPA's CPP, the agency argues that its combination of multiple measures into one "system of emission reduction" is justified by the "broad" definition of a "system" as a "set of things working together as parts of a mechanism or interconnecting network."[52] This characterization of EPA's BSER suggests that the building blocks are like the gears of a watch – interdependent. On the other hand, EPA has asserted that its "proposed findings of the BSER with respect to the various building blocks" are "severable," such that any one or more of its building blocks could stand on its own if a court were to find that the other building blocks are unlawful.[53] EPA similarly asserts that each block "independently" meets the necessary criteria for inclusion in EPA's chosen BSER:

> [E]ach of the four building blocks is a proven way to support either improvements in emissions rates at affected EGUs or reductions in EGU mass emissions; each is in

[49] 42 U.S.C. § 7411(d)(1).
[50] Legal Memorandum at 84-85.
[51] 42 U.S.C. § 7411(d)(1).
[52] 79 Fed. Reg. at 34,885 (quoting *Oxford Dictionary of English* (3rd ed.)).
[53] 79 Fed. Reg. at 34,892.

> widespread use *and is independently capable of supporting significant CO_2 reductions from affected EGUs*, either on an emission rate or mass-emissions basis, at a reasonable cost consistent with ensuring system reliability.[54]

These two positions are incompatible, and neither entirely aligns with EPA's description of the four building blocks that make up its proposed BSER.

EPA's BSER analysis shows that two of the building blocks are somewhat dependent on each other. EPA has noted there could be a "rebound effect" if building block 1 were "applied in isolation."[55] Heat rate improvements at coal-fired EGUs could make those generating units more competitive, resulting in their greater use, "absent other incentives to reduce generation and CO_2 emissions from coal-fired EGUs."[56] According to EPA, building block 2 (re-dispatch) provides the necessary incentive to reduce generation from coal-fired EGUs. Thus, building blocks 1 and 2 are interrelated. A determination that building block 2 is unlawful would require EPA to reconsider its BSER determination in its entirety, or at least the inclusion of building block 1 as a component of BSER.

On the other hand, EPA makes no effort to demonstrate that building blocks 3 and 4 are "interconnected" with building blocks 1 and 2, so as to make the combination of all four measures a "system."[57] EPA suggests that the four building blocks are a system "in light of the integrated nature of the electricity grid."[58] But, it is the building blocks, not the regulated source category, that must be interconnected under EPA's proposed new definition of "system." And, as noted above, EPA repeatedly argues that "the building blocks can be implemented independently of one another," which suggests they are not really a "system" at all.[59] A multiplicity of independent, free-standing elements cannot be a "system" of emission reduction under any reasonable interpretation of that term.

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[54] *Id.* at 34,878 (emphasis added).
[55] 79 Fed. Reg. at 34,882.
[56] *Id.*
[57] EPA has suggested in a recent notice of data availability, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units,* Notice of Data Availability, 79 Fed. Reg. 64,543 (October 30, 2014) (hereinafter referred to as the "NODA"), that increased use of renewable energy resources and energy efficiency measures should be used to "reduce generation, and therefore emissions, from affected fossil fuel-fired generation," and therefore alter and make more stringent the individual state emission rate goals. 79 Fed. Reg. at 64,548. But this conclusion is at odds with the actual operation of the electricity system, which simply responds to load with the most economic available resources that can supply that load, and does not make any other distinctions based on the characteristics of the supply-side resources.
[58] Legal Memorandum at 50; *see also id.* at 54.
[59] 79 Fed. Reg. at 34,895.

In sum, EPA's argument that its BSER components are severable is fundamentally incompatible with its argument that its BSER components combine to form a "system of emission reduction." Either the building blocks "work[ ] together as parts of a mechanism or interconnecting network"[60] or they are severable, but they cannot be both. If EPA finalizes its new approach to determining BSER, it must relinquish its argument that its BSER components are severable. Any finding that a building block is unlawful or invalid will require a reconsideration of the BSER determination as a whole.

B. EPA's Interpretations Of Section 111(d) Are Unreasonable, Arbitrary, and Capricious, And Are Not Entitled To Deference

"[W]hen an agency-administered statute is ambiguous with respect to what it prescribes, [courts will presume] Congress has empowered the agency to resolve the ambiguity."[61] In such instances, courts will defer to an agency's "permissible construction of the statute."[62] The agency's interpretation must be "reasonable," however.[63] Even where Congress has explicitly directed the agency to promulgate rules, courts will not give "[s]uch legislative regulations ... controlling weight [if] they are arbitrary, capricious, or manifestly contrary to the statute."[64] Courts will not defer when "the statute simply will not bear the meaning the [agency] has adopted."[65] For example, "[t]he EPA may not construe [a] statute in a way that completely nullifies textually applicable provisions meant to limit its discretion."[66]

In weighing an agency's interpretation, the court "must be guided to a degree by common sense as to the manner in which Congress is likely to delegate a policy decision of [significant] economic and political magnitude to an administrative agency."[67] Reviewing courts "expect Congress to speak clearly if it wishes to assign an agency decisions of vast 'economic and

[60] *Id.* at 34,885 (citation omitted).
[61] *Util. Air Regulatory Grp.*, 134 S.Ct. at 2439.
[62] *Chevron*, 467 U.S. at 843.
[63] *United States v. Mead Corp.*, 533 U.S. 218, 229, 121 S.Ct. 2164, 2172 (2001).
[64] *Chevron*, 467 U.S. at 844. *See also Mead Corp.*, 533 U.S. at 229 ("We have recognized a very good indicator of delegation meriting Chevron treatment in express congressional authorizations to engage in the process of rulemaking or adjudication that produces regulations or rulings for which deference is claimed.").
[65] *Pittston Coal Grp. v. Sebben*, 488 U.S. 105, 113, 109 S.Ct. 414, 420 (1988). *See also MCI Telecomms. Corp. v. AT&T Co.*, 512 U.S. 218, 245, 114 S.Ct. 2223, 2239 (1994) (stating, "an agency's interpretation of a statute is not entitled to deference when it goes beyond the meaning that the statute can bear").
[66] *Whitman*, 531 U.S. at 485.
[67] *Brown & Williamson Tobacco Corp.*, 529 U.S. at 133.

political significance.'"[68] Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes."[69] An agency interpretation that "would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization" will be rejected as unreasonable.[70]

1. EPA's proposal represents a significant self-expansion of EPA authority without Congressional permission or approval.

An agency's interpretation of its authorizing statute cannot be based on presumed delegation of legislative authority. But that is precisely what EPA's interpretation of the "best system of emission reduction" does. EPA finds in the statute such unbounded discretion, that it presumes the agency itself can write the outer limits on its own authority. EPA's plan stretches the scope of its authority under section 111(d) far beyond anything Congress has expressly delegated to the agency.

If "system of emission reduction" meant what EPA says it means section 111 would be a standardless and, thus, unconstitutional delegation of legislative power from Congress to EPA. Article I, Section 1 of the United States Constitution vests "all legislative Powers herein granted ... in a Congress of the United States." Because this text, by its own terms, actually permits no delegation of legislative powers, when Congress does confer legislative authority upon agencies, Congress must "lay down ... an intelligible principle to which the person or body authorized to [act] is directed to perform."[71] The Supreme Court has twice invoked the nondelegation doctrine to invalidate Congressional acts lacking any intelligible principle to guide executive discretion.[72]

As noted constitutional scholar Cass Sunstein explained, however, the nondelegation doctrine has evolved over time into a doctrine of statutory interpretation that evinces skepticism at overbroad claims of agency authority:

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[68] *Util. Air Regulatory Grp.*, 134 S.Ct. at ___(2014), citing *Brown & Williamson*, 529 U.S., at 159, and *MCI Telecommunications Corp.*, 512 U.S. at 231; *International Union Dept., AFL-CIO v. American Petroleum Institute*, 448 U.S. 607, 645-646 (1980) (plurality opinion).
[69] *Whitman*, 531 U.S. at 468, citing *MCI Telecommunications Corp.*, 512 U.S. at 231 (1994); *Brown & Williamson Tobacco Corp.*, 529 U.S. at 159-160.
[70] *Util. Air Regulatory Grp.*, 134 S.Ct. at 2444.
[71] *J.W. Hampton, Jr. & Co. v. United States*, 276 U.S. 394, 409, 72 L.Ed. 624, 48 S.Ct. 348 (1928) (emphasis added).
[72] *See Panama Refining Co. v. Ryan*, 293 U.S. 388, 405, 79 L.Ed. 446, 55 S.Ct. 241 (1935); *A.L.A. Schecter Poultry Corp. v. United States*, 295 U.S. 495, 537-542, 79 L.Ed. 1570, 55 S.Ct. 837 (1935).

> Federal courts commonly vindicate not a general nondelegation doctrine, but a series of more specific and smaller, though quite important, nondelegation doctrines. Rather than invalidating federal legislation as excessively open-ended, courts hold that federal administrative agencies may not engage in certain activities unless and until Congress has expressly authorized them to do so. *The relevant choices must be made legislatively rather than bureaucratically*.[73]

EPA's current proposal is a prime example of an agency seizing upon an undefined statutory term to make unprecedented legislative policy choices with enormous ramifications for the national economy – choices only properly made by Congress.

Professor Sunstein's above-quoted analysis in *Nondelegation Canons* proved prescient. The following year, in *Whitman v. Am. Trucking Assns.*,[74] the Supreme Court confronted a nondelegation challenge to section 109(b) of the CAA, which requires EPA to promulgate national ambient air quality standards (NAAQS) for various air pollutants. Although the Supreme Court in *American Trucking* rejected a nondelegation challenge to section 109(b) in that case, which had previously succeeded in the D.C. Circuit, the Supreme Court expressly cautioned that "Congress ... does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions -- it does not, one might say, hide elephants in mouseholes."[75] The Supreme Court also noted that Congress "must provide substantial guidance on setting air standards that affect the entire national economy."[76]

The so-called elephants-in-mouseholes doctrine, first expressly announced in those terms in *American Trucking*, "is thus one instance of what Cass Sunstein has dubbed 'nondelegation canons.'"[77] Under this doctrine, which has been applied in other contexts without express reference to elephants or mouseholes,[78] an agency cannot rely upon "vague terms or ancillary

[73] Cass Sunstein, *Nondelegation Canons*, 67 U. Chi. L. Rev. 315, 315-316 (Spring 2000) (emphasis added).
[74] 531 U.S. 457, 149 L.Ed.2d 1, 121 S.Ct. 903 (2001)
[75] *Whitman*, 531 U.S. at 468.
[76] *Id.* at 475.
[77] Jacob Loshin & Aaron Nielson, *Hiding Nondelegation in Mouseholes*, 62 ADMIN. L. REV. 19 (Winter 2010) (citing Sunstein, *Nondelegation Canons*, *supra*).
[78] *See, e.g.*, *MCI Telecommunications Corp. v. American Telephone & Telegraph Co.*, 512 U.S. 218, 231, 129 L.Ed.2d 182, 114 S.Ct. 2223 (1994) (Scalia, J., writing that "[i]t is highly unlikely that Congress would leave the determination of whether an industry will be entirely, or even substantially, rate-regulated to agency discretion -- and even more unlikely that it would achieve that through such a subtle device as permission to 'modify' rate-filing requirements.") *See also FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133, 146 L.Ed.2d 121, 120 S.Ct. 1291 (2000) (Supreme Court holding that the Food and Drug Administration, pursuant to its authority to regulate "drugs" and "devices," could not regulate tobacco, saying "we must be guided to a degree by common sense as to the manner in which Congress is likely to delegate a policy decision of such economic and political magnitude to an administrative agency.")

provisions" in a statute (the mousehole) to alter "the fundamental details of a regulatory scheme" (the elephant).

The Supreme Court most recently revisited this doctrine in its 2014 decision in *UARG v. EPA*. In that opinion, the Court held that EPA is neither required, nor permitted, to require PSD or Title V permits based on a stationary source's GHG emissions.[79] In particular, the Court held that EPA could not reasonably interpret the term "air pollutant" in the context of the permitting triggers for the PSD and Title V programs to include greenhouse gases, because such an interpretation would overwhelmingly expand the scope of both programs:

> The fact that EPA's greenhouse-gas-inclusive interpretation of the PSD and Title V triggers would place plainly excessive demands on limited governmental resources is alone a good reason for rejecting it; but that is not the only reason. EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization. When an agency claims to discover in a long-extant statute an unheralded power to regulate "a significant portion of the American economy," we typically greet its announcement with a measure of skepticism.[80]

Yet that is precisely what EPA proposes to do here. Relying upon an abstract and out-of-context interpretation of the term "system" in section 111(a)(1) of the Act, which it defines broadly (and unhelpfully) to mean "a set of things working together as parts of a mechanism or interconnecting network,"[81] EPA posits that it may impose unprecedented beyond-the-unit (and even beyond the source category) measures in establishing the emission guideline for existing EGUs. EPA asserts that a "system of emission reduction" can be "*virtually any 'set of things' that reduce emissions*."[82] EPA then asserts that the "[i]nterconnected nature of the electricity system" means that EPA's "best system of emission reduction" may include not only measures that increase the efficiency of individual affected EGUs, but also measures that "draw[ ] utilization away from higher-emitting fossil fuel-fired EGUs, thereby lowering those EGUs' emissions."[83] This includes measures to "reduc[e] overall electric demand through demand-side energy efficiency measures."[84] But if the "interconnected nature of the electrical system" permits EPA to bring all aspects of that system under the control of section 111(d), including the

[79] *See Util. Air Regulatory Grp. v. EPA*, 134 S.Ct. 2427, 2449 (2014).
[80] *Id.* at 2444.
[81] 79 Fed. Reg. at 34,885 (citation omitted).
[82] Legal Memorandum at 51 (emphasis added).
[83] Legal Memorandum at 43.
[84] Legal Memorandum at 45.

end-users of electricity,[85] there is no apparent end to EPA's authority to regulate human behavior as a means to reduce CO_2 emissions.

EPA's website, for example, is full of tips for families and businesses to reduce their electricity consumption.[86] Each of these suggestions could be made mandatory and used as the basis for a BSER determination. For example:

- Energy Efficiency: "ENERGY STAR is a U.S. Environmental Protection Agency (EPA) voluntary program that helps businesses and individuals ... ' ... to identify and promote energy–efficient products and buildings in order to reduce energy consumption, improve energy security, and reduce pollution through voluntary labeling of or other forms of communication about products and buildings that meet the highest energy efficiency standards.'"[87] ENERGY STAR asserts that it helped Americans "prevent[ ] more than 277 million metric tons of GHG emissions ... in 2013 alone"[88] and "more than 1.9 billion metric tons of greenhouse gas emissions over the past two decades."[89] Under EPA's definition of "system of emission reduction," EPA could adopt emission performance goals that rely on every state's adoption of ENERGY STAR requirements as binding requirements for appliance manufacturers, residential and commercial developers, and consumers.
- Water Conservation: EPA's Climate Change website advises that "Three percent of the nation's energy is used to pump and treat water[,] so conserving water conserves energy that reduces greenhouse gas pollution."[90] EPA's WaterSense website, in turn, advises that installing water-efficient WaterSense products in homes throughout America would save trillions of gallons of water per year. For example, according to EPA, "if every home in the United States installed WaterSense labeled showerheads, we could save ...more than 260 billion gallons of water annually" and "avoid about $2.6 billion in energy costs for heating water."[91] As another example, "[i]f all old, inefficient toilets in the United States were replaced with WaterSense labeled models, we could save 520 billion gallons of water per year ... ."[92] And, according to EPA, "[w]e could save billions of gallons nationwide each year by retrofitting bathroom sink faucets with models that have earned the WaterSense label."[93] Under EPA's definition of "system of emission reduction," then, EPA could adopt emission performance goals that rely on every states' adoption of its WaterSense specifications as binding requirements for manufacturers, developers and consumers.

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[85] *See, e.g.*, 79 Fed. Reg. at 34,871; *see also* Legal Memorandum at 44.
[86] EPA, Climate Change, What You Can Do, http://www.epa.gov/climatechange/wycd/.
[87] ENERGY STAR, About ENERGY STAR, http://www.energystar.gov/about/.
[88] ENERGY STAR, *ENERGY STAR® Overview of 2013 Achievements*, www.energystar.gov/sites/default/uploads/about/old/files/EnergyStar_POY_4page_040414_PrintReady_508compliant.pdf.
[89] ENERGY STAR, About ENERGY STAR, http://www.energystar.gov/about/.
[90] EPA, Climate Change, What You Can Do: At Home, http://www.epa.gov/climatechange/wycd/home.html.
[91] EPA, WaterSense, Products, Showerheads, http://www.epa.gov/watersense/products/showerheads.html.
[92] EPA, WaterSense, Products, Toilets, http://www.epa.gov/watersense/products/toilets.html.
[93] EPA, WaterSense, Products, Bathroom Sink Faucets & Accessories, www.epa.gov/watersense/products/bathroom_sink_faucets.html.

EPA's new-found power would not just allow it to determine the kinds of appliances families and businesses can buy; it would also give EPA the power to restrict consumer choices in the supermarket. The "reduced generation" building block in EPA's alternative BSER approach – replacing "generation from higher-emitting affected sources in specific amounts" with "increased zero- or low-emitting generation [or] eliminat[ing] it by increased demand-side energy efficiency"[94] – is just an electricity-specific example of product substitution. "[E]lectricity and electricity services" are not the only products produced by stationary sources in a regulated New Source Performance Standard (NSPS) category that are "fungible."[95] EPA could, theoretically, adopt emission guidelines for magnetic tape coating facilities[96] that assume states will impose restrictions on the production of tape-based information storage media. Production would simply switch to CDs, DVDs, and thumb drives.[97] And, depending on whether EPA was more concerned with emissions from glass manufacturing plants[98] or the beverage can surface coating industry,[99] EPA could craft emission guidelines that effectively required beverage manufacturers to put more of their products into cans instead of bottles, or vice versa. In the guise of environmental regulation, EPA could assume increasing control over the products, raw materials, and production choices of numerous industries.

Clearly, EPA's proposed interpretation of "system of emission reduction" would bring about an "enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization."[100] An almost limitless interpretation of "system of emission reduction" that would expand EPA's authority to regulate not only all aspects of the national electricity system, but all end-users of electricity and purchasers of multiple consumer goods, must be rejected as unreasonable. EPA's limitless interpretation of BSER is wrong, and its proposal is properly subject to challenge under either traditional or modern, "relocated" nondelegation principles.

[94] Legal Memorandum at 34.
[95] *Id.* at 44.
[96] *See* 40 C.F.R. Part 60, Subpart SSS.
[97] *See* 76 Fed. Reg. 65,653, 65,658 (Oct. 24, 2011) (noting that "the primary product of this industry has been superseded by ... optical storage media[.]").
[98] *See* 40 C.F.R. Part 60, Subpart CC.
[99] *See* 40 C.F.R. Part 60, Subpart WW.
[100] *See Util. Air Regulatory Grp.*, 134 S.Ct. at 2444.

2. EPA's interpretation of "system of emission reduction" is unreasonable because it is inconsistent with the agency's longstanding, and continuing, interpretation of that phrase as a technology-based system of emissions control.

EPA's proposed interpretation of "system" (in the phrase "best system of emission reduction") is not only contrary to the statute and Congressional intent, as discussed above, it is contrary to EPA's own historical *and current* interpretations of the same word as used in section 111(a)(1). EPA stated repeatedly, when it adopted Subpart B, that it read the legislative history as requiring EPA to take a "technology-based approach" to setting emission limitations.[101] In particular, EPA said that, in determining BSER, Congress intended EPA to use as "criteria for decision-making ... the availability and costs of control technology."[102] In other words, EPA said, "EPA's emission guidelines will reflect best available technology considering cost ... ."[103] Since then, EPA has repeatedly interpreted BSER as a control technology, for both new source and existing source performance standards.

Earlier this year, in the preamble to EPA's proposed NSPS for GHG emissions from new electric utility generating units, EPA commented that it has "frequently referred to [BSER] as the 'best demonstrated technology' (BDT)."[104] EPA was correct. EPA has traditionally explained the process by which it crafts emission guidelines as one in which it first defines the specific kind of apparatus to which the guidelines will apply, identifies the "best demonstrated technology" for that apparatus, and then develops guidelines based on the performance of that "best demonstrated technology." In a 1989 *Federal Register* notice, EPA stated:

> Emission guidelines for existing sources are the product of a series of decisions related to certain key elements for the source category being considered for regulation. The elements in this "decision" are generally the following:
>
> (1) Identification of source category to be regulated – usually an emission source category, but can be a process or group of processes within an industry.
>
> (2) Definition of designated facility – the piece or pieces of equipment that comprise the sources to which the guidelines apply.
>
> (3) Selection of designated pollutant(s) . . .
>
> (4) Identification of "*best demonstrated technology*" – the *technology* on which the guidelines are based ...

[101] 40 Fed. Reg. at 53,342.
[102] *Id.*
[103] *Id.*
[104] 79 Fed. Reg. 1430, 1444 n. 62 (Jan. 8, 2014).

(5) Selection of format for the guidelines – the form in which the guidelines are expressed, i.e., as a percent reduction in emissions, as emission limits, as pollutant concentrations, or as equipment or work practice guidelines.

(6) Development of actual guidelines – generally emission limits based on what "*best demonstrated technology*" can achieve. Only in unusual cases do guidelines require that a specific technology be used. In general, the source owner or operator may select any method for complying with the guidelines.

(7) Other considerations – in addition to emission limits, emission guidelines usually include: guidelines for visible emissions, modification/ reconstruction provisions, monitoring requirements, performance test methods and compliance procedures, and reporting and recordkeeping requirements.[105]

Since then, EPA has routinely repeated its understanding that a "system of emission reduction" (for purposes of determining BSER) is a technology:

- <u>2005</u>: "As with any NSPS analysis, EPA evaluated the controls that effect the best emission reduction of the pollutant in question"[106]
- <u>2008</u>: "[S]tandards of performance promulgated under section 111 are based on 'the best system of emission reductions' which generally equates to some type of control technology."[107]
- <u>2012</u>: "NSPS are based on the effectiveness of one or more specific technological systems of emissions control, unless certain conditions are met."[108]

As recently as September 2013, EPA was describing BSER as emissions reduction technology:

> Section 111(a)(1) provides that NSPS are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of *control* is commonly referred to as *best demonstrated technology (BDT)*. In determining BDT, EPA typically conducts a technology review that identifies what *emission reduction systems* exist and how much they reduce air pollution in practice. This allows EPA to identify potential emission limits. Next, EPA evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation. The resultant standard is commonly a numerical emissions limit, expressed as a performance level (i.e. a rate-based standard). ... Section 111(d)

[105] 54 Fed. Reg. 52,209, 52,211 (Dec. 20, 1989) (emphasis added).
[106] 70 Fed. Reg. 62,213, 62,216 (Oct. 28, 2005).
[107] 73 Fed. Reg. 72,962, 72,970 (Dec. 1, 2008).
[108] 77 Fed. Reg. 48,433, 48,439 (Aug. 14, 2012).

guidelines, like NSPS standards, must reflect the emission reduction achievable through the application of BDT.[109]

Even this year, outside this rulemaking, EPA has continued to construe BSER in the traditional fashion. For example, In July 2014, EPA proposed revisions to its NSPS for grain elevators.[110] EPA acknowledged that BSER "has been referred to in the past as 'best demonstrated technology' or BDT."[111] To conduct its BSER analysis, EPA "identified currently used, new and emerging control systems and assessed whether they represent advances in emission reduction techniques compared to the control techniques used to comply with the existing NSPS."[112] In particular, EPA looked at "control techniques" such as "application of mineral oil as a dust suppression technique," but identified "[n]o other [new] emission control technologies or work practices."[113] EPA did not mandate that elevator operators limit the storage of wheat in favor of storing more corn, because it produces less fugitive dust. And, in its rulemaking to establish NSPS for GHG emissions from EGUs, EPA commented that BSER is "generally, but not required to be always, a technological control."[114] EPA quoted the legislative history for the 1977 CAA Amendments, which described Congress's adoption of the BSER requirement in 1970 as "the first time [Congress] imposed a requirement for specified levels of control technology."[115] EPA took the position that the definition of "standard of performance" "makes clear that the standard of performance must be based on *controls* that constitute 'the best system of emission reduction ... adequately demonstrated' (BSER)."[116] And, ultimately, after "consider[ing] three alternative control technology configurations as potentially representing the BSER," EPA proposed that "efficient generating technology implementing partial [carbon capture and storage] is the BSER adequately demonstrated for [new fossil fuel-fired boiler and IGCC EGUs]."[117]

The only place EPA has proposed to interpret "system of emission reduction" so broadly as to mean "virtually any 'set of things' that reduce[s] emissions" is in EPA's proposed CPP. In

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[109] EPA, Background on Establishing New Source Performance Standards (NSPS) Under the CAA (*available at* www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf) (emphasis added).
[110] *See* 79 Fed. Reg. 39,242 (July 9, 2014).
[111] 79 Fed. Reg. at 39,245.
[112] 79 Fed. Reg. at 39,248.
[113] 79 Fed. Reg. at 39,249.
[114] 79 Fed. Reg. at 1463.
[115] 79 Fed. Reg. at 1465, *quoting* S. Rep. 95-127 at 17 (1977).
[116] 79 Fed. Reg. at 1443 (emphasis added).
[117] 79 Fed. Reg. at 1467-1468.

Subpart B, in 44 years of *Federal Register* notices, and even in other rulemaking notices published this year for new sources emitting the same pollutant, EPA has continued to interpret "system of emission reduction" to mean something akin to emission control equipment and process changes. Because EPA's proposed CPP contradicts its historical and on-going interpretation of "best system of emission reduction," it is unreasonable and unlawful.

3. EPA's chosen BSER is not "adequately demonstrated" as a whole.

The standards of performance that states include in their § 111(d) implementation plans must, under § 111(a)(1) of the Clean Air Act, reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[118] "An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[119]

Here, EPA proposes a "best system of emission reduction" that comprises (1) heat rate improvements, (2) re-dispatch to existing NGCC units, (3) increased use of renewable energy, and (4) increased use of demand-side energy efficiency. EPA asserts that the "combination of all four building blocks" is "adequately demonstrated" because, EPA says, it is "technically feasible; it is capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost; it satisfies the other BSER criteria as well; and its components are well-established."[120] In the Legal Memorandum, EPA asserts that "the measures in each of the building blocks are 'adequately demonstrated' because they are each well-established in numerous states, many of them have already been relied on to reduce air pollutants, including CO_2, from fossil fuel-fired EGUs and, as noted, they may be undertaken by the affected EGUs or, in general, required by the states."[121] In essence, EPA asserts that each building block is "adequately demonstrated" because those measures, individually, "already have been

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118 42 U.S.C. § 7411(a)(1).
119 *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-434 (D.C. Cir. 1973).
120 79 Fed. Reg. at 34,885.
121 Legal Memorandum at 15.

implemented in many states..."[122] With regard to the alternative approach to BSER, EPA asserts that reduced utilization is "adequately demonstrated" because affected EGUs can "adjust their own generation," states can "impose requirements," and "other entities that operate in the various types of markets in the states can be expected to respond to the reduction in generation from the fossil-fuel fired EGUs by undertaking the measures in the building blocks or other actions that would assure reliability."[123] But this, to some extent, begs the question. EPA does not point to any state that is currently utilizing *every* building block, combined, in the manner and at the levels proposed in the Clean Power Plan. EPA does not point to any state that has imposed operating restrictions on affected EGUs at the levels that would have to be imposed to meet EPA's proposed carbon intensity goals. EPA asserts that each building block, by itself, has worked in some state at some point, and thus assumes that they will work in combination. But an assumption is not a demonstration. EPA has not shown that either variation of its building block BSER is "adequately demonstrated."

4. EPA's broad interpretation of "system of emission reduction" would lead to absurd results.

As EPA has acknowledged in the past, "the literal meaning of statutory requirements should not be considered to indicate congressional intent if that literal meaning would produce a result that is senseless or that is otherwise inconsistent with – and especially one that undermines – underlying congressional purpose."[124] In other words, when interpreting statutes, "absurd results are to be avoided."[125] Yet, the boundless interpretation of "system of emission reduction" that EPA has proposed -- "a set of things working together as parts of a mechanism or interconnecting network"[126] opens the floodgates to absurd results.

On the one hand, EPA's proposed definition is too narrow. Burning low-sulfur coal, for example, is not alone a "set of things working together," but would clearly qualify as a "system of emission reduction" under section 301(m) and the 1990 amendments to the CAA. Indeed, the first building block of EPA's proposed BSER – heat rate improvements – would not, by itself, meet EPA's proposed definition of a "system of emission reduction." Nor would increased

[122] *Id.* at 67.
[123] *Id.* at 16.
[124] *See* 75 Fed. Reg. 31,514, 31,517 (June 3, 2010).
[125] *United States* v. *Wilson*, 503 U. S. 329, 334 (1992).
[126] EPA Legal Memorandum at 36-37, n. 31 (citing *Oxford Dictionary of English* (3rd ed. 2010)).

generation from NGCC units alone qualify as a "system of emission reduction." EPA asserts that "reduced generation is a 'set of things' – which include reduced use of generating equipment and therefore reduced fuel input – that the affected source may take to reduce its CO_2 emissions,"[127] but this increased utilization of a different source may not be within the control of the source whose emissions are to be reduced. This mangled reasoning ("a 'set of things' ... that the affected source may take") ignores the reality of the electricity generating system and stretches the meaning of "set of things" beyond any reasonable interpretation. "Reduced generation" is not a "thing," it is the product of a comparison between two operating states. It is, in fact, the *absence* of a thing – a quantity of generation. Even in EPA's model, this reduced generation must be offset by increased generation from other types of generators, most of which are not under common control. Thus, EPA's proposed definition excludes pollution control measures that are inarguably "systems of emission reduction" and would also exclude at least some of the new "systems of emission reduction" on which EPA's current BSER proposal relies.

EPA's proposed definition is also too broad. EPA interprets its new definition of "system of emission reduction" to "encompass[ ] virtually any 'set of things' that reduce emissions."[128] These "things," moreover, do not all take place at the existing sources in the source category being regulated. Two of the four "building blocks" in EPA's main BSER approach rely on using alternative sources of electricity (NGCC units or low- or zero-carbon generation).[129] The fourth building block is simply encouraging people to use less electricity.[130] Under EPA's interpretation of "system of emission reduction," EPA could have adopted a BSER that comprised only the last three building blocks. In other words, EPA could have selected a "best system for emission reduction" for affected EGUs that imposed no direct obligations on the category of existing sources that EPA is purportedly regulating. Indeed, under EPA's "portfolio approach," states could develop plans that only "impos[e] requirements on other entities," not including EGUs, "as long as, again, the required emission performance level is met."[131] In short, EPA has taken a statute that requires states to adopt plans that "establish[ ] standards of

[127] Legal Memorandum at 82.
[128] Legal Memorandum at 51.
[129] 79 Fed. Reg. at 34,858.
[130] 79 Fed. Reg. at 34,858.
[131] 79 Fed. Reg. at 34,853.

performance for any existing source,"[132] and interpreted it in a way that would allow states to adopt plans that impose *no* obligations on *any* existing source in the relevant source category.[133]

Moreover, if EPA's new interpretations allow the agency to base BSER on any measures that "displace, or avoid the need for, generation from the affected EGUs,"[134] there is no end to the restrictions on human and commercial activities that EPA could contemplate as BSER. As discussed above, under EPA's definition of "system of emission reduction," EPA could adopt emission performance goals that rely on every state's adoption of ENERGY STAR and WaterSense requirements as binding requirements for appliance manufacturers, developers, and consumers. But, EPA would not need to stop at regulating the kinds of homes and businesses people build, and the kinds of appliances their families and customers use.[135]

EPA's proposed interpretation of "system of emission reduction" and the new "portfolio approach" to setting inviolate state goals that EPA has proposed to adopt in its CPP, contains no limiting principle that constrains the agency's regulatory reach. Never before has EPA claimed the authority to limit productive capacity or control the rate of customer usage of a particular product, and the assertion of authority to do so here has no foundation in the CAA. Because EPA's interpretation would purport to give EPA broad power to regulate human behavior, EPA's interpretation of "system of emission reduction" must be rejected.

C. The Proposed Guidelines Violate the Requirements of EPA's Own Implementing Regulations

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") recently confirmed the common-sense concept that federal agencies are bound by their own regulations. In *National Environmental Development Association's Clean Air Project v. EPA*, the court held:

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[132] 42 U.S.C. § 7411(d)(1).

[133] *See* Legal Memorandum at 94 ("The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance – and, for the portfolio approach, in imposing requirements on other entities – as long as, again, the required emission performance level is met.").

[134] Legal Memorandum at 96.

[135] The Center for Biological Diversity suggests that reducing population growth may be necessary to reduce greenhouse gas emissions, stating, "A 2009 study of the relationship between population growth and global warming determined that the 'carbon legacy' of just one child can produce 20 times more greenhouse gas than a person will save by driving a high-mileage car, recycling, using energy-efficient appliances and light bulbs, etc. Each child born in the United States will add about 9,441 metric tons of carbon dioxide to the carbon legacy of an average parent." The study concludes, "Clearly, the potential savings from reduced reproduction are huge compared to the savings that can be achieved by changes in lifestyle." Center for Biological Diversity, *Human Population Growth and Climate Change*, http://www.biologicaldiversity.org/programs/population_and_sustainability/climate/.

> It is "axiomatic[ ]" ... "that an agency is bound by its own regulations." *Panhandle Eastern Pipe Line Co. v. FERC*, 613 F.2d 1120, 1135 (D.C. Cir. 1979) (holding that an agency does not have authority to "play fast and loose with its own regulations"). "Although it is within the power of [an] agency to amend or repeal its own regulations, [an] agency is not free to ignore or violate its regulations while they remain in effect." *U.S. Lines, Inc. v. Fed. Mar. Comm'n*, 584 F.2d 519, 526 n.20 (D.C. Cir. 1978). Thus, an agency action may be set aside as arbitrary and capricious if the agency fails to "comply with its own regulations." *Environmental, LLC v. FCC*, 661 F.3d 80, 85 (D.C. Cir. 2011).[136]

Thus, to the extent that the CPP violates EPA's own regulations, it is unlawful.

EPA asserts that it developed its proposed emission guidelines "in accordance with sections 111(d) of the CAA and subpart B of this part."[137] Indeed, the proposed regulations explicitly require states to "follow the requirements of subpart B of this part (Adoption and Submittal of state plans for Designated Facilities) and demonstrate that they were met in [the] state plan."[138] The proposed regulations do state that, "[t]o the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply."[139] EPA's Legal Memorandum makes clear, however, that "the present rulemaking ... follow[s] the requirements of the implementing regulations, except that the EPA is extending certain timetables, as described in the preamble."[140] Thus, EPA acknowledges that its Clean Power Plan must comply with 40 C.F.R. Part 60, Subpart B (with the extended timetables). Nonetheless, several provisions of the CPP contradict the literal requirements of Subpart B, which, as explained below, are unlawful and must be removed from EPA's proposal.

D. EPA's proposal reflects what EPA believes to be the best system of emission reduction for *states*, in violation of Subpart B's requirement to promulgate a guideline document that "reflects the best system of emission reduction ... for *designated facilities*."

EPA's rules for adoption and submittal of state plans for designated facilities are set forth in 40 C.F.R. Part 60, Subpart B. Subpart B instructs EPA that, "[c]oncurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information

[136] *Nat'l Envtl. Dev. Ass'ns Clean Air Project v. EPA*, 752 F.3d 999 (D.C. Cir. 2014).
[137] Proposed 40 C.F.R. § 60.5700. *See also* 79 Fed. Reg. at 34,852 ("This proposed action is consistent with the requirements of CAA section 111(d) and the implementing regulations.").
[138] Proposed 40 C.F.R. § 60.5740(b).
[139] Proposed 40 C.F.R. § 60.5700.
[140] Legal Memorandum at 9; *see also* 79 Fed. Reg. at 34,853.

pertinent to control of the designated pollutant f[ro]m designated facilities."[141] EPA has stated that its *Federal Register* notice, along with its supporting documents, constitute its draft guideline document.[142]

Subpart B lists the information that a guideline document must include. That information includes, among other things, "[i]nformation on the degree of emission reduction which is achievable with each system [of emission reduction that has been adequately demonstrated], together with information on the costs and environmental effects of applying each system *to designated facilities*."[143] The guideline document also must include "[a]n emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved."[144] EPA's regulations define "emission guideline" to mean:

> a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated *for designated facilities*.[145]

Both of these provisions, then, instruct EPA to develop emission guidelines that are based on "the best system of emission reduction" that "has been adequately demonstrated *for designated facilities*."

"Designated facilities" is also a defined term. Subpart B defines "designated facility" to mean "any existing facility ... which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility ...."[146] "Existing facility" and "affected facility" are also defined terms. "Existing facility" means "any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type."[147] "Affected facility," in

[141] 40 C.F.R. § 60.22(a).
[142] Legal Memorandum at 32.
[143] 40 C.F.R. § 60.22(b)(3) (emphasis added).
[144] 40 C.F.R. § 60.22(b)(5).
[145] 40 C.F.R. § 60.21(e) (emphasis added).
[146] 40 C.F.R. § 60.21(b).
[147] 40 C.F.R. §60.2.

turn, means "any apparatus to which a standard is applicable."[148] Finally, "standard" is defined to mean "a standard of performance proposed or promulgated under [Part 60]."[149] Thus, a "designated facility" is an existing stationary source that is the same type of source for which EPA has proposed or promulgated a New Source Performance Standard and emits the pollutant that is the subject of the emission guidelines.[150]

Here, the "designated facilities" are the "affected EGUs."[151] Yet, EPA's emission guidelines do not reflect the best system of emission reduction that has been adequately demonstrated *for those affected EGUs*, as required by Subpart B. Instead, it reflects the degree of emission reduction that EPA believes is achievable through the application of the best system of emission reduction that EPA has determined has been adequately demonstrated for *states.* EPA's Legal Memorandum makes this quite clear: "In this rulemaking, the EPA proposes to determine the 'best system of emission reduction ... adequately demonstrated' *on a state-by-state basis*."[152] EPA further explains that its emission guidelines are then based on this state-by-state determination of BSER:

> This proposed rulemaking – including the preamble and the supporting documents -- comprise the "draft guideline document." The documents contain the "information for the development of State plans" described in the regulations. This information includes descriptions as well as technical and economic evaluations of the four building blocks. This information also includes the EPA's application of the BSER *to each state*, and the EPA's calculation of the resulting proposed *state goals*. *These state goals comprise the proposed "emission guidelines.*[153]

The Legal Memorandum confirms that this "statewide" determination of the BSER is fundamental to EPA's approach.[154]

The preamble, too, makes clear that EPA determined BSER by reference to what it believed had been adequately demonstrated by *the states*. The preamble explains that "the EPA

[148] *Id.*
[149] *Id.*
[150] *See* 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975).
[151] *See* Proposed 40 C.F.R. §§ 60.5700, 60.5795.
[152] Legal Memorandum at 42 (emphasis added).
[153] Legal Memorandum at 32-33 (emphasis added). *See also* 79 Fed. Reg. at 34,851 (stating: "Based on the EPA's application of the BSER *to each state*, the EPA is proposing to establish, as part of the emission guidelines, state-specific goals, expressed as average emission rates for fossil fuel-fired EGUs. Each state's goals comprise the EPA's determination of the emission limitation achievable through application of the BSER in that state.") (emphasis added).
[154] Legal Memorandum at 18 ("It should be noted that an important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis.").

is proposing state-specific goals that reflect the EPA's calculation of the emission limitation that *each state* can achieve through the application of the BSER."[155] It further explains:

> To set the state-specific CO_2 goals, the EPA analyzed the practical and affordable strategies that *states* and utilities are already using to lower carbon pollution from the power sector. These strategies include improvements in efficiency at carbon-intensive power plants, programs that enhance the dispatch priority of, and spur private investments in, low emitting and renewable power sources, as well as programs that help homes and businesses use electricity more efficiently. In addition, in calculating each state's CO_2 goal, the EPA took into consideration the state's fuel mix, its electricity market and numerous other factors. Thus, each state's goal reflects its unique conditions.[156]

Thus, EPA's proposed CPP overlooks the fundamental regulatory requirement that its guideline documents must provide information on systems of emission reduction that can be applied *to affected EGUs*,[157] and emission guidelines that are based on the best system of emission reduction that has been adequately demonstrated *for affected EGUs*.[158] Instead, EPA's proposed guideline document discusses and selects what it believes to be the best system of emission reduction that has been adequately demonstrated for the *states* in which those affected EGUs are found, which is contrary to 40 C.F.R. Part 60, Subpart B, and therefore unlawful.

E. EPA's broad interpretation of "system of emission reduction" conflicts with its more limited interpretation of "system" in Subparts A and B.

As discussed above, EPA has proposed to interpret the word "system" in "system of emission reduction" to mean "a set of things working together as parts of a mechanism or interconnecting network; a complex whole."[159] Based on this nebulous definition, EPA has proposed that "virtually any 'set of things' that reduce[s] emissions" is a "system of emission reduction."[160] As discussed above, this broad interpretation of "system of emission reduction" conflicts with the narrower interpretation reflected in the legislative history and for related terms in the CAA. EPA's broad interpretation also conflicts with the narrower interpretation of "system of emission reduction" reflected in Subparts A and B.

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[155] 79 Fed. Reg. at 34,834.
[156] 79 Fed. Reg. at 34,833(emphasis added).
[157] *See* 40 C.F.R. § 60.22(b)(3).
[158] *See* 40 C.F.R. § 60.22(b)(5).
[159] Legal Memorandum at 51.
[160] *Id.*

This narrower interpretation is best reflected in Subpart B's discussion of state plans' compliance schedules. Under EPA's implementing regulations, "[e]ach plan shall include emission standards and compliance schedules." "Compliance schedule" is defined as "a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific emission standards contained in a plan or with any increments of progress to achieve such compliance."[161] The regulations further state that "[a]ny compliance schedule extending more than 12 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities."[162] "Increments of progress," in turn, is defined to mean "steps to achieve compliance which must be taken by an owner or operator of a designated facility."[163] The regulations go on to describe the minimum increments of progress that must be included, all of which focus on activities to be accomplished at the designated facility:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for *emission control systems or for process modifications*, or issuance of orders for the purchase of component parts to accomplish *emission control or process modification*;

(3) Initiation of on-site construction or installation of *emission control equipment or process change*;

(4) Completion of on-site construction or installation of *emission control equipment or process change*; and

(5) Final compliance.[164]

These standard increments of progress merely reinforce what is obvious from a review of the statute – "system of emission reduction" is properly understood to mean, and except for the CPP proposal has been understood by EPA to mean, something akin to emission control equipment or process modifications.

The states need not include these specific "increments of progress" if it is not "practicable," or if a specific subpart specifies otherwise.[165] This does not indicate, however, that EPA understands "systems of emission reduction" to mean something significantly different

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[161] 40 C.F.R. § 60.21(g).
[162] 40 C.F.R. § 60.24(e)(1).
[163] 40 C.F.R. § 60.21(h).
[164] *Id.* (emphasis added).
[165] 40 C.F.R. § 60.24(e)(1).

from emission control systems or process modifications. EPA promulgated the regulatory language discussed above, including the definition of "increments of progress" and the exception for when such increments are not "practicable," in 1975 – two years *before* Congress inserted the word "technological" into the phrase "best system of emission reduction"[166] – and the language in the implementing regulation has not changed since.[167] And as explained above, in 1975, EPA understood "system of emission control" to mean "control technology."[168]

This understanding of "system of emission reduction" to mean a piece of emission control equipment, or an emission control system, is also reflected in the Subpart A rules for new sources. Subpart A states that an existing facility that undertakes a "physical or operational change … which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification," rendering the facility an "affected facility" for purposes of Subpart A.[169] The rules go on to list several actions that will not be considered modifications, including "[t]he addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial."[170] The rule thus clarifies that the installation of a system of emission reduction, to comply with a state plan under Subpart B or another Clean Air Act program, will not turn an existing source into a modified source. But more importantly, for purposes of the Clean Power Plan, it demonstrates yet again that "system of emission reduction" is properly understood to mean, and has otherwise been understood by EPA to mean, something akin to emission control equipment or process modifications.

Because EPA's proposed interpretation of BSER is contrary to Subpart B's interpretation of a "system of emission reduction" as "emission control equipment or [a] process change," and Subpart A's interpretation of a "system of emission reduction" as an "emission control system" or "device," it is unreasonable and unlawful.

[166] *See, e.g.,* 79 Fed. Reg. 1430, 1462-1463 at n. 131 (Jan. 8, 2014).
[167] *See* 40 Fed. Reg. 53,340 (Nov. 17, 1975).
[168] 40 Fed. Reg. at 53,341.
[169] 40 C.F.R. § 60.14(a).
[170] 40 C.F.R § 60.14(e)(5).

F. EPA's emission guidelines permit states to apply emission standards to both "designated facilities" and other entities, but Subpart B permits the application of emissions standards only to "designated facilities."

Under section 111(d)(1), states are required to submit plans that establish "standards of performance for" existing sources.[171] "Standard of performance" is defined to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction..."[172] Under this definition, originally, "standards of performance could be established only in the form of emissions limitations, based on output, and not in the form of work practice or operation requirements."[173] Congress then amended section 111 in 1977 to add subsection (h), which allows EPA to "promulgate a design, equipment, work practice, or operational standard, or combination thereof," if EPA concludes "it is not feasible to prescribe or enforce a standard of performance..."[174]

The statutory definition of "standard of performance," and the alternatives to standards of performance that section 111(h) authorizes in limited circumstances, are reflected in the implementing regulations' definition of "emission standard." Under Subpart B, states' section 111(d) plans must "establish[ ] emission standards for designated pollutants from designated facilities ... ."[175] Under the rules, an "emission standard" generally may be written as "*an allowable rate of emissions into the atmosphere*, ... an allowance system, or ... *equipment specifications* for control of air pollution emissions."[176] However, the rules require the emission standards to be "based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable."[177] Thus, like the Clean Air Act, EPA's Subpart B rules generally require emission standards to be written as emission limitations (or allowance systems), unless they cannot be written in that manner, in which case they may be written as equipment specifications (or, under the Act, design, work practice, or operational standards).

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[171] 42 U.S.C. § 7411(d)(1).
[172] 42 U.S.C. § 7411(a)(1).
[173] *PPG Industries, Inc. v. Harrison*, 660 F.2d 628, 636 (5th Cir. 1981) (citation omitted).
[174] 42 U.S.C. § 7411(h)(1). *See PPG Industries*, 660 F.2d at 636.
[175] 40 C.F.R. § 60.21(c).
[176] 40 C.F.R. § 60.21(f) (emphasis added). AEP will not address, in these comments, whether the inclusion of allowance systems in the regulatory definition of "emission standard" is statutorily permissible, as that issue was not raised by EPA's proposal.
[177] 40 C.F.R. § 60.24(b)(1).

EPA's proposed CPP, however, would provide a new, expanded definition of "emission standard," limited only to Subpart UUUU, which would incorporate the Subpart B definition of "emission standard," but also add "any requirement applicable *to any affected entity other than an affected source* that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources ...."[178] The Plan defines "Affected Entity" to mean "[a]n affected EGU, *or another entity with obligations under this subpart* for the purpose of meeting the emissions performance goal requirements in these emission guidelines."[179] Thus, the proposed CPP presumes that states will adopt plans that impose obligations on sources other than affected EGUs, and would expand the definition of "emission standard" to make that possible. The preamble explains:

> The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance – and, for the portfolio approach, in imposing requirements on other entities – as long as, again, the required emission performance level is met.[180]

EPA lacks the statutory authority to expand the regulatory definition of "emission standard" in that manner. A requirement to reduce utilization is not a "standard of performance," whether it is effectuated indirectly through building blocks 2, 3, and 4 (in EPA's primary BSER proposal) or by directly requiring reduced utilization of affected EGUs (under EPA's alternative BSER proposal). And, there is nothing in Subpart B that permits the states to adopt a plan that imposes obligations on any category of sources or entities other than affected EGUs in the source category. EPA has said that it "is following the requirements of the implementing regulations" in its CPP.[181] Although EPA's proposed CPP would amend the definition of "emission standard," it does not amend the definition of "plan," the requirements of §60.24(b)(3), or any other portion of Subpart B. And numerous provisions of the implementing regulations make clear that emission standards may apply only to "designated facilities."

First, following EPA's promulgation of a final guideline document, Subpart B requires each state to "adopt and submit ... a plan for the control of the designated pollutant to which the guideline document applies."[182] "Plan" is a defined term meaning "a plan under section 111(d)

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[178] Proposed 40 C.F.R. § 60.5820 (emphasis added).
[179] *Id.* (emphasis added).
[180] 79 Fed. Reg. at 34,853.
[181] Legal Memorandum at 9.
[182] 40 C.F.R. § 60.23(a)(1).

of the Act which establishes emission standards for designated pollutants from designated facilities and provides for the implementation and enforcement of such emission standards."[183] Subpart B further states that "[e]mission standards shall apply to all designated facilities within the State."[184] Combined, these provisions make clear that "emission standards" are to be applied to "designated facilities."

Next, state plans must contain provisions for "[p]eriodic inspection and, when applicable, testing of *designated facilities*."[185] If a plan has a "compliance schedule extending more than 12 months from the date required for submittal of the plan," that plan "must include legally enforceable increments of progress to achieve compliance for each *designated facility* or category of facilities."[186] States, then, may take into account individual facilities' characteristics when determining the emissions standards and compliance schedules that will apply to each facility. EPA's regulations authorize states to give particular facilities, or classes of facilities, "less stringent emissions standards or longer compliance schedules" if the state can demonstrate:

> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility of installing necessary control equipment; or
>
> (3) Other factors *specific to the facility* (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.[187]

And, under certain circumstances, "the owner or operator of a *designated facility to which regulations proposed and promulgated under this section will apply*" may apply to EPA for "less stringent emission standards or longer compliance schedules than those otherwise required."[188] These provisions, again, demonstrate that Subpart B expects the states to take a "source-based" approach in preparing their plans. Consequently, EPA's proposal to allow states to impose legal obligations on sources or entities other than affected EGUs violates 40 C.F.R. Part 60, Subpart B, and is unreasonable and unlawful.

It should be noted that EPA's alternative proposal, under which state plans would "impose legal responsibility on the affected EGUs to achieve the full level of ... emission performance" required under the CPP, "but also include enforceable or complementary RE and

[183] 40 C.F.R. § 60.21(c).
[184] 40 C.F.R. § 60.24(b)(3).
[185] 40 C.F.R. § 60.25(b)(1) (emphasis added).
[186] 40 C.F.R. § 60.24(e)(1) (emphasis added).
[187] 40 C.F.R. § 60.24(f) (emphasis added).
[188] 40 C.F.R. § 60.27(e)(2) (emphasis added).

demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions"[189] would also be unlawful. Under any such plan, affected EGUs would not control their own compliance. A plan that imposed legal responsibility only on affected EGUs, but made compliance with standards of performance possible only through redispatch to less carbon-intensive affected EGUs, substitution with low- and zero-carbon generation, and the adoption or expansion of demand-side energy efficiency programs would, in effect, impose vicarious liability on the owners and operators of affected EGUs for the acts or omissions of third parties. Affected EGUs would have to rely on RTOs to change their dispatch models;[190] NGCC owners and operators to operate and maintain their units;[191] other independent power producers to build wind and solar farms;[192] and electric utilities' residential, commercial, and industrial customers to better insulate their homes, install energy-efficient lighting, and otherwise reduce their power consumption.[193]

The imposition of vicarious liability violates substantive due process if the party exposed to the vicarious liability does not have control over the party, or is not in a business relationship with the party, that is primarily responsible.[194] Thus, EPA's alternative proposal to allow states to impose 100% of the legal responsibility for meeting the state carbon-intensity goals on affected EGUs, while leaving the practical ability to meet those goals in the hands of hundreds of thousands of unaffiliated utility customers and governmental agencies, would not withstand constitutional scrutiny. EPA cannot promulgate state goals that can only be met through the efforts of affected entities other than affected EGUs, and yet impose the obligation to meet those goals entirely on the affected EGUs, if the affected EGUs' owners and operators do not control these other entities or are not in a business relationship with them that would allow them to re-

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[189] 79 Fed. Reg. at 34,902.
[190] *See* 79 Fed. Reg. at 34,888 ("On the regional level, ISO/RTOs control dispatch").
[191] EPA suggests that affected EGUs could take control of their own ability to comply by "invest[ing] in NGCC capacity." Legal Memorandum at 74. However, EPA's analysis assumes that "the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking." 79 Fed. Reg. at 34,882.
[192] EPA suggests, too, that affected EGUs could "invest in renewable capacity." Legal Memorandum at 74. Yet, the owners and operators of one affected EGU would not likely control every renewable energy source in its state.
[193] *See, e.g.*, 79 Fed. Reg. at 34,884 ("Owners of affected EGUs as well as other parties can contract for demand-side energy efficiency.").
[194] *Compare Portland Pipe Line Corp. v. Environmental Improvement Comm'n*, 307 A.2d 1, 19 (Me. 1973) (holding, "there is no constitutional bar to the imposition of vicarious liability upon one engaged in business, for the acts of a business associate, when both are engaged in a mutually beneficial relationship and there is, in the relationship, adequate opportunity to locate, among the business associates, the primary liability."),

allocate the costs of non-compliance to the entities primarily responsible for the failure to achieve state performance standards.

V. The Emission Reductions Required by Building Block 1 Are Not Achievable

From the opening sentence of EPA's evaluation of potential heat rate improvement opportunities, the agency mischaracterizes observed differences in operating efficiencies as being "evidence" that existing coal-based generating units are not being adequately operated or maintained.[195] EPA is incorrect in this conclusion. Heat rate performance is influenced by a variety of known and unknown, controllable and uncontrollable factors, whose interaction and degree of impact is unit-specific and will vary throughout the life of the unit. EPA itself in a 2010 report on available and emerging technologies for reducing greenhouse gas emissions from coal-fired electric generating units stated that:

> The actual overall efficiency that a given coal-fired EGU achieves is determined by the interaction of a combination of site-specific factors that impact efficiency to varying degrees… Because of these factors, coal-fired EGUs that are identical in design but operated by different utility companies in different locations may have different efficiencies. Thus, the level of effectiveness of a given GHG control technology used to improve the efficiency at one coal-fired EGU facility may not necessarily directly transfer to a coal-fired EGU facility at a different location.[196]

Although EPA in the proposed rule alludes to this wide scope of influences and the "site specific" factors that drive heat rate performance, the agency fails to objectively and holistically account for these drivers, and concludes that, except for the variability attributable to ambient temperatures and load factor, poor operational practices and lack of equipment maintenance or upgrades are the exclusive source of observed "difference[s] in operating efficiency."[197] In fact, EPA's evaluation ignores or does not fully consider the following:

- the other uncontrollable factors that impact heat rate performance;
- the availability, technical viability, and economic feasibility of potential improvement opportunities at individual units;
- heat rate improvement measures that have already been implemented;
- unit-specific factors that influence the magnitude and sustainability of potential heat rate improvements; and
- the impact of other environmental requirements that may mask or eliminate potential heat rate improvements.

[195] "GHG Abatement Measures TSD". U.S. EPA. June 10, 2014. p. 2-1
[196] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA Office of Air & Radiation, October 2010. p 22-23. (emphasis added)
[197] "GHG Abatement Measures TSD". U.S.EPA. June 2014. p.2-1.

Had EPA fully considered these factors, the agency would have correctly concluded that both the proposed 6% and alternative 4% targets for heat rate improvements are overly aggressive, and cannot feasibly be implemented by the majority of existing coal-based generating units. Instead of collecting the information necessary to reasonably evaluate these issues, EPA chose to evaluate potential heat rate improvement opportunities by:

- performing a flawed statistical analysis of heat rate variability;
- performing a narrow review of available information on heat rate performance by examining a single technical report with a study of just two units and select vendor information;[198]
- incorrectly estimating the applicability of and cumulative impact of a portfolio of potential improvement measures; and
- incorrectly assuming that a high rate of cumulative improvements are achievable by all coal units.

Based on this evaluation, EPA determined that a 6% efficiency improvement has been adequately demonstrated to be achievable through improved operating practices (4%) and equipment maintenance/upgrades (2%). EPA's flawed assessment is grounded in uninformed and inaccurate assumptions and conclusions that reflect an incomplete understanding of the nature, cost, and availability of potential heat rate improvement opportunities. The sections below provide detailed comments on these fundamental flaws and offer greater context on the factors that drive heat rate performance and the limited opportunities for improvement.

A. EPA should objectively and holistically consider the full range of issues that influence heat rate performance

Although EPA identifies various factors that influence heat rate, the agency fails to fully or accurately consider these factors when evaluating potential improvement opportunities. This inconsistency results in a BSER determination that is made within a vacuum of what may *potentially* be achievable with operational best practices and equipment upgrades, but which completely ignores competing variables that may diminish or in some cases prohibit measurable improvement. For example, EPA correctly notes that:

> A variety of factors must be considered when comparing the effectiveness of heat rate improvement technologies to increase the efficiency of a given coal-fired EGU. The

[198] Sargent & Lundy's 2009 report "Coal-Fired Power Plant Heat Rate Reductions" provided two examples of heat rate reductions. These two examples are NOT an appropriate basis for an across the board prediction of improvement.

> actual overall efficiency that a given coal-fired EGU achieves is determined by the interaction of a combination of site-specific factors that impact efficiency to varying degrees. Examples of the factors affecting EGU efficiency at a given facility include:
>
> - thermodynamic cycle
> - coal rank and quality
> - [unit] size
> - pollution control systems
> - operating and maintenance practices
> - cooling system
> - geographic location and ambient conditions
> - load generation flexibility requirements
> - [balance] of plant components.[199]

EPA further states:

> All of the improvement technologies...[identified]... cannot necessarily be implemented at every existing coal-fired EGU facility in the U.S. electric utility fleet. The existing EGU design configuration and other site-specific factors may prevent the technical feasibility of using a given technology.[200]

Despite acknowledging the number of design and operational variables, as well as site-specific factors that affect heat rate performance, EPA fails to adequately consider and apply this knowledge in its evaluation of potential improvement opportunities and in its BSER determination. The following sections examine the fundamental concepts that EPA should objectively consider and apply in developing a final rule. An expanded discussion of these fundamental issues is provided in Appendix A, which contains a white paper developed by AEP on heat rate issues and potential improvement opportunities at coal-based generating plants.

1. Heat rate improvement opportunities are unique to each unit

In examining potential heat rate improvement opportunities at existing units, there are several principles that are critical in determining the realistic applicability and degree of potential heat rate improvement that any specific project might afford, including the following:

- improvements are not uniform and what may work for one unit, may not work for another;

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[199] "GHG Abatement Measures TSD". U.S.EPA. June 2014. p.2-4 – 2.5. (emphasis added)
[200] "GHG Abatement Measures TSD". U.S.EPA. June 2014. p.2-5 – 2.6. (emphasis added)

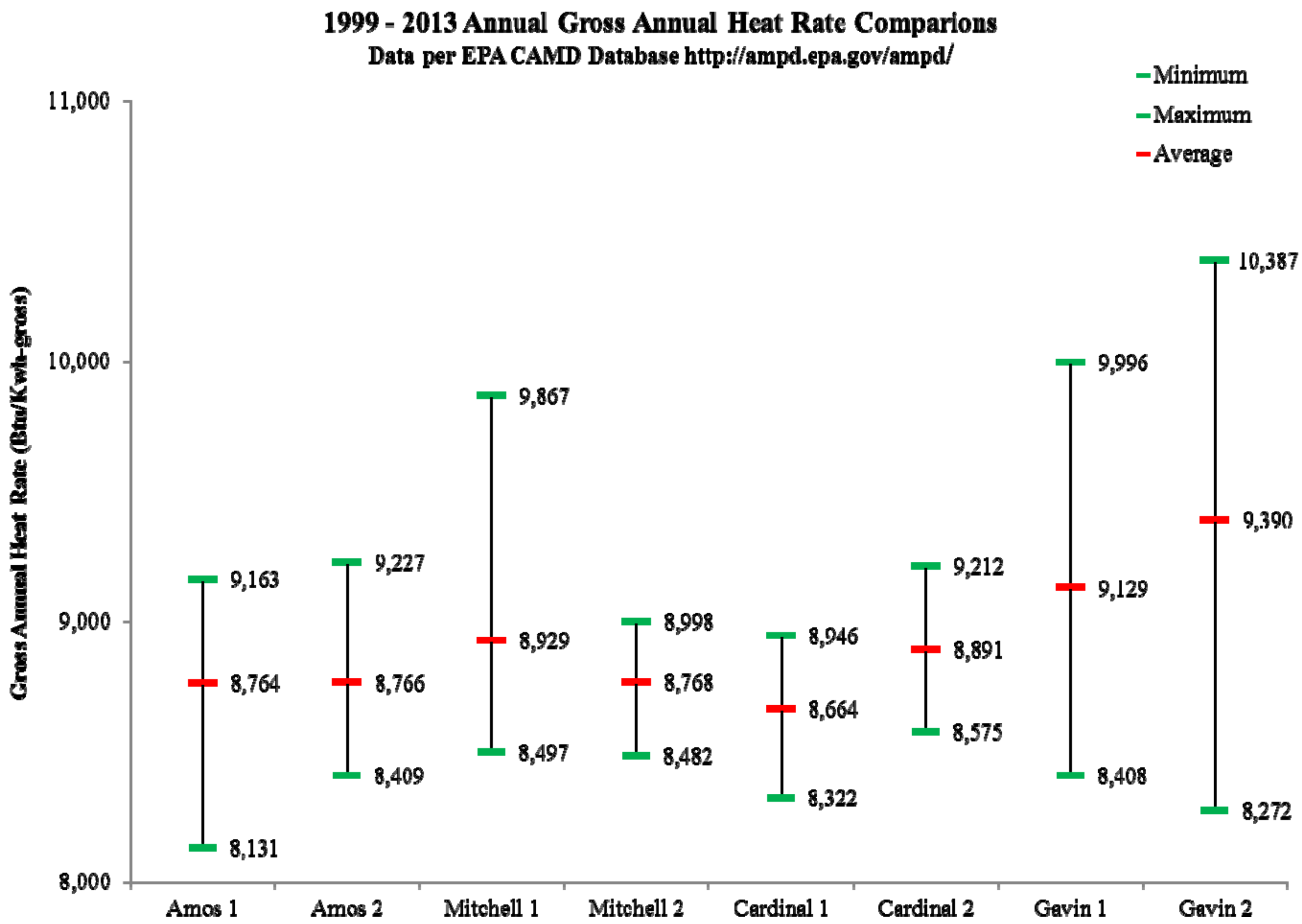
- the heat rate benefit of multiple improvement projects is not necessarily cumulative; improvements in one area can be masked by operations or conditions in another, thus diminishing any overall heat rate improvement;
- outside influences beyond the control of the unit operators can alter or erase heat rate improvements, because plants are dispatched based upon electricity demand, and the availability of other units;
- improvements must be cost-effective and measurable to justify their implementation;
- space constraints may exist on a particular unit that prohibit the addition of equipment or re-routing of ductwork/piping to implement a heat rate improvement project;
- the benefit derived from many of the suggested heat rate improvement technologies is temporary and will diminish over time due to the age and operation of the unit;
- for some heat rate improvement projects the potential benefits will only be apparent at full load operations, and offer no measurable improvements for cyclic or minimum load operations;
- conversely, some base load units would show no benefit to heat rate if the improvement is experienced only at lower loads or during cycling operations;
- EPA's 111(d) proposal suggests that existing coal power plants will be dispatched and operated much differently from the past, so historic experience may not provide an accurate projection of future benefits.

Heat rate improvement projects are valuable and have been frequently implemented because of the benefits of more efficient fuel use, lowered operating costs and improved equipment performance. Most power plant owners regularly assess the potential for heat rate improvements in order to capture these cost savings. However, this past practice means that every well-maintained unit likely has implemented several cost-justified methods to improve heat rate, and that only marginal projects remain for consideration.

Existing coal-fired generating units are also constrained by their original design basis and past operations. Units vary significantly due to their design, manufacturer, operating history, age, and type of coal consumed, among many other factors. It is completely unreasonable and technically infeasible to expect that this widely diverse fleet could all achieve the same level of improvement in heat rate performance. For example, the AEP John W. Turk, Jr. Plant ("Turk") that began operation in 2012 represents a state-of-the-art ultra-supercritical steam cycle, which is a design that produces higher steam temperatures and pressures than is typical in most units. The result is that the Turk Plant has a much higher overall efficiency (~38%) and much lower average net unit heat rate (~9,000 Btu/kWh net), than the 2012 coal-fired generation fleet average of 34 % and 10,107 Btu/kWh net.[201] Turk is the only operating ultra-supercritical unit in the U.S., in large part because it has only been within the last decade that advanced steam piping materials have been available. EPA's flawed "one-size-fits-all" approach in building block one (a) incorrectly assumes that the newest and most efficient coal units, including the Turk Plant, could achieve a 6% heat rate improvement, and (b) ignores the significant unit-specific design differences that physically limit the potential opportunities for improvement.

Conversely, even similar or identical unit types can experience significant variability in heat rate performance. To support this point, the graph below plots the range of gross annual unit heat rates from 1999-2013 of AEP units that are of similar size and/or design. The units at each respective plant below, while sharing similar attributes in terms of the equipment technology and vintage, location (ambient temperature), fuel supply, operational characteristics, and other factors, have experienced quite dissimilar average gross annual heat rates, attributable to many of the factors discussed herein. Even similar units operating under similar ambient conditions can have significant variations in heat rate.

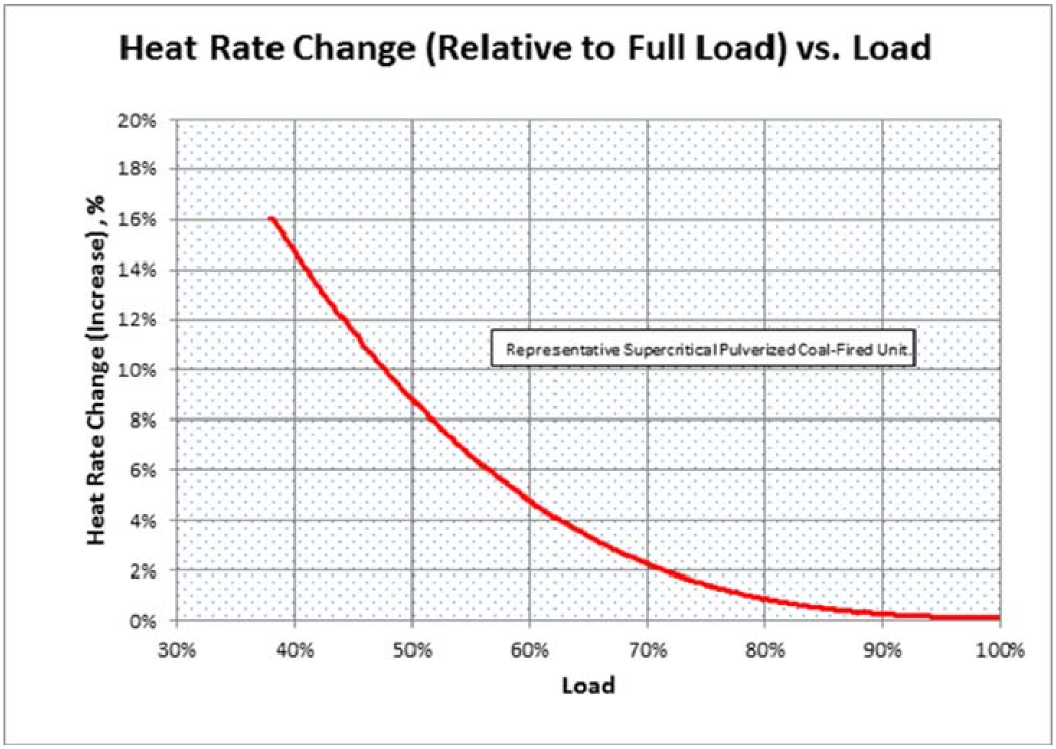
[201] U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'


1999 - 2013 Annual Gross Annual Heat Rate Comparions
Data per EPA CAMD Database http://ampd.epa.gov/ampd/
Minimum
Maximum
Average
Gross Annual Heat Rate (Btu/Kwh-gross)
11,000
10,000
9,000
8,000
9,163
8,764
8,131
9,227
8,766
8,409
9,867
8,929
8,497
8,998
8,768
8,482
8,946
8,664
8,322
9,212
8,891
8,575
9,996
9,129
8,408
10,387
9,390
8,272
Amos 1
Amos 2
Mitchell 1
Mitchell 2
Cardinal 1
Cardinal 2
Gavin 1
Gavin 2

It is important to differentiate between the "design heat rate" and the average heat rate of a unit. Design heat rate is a theoretical target that represents an optimal, full-load, steady-state condition and is considered the best level of unit performance that could potentially be achieved under original design conditions. It is possible that units may achieve their design heat rate when new with all components in their best condition. It is well-understood by manufacturers, operators, and most regulators, however, that the unit will not, and should not be expected to achieve its design unit heat rate under all operating conditions or throughout its operating life. The age of the unit, historic operations and maintenance over its life, as well as the retrofit of any auxiliary equipment like emissions controls, will all negatively impact the heat rate over the life of the unit, resulting in an average unit heat rate that is higher than the unit's original design heat rate. While there may be similarities between units, often even identically designed units at the same plant site have very different heat rates because each unit has been operated and maintained differently.

2. Actual heat rate performance varies due to a number of known and unknown, controllable and uncontrollable factors

Heat rate is *not* a constant value. It varies significantly due to numerous factors that both positively and negative impact performance. Heat rate is an operating variable that is constantly changing as the dynamic conditions of an individual unit's operating environment change. Heat rate is like the fuel efficiency rating of an automobile (typically expressed in miles per gallon or MPG), which is widely recognized to be affected by the conditions of "city" versus "highway" driving. The frequent stops, starts and speed changes associated with city driving result in higher fuel usage, whereas driving on a highway at a constant rate of speed with fewer changing conditions uses less fuel. Variability in operations or operating at less than "full load" have similar impacts on a generating unit. The relationship of unit load to heat rate is shown for a typical supercritical unit in the graph below. As a unit cycles loads up and down, or runs at minimum loads for which the unit was not optimally designed, heat rate increases significantly.



City and highway driving is not the only variable that impacts an automobile's fuel efficiency. Things like the basic aerodynamic design of the car, the condition of the road (wet vs. dry; gravel vs. pavement; uphill vs. downhill), the air pressure in the tires, the cleanliness of the engine's air and fuel filtration systems, the fuel type, and even the outside air temperature and humidity can all impact the fuel efficiency of an automobile. Likewise, heat rate can be impacted by process and equipment design, maintenance and cleanliness of critical components, changes in weather conditions, changes in fuel energy content or fuel delivery, changes in process water and cooling water temperatures, and other factors.

Although EPA attempted to identify operational practices and equipment upgrades that affect heat rate performance, the agency failed to fully consider the range of variables that drive performance, incorrectly identified the level of improved performance associated with the variables considered, and erroneously concluded that all existing coal units could achieve the same level of improvement from implementing a common set of measures. EPA must broaden its analysis of heat rate improvement opportunities to more accurately evaluate the range of unit-specific factors that impact performance.

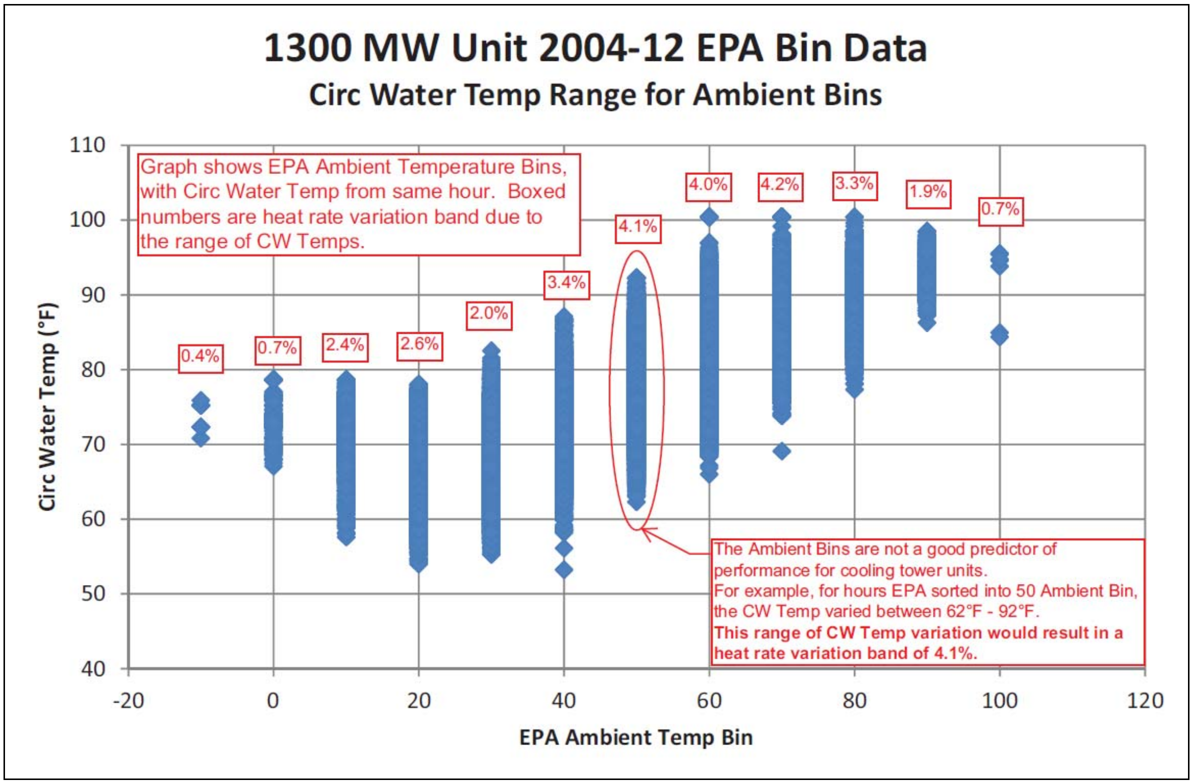
3. EPA has overstated the potential heat rate improvements related to operating practices

EPA attempted to evaluate the variability in unit heat rates related to operational practices by performing a statistical analysis (e.g. "bin analysis") of heat rate data at 884 coal- and petcoke-fired generating units from 2002-2012. Based on this analysis, EPA determined that application of "best operating practices" can improve heat rate by 4%. However, EPA's bin analysis is poorly designed and plagued with data scope and data quality issues that render it unsuitable as a foundation for any meaningful conclusions. As discussed in the sections that follow, EPA's determination is incorrect and significantly overstates the technical potential and understates the cost of such improvement opportunities, while ignoring significant feasibility, sustainability, measurability, and regulatory challenges.

a. The design of EPA's statistical analysis is fundamentally flawed

EPA's statistical analysis is fundamentally flawed, in part, because it assumes there is a strong correlation between heat rate and only two other factors: unit load (utilization) and differences in ambient air temperature. While EPA has correctly identified unit load as a key variable influencing unit heat rate, its assumptions about the impact of ambient air temperatures are not accurate. In reality, cooling water temperatures have a much stronger correlation with unit heat rate differences. Cooling water temperatures directly affect a unit's ability to remove/recover heat in the thermal cycle. Ambient air temperatures eventually affect cooling water temperature, but relatively quick changes in ambient air temperatures do not result in equally rapid changes in the temperature of a cooling water body. For example, warmer weather in the early spring does not initially elevate cold circulating water temperatures; or vice versa, colder early fall days will not immediately reduce warm circulating water temperatures. Similarly, day-to-night ambient temperature variations were used to sort the hourly data collected by EPA without regard to their actual ability to impact heat rate. These realities skew the temperature "bin" data analysis performed by EPA significantly. The figure below shows the wide range of circulating water temperatures associated with the "bins" EPA created based on hourly ambient temperature data. During the hours sorted into EPA's 50 degree Fahrenheit ambient temperature bin, the circulating water temperature varies from 62 degrees Fahrenheit to

92 degrees Fahrenheit. For some "bins," the circulating water temperatures varied by as much as 34 degrees Fahrenheit.



EPA oversimplified its analysis approach by simply aggregating data based on ambient air temperatures and unit load, then assuming that any remaining variability is under the control of unit operators. Such a simplified approach arbitrarily ignores the role that other variables, like circulating water temperature, play in heat rate variability. In the above graph, the variation (%) in heat rate within each temperature bin directly corresponds to the widening range in recorded circulating water temperatures within each ambient bin, suggesting a stronger correlation between heat rate and circulating water temperature, than ambient temperature. The above graph does not suggest that EPA could simply replace ambient temperature with circulating water temperature in its analysis, but is used to point out that EPA dramatically oversimplified its analytical approach to explaining controllable heat rate variability. The Utility Air Regulatory Group (UARG) performed a detailed critique of EPA's statistical bin analysis.[202] Using

[202] Cichanowicz & Hein. "Critique of EPA's Statistical Evaluation Defining Feasible Heat Rate Improvements." Prepared for UARG. December 1, 2014.

information provided in the EPA-referenced GHG Technical Support Document (TSD), UARG successfully reproduced the EPA results. However, UARG further evaluated the units within the EPA bins and discovered that significant design differences (e.g. unit age, steam cycle design, capacity factor, cooling system design) exist between the analyzed units.[203] These design differences contribute to the heat rate variability, and cannot necessarily be mitigated through "best practices" or heat rate improvement projects. Consequently, EPA's estimate of potential improvement opportunities is flawed and inaccurate.

EPA's calculation of its coefficient of determination or the "r-squared" value (0.26), which describes the relationship of unit load and ambient temperature, reinforces this conclusion, as these variables only account for 26% of the variability in overall heat rate of the population.[204] EPA should have stopped there, since 74% of the variability in heat rate is unexplained. Instead, EPA relied upon these two variables as a basis to identify available heat rate improvement opportunities. EPA's failure to examine other contributing uncontrollable factors leads to a significant overstatement of heat rate improvement opportunities.

UARG's replication of the "r-squared" value using the EPA data, along with further analyses of the unit designs and other contributing factors to heat rate significantly weaken EPA's assertion that unexplained heat rate variability represents the potential for improvement. Not only did EPA's analysis not fully account for the role of load and ambient temperature, but also several other variables were ignored – most significantly boiler design differences and coal composition. Boiler type (e.g. subcritical, supercritical, ultra-supercritical), along with size, age, and ability to respond to load changes all will have impact on heat rate. Coal composition can affect heat rate through boiler thermal efficiency and slagging impacts, changes in flue gas moisture content, and auxiliary power requirements. If EPA bases its final guideline on the existence of heat rate improvement opportunities, then the agency must reject the bin analysis and revisit its methodology for determining potential heat rate improvements through "best operational practices." Such a revised analysis must more accurately account for unit-specific

[203] Id. P. 6-8.
[204] U.S. EPA Office of Air and Radiation. GHG Abatement Measures. Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units. Docket ID No. EPA-HQ-OAR-2013-0602. June 2014. p. 2-24

design differences and be premised on factors that more directly affect unit performance and accurately reflect available opportunities for improvement.

EPA's evaluation of historic heat rate data is also biased by the inclusion of units that have been or will be retired before the first compliance period. Many of these retiring units were designed with less efficient processes (no reheat cycles, subcritical designs, and age-related operational constraints) which suggests a larger amount of heat rate variability and potential opportunities for improvement, than is present for the high-performing units that are suggested to remain in-service when the rule becomes effective. Units that are retired or that will be retired before 2020 should be excluded from the analysis to ensure that the evaluation reflects only those potential opportunities that may be available on the units that will remain in operation during the period affected by the guidelines.

b. EPA's dataset contains inherent sources of variability

EPA used data reported to the Clean Air Markets Division (CAMD) over the period from 2002 to 2012 as the basis for its statistical analysis of heat rate variability. Originally designed to capture emission data to support the emission allowance trading program created by the 1990 CAA Amendments, the requirements for reporting data to CAMD have evolved significantly over time. Many changes have occurred over this period that contribute to the variability in the heat rate data, yet these inherent sources of variability were not addressed in EPA's analysis:

- Continuous Emissions Monitoring Systems (CEMS) Flow monitor changes/upgrades. Allowable switching between redundant monitors and acceptable calibration ranges could result in as much as a 3% change in flow.
- Measurement instrumentation and locations may have changed as a result of emissions controls retrofits or other changes which may have occurred on the units.
- In 2008 EPA changed its fuel-specific emission factor (F-factor) requirement for CEMS reporting. On units firing bituminous fuel, this change would be interpreted as a 2% increase in heat input (2.2% degradation of heat rate).
- EPA's QA/QC steps and overall processes for reporting data have evolved over the years. Data from 2009 forward is likely to be the most homogeneous because of more widespread use of Emissions Collection and Monitoring Plan System (ECMPS) by reporting sources.
- Allowable Relative Accuracy Test Audit (RATA) flow instrument recalibration is typically less than +/-7.5%, but can be +/-10% or more.

These changes contribute to the overall range of variability in unit heat rates calculated based on the CAMD data and undermine the validity of EPA's analysis to determine an across-the-board recommendation for heat rate improvement. EPA made no effort to identify the effect of these changes in data reporting protocols, or to eliminate their impact before determining the range of potential heat rate improvement at coal-fired power plants.

c. EPA failed to account for physical and operational changes at existing units that affect potential heat rate improvement opportunities

The potential for future heat rate improvements depends on the current physical and operational characteristics of the existing fleet. By way of analogy, replacing the air filter in your car can improve fuel efficiency, typically at higher vehicle speeds. However, if the highway by which you commute to work is suddenly closed and you are rerouted through busy city streets, any fuel efficiency improvement from the new air filter will be overwhelmed by the result of more "city" driving. Similarly, if improvements are made to components or systems within a power plant, and then the unit is cycled more frequently to balance intermittent loads from new wind and solar generation, the effect of the heat rate improvements may never be measureable. In fact, depending upon the situation, the unit's average heat rate might actually deteriorate.

EPA's heat rate improvement determination was based on an analysis of gross heat rate data for a large population of units over a ten-year period. However, EPA did not consider or account for the many physical and operational changes that occurred over this period, and that have a direct affect on heat rate. Specifically, EPA should have considered heat rate changes from the installation of new emission control systems, prior heat rate improvement projects, and changes in duty cycle before estimating any remaining potential for heat rate improvements at existing coal-fired units.

Installing and operating emission control systems can often mask or offset any future heat rate improvement actions. From a net unit heat rate standpoint, these systems have a direct impact as the auxiliary power requirements reduce the amount of net energy (MWh) produced. The retrofit of selective catalytic reactors (SCRs) consumes on average about 1.5% of net output. The retrofit of flue gas desulfurization (FGD) systems on units fired by subbituminous coals increases auxiliary power usage by approximately 1.5%, while retrofits on units firing bituminous coals or a blend of these fuels increases auxiliary power usage by approximately 2.5%. In addition, a limestone-based wet FGD system introduces additional CO_2 into the flue gas stream as a result of chemical reactions in the scrubber, which increases the CO_2 content of the gas stream by several percentage points, in addition to the increase in auxiliary power requirements. There may be ways to minimize the detrimental heat rate impacts of adding these systems (e.g. employing efficient axial fans, considering variable speed drives where practical, optimizing ductwork configurations, etc.), but these design options are site-specific, and in no case are they enough to offset a net heat rate increase from the addition of these control systems. All of these changes affect heat rate, but do not "create" any additional heat rate improvement opportunities. EPA's analysis failed to eliminate these causes of heat rate variability, and thus overstates the remaining opportunities for improvement. For units with current obligations for future emissions control system retrofits, the adverse impact to net heat rate (2-4%) from the control installations makes a 6% improvement in heat rate even more unachievable.

Many units have already undertaken equipment upgrades and as such, the potential for additional improvement is marginal. Steam turbine upgrades represent the most significant heat rate improvement option available to the industry and to date, 86% of AEP's coal-fired generating capacity that will still be in service in 2020 and beyond undertook steam turbine upgrades prior to 2012. These units would receive no credit for these upgrades, and have limited options for additional heat rate improvements since turbine upgrades are generally the most effective heat rate improvement option available to reduce emissions.

It is standard practice in the utility industry to utilize preventative maintenance and routine cleaning practices that promote and sustain efficient operations. AEP, along with other utilities, the Electric Power Research Institute (EPRI), and power plant system original equipment manufacturers (OEMs) have for years participated in industry workshops, users group meetings and other forums to share best operating and maintenance practices to improve overall plant performance. Many of these targeted efforts have specifically focused on improving heat rate, i.e. reducing the amount of fuel consumed to generate electricity, thus lowering operating costs. Yet, the CPP offers no credit for proactive efforts like these, and the amount of heat rate improvement contemplated by EPA is very aggressive and overly ambitious for units that have historically been well maintained and operated. For recently constructed coal units that were built with more advanced and more efficient technologies, many of the potential heat rate improvement opportunities have already been incorporated into their base designs. Any potential improvement opportunity will be minimal and certainly far from the 6% level that EPA has considered in the proposed rule.

EPA's analysis also failed to consider unit operational changes that have occurred and will occur if the CPP is implemented as proposed. Many coal-fired units have gone from being base-loaded to load-following or cycling units, based on market/economic conditions or other factors. As such, the heat rate of a unit can change significantly, reflecting these operational changes. EPRI issued a report in 2011 which outlined the effects of cycling on heat rate. The report studied a 700 MW coal-fired unit which ran base-loaded (usually operated at net loads at or above 650 MW) from January to August of 2008. From August through the end of 2008, the unit was cycled frequently to follow the demand for generation. Average net unit heat rate during the months when the unit was cycled increased by 2.3%.[205] The unit continued to cycle with generation demand through 2010, and over the operating period from 2008-2010 the plant initiated programs to target heat rate improvement. EPRI performed an initial assessment of the plant's "heat rate culture" and found that many of the heat rate best practices were already in place at the plant. On the basis of the EPRI assessment, the plant took additional actions which included:

- Formation of heat rate teams to brainstorm heat rate improvement ideas and monitor performance;
- Implemented daily, weekly and monthly reporting of key performance indicators;
- Offered refresher training to operators on heat rate awareness;
- Completed routine equipment and site walk-downs targeting equipment and component maintenance and cleanliness;
- Improved management of excess air on the unit; and
- Improved coal sampling techniques.[206]

Average net unit heat rates in 2009 and 2010 were only about 1% above the average heat rate for when the unit operated as a base-loaded unit.[207] However, this is a good example of how implementation of best-practices and diligent attention to improving heat rate could not overcome the 2.3% heat rate increase brought about by increased cycling of the unit.

[205] "Cycling and Load Following Effects on Heat Rate." Electric Power Research Institute. July 2011. p.4-1 .
[206] Id. p. 3-33 & 3-34.
[207] Id. p. 3-32.

B. EPA has overstated heat rate improvements related to equipment upgrades

EPA determined potential heat rate improvement opportunities related to equipment upgrades based on a review of engineering studies, an evaluation of year-to-year performance trends, and an analysis of data from units identified by EPA that allegedly demonstrate that such improvements are achievable. For each of these areas, EPA generalized data and assumptions on potential heat rate improvement opportunities and concluded that a 2% improvement from equipment upgrades is achievable across the U.S. coal fleet without any serious consideration of unit-specific factors. EPA's determination significantly overstates the technical potential and cost of such improvement opportunities, while ignoring significant feasibility, sustainability, measurability, and regulatory challenges.

1. The 2009 Sargent & Lundy study does not support EPA's BSER determination on heat rate improvements from equipment upgrades

S&L has publicly stated in correspondence with National Rural Electric Cooperative Association (NRECA) and the Utility Air Regulatory Group (UARG) that EPA mischaracterized their 2009 report, entitled "Coal-Fired Power Plant Heat Rate Reductions," and that the report does not in any way support a conclusion that any individual coal-fired unit or any group of coal-fired units can achieve 6% heat rate improvement. S&L goes on to say:

- The results were based primarily on publicly available and conceptual data from equipment suppliers and in no way concluded that the options examined could be applied at each and every unit, but rather each option would need to be explored on a unit-by-unit and case-by-case basis to determine the applicability and feasibility.
- The two specific heat rate improvement case studies presented in the report were estimated at a conceptual level, and were not based on detailed unit-specific analysis. Verification of the improvements was not carried out to determine what, if any, actual heat rate improvements were realized.
- Combinations of strategies to achieve heat rate improvements do not always provide improvement reductions equal to the sum of each individual strategy's heat rate improvement because of inter-related plant operational variables.
- The performance of evaluated heat rate improvement strategies degrades over time, even with best maintenance practices.
- The benefit of heat rate improvement is reduced at lower operating loads. Therefore, a unit which undergoes a switch from base-load operation to cyclical or load-following operation will see an increase in annual average heat rate and the improvement strategy or strategies implemented are unlikely to make up the

difference. In some cases, any heat rate improvements achieved through options described in the 2009 report could be negated by load-cycling losses.

- Based on S&L studies, it appears most utilities are already employing best operational and maintenance practices and further significant reduction in heat rate may not be feasible.[208]

AEP completed a fleet assessment based upon the options suggested in the 2009 S&L report to determine, at a high level, the applicability and potential for further improvement on the fleet. Many AEP units have already implemented many of the improvement options as part of targeted performance improvement efforts, or simply as "business as usual" maintenance and due diligence. As a result, AEP supports S&L's conclusions that further reductions in heat rate are not technically achievable or feasible. The table below summarizes AEP's review of the applicability of the heat rate improvement strategies identified by the S&L report.

[208] Letter from Raj Gaikwad, Ph.D, Vice President Advanced Fossil Technologies, Sargent & Lundy, LLC to Mr. Rae Cronmiller, Senior Principal Environmental Counsel, National Rural Electric Cooperative Association.

HR Improvement Strategy	Sargent & Lundy Description	Applicability to AEP Units
Boiler Island – Materials Handling (fuel and ash)	Variable frequency drives provide no substantial reduction in plant heat rate. Pulverizer upgrades warranted only if facility is switching fuels. Ash handling is not considered a prime area of investment for plant heat rate reduction.	Variable frequency drives provide very limited benefit to systems which are NOT frequently cycled but operated at a steady output. Targeting such systems can provide small incremental benefit, but likely minimal measurable improvement to overall heat rate.
Boiler Overhaul	Major changes to a furnace are not undertaken due to regulations currently in place (NSR enforcement). Economizer replacements do occur during some SCR retrofit projects.	Addressed with proper maintenance. Heat transfer sections within the boiler (economizer, superheaters, reheaters), when needed are usually replaced in-kind (no heat rate improvement). May offer some restorative impact on heat rate, but no significant improvement.
Neural Network	Used to optimize plant performance during load changes.	Neural Networks "tested" on several units. No substantial benefit could be derived. Biggest heat rate benefit derived by minimizing excess air levels (set by limits). NN provided no benefit beyond unit operators' abilities and available tools to monitor and control excess air. AEP has a Generation Fleet Monitoring and Diagnostics team with intelligent software that identifies/flags pattern changes in operation and communicates performance analytics and best-practices back to the fleet.
Intelligent Sootblowers	Applicable to units burning PRB and lignite fuels - engages DCS with system controls for the sootblowers.	Only high-slagging units will see heat rate improvements. AEP has considered intelligent sootblowers and several units employ advanced water cannons for online boiler cleaning and slag removal. This option is site and fuel specific (high-slagging fuels) and not feasible for all units.
Air Heaters	Replace seals to reduce leakage and examine during emissions controls retrofits. Control acid dew point, particularly in connection with SCR retrofits.	Flue gas O_2 monitoring in place at many facilities to identify seal and air in-leakage issues. Addressed as part of ongoing maintenance.
Turbine Overhaul	Degradation and improved designs can be addressed, but greatest reductions are associated with changes in design, and performance will degrade over time.	Generally seals wear uniformly over time and heat rate improvement degrades. Turbine overhauls are routinely evaluated for each unit on a techno-economic basis and conducted on a schedule. AEP has performed turbine upgrades on 86% of the fleet that will be operating beyond 2016.

HR Improvement Strategy	Sargent & Lundy Description	Applicability to AEP Units
Feedwater Heaters	Cost of increasing heat transfer surfaces is prohibitive due to small incremental reductions in heat rate.	No feasible measures identified.
Condensers	Regular cleaning schedule has varying impacts on heat rate depending on location and cooling water characteristics.	Back pressures routinely monitored and diligent maintenance programs already in place across the fleet to address issues as soon as reasonably possible. Condenser tubes cleaned as necessary.
Boiler Feed Pumps	Ordinary wear and tear degrades performance and is addressed during overhauls or upgrades.	BFP rotors are swapped out on routine schedules to maintain high feedpump efficiency. Turbine drives on many AEP feed pumps already incorporate VFD efficiency.
Fans and VFDs	Installation of upgrades usually made in connection with emissions controls.	Many units have installed high-efficiency axial vane ID fans as part of emissions control projects to offset a portion of the heat rate penalty of adding emissions control equipment.
Emission Control Technologies	Discussion of potential improvements associated improved control system designs and power management features.	Limited power management savings benefit available for vast majority of units. Often state implemented Compliance Assurance Monitoring (CAM) Plans prohibit the use of power management features.
Boiler Water Treatment	Most power plants already have advanced water treatment systems installed.	AEP maintains very tight control over boiler water chemistry standards. Well defined corporate oversight program in place to insure high performance and high reliability.
Cooling Water Treatment	Proper maintenance of water quality in the cooling system maintains efficiency that could be lost through fouling.	Proper maintenance procedures are in place for cooling water treatment. Cells taken out service during part load and cool periods (auxiliary power management).
Advanced Cooling Tower Packing	Optimization of cooling water temperatures and fan requirements must be conducted to investigate effectiveness of upgrading fill or implementing VFDs for older fans.	High efficiency fills have proven to be problematic and susceptible to fouling thereby increasing heat rate. High efficiency fills have actually been replaced on many cooling tower units and heat rate improved. Fans (cells) taken out of service to reduce auxiliary loads during part load and cool periods.
Other Improvements	Motor replacement programs can yield minor heat rate improvements.	Similar to the assessment of VFDs, motor replacements are assessed on a system by system basis to determine feasibility and benefits.

2. EPA's review of other documents discussing heat rate improvements does not support the BSER determination on heat rate improvements from equipment upgrades

EPA TSD also references a NETL report, entitled "Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet;" however, the link provided in the TSD is to a deck of slides and charts describing the NETL report, not the full report. No link is provided to the full report or any text which might explain the data in the slides. Additional searches to uncover the complete report were unsuccessful. Without the underlying text of the report, the administrative record is incomplete, and it is unclear as to whether NETL discussed the challenges and limitations to efficiency improvements.

A 2010 NETL report, entitled "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emission Reductions," examined 10 years (1998-2008) of unit efficiency data from 892 coal-fired units. While the report projected that efficiency improvements across the fleet were possible, key takeaways from the NETL analysis were:

- Load factors (ratio of average load to peak load) for the top decile of the units studied averaged 83%, meaning that these units, when operating, operated at nearly full load, and their performance would not be achievable by units operating at lower load factors.
- NETL acknowledged that quantification of the opportunity to improve efficiency could be improved by things such as:
  - Verification of the data;
  - Unit-specific data to enable estimation of the heat rates;
  - Estimates of the costs to improve efficiency; and
  - Case studies at specific units and computer models to provide more details into the opportunities to improve heat rate.[209]

The bulleted items above indicate that NETL had an appreciation for the variability, possible inaccuracy, and overall feasibility of the heat rate improvement potential which they analyzed. The report suggests that these items should be considered to better assess the improvement opportunity. EPA ignored such language in the NETL report and simply cited the report as a reference for their determination of achievable improvements.

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[209] DiPietro & Krulla. "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions" – DOE/NETL April 16, 2010

EPA also cites a very brief two-page report, entitled "Reducing Heat Rates of Coal-Fired Power Plants," from Lehigh University, that relies upon high-level conceptual information regarding heat rate improvement options and very general reduction percentages.[210] The Lehigh report does a poor job of characterizing the unit-specific nature of heat rate improvements and fails to discuss factors that affect heat rate improvement. It does, however, accurately state that "it would not be possible to take full advantage of all possible improvements on every coal-fired unit," but does not provide any substantiated evidence as to what level of improvement is achievable. Examples provided in the report are largely comprised of unsupported conceptual estimates and/or limited operational data and there is no real data on which EPA could base any determination of achievable heat rate improvement.

A paper from Resources for the Future, entitled "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act," does not attempt to assess or evaluate what percentage of heat rate improvement exists on coal-fired generating units, but rather relies upon an EPA statement from the 2008 "Technical Support Document for the Advance Notice of Proposed Rulemaking for Greenhouse Gases: Stationary Sources," in which EPA then estimated that a 2-5% efficiency improvement was possible, along with additional references to the 2009 S&L report.[211] The authors do, however, acknowledge that "significant analysis and expertise are required to find the optimal combination of [heat rate] upgrades and techniques, *if any*, for each specific plant."[212]

The paper then goes on to consider how market and/or regulatory impacts might influence or "force" the realization of heat rate improvements. In similar fashion to other EPA references in the TSD, the entire report is based on the assumption that EPA's estimates for improvement potential from the measures discussed in the S&L report are achievable across the fleet, which is simply not the case.

NRDC prepared a report, entitled "Closing the Power Plant Carbon Pollution Loophole," that relies heavily on the same 2009 S&L report used by EPA in the proposed rulemaking to

[210] "Reducing Heat Rates of Coal-Fired Power Plants" – Lehigh Energy Update. Vol. 27, No.1. Jan 2009.
[211] Linn, et.al. "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act" – Resources for the Future. February 2013.
[212] Id p.9 (emphasis added)

characterize and support its assumptions for heat rate improvement.[213] NRDC provided a table in Appendix V to show that the technical heat rate improvement options addressed conceptually in the S&L report were simply added to determine the total available heat rate improvement potential.[214] For reasons stated earlier in this report, this is simply not a practical feasible approach, and the S&L technical information was not intended to characterize the actual heat rate improvement potential for any one unit or group of units.

Other relevant reports and studies have been carried out that address the complexities, opportunities and challenges associated with heat rate improvements. EPA failed to consider these reports and the issues they raise. For instance, in 2009 and 2010, US DOE and NETL sponsored industry workshops specifically targeted toward opportunities to improve the efficiency (heat rate) of existing coal-fired power plants.[215],[216] These workshops brought together industry experts, utility owners and operators, equipment suppliers, consultants, industry associations, and research organizations to explore heat rate improvement. Key takeaways from the workshops were documented and several are listed below:

- "The heat rate of a coal-fired power plant is costly and difficult to accurately measure in real-time."
- "Better national data on plant efficiency is needed, but this is hindered by the variation in methods and accuracy for measuring plant heat rate."
- "Without adequate heat rate data, it will be difficult to monitor improvements in the overall efficiency of the U.S. fleet of coal-fired power plants."
- "Plant operators often lack sufficient monitoring tools or measurement frameworks to measure both baselines and future improvements for a given process."
- "The industry also lacks clear guidelines and standards for measuring and reporting efficiency improvements."
- "Hard to make a business case for something one cannot measure (heat rate)"
- Four of the top five barriers and challenges identified that inhibit the adoption and application of technical options to improve heat rate were:
  - Age of fleet prevents significant changes
  - Inability to compare plants on a similar basis

[213] Lashof, et.al. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters" – NRDC. March 2013.
[214] Id. Table V.1. p. 69
[215] Eisenhauer & Scheer. "Opportunities to Improve the Efficiency of Existing Coal-fired Power Plants." NETL Technical Workshop: July 15-16, 2009.
[216] Brindle, et.al. "NETL Technical Workshop Report: Improving the Thermal Efficiecny of Coal-fired Power Plants in the United States." February 24-25, 2010.

- Difficult to measure improvement and monetize benefits
- Efficiency is limited by exiting design

These issues and concerns still exist, and further support the fact that achieving, measuring, and sustaining a 6% heat rate improvement across the fleet is simply not practical.

3. The unit-specific examples identified by EPA do not demonstrate that its heat rate improvement targets are achievable or adequately demonstrated.

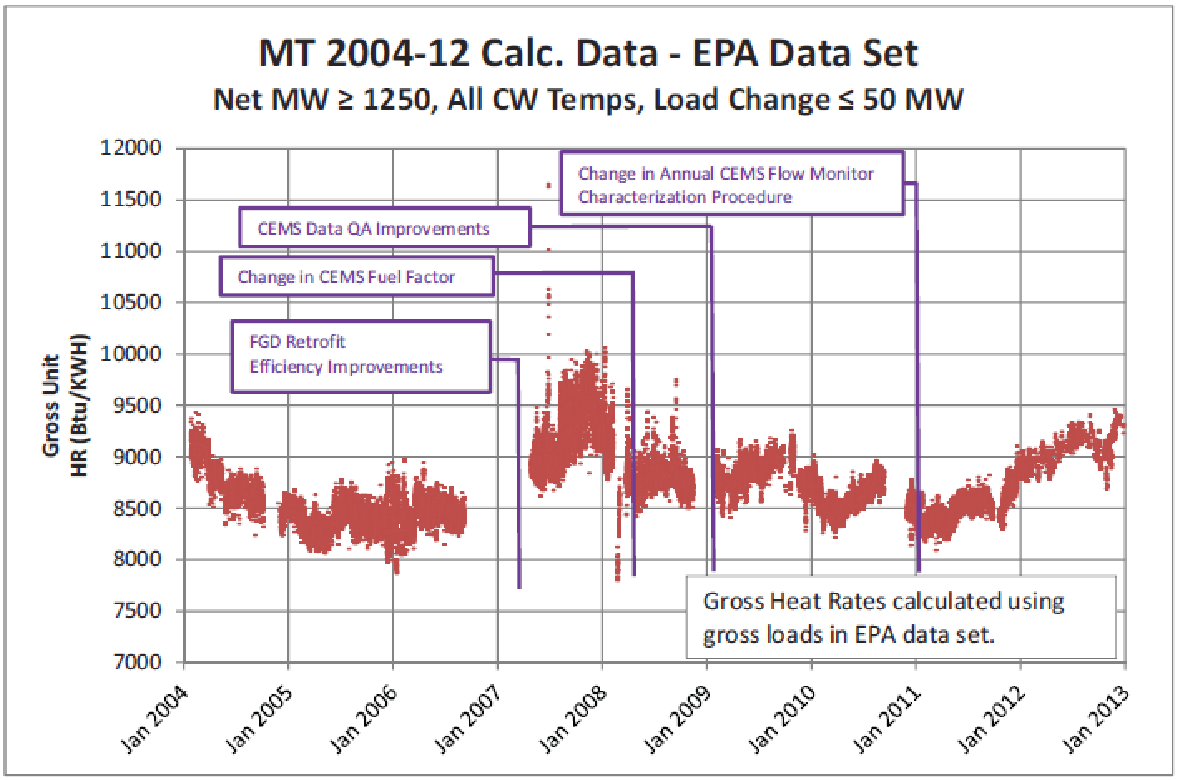
EPA identified 16 units, based on the results of its statistical analysis, that EPA concludes are examples of equipment upgrades that achieved 3-8% gross heat rate reductions. EPA claims that after accounting for "capacity factor, reporting method, or other events," these 16 units emerged from the national inventory and reported a single year-over-year improvement in gross heat rate of at least 3-8%. The sixteen units, owned by twelve utilities, were identified in a table posted in the rulemaking docket. UARG contacted and received technical responses from 10 of the 12 owners, addressing 14 of the 16 units.[217] The UARG investigation found that:

- Eight owners of eleven units report all changes are due either exclusively or almost exclusively to variability in CEMS heat input measurements. The most frequently cited CEMS-based action was the routine calibration of the stack flow monitor in conjunction with an annual relative accuracy test audit ("RATA"). The units reporting this experience are Rodemacher unit 2; Valmy unit 2; Southwest unit 1; Johnson unit 2; Sheldon unit 1; Bridger unit 3; Colbert units 1-3; Weston unit 3; and Gorgas unit 2.
- Five units reported that upgrading the steam turbine appeared to lower gross heat rate, with modest payoff of approximately 3%. However, at three units this benefit was more than negated by an increase in net heat rate due to retrofit of environmental controls. Specifically, the Gibson unit 1 incurred higher net plant heat rate starting in 2007, when FGD was retrofit and gas handling was changed to employ a single dedicated stack. Petersburg unit 2 similarly observed a net heat rate increase in 2005, following retrofit of SCR in 2004. In 2007, King unit 1 completed a significant rehabilitation of the unit, including a new steam turbine, feedwater heaters, circulating water system upgrades and coal handling upgrades as part of a project to add SCR, FGD and fabric filter to the unit for emissions controls. The upgrade of the steam turbine and other components improved heat rate by 2.7% but was offset by the losses imposed by the addition of the emissions controls equipment.
- Southwest unit 1 upgraded its steam turbine in 2010, and a pre- vs. post-upgrade comparison suggests this action delivered a gross heat rate reduction of 2%. However, the accuracy of the CEMS-informed heat rate improvements is questionable - the same

[217] Cichanowicz & Hein. "Critique of EPA's Use of Reference Units to Select Heat Rate Reduction Targets." Prepared for UARG. November 25, 2014.

data suggested a 15% heat rate reduction from 2002 through 2008, when no actions were taken.[218]

The preceding observations suggest that CEMS-derived heat rate data is more often influenced by changes to reporting methods, and not proactive steps to lower heat rate. AEP charted a similar experience at its Mountaineer Plant. Full load gross unit heat rates calculated from CEMS data were charted using hourly gross loads from the EPA dataset. As the graph below shows, a more significant reduction in heat rate occurred as a result of CEMS measurement procedure changes than occurred with efficiency improvement projects which coincided with the FGD installation.



4. EPA fails to adequately address NSR-related issues that challenge the efficacy of heat rate improvement opportunities.

EPA acknowledges that many of the heat rate improvement projects involve equipment replacements or upgrades that have been targeted in suits filed by EPA and citizen groups under the new source review ("NSR") provisions of the Clean Air Act. These suits claim that by

[218] Id. p. 3-24

improving unit efficiency, operators will run units for more hours during the year, increasing annual emissions above the thresholds that trigger an NSR permitting obligation. These suits have resulted in widely differing opinions about what remedies are barred by the statute of limitations, how to interpret the exclusion for “routine maintenance, repair, and replacement,” and how to calculate emissions before and after an efficiency improvement project. EPA offers no relief from NSR enforcement for operators who seek to comply with the Clean Power Plan by improving unit efficiency, and without such relief, many operators will be reluctant to engage in more expensive efficiency improvements like turbine replacements and other equipment upgrades that offer the most cost-effective improvements.

Over 400 specific efficiency improvement projects of the type described in the S&L report referenced in the proposed rule have been identified based on a review of Notices of Violation (“NOVs”) issued by the EPA, and complaints filed by the Department of Justice or environmental advocacy groups alleging violations of the NSR permitting program for failing to obtain a permit prior to undertaking equipment replacement or other heat rate improvement projects at EGUs.[219] Those NOVs and complaints also identify another 600 equipment replacement or repair projects that involve other components not specifically identified in the S&L report or EPA’s GHG Abatement Measures Technical Support Document. These allegations are not an indication that a violation actually occurred, but are an indication of the chilling effect that EPA’s enforcement initiative will have on the willingness of EGU operators to pursue these or other heat rate improvement opportunities identified in EPA’s GHG Abatement Measures Technical Support Document in the absence of clarification from EPA that these activities will not trigger NSR permitting requirements.

The first element of an NSR-triggering change mentioned by EPA in the preamble, a “physical or operational change,” is a phrase in the statutory definition of “modification” in section 111(a)(4), incorporated by reference in sections 169(2)(C) and 171(4).[220] EPA has interpreted that phrase in notice-and-comment rulemaking, going back to the 1970s, to have some common-sense exclusions.[221] It is well within EPA’s discretion to add to its existing exclusions from the meaning of “modification” and/or “physical change or change in the method

[219] See Appendix A for the list of heat rate improvement projects that have been the subject of EPA enforcement actions.
[220] 42 U.S.C. §§7411(A)(4), 7469(2)(c), and 7471(4).
[221] *See, e.g.*, 40 C.F.R. §§ 60.14(e) and 52.21(b)(2)(iii).

of operation" those efficiency improvements an affected EGU makes in furtherance of a section 111(d) plan pursuant to EPA's Clean Power Plan. If EPA does not eliminate the risk of NSR applicability for building block 1 heat rate improvements, then the agency needs to reevaluate its proposed BSER and repropose appropriately revised emission guidelines.

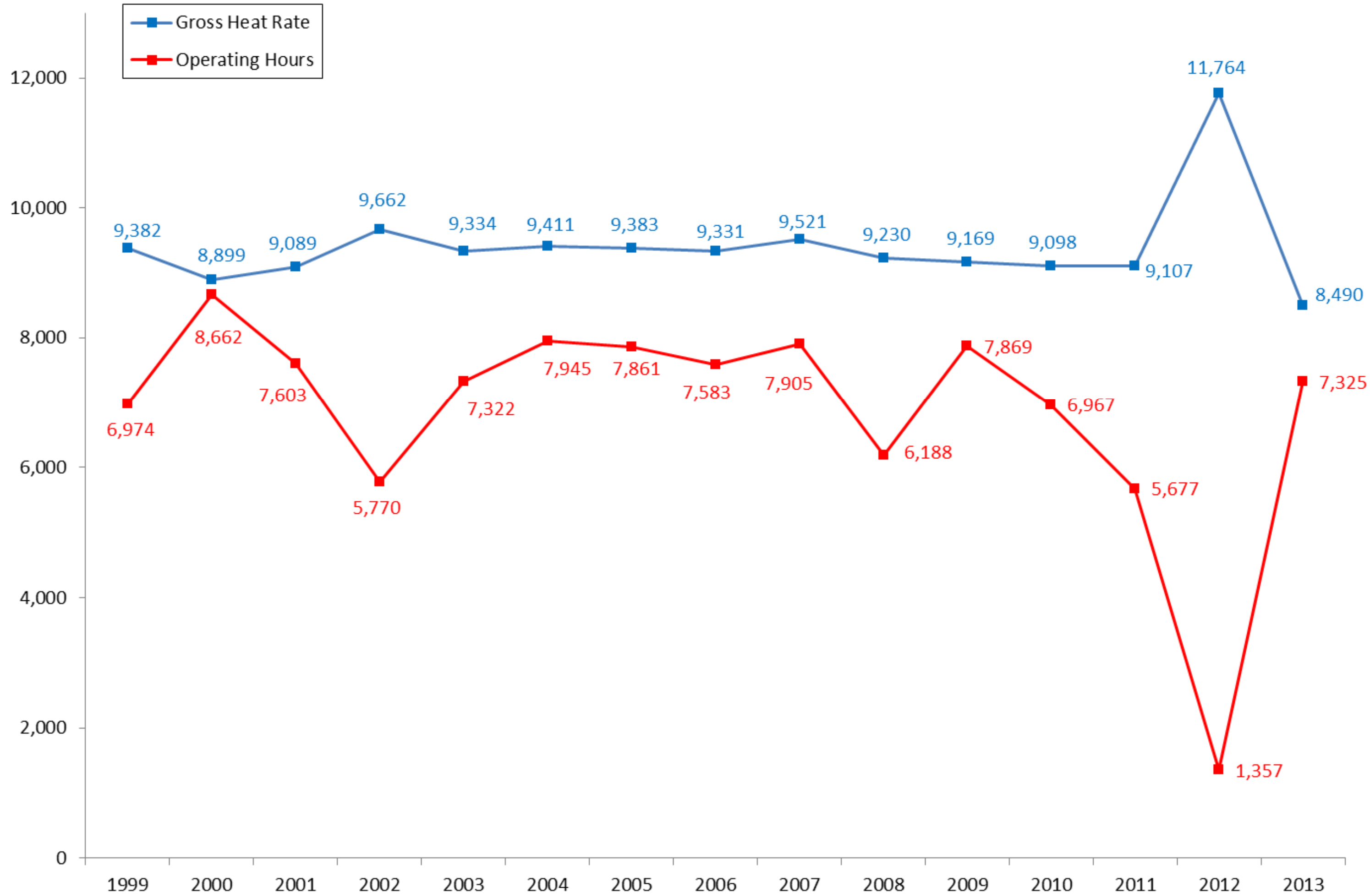
C. EPA fails to evaluate whether the 2012 heat rate data is representative of typical unit operations or if the application of a 6% improvement is feasible given prior improvement efforts and historic unit trends

The use of any single year as a baseline for heat rate is not feasible or practical considering the vast array of variables that can impact heat rate on any given unit at any given time. If the baseline year happened to be a particularly unique year for an individual unit, any heat rate improvement based upon that particular base year will not be meaningful. The graph below represents one particular unit's average gross annual heat rate from 1999-2013. Operation in 2012 happened to be anomalous for this particular unit, as equipment outages and maintenance issues kept the unit out of service much of the year, resulting in significantly lower than normal capacity factors and output factors. In 2013, the unit returned to more typical operations having incorporated no significant heat rate improvements. Yet, from 2012 data, it appears that the unit's heat rate improved on the order of 27%. This is but one example demonstrating the flaw in selecting a single baseline year. It also demonstrates why it is impractical to design, implement, and enforce heat rate limitations. In fact, a review of recent air permits for fossil fuel-fired electric generating units nationwide revealed not a single example of a heat rate limit.[222]

[222] Appendix D lists the permits reviewed and indicates the absence of any heat rate limitations.

Cardinal 3 - Gross Annual Heat Rate 1999-2013

Data per EPA CAMD Database http://ampd.epa.gov/ampd

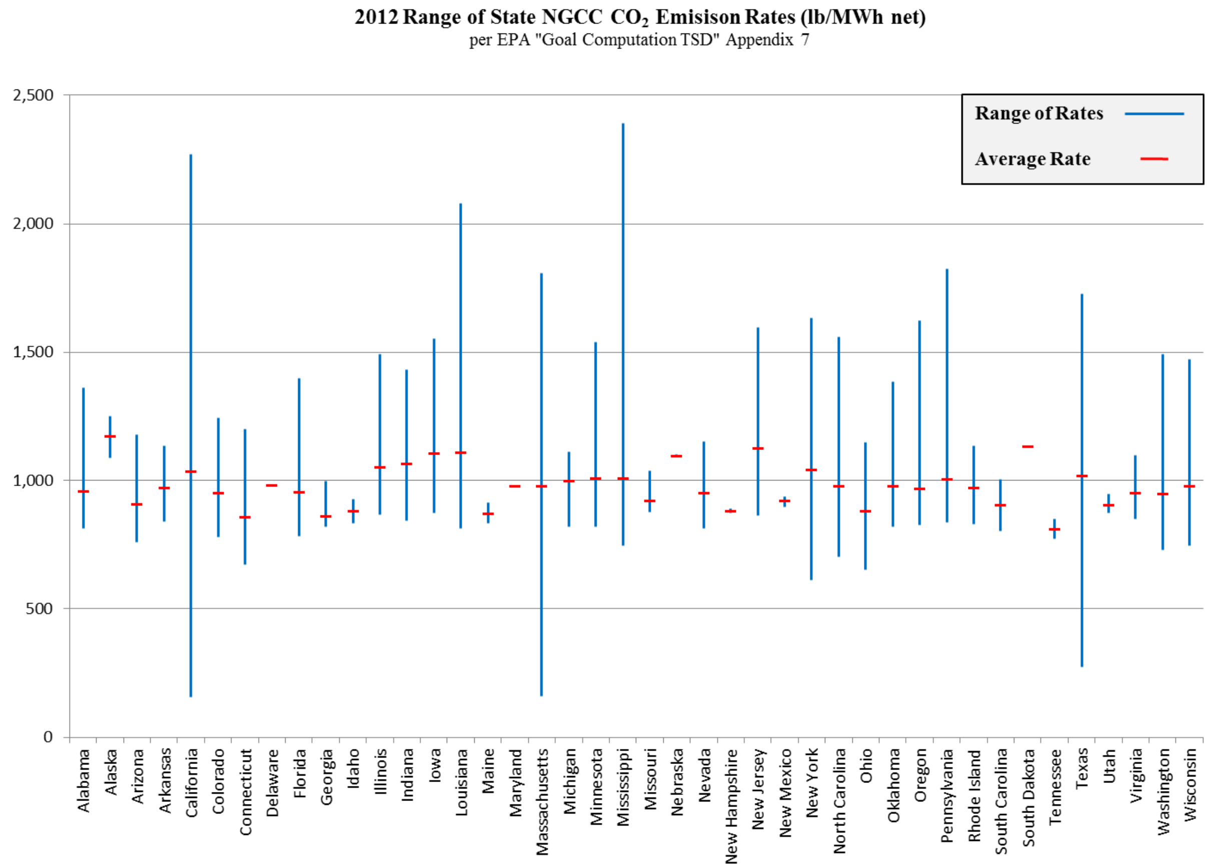


D. EPA failed to examine heat rate improvement opportunities at other designated facilities

As with the Section 111(b) proposal for new sources, EPA has applied a double-standard when evaluating potential heat rate improvement opportunities for coal-fired units and other designated facilities. Although EPA discusses differences in the design, operation, age, and condition of the existing NGCC fleet, the proposed rule does not attempt to analyze whether any opportunity for improved efficiency exists, or, if so, how significant that opportunity might be. It is ironic that EPA is relying on increased utilization of NGCC resources, but has ignored whether or not those units are achieving optimal efficiency.

Based on a review of the data EPA relied upon to propose the state goals, it is readily apparent that the efficiency and performance of the existing NGCC fleet varies significantly within individual states and across the country.[223] The graph below is based on an analysis of unit-specific emission rates, and identifies the minimum, maximum, and average NGCC CO_2 emission rate for each state in 2012. The blue line represents the range of emission rates calculated, while the red marker is the average for the state.

[223] "State Computations TSD." Appendix 7. EPA. June 2014.



A number of potential opportunities to improve the performance of NGCC have been identified that are, at a minimum, worth evaluating. This includes opportunities related to turbine improvements and air cooling systems. These types of opportunities and others are discussed within various technical reports, such as the following:

- "Gas Turbines: How to Improve Operability, Output and Efficiency. Cogeneration & Onsite Power Production Magazine. (2010)
- "GE Combined Cycle Product Line and Performance." GE Power Systems. (2000)
- Bastianen & Voeller. "Economic Considerations for Gas Turbine Power Augmentation with Inlet Cooling." Energy-Tech.com. (2010)

E. EPA should develop a work practice standard for heat rate improvements at designated facilities

Available information about the fossil units in the existing EGU fleet demonstrates that:

- There is a wide range of inherent limitations on the potential for heat rate improvements, including original design, geographic location, availability of space, emission controls, and prior improvement efforts;

- Unit efficiency naturally degrades over time;
- There is no accurate method to measure heat rate in real time;
- Heat rate improvements may be masked by control technology installations or changes in duty cycle; and
- Remaining useful life will affect the economic feasibility of continued efficiency investments.

Given these realities, there is no single emission standard or limitation that is achievable by or adequately demonstrated for the fossil fleet. However, there is also a long history of successful advancement and adaptation of new technologies, operating procedures, materials, and equipment upgrades that have allowed the existing fleet to maintain and improve efficiency through adoption of best practices.

Section 111(h)(1) of the CAA authorizes the Administrator to identify design, equipment, work practice, or operational standards, or a combination thereof when it is not feasible to establish a standard of performance.[224] The phrase "not feasible to prescribe or enforce a standard of performance" means, for purposes of section 111(h)(1), that the "application of measurement methodology to a particular class of sources is not practical due to technological or economic limitations."[225] As applied to heat rate improvement opportunities, the Administrator could collect information on actual unit experiences associated with implementation of the suite of measures described in the S&L report and elsewhere, and develop a standard assessment for heat rate improvements that could be evaluated during regular planned outage cycles. Unit operators could submit a report and recommendation to the state that describes the measures evaluated, the lead time necessary to implement the project(s), and the relative cost-effectiveness of the recommended measures, based on the unit's remaining useful life. A reasonable cost-effectiveness threshold could be established, above which measures would not be required. Reports could be submitted to the state agency regarding implementation. In such a manner, available and cost-effective opportunities could be identified and implemented throughout the remainder of the existing units' operating lives. Actions taken to implement the CPP under such a work practice standard could be classified as "routine maintenance, repair and replacement," and thereby not expose unit operators to the risk of NSR enforcement. Such a standard would allow the greatest possible incorporation of efficiency improvements without disruption to the

[224] 42 U.S.C.§7411(h)(1).
[225] 42 U.S.C §7411(h)(2).

operation of the existing fleet, protecting electricity reliability and encouraging the development of new technologies. AEP respectfully requests that the Administrator consider the benefits of such an approach in finalizing the CPP proposal.

VI. Building Block 2 Exceeds EPA's Authority and Is Based on Flawed Data and Methods

Building block 2 is based on EPA's generalized assumption that all existing NGCC units can be redispatched to sustainably achieve a 70% capacity factor. The analysis underlying this assumption is incomplete, relies on inaccurate data, and generally represents a poor understanding and application of the basic concepts and operating metrics used to assess historic and future unit performance. In addition, EPA fails to adequately define, let alone evaluate, significant technical, regulatory, legal, and practical factors that can and do impact the efficacy of the 70% assumption. The result is an assumed level of performance that simply has not been adequately demonstrated to be achievable across the fleet of existing NGCC units.

Further, an extensive number of methodological errors and data quality issues have been identified that erode the fundamental credibility of building block 2 *and* the entire proposal. Any attempt to correct the litany of concerns or determine how these corrections alter state goal calculations, "flexible" compliance strategies, reliability evaluations, and cost-benefit analyses is too complex to complete within the public comment period. Rather, it is EPA's responsibility to resolve these concerns and present a proposal that, at a minimum, is grounded upon accurate, complete data and conforms with acknowledged principles of mathematics and logic. Given the egregious nature and scope of concerns to be resolved in building block 2 *alone*, EPA has no other legitimate choice than to withdraw the current proposal, address these concerns, and publish a new proposed rule for public comment.

A. EPA lacks the statutory and regulatory authority to redispatch EGUs

The dispatch of most electric generating units is controlled by balancing authorities, primarily Regional Transmission Organizations or Independent System Operators (generically referred to as "RTOs") according to market-based tariffs and operating agreements that are intended to capture the benefits of security constrained market-based economic dispatch across wide regions of the U.S. This allows for a more cost-effective operation of these collective assets for the benefit of the wholesale and retail customer.[226] RTO operations are based on agreements of the system owners and operators, and are subject to oversight by FERC, but even

[226] 16 U.S.C Section 824a(a).

FERC has no ability to compel any particular technique of coordination.[227] Indeed, no provisions of state or federal law have been identified that would allow EPA or the states to alter those arrangements and dictate a specific generation technique to achieve an arbitrary level of dispatch. The RTO energy markets have been carefully structured to achieve the least cost dispatch operation of committed generation, and to allow operators of individual units the flexibility to respond to dynamic and constantly changing circumstances in both the supply of and demand for electricity.

The comments submitted by EEI contain a detailed description of the functions performed by various generating resources as components of the bulk electric system and the detailed planning that must occur in order to accommodate changes in the location, type, size, and utilization of generation resources to assure the reliability of the electricity grid. Further, both transmission and natural gas pipeline capacity limitations could significantly impact the feasibility of achieving the capacity factors that EPA is targeting for NGCC facilities.

The comments submitted by UARG contain a detailed description of the authorities vested in the balancing authorities, RTOs, FERC and NERC under the Federal Power Act ("FPA")[228] for the coordination and operation of the interconnected grid. Section 201 of the FPA recognizes that federal regulation of interstate transmission of electricity is necessary in the public interest.[229] FERC has exclusive jurisdiction over all facilities for interstate transmission, and FERC has exercised that authority through orders and individual tariffs that mandate open access of the interstate transmission system to facilitate reliable and economic use of those facilities.[230] All practices of public utilities that significantly affect rates for wholesale power or transmission service must be filed with and approved by FERC.[231] FERC is authorized to revise any rate that it finds is "unjust, unreasonable, unduly discriminatory or preferential."[232]

Increasingly, FERC has relied upon market forces to ensure that rates are non-discriminatory and reasonable. The RTOs have assumed responsibility for economic dispatch of generation resources within their respective jurisdictions, subject to the terms of the agreements

[227] *Atlantic City Elec. Co. v. FERC.* 295 F.3d 1 (D.C. Cir. 2002).
[228] 16 U.S.C.§824 *et seq.*
[229] 16 U.S.C.§824(A).
[230] *See, e.g.*, *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, Order 888, 61 Fed. Reg. 21,540 (May 10, 1996).
[231] 16 U.S.C. § 824d(c).
[232] 16 U.S.C. § 824e(a).

and tariffs that govern their operations. These agreements and tariffs are filed under Section 205 of the FPA, and are subject to FERC approval because of their significant impact on the rates and terms of service on the interstate electricity grid. Yet EPA fails to acknowledge that its limited authority under the CAA, and the responsibilities imposed on states as a result of the exercise of that authority, cannot interfere with or override these other federal authorities.[233]

Even if a mechanism existed through which NGCC facilities could be required to dispatch at capacity factors in excess of their historic rates, no certainty exists that increased utilization of those units would offset higher CO_2 emitting generation from existing facilities. The transmission grid is still largely based on connecting local loads to nearby generating assets, and is constrained in its ability to transmit power in ways that EPA never studied. Moreover, neither EPA, nor the states, have the authority to regulate emissions by creating a preference for one type of generating asset over another.[234] Even if each NGCC unit could achieve and maintain a 70% capacity factor that would exclusively offset higher CO_2 emitting generation within the state where it is located, the proposed rule ignores the realities of multi-state utilities whose generation is shared by retail and wholesale customers in multiple states. It also ignores the fact that multiple RTOs have control over transmission systems within the same state. For example, the state of Texas is included in four different regions: ERCOT, SPP, MISO, and WECC. None of these factors are adequately addressed in the proposed CPP.

B. EPA has not demonstrated that a 70% capacity factor is achievable by all existing NGCC units

The Clean Air Act defines a "standard of performance" as follows:

> a standard for emissions of air pollutants which reflects the degree of *emission limitation* achievable through the application of the best system of emission reduction which the Administrator determines has been *adequately demonstrated*.[235]

EPA has failed to adequately demonstrate that a minimum 70% capacity factor requirement has been achieved by any existing NGCC unit. Based on an AEP survey of over 300 air permits for coal and NGCC units, no examples have been identified of a specific requirement that establishes a minimum capacity factor from the regulated source.[236] In fact,

[233] 74 U.S.C.§7610(a).
[234] See the Legal Section for more information.
[235] 42 U.S.C. Section 7411(a)(1) (emphasis added).
[236] See Appendix D

EPA does not identify a single permit or regulatory obligation for an existing NGCC unit that establishes a requirement that the source achieve a specific capacity factor, let alone a 70% capacity factor. While certain units have operated at capacity factors at or above a 70% capacity factor because they were economical and otherwise available to run, this in no way adequately demonstrates that a minimum 70% capacity factor threshold could be manifested into a permit condition for any or all units that could be sustainably achievable across the range of operating, outage, and market conditions experienced over the life of a unit.

Building block two is focused on "increasing utilization, *to the extent possible*,...of existing natural gas combined cycle units."[237] EPA notes "[i]n order to redispatch....there needs to be some existing *unused generation potential* in the current NGCC fleet that could displace generation from more CO_2 intensive generating resources."[238] EPA erroneously interprets "to the extent possible" and "unused generation potential" to be the same for all units and applies a one-size-fits-all capacity factor that would be sustainably achieved by all existing NGCC units.

Such an approach ignores unit-specific factors that uniquely influence the potential amount of increased utilization that may be achievable by an individual unit. It is unclear why EPA gave no consideration to these unit-specific variables when the agency has previously acknowledged and analyzed such differences. In analyses supporting the Section 111(b) proposal, the agency notes that:

- ...some 1,000 [units] are NGCC located in 41 states and encompass a diverse population in capacity, years of service and configuration;
- NGCC technology performance and efficiency has improved over time;
- [NGCC units] fall into two groups: single-shaft...and multiple-shaft;
- The [study] population of 307 NGCC units [in-service since 2000] is heterogeneous in location, age, capacity, and operating profile;
- The study population includes...units that....were retrofits or conversions of simple cycle turbines to NGCC or that operated in single cycle mode for a period of time during commencement of operations;
- In general, smaller capacity NGCC units available on the market today are less efficient than the largest units; and

[237] GHG Abatement Measures TSD. EPA. 2014. p. 3-1. (emphasis added)
[238] Id. p. 3-5. (emphasis added)

- The average capacity factor from 2007-2011 of "small units" is 27% versus 36% for "large units.[239]

The EPA study identified a number of differences among NGCC units commissioned from 2000 to 2010. However, these differences become even more pervasive when considered across the entire fleet, which encompasses units commissioned from 1949 through 2014. These units represent a wide spectrum of process designs, business models, regulatory requirements, and operating conditions that collectively and uniquely influence the potential future performance of each individual unit.[240] Factors contributing to these differences include:

- variations between combustion turbine manufacturers and suppliers;
- variations in the vintage model combustion turbine employed;
- options for duel-firing natural gas, oil, or other gases in the combustion turbine;
- HRSG and steam turbine design differences;
- unit designs that integrate other, non-combustion-turbine related steam sources into the HRSG and steam turbine design;
- differences in equipment redundancy to support increased utilization;
- differences in the winterization of equipment to enable cold weather operations;
- differences in the condition of process equipment to support increased utilization;

EPA also ignores the fact that some existing NGCC units simply may not have been designed and constructed for the purpose of operating at higher capacity factors. For example, the language below from the air permits for two NGCC facilities in Arkansas states how these units are primarily intended to generate power during specific operating scenarios:

> The plant is designed to supply approximately 450 to 510 MW of power *during high electrical demand hours* of each day (usually between the hours of 7:00 a.m. and 11:00 p.m.) and ramp down to approximately 75 MW during off-peak hours. This daily load cycling results in reduced power production each day during hours when there is no demand for the power.[241]

and

> This unit is used primarily *for intermediate and peak* load conditions.[242]

[239] Combustion Turbine Standard TSD. EPA. 2014. Docket #: EPA-HQ-OAR-2013-0495-0082. pp. 1-4.
[240] EIA-860 and GHG Abatement Measures TSD.
[241] Arkansas Department of Environmental Quality Air Permit #l842-AOP-R5. March 15, 2010. p.5.
[242] Arkansas Department of Environmental Quality Air Permit #1165-AOP-R5. July 30, 2013. p.10.

A review of the historic data for these units is summarized below and indicates that both have operated at very low capacity factors – as they were designed and intended to operate - for various technical and economic reasons.[243] The full analysis provided in Appendix B.

	Maximum Annual Capacity Factor (summer basis) 2003 - 2013	Average Annual Capacity Factor (summer basis) 2003 - 2013	Maximum Monthly Capacity Factor (summer basis) 2003 - 2013
Oswald NGCC Unit regulated by ADEQ Permit #1842-AOP-R5	3.8% (occurred in 2011)	1.8%	46% (occurred in 2011)
Fitzhugh NGCC Plant regulated by ADEQ Permit #1165-AOP-R5	18.5% (occurred in 2006)	6.6%	44% (occurred in 2011)

The historical operation of both units is *much less* than a 70% capacity factor, or even EPA's alternative 65% capacity factor. In fact, the highest *monthly* capacity ever recorded for these facilities is only a little better than half of EPA assumed rate. These two NGCC facilities have operated so little that if the total generation for each unit during the last 10 years (2004-2013) was added together and assumed to have occurred during one year, even those "hypothetical" annual generation totals are less than 70%. Under that scenario the annual capacity factors would be 61% (Oswald) and 68% (Fitzhugh). Clearly, EPA did not consider whether such units have the technical and economic feasibility to increase operations to obtain a 70% capacity factor during any one year, let alone to sustainably obtain that high capacity factor in the future. EPA merely assumes that this is the case by noting that:

> NGCCs are designed for, and are demonstrably capable of, reliable and efficient operation at much higher annual capacity factors, as shown in observed historical data for particular units and their design and engineering specifications.[244]

Ironically, in the proposed 111(b) standards for new sources, EPA did acknowledge that certain *existing and future NGCC units* may actually be designed for the purpose of operating at lower capacity factors by noting that:

> Small NGCC units...that are generally *designed for operation during peak demand* will usually supply less than one-third of their potential electric output to the grid.[245]

and

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[243] Reviewed 2003-2013 Annual EIA860 and EIA923 reports available at www.eia.gov/electricity/data/eia860/ and www.eia.gov/electricity/data/eia923/index.html
[244] GHG Abatement Measures TSD. EPA. 2014. p. 3-14
[245] 79 Fed. Reg. 1445 (January 8, 2014). (emphasis added)

> A capacity factor exemption at 40%... would allow conventional combined cycle facilities *built with the intent to operate at relatively low capacity factors* as an alternative technology to simple cycle turbines because neither would be subject to the NSPS requirements.[246]

For those units that, perhaps, are not designed to readily increase utilization or that may not have historically operated at higher capacity factors, EPA references in the proposed CPP a 2011 paper to suggest that increased operation across the NGCC fleet is feasible. That paper notes that:

> "*...a four-pronged approach for achieving higher availability and reliability is outlined: (1) robust design utilizing the field data gathered during scheduled outages; (2) efficient scheduled outage management with emphasis on quality; (3) proactive intervention with remote monitoring technology and (4) improved design and upgrades for longer parts life*."[247]

EPA provides no evaluation to assess whether this "approach for achieving higher availability and reliability" has been or even could be implemented across the entire NGCC fleet. In fact, EPA fails to examine how any of the aforementioned unit-specific criteria may lessen the potential for existing units to increase operations in the future. EPA did recognize and account for some of these factors in the 111(b) proposal for new sources by proposing separate standards for two subcategories of combustion turbines based on the size of the unit. EPA explained these differences and the rationale for it subcategorization as follows:

> This subcategorization has a basis in differences in several types of equipment used in the differently sized units, which affect the efficiency of the units. Large-size combustion turbines use industrial frame type combustion turbines and may use multiple pressure or steam reheat turbines in the heat recovery steam generator (HRSG) portion of a combined cycle facility. Multiple pressure HRSGs employ two or three steam drums that produce steam at multiple pressures. The availability of multiple pressure steam allows the use of a more efficient multiple pressure steam turbine, compared to a single pressure steam turbine. A steam reheat turbine is used to improve the overall efficiency of the generation of electricity. In a steam reheat turbine, steam is withdrawn after the high pressure section of the turbine and returned to the boiler for additional heating. The superheated steam is then returned to the intermediate section of the turbine, where it is further expanded to create electricity. Although HRSGs with steam reheat turbines are more expensive and complex than HRSGs without them, steam reheat turbines offer significant reductions in CO_2 emission rates.
>
> Due to the higher efficiency of the simple cycle portion of an aeroderivative turbine based combined cycle facility, the HRSG portion would contribute relatively less to the

[246] Id.. 1459. (emphasis added)
[247] GHG Abatement Measures TSD. EPA. 2014. p. 3-6. (emphasis added)

> overall efficiency than a HRSG in a frame turbine based combined cycle facility. Therefore, adding a multiple steam pressure and/or a reheat steam turbine to the HRSG would be relatively more expensive to an aeroderivative turbine based combined cycle facility compared to a frame based combined cycle facility. Consequently, multiple pressure steam and reheat steam turbine HRSG are not widely available for aeroderivative turbine based combined cycle facilities. In addition, since aeroderivative turbine engines have faster start times and change load more quickly than frame turbines, aeroderivative turbine based combined cycle facilities are more likely to run at part load conditions and to potentially bypass the HRSG and run in simple cycle mode for short periods of time than industrial frame turbine based combined cycle facilities.
>
> Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) available on the market today are less efficient than the larger units (larger than 850 MMBtu/h). According to the data in the EPA's Clean Air Markets Division database, which contains information on 307 NGCC facilities, there is a 7 percent difference in average CO_2 emission rate between the small- and large-size units. This relative difference is consistent with what would be predicted when comparing the efficiency values reported in Gas Turbine World of small and large combined cycle designs.[248]

In summary, EPA has not demonstrated that it is feasible to establish a single capacity factor goal that can adequately account for and address unit-specific factors that affect the potential for increased utilization, whether that capacity factor is set at 65% or 70%. Aside from deferring to the lowest common denominator capacity factor that could potentially be achieved by an individual unit, it is not possible to determine a single goal that could be achieved by all units. Given the inherent differences that determine a unit's potential for increased utilization, EPA should abandon any attempt to apply a single capacity factor to all existing NGCC units.

C. The criteria used by EPA to evaluate NGCC performance and to determine a redispatch capacity factor as the BSER is flawed

Any attempt by EPA to evaluate the potential level of NGCC redispatch for an individual unit or a broader group of similar units <u>must at least be grounded</u> in a firm understanding of the definition, purpose, and limitations of the unit operation and performance data considered. In describing its evaluation, EPA notes that "...the actual potential to realize emission reductions through this technology depends on the availability and capacity factors of the existing NGCC fleet."[249] By focusing its assessment on these two metrics, EPA not only narrows its review to

[248] 79 Fed. Reg. 1486-1487 (January 8, 2014)
[249] Id. p. 3-5.

irrelevant (availability factors) and inaccurate (capacity factors) information, but also ignores other more significant factors that influence the utilization of a unit.

With respect to the availability factor, EPA states that "availability refers to the maximum amount of generation that could be expected from a given source," and that "[m]ore than 80% of the [existing NGCC] capacity...are able to achieve to achieve high availability factors."[250] EPA also notes that:

> The capability of NGCCs to operate at capacity factors of 70% and greater is indicated, in part, by statistics on the average availability factor of NGCCs, [which] in the U.S. generally exceeds 85%, and can exceed 90% for selected groups... Advanced NGCCs being built today have availability factors of over 95%.[251]

The availability factor is the percentage of time that a unit is available to provide energy to the grid, and is an indicator of the reliability of the unit and associated outage rates. In terms of assessing the potential for increased utilization of the NGCC fleet, the availability factor is of trivial value. The fact that a unit is available does not automatically imply that it can generate all of its demonstrated capacity. For example, a hydroelectric unit or wind turbine facility may be available, but water levels or wind conditions may be insufficient for those units to achieve their maximum potential output. The operation of every type of generation resource is affected by any number of factors that determine not only *if the unit is operated* when it is available, but also *how it is operated* when available. Therefore, the issue is not whether the unit has a high availability factor, as nearly all units and types of generation achieve that regularly. Rather, the issue is how the unit operates when it is available, which is a more complex evaluation given the number of dynamic technical, regulatory, economic, and market factors that must be weighted. Capacity factor is one metric to assess how often units operate when available. However, consideration of historic capacity factors in a vacuum is insufficient for evaluating the potential increased utilization that may be achievable by a unit.

[250] Id. pp. 3-6 to 3-7.
[251] GHG Abatement Measures TSD. EPA. 2014. p. 3-14.

The table below from NERC summarizes the availability factor and net capacity factor from 2009-2013 for various generation resources. All have high availability factors, but for various reasons have different capacity factors:

2009-2013 Average Fleet Values[252]

	Weighted Equivalent Availability Factor	Net Capacity Factor
All Fossil Steam Units	82%	49%
Coal	83%	61%
Combined Cycle	86%	48%
Hydro	84%	41%
Oil Boilers	80%	9%
Gas Turbines	90%	2%

EPA contends that part of the BSER for existing sources involves the redispatch of low-carbon emitting generation resources. Using this logic and the table above, then hypothetically existing combined cycle units, *as well as* oil steam boiler, simple cycle turbine, and hydroelectric units are all underutilized and should all be demonstrably redispatched at higher rates to offset higher emitting coal units. This overly simplistic scenario fails to consider the numerous aforementioned factors that influence how units are dispatched and the potential amount of increased utilization that may be achievable.

In addition, EPA's calculation of historic capacity factors based on the use of nameplate capacity is fundamentally inaccurate. Nameplate capacity is a nominal value used to represent and describe the gross rating or size of an electric *generator* – a specific piece of equipment. Nameplate capacity *does not* represent the maximum capacity of an electric *generating unit* – the entire power plant, including the electric generator. Because nameplate capacity is a descriptive value specific to the electric generator, it does not reflect the balance of plant equipment and systems, auxiliary load requirements, or site-specific conditions such as ambient temperature, humidity, or elevation that influence the actual net capability or rating of the unit. These factors are considered by the summer and winter net demonstrated capacity ratings reported for each unit. EPA alludes to these seasonal differences in the proposed rule by noting that:

> Net generating capacity is a function of weather/temperature conditions at the site, which varies throughout the year. While some units may model actual weather adjusted

[252] "2009-2013 Generating Unit Statistical Brochure – All Units Reporting." Aug. 14, 2014. NERC. www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

> capacity by the hour/minute, these data are not reported for the fleet. Therefore, the EPA used the nameplate capacity reported for units.[253]

EPA suggestion that "weather adjusted capacity....data are not reported for the fleet" is also incorrect as both summer and winter net demonstrated capacities are reported annually to the Energy Information Agency ("EIA") and are summarized in the publically accessible EIA-860 report.[254] In fact, EPA's Regulatory Impact Analysis ("RIA') for the proposed 111(d) rule actually uses the net summer and net winter capacity data from the EIA-860 report to evaluate existing generation resources.[255] The RIA also summarizes an EPA analysis of coal-based generating units that includes an assessment of net summer capacity.[256] Data for this assessment is provided by the EPA National Electric Energy Data System ("NEEDS") database, which notes the following with respect to calculating capacity factors:

> The NEEDS unit capacity values implemented in EPA Base Case v.5.13 reflect net summer dependable capacity, to the extent possible. Table 4-4 summarizes the hierarchy of primary data sources used in compiling capacity data for NEEDS v.5.13; in other words, data sources are evaluated in this order, and capacity values are taken from a particular source only if the sources listed above it do not provide adequate data for the unit in question.[257]

Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v.5.13 Sources Presented in Hierarchy
2010 EIA 860 Summer Capacity *2011 EIA 860 Summer Capacity* *2010 EIA 860 Winter Capacity* *2011 EIA 860 Winter Capacity* *2010 EIA 860 Nameplate Capacity* *2011 EIA 860 Nameplate Capacity*
Notes: Presented in hierarchical order that applies. If capacity is zero, unit is not included.

Seasonal net demonstrated capacity is also commonly used to calculate capacity factors by a variety of regulatory agencies, including the North American Electric Reliability Corporation ("NERC). The NERC instructions for reporting data to the generation availability data system ("GADS") provide the following equation for calculating capacity factor from net

[253] GHG Abatement Measures TSD. EPA. 2014. p. 3-6.
[254] Historic EIA-860 Reports. www.eia.gov/electricity/data/eia860/
[255] Regulatory Impact Analysis for the Propose Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. EPA. June 2014. EPA-452/R-14-002. p. 2-2.
[256] Id. p. 2-4.
[257] Chapter 4: Generating Resources. "Documentation for v.5.13". EPA. p. 4-4. www.epa.gov/powersectormodeling/BaseCasev513.html

generation data: Net Capacity Factor (%) = (Net Generation) / (Operating Hours x Net Maximum Capacity). The net capacity factor is the value that is then used to represent unit performance in NERC's annual Generating Unit Statistical Brochure.[258]

This widespread recognition and use of net seasonal capacity, including the rationale underlying EPA's own NEEDS database, renders EPA's use of nominal nameplate capacity for purposes of evaluating available underutilized NGCC capacity arbitrary and unreasonable. EPA's analysis incorrectly uses an "apples and oranges" comparison of actual net generation divided by nominal gross generation capacity to calculate an unrepresentative capacity factor that is biased low and is in no way representative of historic unit performance. This artificial capacity factor leads to an overestimate of the amount of NGCC capacity to be redispatched, an overly stringent state emission rate goal, as well as a false sense of flexibility that redispatch is a viable option for state plans and that redispatch will not significantly impact the reliability of the grid. Any use of historic capacity factor data to assess the potential for increased utilization of NGCC *must, first and foremost, be calculated correctly* and it must be evaluated in context with the broad scope of other factors that may influence the potential for greater operation.

D. EPA provides no legitimate rationale for determining that a 70% capacity factor is achievable by the entire NGCC fleet

In the proposed rule, EPA rationalized the assumed 70% capacity factor redispatch rate as follows:

- In 2012, more than 10% of the NGCC plants operated at an annual capacity factor of 70% or greater.
- ...during the summer and winter peak electricity demand timeframes nationwide, more than 10% of NGCCs were operated at a capacity factor greater than 70%."
- ...19% of NGCCs achieved 70% capacity factor during the winter of 2011/2012 and 20% hit that level or higher during the summer.
- ...a notable number of existing NGCCs have demonstrated the ability to achieve a 70% capacity factor for extended periods of time....without adverse effects on the electric system.
- ...roughly 6% of units operated at a 75% capacity factor, or higher, in 2012...[and] 16% of units operated at 65%, or higher.

[258] Historic Generating Unit Statistical Brochures. www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

- While many units demonstrated the ability to deliver net generation that was more than 70% of their nameplate capacity, the EPA assumed 70% was a reasonable fleet-wide ceiling for each state.
- The demonstrated ability of the NGCC plants to consistently operate at levels greater than 70% of their nameplate capacity (e.g. this was the utilization of the ~90 percentile plant), the historic evidence supporting quick and significant redispatch to NGCC, and the cost-effectiveness of high NGCC utilization....all supported the notion of a NGCC fleet capacity factor of 70% as a reasonable ceiling in the EPA's BSER approach.[259]

The 70% capacity factor used by EPA is an arbitrary number selected based on the historic operation of a small percentage of NGCC units. While EPA rationalizes that the 70% value was "assumed [to be] reasonable" and that "more than 10%" of the existing units have operated at that level, such qualitative criteria offer nothing to credibly conclude that the 70% determination is technically, economically, or legally feasible. Indeed, EPA's process for selecting the 70% capacity factor gives no regard to important considerations such as the availability of adequate transmission capacity to allow increased NGCC utilization to offset the operations of other fossil fuel-fired facilities located in the same state; the availability of adequate and reliable sources of gas supply; existing unit conditions; outage scheduling; or the lack of regulatory authority or mechanisms necessary to establish and enforce such utilization requirements. EPA's own modeling of the proposed rule confirms that there are technical and/or economic constraints to running all NGCC units at a 70% capacity factor as the nationwide average capacity factors for NGCC units were 50 and 56% for the two Option 1 scenarios modeled by EPA.

E. EPA has not fully evaluated the transmission and gas supply infrastructure issues that may significantly impact the feasibility and amount of potential redispatch

EPA identifies natural gas supply and electric transmission as other influences that must be considered in evaluating the feasibility of increased utilization of the NGCC fleet, by noting

> EPA believes that the natural gas pipeline and electricity transmission networks can support aggregate operation of the NGCC fleet at up to a 70% capacity factor on average, either <u>as they currently exist or with modifications</u> that can be reasonably expected in the time frame for compliance with this rule.[260]

[259] GHG Abatement Measures TSD. EPA. 2014. pp 3-9 to 3-11.
[260] GHG Abatement Measures TSD. EPA. 2014. pp 3-14 to 3-15. (emphasis added)

Aside from qualitative statements and a high-level, incomplete, and generally irrelevant "analysis" of historic interstate natural gas flows, EPA fails to provide any credible or applicable review of the current state of the natural gas or electric transmission systems to determine areas that are sufficiently robust, that need "modifications" or that require new infrastructure to be developed. Instead of legitimately examining potential "reliability constraints" and the scope, cost, and timing of steps to address those issues, EPA chooses to address "compliance constraints" by stating that:

> <u>constraints</u> that occur at peak times are <u>unlikely to be a barrier to achieving compliance</u> with the rule, because these peak times are only a small percentage of the year and will constrain only a limited percentage of the state-wide NGCC fleet. These peak hours are the period when there are most likely to be constraints on the pipeline or electricity transmission networks; during other hours of the day, continued NGCC operation at equal, or higher levels, are technically feasible but may be limited by economic considerations... It is *reasonable to expect* that average *capacity factors could be extended* to higher levels at all hours *without experiencing technical feasibility barriers* from either pipeline supplies or electricity transmission."[261]

EPA's focus is on compliance with an annual limit, and not on maintaining reliability during "peak hours" when it is most critical to maintain natural gas supplies and the electric transmission system. The importance of maintaining the reliability of the gas supply and transmission systems should prompt a much more in-depth analysis, as opposed to one based on a cursory review of what is "reasonable to expect." EPA failed to fully evaluate existing natural gas supply and electric transmission constraints, contractual arrangements, or the timing and feasibility of necessary gas supply or transmission grid infrastructure improvements or expansion, each of which may limit the feasibility, reliability, and sustainability of units collectively operating at such high capacity factors. As discussed in the implementation section of comments below, timing considerations are also of significant concern with regards the time to plan, design, approve, and construct any necessary pipeline and transmission infrastructure.

1. EPA should thoroughly evaluate natural gas supply issues

EPA should thoroughly review the current state of the existing natural gas supply network and related contractual arrangements to determine if the system can readily support an

[261] Id. pp.3-15 to 3-16. (emphasis added)

increased utilization of the entire NGCC fleet and/or what infrastructure challenges must be addressed. Issues that EPA should investigate include the following:

- Natural gas pipeline transmission infrastructure is typically not built on speculation. FERC requires that pipelines demonstrate market need, most commonly shown through the execution of a sufficient level of long-term service contracts, before approving either expansions of existing infrastructure or development of new infrastructure. Pipeline and storage infrastructure capacity is sized to meet the contractual demand of firm customers, with little or no reserve capacity. Because the pipelines are sized to accommodate the needs of firm shippers, many pipelines are fully subscribed.
- Competition determines which natural gas pipeline will serve new load. There is no natural gas transmission pipeline equivalent to the electric industry's RTO's. The Interstate Natural Gas Association of America, the trade association that advocates regulatory and legislative positions of importance to the pipeline industry in North America, has stated, "the competitive model has worked well in the past and will continue to work well into the future". This competitive model may not, in fact, result in the most expedient, economic and holistic national expansion of the natural gas pipeline infrastructure.
- The availability of existing infrastructure and the construction of new infrastructure is locational. Economic access to sufficient, reliable delivery capacity will be location-specific. Each NGCC that has already been built may have enough pipeline infrastructure in place to meet its needs if it has made a Firm Transportation capacity commitment for its full requirements. If it has not, then additional pipeline infrastructure may be needed to support a 70% capacity factor. The siting of new gas-fired electric generation will need to balance the cost and timing of both natural gas pipeline and electric transmission system expansion.
- Incremental costs for Firm Transportation and balancing services unique to electric generation loads may not result in the economic dispatch of NGCC's up to 70% capacity factor. However, if the units are dispatched at a 70% or greater capacity factor, the reservation charges associated with Firm Transportation Service (FTS) could be more efficiently utilized. Currently, the RTO model does not allow the cost of FTS to be included in the bid/offer. Consequently, it is estimated that less than 50% of the nation's gas-fired electric generation is served by FTS as the electric generators have no ability to recover this cost from the RTO.
- EPA's proposed timeline may not be sufficient to increase existing NGCC plant capacity factors to as much as 70%. If new infrastructure is necessary, it could take up to three years from Service Agreement execution until initial natural gas deliveries. Regulatory and environmental approvals, engineering design, easement acquisition and construction have discrete timeframes that allow only minimal flexibility by location. Furthermore, electric generating utilities will not be able to make the commitment for Firm Transportation service until the proposed rule is finalized and the state plan is approved. If additional NGCC capacity is needed the utility will also need Certificate of Public Convenience and Necessity approval from

the governing state public service commission before it will be in a position to subscribe for Firm Transportation.

- Increased demand for pipeline infrastructure across the country to comply with the final requirements could increase competition for construction labor and materials. Significant expansion is already occurring throughout the northeast and the demand for limited resources is being stretched. Additional pressure on these resources could increase costs and delay completion of projects by the required to support compliance with the final rule.

Evaluating these types of issues in more detail would offer a more credible assessment of potential natural gas supply concerns than the following qualitative conclusions that EPA makes in the proposed rule:

- natural gas pipeline *capacity is regularly added* in response to increased gas demand and supply;
- Upgrades to pipeline...infrastructure...will *generally* be less expensive than upgrades of that infrastructure potentially needed for siting of new capacity;
- significant[ly] higher levels of end-use *energy efficiency....will reduce the load* on the... natural gas pipeline infrastructure... [which will] decrease need for new generating units and reduced peak demands; and
- Based on a review of interstate natural gas pipeline flows, increased use of natural gas in existing facilities can be largely met with expansions to existing pipeline facilities and corridors.[262]

2. EPA should thoroughly evaluate electric transmission issues

EPA failed to identify or fully evaluate potential constraints within or impacts to the electric transmission system that may limit the feasibility, reliability, and sustainability of NGCC units collectively operating at higher capacity factors. Instead, EPA dedicates only two paragraphs within their 27 page review of building block two, along with a couple of minor passing references, to the process of completing potential transmission system upgrades. These qualitative references include:

- The electric transmission system has also been expanded in the past few years, and continued investment is expected.
- Upgrades to transmission infrastructure...will generally be less expensive than upgrades of that infrastructure potentially needed for siting of new capacity
- significant higher levels of end-use energy efficiency....will reduce the load on the electricity transmission...[which will] decrease need for new generating units and reduce peak demands[263]

[262] Id. pp. 3-16 to 3-18 (emphasis added)

EPA also references EIA and EEI reports of “planned” transmission projects, but offers no context as to whether these “planned’ projects will address any specific issues related to the increased dispatch of NGCC units.[264] Detailed comments on the significant transmission and reliability concerns associated with the proposed rule are provided in a separate section. EPA must perform a more thorough review of transmission issues to determine the feasibility of building block two and the entire proposal.

F. EPA failed to evaluate existing air permit conditions that may significantly impact the feasibility and amount of potential redispatch

A variety of air permit requirements are in place that provide operational flexibility or that restrict operations, which may significantly impact the amount of potential redispatch that may be available for certain units. Examples include NGCC units that are permitted:[265]

- to combust fuel oil and natural gas;
- to co-fire other fuels with natural gas (oil, landfill gas, coal gas, etc.);
- with conditions that limit natural gas use, which effectively limits the potential capacity factor that is achievable;
- to operate in simple-cycle or combined cycle mode; and
- to operate the steam turbine with steam that is comingled from sources that are separate from the HRSG.

Some permits actually envision scenarios when natural gas supplies would not be available to operate the unit and allow the generator the flexibility to use oil or other fuels as an alternative. For example, consider the following permit condition from an NGCC facility in Rhode Island:

> Natural gas shall be deemed unavailable in cases of interruption in supply or transportation resulting from equipment failure, regulatory actions or interruption of supply outside of the control of the permittee.
>
> Natural gas shall be deemed unavailable if:
>
> (1) ISO-New England has declared a “Cold Weather Event” pursuant to Market Rule 1, Appendix H, “Operations During Cold Weather Conditions”. The permittee may utilize fuel oil for each Operating Day (12AM-12PM) that this condition exists; or,

[263] Id. pp.3-16 to 3-20.
[264] Id. p. 3-20.
[265] See Appendix D.

> (2) ISO-New England has declared a "Cold Weather Watch" or a "Cold Weather Warning" pursuant to Market Rule 1, Appendix H, "Operations During Cold Weather Conditions" and either ISO-New England has forecast ISO New England Operating Procedure No. 4 conditions in its Morning Report or as revised/updated during the Operating Day, or has taken any action under ISO New England Operating Procedure No. 4. The permittee may utilize fuel oil for the 24-hour period between issuance of the Morning Reports (9AM Day 1 to 9AM Day 2) that this condition exists;
>
> Natural gas shall not be deemed unavailable on the basis of any increase in the cost of supply or transportation or allocation of available natural gas to other facilities within the control of the permittee.
>
> If natural gas is unavailable, the permittee may utilize fuel oil, with sulfur content of 0.05 percent or less by weight, as replacement fuel.[266]

Although these types of issues should have been considered, EPA made no attempt to evaluate existing permit limits or determine how existing requirements may limit the feasibility of NGCC units to achieve increased utilization rates.

G. EPA should exclude combined heat and power ("CHP") facilities from the building block two calculations for NGCC units

1. CHP units should be considered separately from NGCC units

Major differences exist between the purpose, design, fuel flexibility, and operating philosophy of combined heat and power facilities and NGCC units such that CHP facilities that meet the definition of a 111(d) affected source should considered separately in the building block calculations. EPA acknowledges and discusses these distinguishing characteristics thorough a website and support documents associated the "EPA Combined Heat and Power Partnership," which the agency describes as:

> a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP. The Partnership works closely with energy users, the CHP industry, state and local governments, and other clean energy stakeholders to facilitate the development of new projects[267]

In fact, EPA developed a "CHP Project Development Handbook" to support the development of new projects, which notes the following with respect to feasibility:

[266] Manchester Street NGCC Plant Air Permit. RI-22-07. Rhode Island Department of Environmental Management. July 31, 2009.
[267] www.epa.gov/chp/

> Whether CHP can be economically beneficial at any particular site depends on a host of site-specific characteristics such as the energy consumption profiles of the facility, the relative prices of fuel and retail electricity, and the costs of installing and maintaining the CHP equipment.[268]

Further, to highlight the differences in how CHP facilities operate, consider the permit condition for one CHP facility in Connecticut, which discusses significantly different options for operation the unit as follows:

> General Electric turbine (EU1-Permit No. 213-0029) and two Nebraska boilers (EU2 – Permit No. 213-0031 and EU3 – Permit No. 213-0032) burn natural gas and No. 2 fuel oil. The turbine and the boilers can be operated by themselves or under the following combinations: turbine and the equivalent of one boiler, two boilers without the turbine.[269]

2. EPA should evaluate whether individual CHP units are affected sources subject to the 111(d) guidelines

In addition to considering CHP facilities apart from NGCC units, EPA must also thoroughly assess whether the CHP units identified in the proposed rule even meet the definition of an affected source that is subject to the 111(d) guidelines. Several examples have been identified in the building block two calculations of certain CHP units that clearly do not meet the definition of "affected sources" subject to the proposed rule. EPA's criteria for determining "affected sources" in the proposed rule is summarized as follows:

> The EPA is proposing that, for the emission guidelines, an <u>affected EGU</u> is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an "existing source" for purposes of CAA section 111, and that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs (79 FR 1430; January 8, 2014).[270]

The proposed 111(b) standards for new sources revised the "applicability criteria" in several ways for determining whether a facility is an "affected source." Most relevant to combined heat and power facilities are revisions to (1) the averaging period used to assess applicability with the net electric output criterion, and (2) the exclusion of electric output consumed by the host industrial facility.

Specifically, revisions in the averaging period are related to the applicability criteria that "affected sources" are those EGUs that are "*constructed for the purpose of supplying more than*

[268] "CHP Project Development Handbook." p. 17. www.epa.gov/chp/documents/chp_handbook.pdf
[269] Algonquin Power Windsor Locks, LLC Title V Permit #213-0069-TV. Connecticut DEP. Oct. 31. 2012. p.7.
[270] 79 Fed. Reg. 34854. June 18, 2014. (emphasis added)

219,000 MWh...net-electrical output to the grid." To evaluate this requirement EPA notes that "We are also proposing to *revise the averaging period* for electric sales from an annual basis to a *three-year* rolling average for stationary combustion turbines."[271] With respect to the definition of net electric output, EPA proposed adding the clause "*of the thermal host facility or facilities*."[272] In describing the rationale for that revision, EPA notes:

> [O]ne potential issue that we have identified is inequitable applicability of third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility. The current definition of net electric output...is 'the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis. Owners/operators of a CHP facility under common ownership as an adjacent facility using the thermal output from the CHP (i.e. the thermal host) can subtract out power purchased by the adjacent facility on an annual basis when determining applicability. However, third-party CHP developers would not be able to benefit from the 'minus purchased power on a calendar basis' provision in the definition of net electric output when determining applicability since the CHP facility and the thermal host(s) are not under common ownership. We are therefore proposing to....make applicability consistent for both facility-owned CHP and third-party owned CHP. [273]

The applicable definitions in the 111(b) proposals for new sources and for modified and reconstructed sources incorporate these revisions.[274] However, the 111(d) proposal selectively includes only the language related to using a three-year average. A comparison of the definitions in each proposal is provided below:

Proposed 111(b) for New Sources 79 Federal Register 1509-1510 (January 8, 2014)	Proposed 111(d) for Existing Sources 79 Federal Register 34956 – 34957 (June 18, 2014)
"Net-electric output means... (2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a <u>3 calendar year rolling average basis</u>, the gross electric sales to the utility power distribution system <u>minus purchased power of the thermal host facility or facilities on a three calendar year rolling average basis.</u>"	"Net energy output means... (2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a <u>rolling 3 year basis</u>, the net electric or mechanical output from the affected facility divided by 0.95, plus 75 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application)"

[271] 79 Fed. Reg. 1446. January 8, 2014. (emphasis added)
[272] Id. 1460. Note the "emphasis added" statement comes directly from the proposed rule.
[273] Id.
[274] See 79 Fed. Reg. 34979 pertaining to the proposed 111(b) standards for modified and reconstructed sources.

The proposed 111(d) guidelines *fail to mention* EPA's concern of the "*inequitable applicability of third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility*." Further, even though EPA included the "rolling 3 year basis" in the definition, *nothing has been found in the docket* to suggest that EPA actually performed an analysis of 3 year averages to determine the applicability of individual CHP facilities. Multiple CHP facilities have been identified that appear to have been erroneously included in the building block two calculations that otherwise would have been excluded had EPA properly considered all of the definitional revisions proposed in the 111(b) rulemakings. For example, EPA appears to have incorrectly included the Portside Energy CHP unit as an existing NGCC facility when performing the building block two calculations for the state of Indiana. A review of the facility in context with how it is designed, where its located, and how its electric and thermal output is employed strongly suggests that the facility provides nearly all of its electricity to the "host facility" (not to a "utility distribution system"), and thus is not an affected source. A recent article about the facility noted that:

> Portside Energy's plant on the grounds of the U.S. Steel Midwest mill.. provides most of the steel mill's electricity needs and all of its steam and hot water needs [275]

A sufficient number of similar examples were identified through a cursory review of other cogeneration facilities to suggest that the inclusion of CHP units within the building block two calculations for NGCC units is fundamentally flawed. The end result is (1) that the 111(d) proposal is illegally applicable to a broader suite of sources than those that are subject to 111(b) new source standards;[276] (2) EPA's building block two calculations inaccurately include co-generation sources that are <u>not</u> affected sources subject to the proposed requirements; and (3) the corresponding state goal calculations, reliability assessments, and cost-benefit analysis are derived from inaccurate data.

If EPA intended to identify affected sources under 111(d) "*that in all other respects would meet the applicability criteria for coverage under the proposed* [111(b)] *standards*," then EPA must *adopt and apply* that criteria in determining the applicability of existing co-generation units to the proposed rule. Further, co-generation units are principally designed and operated to supply heat and power to a specific industrial or commercial process. EPA must evaluate

[275] www.midwestenergynews.com/2014/06/20/combined-heat-and-power-is-a-boon-for-midwest-steel-mills/
[276] See the supporting legal discussion in Section IV.F.

whether co-generation units could even be redispatched at higher capacity factors if such increased utilization would significantly impact or jeopardize the ability of units to achieve their primary objective of providing heat and power to a host process.

3. EPA incorrectly applies the electric output associated with useful thermal output from CHP units in the building block two calculations

Co-generation units are capable of providing both electric energy output and useful thermal output ("UTO"). For combined heat and power facilities subject to the proposed rule, EPA calculates CO_2 emissions and energy output (in MWh) associated with the useful thermal output that is not used for electricity production. EPA then adds only the UTO related energy output to the electric output to calculate a revised baseline NGCC emission rate for the facility. The UTO related CO_2 emissions *are not* used to calculate the revised baseline NGCC emission rate, but instead are added into the "Other Emissions" component of the building block two methodology. The affect is significant as it creates an artificially low CO_2 emission rate for the facility that leads to an inaccurate baseline NGCC emission rate that is biased low and that has not been adequately demonstrated. This results in overly stringent state emission rate goal.

This concern is illustrated using the EPA goal calculations for Arkansas where the agency identifies seven NGCC facilities in the state, one of which is a CHP unit (Pine Bluff) where energy output and CO_2 emissions associated with useful thermal output were calculated. The impact of EPA's methodology for considering UTO energy output is significant as it reduces Pine Bluff's emission rate by 47% from 1,132 lb./MWh to 602 lb./MWh – a rate that is not remotely close to have been demonstrated by any NGCC unit. In turn, the average NGCC CO_2 emission rate for Arkansas is reduced by 8% from 896 lb./MWh to 827 lb./MWh, as shown in the table below. *None* of the other six NGCC units had annual CO_2 emission rates less than or equal to 827 lb./MW, and *none* would ever be expected to achieve a rate of 602 lb./MWh. The absurdity of the 602 lb./MWh value becomes apparent after review of any number of EPA databases, studies, and reports that have evaluated NGCC CO_2 emission rates,[277] which indicates that even the most optimistic of CO_2 emission rates are much higher (hundreds of lb./MWh higher) than the 602 lb./MWh rate calculated for Pine Bluff.

[277] For example, EPA RBLC database (http://cfpub.epa.gov/rblc/); EPA Region 6 GHG PSD permit database (http://yosemite.epa.gov/r6/Apermit.nsf/AirP#A); or EPA Combustion Turbine TSD (www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0082)

EPA Building Block Two Calculations for Arkansas NGCC Facilities[278]

	2012 CO2 (tons)	2012 Net Generation (MWh)	2012 CO2 Rate lb/MWh net	Useful Thermal Output (MWh)	Useful Thermal Output (CO2 tons)	2012 Net Energy Output (Net Gen + UTO MWh)	2012 CO2 Rate lb/MWh - net energy output	CO2 Emission Rate % Reduction lb/MWh (net gen) vs. lb/MWh (net gen + UTO)
Data Source	EPA	EPA	Calculated	EPA	EPA	EPA	Calcuated	Calculated
Dell Power Station	317,306	687,809	923	---	---	687,809	923	---
Harry L. Oswald	180,415	356,365	1,013	---	---	356,365	1,013	---
Hot Spring Gen. Facility	226,155	513,634	881	---	---	513,634	881	---
Magnet Cove	1,082,150	2,578,521	839	---	---	2,578,521	839	---
Pine Bluff Energy Center	842,709	1,489,105	1,132	1,310,917	394,540	2,800,022	602	-47%
Thomas Fitzhugh	64,818	114,459	1,133	---	---	114,459	1,133	---
Union Power Partners LP	4,302,025	9,911,292	868	---	---	9,911,292	868	---
ARKANSAS NGCC Fleet 2012 Average CO2 Rate	7,015,577	15,651,185	896			16,962,102	827	-8%

[278] EPA data from "Goal Computation Technical Support Document – Appendix 7." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602.

In addition to the Pine Bluff facility, the CO_2 emission rates for 82 other NGCC units were calculated using the UTO-related energy output. A summary of the UTO impact to the emission rates calculated for all of these facilities is provided in Appendix B. It is noteworthy, that eight facilities had CO_2 emission rates that were even lower than the absurd value EPA calculated for Pine Bluff. The units are summarized below:[279]

State	Plant	2012 CO2 Rate lb./MWh net generation	2012 CO2 Rate lb./MWh net energy output	CO2 Emission Rate % Reduction lb./MWh (net gen) vs. lb./MWh (net gen + UTO)
PA	Grays Ferry Cogeneration	1,451	348	-76%
TX	Gregory Power Facility	1,301	485	-63%
CT	Algonquin Windsor Locks	673	532	-21%
TX	Channel Energy Center LLC	937	543	-42%
MI	Dearborn Industrial Generation	1,059	578	-45%
TX	Channelview Cogeneration Plant	1,193	587	-51%
CA	Greenleaf 1 Power Plant	808	593	-27%
LA	Louisiana 1	1,447	599	-59%
AR	Pine Bluff Energy Center	1,132	602	-47%

[279] Id.

It also worth noting while a single co-generation facility reduced the overall state NGCC fleet CO_2 rate in Arkansas by 8%, other states have multiple co-generation units that may have much more significant impact. For example, EPA identified 14 co-generation facilities in Texas whose CO_2 emission decreased on average by 34% with the application of the UTO energy output. These results are summarized below:[280]

State	Plant	2012 CO2 Rate lb./MWh net generation	2012 CO2 Rate lb./MWh net energy output	CO2 Emission Rate % Reduction lb./MWh (net gen) vs. lb./MWh (net gen + UTO)
TX	Gregory Power Facility	1,301	485	-63%
TX	Channel Energy Center LLC	937	543	-42%
TX	Channelview Cogeneration	1,193	587	-51%
TX	Clear Lake Cogeneration Ltd	1,222	623	-49%
TX	Sabine Cogen	1,534	633	-59%
TX	Deer Park Energy Center	1,193	643	-46%
TX	Pasadena Cogeneration	830	705	-15%
TX	Texas City Power Plant	1,500	751	-50%
TX	Eastman Cogeneration Facility	1,176	754	-36%
TX	Baytown Energy Center	889	850	-4%
TX	C R Wing Cogen Plant	1,125	928	-18%
TX	Oyster Creek Unit VIII	1,336	1,127	-16%
TX	Optim Energy Altura Cogen	1,413	1,327	-6%
TX	SRW Cogen LP	1,728	1,454	-16%
			Average Reduction =	-34%

The building block two calculations for 24 states included the addition of UTO related energy output when determining the baseline NGCC CO_2 emission rate. The impact of the added UTO energy output can be significant as is most evident in the reduction in the baseline NGCC CO_2 emission rates for Louisiana (-21%), Michigan (-19%), Washington (-17%), and Texas (-14%).[281]

[280] Id.
[281] Id.

H. EPA has significantly overestimated the amount of NGCC capacity available for redispatch due to egregious methodological issues and data quality errors

Close examination of EPA NGCC redispatch calculations identified numerous fundamental calculation errors and data quality issues that result in the amount of potential redispatch to be substantially overstated. These flaws include (1) incorrect data inputs; (2) inappropriate use of nominal nameplate capacity instead of the actual net demonstrated capacity; (3) incorrect inclusion of units that do not meet the definition of an "affected source" subject to the proposed rule; (4) incorrect inclusion of NGCC units that were never constructed; along with (5) incorrect and inconsistent assumptions on units that were commissioned in 2012 or later. Each of these issues and other concerns are discussed in detail below. EPA must correct these errors and determine how these corrections affect the state goal calculations, "flexible" compliance strategies, reliability evaluations, and cost-benefit analyses reflected in the proposed rule. Given the scope of issues to be resolved, EPA must withdraw the current proposal, correct the errors within building block two, and publish a new proposed rule for public comment.

1. EPA incorrectly uses "nameplate" capacity in the block 2 calculations

As detailed in the comments above, nameplate capacity is a nominal value used to represent and describe the gross rating or size of an electric *generator* – a specific piece of equipment. Nameplate capacity *does not* represent the maximum capacity of an electric *generating unit* – the entire power plant, including the electric generator. Because nameplate capacity is a descriptive value specific to the electric generator, it does not reflect the balance of plant equipment and systems, auxiliary load requirements, or site-specific conditions such as ambient temperature, humidity, or elevation, all of which can influence the actual net capability or rating of the unit. Use of the descriptive nameplate value results in an artificial capacity factor that in turn overestimates of the amount of NGCC capacity to be redispatched, produces a more stringent state emission rate goal, and exaggerates the viability of redispatch as an option for state plans. The table below compares differences in the demonstrated net capacity and the nominal nameplate descriptor for Ohio, which is typical for each state where NGCC capacity was identified by EPA.[282]

[282] Nameplate and Summer Capacity Data per the 2012 EIA-860 Report. www.eia.gov/electricity/data/eia860/

Ohio NGGC Plant	Nameplate Capacity (MW)	Summer Capacity (MW)
Dresden	678.3	540.0
Fremont	739.5	667.3
Hanging Rock	1,288.2	1,252.0
Washington	714.9	626.0
Waterford	921.6	810.0
Ohio Total:	4,342.5	3,895.3

EPA actually compares the nameplate and summer capacities for each existing electric generation source in the Regulatory Impact Analysis for the proposed rule. On a national basis for units combusting natural gas the summer capacity is 13% less than the nameplate capacity (422,364 MW vs. 485,957 MW).[283] EPA must resolve this significant methodological error and use the net demonstrated seasonal capacity values for each unit, not the nominal nameplate descriptor.

2. EPA incorrectly includes simple-cycle and gas boiler units in their calculation of "existing" NGCC capacity

EPA designed building block two to apply to existing NGCC units that are within the regulated source categories. However, in the goal calculations for some states, EPA incorrectly included natural gas simple-cycle and gas steam units as part of the existing NGCC capacity. EPA must revise its state goal calculations to ensure that natural gas simple-cycle and steam boiler units are not included as part of the existing NGCC capacity. Examples of this issue include the following:

State	Plant	Unit	Identified by EPA as an existing NGCC unit?[284]	Actual Unit Type
Louisiana	Louisiana 1	1A	yes	natural gas steam boiler
Louisiana	Louisiana 1	2A	yes	natural gas steam boiler
Louisiana	Louisiana 1	3A	yes	natural gas steam boiler[285]
Louisiana	Perryville Power Station	2-CT	yes	simple cycle CT[286]

[283] RIA for the Propose Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. EPA. June 2014. EPA-452/R-14-002. p. 2-2.
[284] "Goal Computation Technical Support Document – Appendix 7." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602
[285] Louisiana Department of Environmental Quality Air Permit #PER20130004. December 16, 2013.
[286] Louisiana Department of Environmental Quality Air Permit #PER20120003. September 14, 2012.

3. Building block two incorrectly and inconsistently includes NGCC units that were constructed after 2011

EPA defines two categories of applicable 111(d) NGCC units in the building block two calculations: “existing” units and “under construction” units. EPA assumes that the “existing” category of units were available to operate all of 2012 in order to calculate a baseline generation rate for these units that is then redispatched to a 70% capacity factor. For the “under construction” category of units, EPA assumes that those units were constructed to meet a specific demand requirement that is equivalent to a 55% capacity factor from those units. EPA then assumes that these “under construction” units are available for redispatch at a 15% capacity factor (70% - 55% = 15%). The fatal flaw of EPA’s approach is its inconsistent, incomplete, and inaccurate consideration of all NGCC units that were commissioned during and after 2012 in terms of if and how these units were classified into the “existing” or “under construction” category.

Clearly, EPA does not have an accurate grasp of the status of these “new” units as numerous errors have been identified related to the scope of units considered (or not considered), EPA’s assumptions regarding the status of these projects, and EPA’s methodology for considering these units within the block two calculations. A detailed discussion of these issues is provided in the comments below. EPA must correct these issues, which significantly diminish the capacity to be included within building block two. For accuracy and completeness, EPA should first review the scope of all NGCC units commissioned or to be commissioned after December 31, 2011 and second treat all of these units equally as “under construction” in the building block 2 calculations.

a. In the calculation of existing NGCC capacity available in 2012, EPA incorrectly included units that had/have not yet been commissioned

In the goal calculations for certain states, EPA incorrectly included certain NGCC projects that were not commissioned until after 2012 as part of the "existing" NGCC units that were redispatched up to a 70% capacity factor. In fact, one example was identified for a facility that has not received its air permit or commenced construction, and as such would not be an affected source subject to the proposed section 111(d) guidelines. EPA must revise these calculations to exclude such units and to ensure that the existing NGCC units considered have actually been constructed. Examples include the following:

State	Plant	Identified by EPA as an existing NGCC unit?[287]	Status
AK	Southcentral Power Plant	yes	commissioned – Jan. 2013[288]
CA	El Segundo Energy Center	yes	commissioned – Sep. 2013[289]
CA	Russell City Energy Center	yes	commissioned – Aug. 2013[290]
FL	Cape Canaveral	yes	commissioned – April 2014[291]
UT	Lake Side 2	yes	commissioned in 2014[292]
LA	Washington Parish Energy Center	yes	not commenced construction[293] air permit has not been issued[294]

b. EPA has incorrectly calculated the post-2012 "under construction" NGCC capacity for *all states* where the agency determined it applied

In terms of the NGCC capacity that EPA classified as "under construction" in the building block two calculations, EPA assumed that these facilities are being constructed to meet a specific demand that is equivalent to a 55% capacity factor.[295] Based on this assumption, EPA

[287] "Goal Computation Technical Support Document – Appendix 7." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602
[288] www.mlandp.com/FACT%20SHEET_SouthcentralPowerProject_2013.pdf
[289] www.dailybreeze.com/government-and-politics/20130912/new-energy-efficient-power-plant-unveiled-in-el-segundo and http://elsegundorepowering.com/
[290] www.calpine.com/power/plant.asp?plant=261
[291] www.fpl.com/news/2014/041014.shtml
[292] www.pacificorp.com/.../pacificorp/doc/Energy_Sources/EnergyGeneration_FactSheets/RMP_GFS_Lake_Side.pdf
[293] http://theadvocate.com/home/8941063-125/calpine-sells-st-gabriel-power. April 22, 2014.
[294] http://edms.deq.louisiana.gov/app/doc/queryresults.aspx
[295] EPA's assumption that units under construction were anticipated to reach a 55% capacity factor is inherently inconsistent with the premise of this entire building block. If a 55% capacity factor is sufficient to incent construction of a new unit, a 70% capacity factor would seem to represent an extraordinarily high utilization rate.

calculated that 15% of this "under construction" capacity would be redispatched under building block two.

EPA determined that nine states had NGCC units that were "under construction" – a determination that is *incorrect for each of the nine states*. For five of these states, the units determined to be "under construction" by EPA represent fictitious "potential" units identified within EPA's NEEDS database and Integrated Planning Model. NEEDS describes potential units as follows:

> "Potential" units refer to new generating options used in IPM for capacity expansion projections of the electric industry... whereas *potential units are endogenous to the model* in the sense that the model determines the location and size of all the potential units that end up in the final solution for a specific model run.[296]

These "potential" units are nothing more that phantom units that do not represent real projects that have been proposed, designed, permitted, or constructed. To the extent that these "potential" projects come to fruition, they would be subject to the new source standards under 111(b), not the existing source 111(d) guidelines. As such, these "potential" units should not be considered in building block two.

For the remaining four states, the inaccurate inclusion of these units as "under construction" capacity is largely a result of the EPA incorrectly assessing the actual status of these units. For example, the one "under construction" facility identified by EPA for Ohio is the Dresden Plant that was actually commissioned in 2012. The one "under construction" facility in Kentucky is the Cane Run project, which has yet to receive an air permit and has not yet commenced construction.[297]

For Virginia, the data source used by EPA to determine that 1,928 MW of NGCC capacity is "under construction" has not been determined. EPA employed the NEEDS database to determine the under construction capacity in other states, but NEEDS lists only 570 MW of capacity related to a plant that has yet to receive an air permit or commenced construction.[298] A separate review of the 2012 EIA860 report identified 2,801 MW of "proposed" NGCC capacity in Virginia, but only 1,472 MW of that capacity represents units that are known to have

[296] Chapter 4: Generating Resources. "Documentation for v.5.13". EPA. p. 4-1. www.epa.gov/powersectormodeling/BaseCasev513.html
[297] 2013 EIA-860 Report. www.eia.gov/electricity/data/eia860/
[298] www.deq.state.va.us

commenced construction.[299] Finally, EPA identified 220 MW of "under construction" capacity in Wyoming, which is associated with the Cheyenne Prairie Generating Station. This project includes both a combined cycle unit and a separate simple cycle unit that together have a nameplate capacity of 220 MW. However, only 100 MW of that capacity is associated with the combined cycle process.[300]

Not only has EPA mischaracterized the under construction NGCC capacity for nine states, but the agency has not recognized other proposed NGCC projects that may fall into the under construction category. For example, a review of the spreadsheet tab marked "proposed" in the EIA860 report that has been referenced by EPA quickly identifies many potential NGCC projects that were simply ignored by EPA in building block two. Potential NGCC projects have been identified for over 20 states, which may meet the definition of "under construction" as currently defined in building block two.[301]

Further, in determining the CO_2 emissions associated with the redispatch of "under construction" capacity, EPA used either the average emission rate for existing NGCC units in the state, or a national average if the state did not have any existing units.[302] Based on the significant flaws in how the state average NGCC emission rates were calculated, EPA's approach for determining the future emissions from under construction units is inaccurate and inequitable. To highlight these differences, consider the emission rates that were assumed for the NGCC facilities that EPA alleges are "under construction," even though most of these examples are not actual projects.

[299] *See* www.eia.gov/electricity/data/eia860/ and www.deq.state.va.us
[300] www.blackhillscorp.com/cpgs
[301] EIA-860 Report. www.eia.gov/electricity/data/eia860/
[302] "Goal Computation Technical Support Document." June 2014. EPA. p. 13.

State Identified by EPA as having "under construction" NGCC Capacity	Baseline State NGCC CO_2 Emission Rate Used to Calculate Future Emissions from "Under Construction" NGCC units[303]
California	867
Colorado	928
Florida	864
Kentucky	907
Mississippi	848
North Carolina	851
Ohio	963
Virginia	903
Wyoming	907

EPA must correct these errors in both the scope of "under construction" units considered and the assumptions for consistently estimating emissions from these units.

c. EPA fails to consider certain existing NGCC units that were commissioned during or after 2012

A number of NGCC projects were identified that could be considered existing 111(d) facilities, but were ignored by EPA in the building block two calculations. These are units that commenced construction after 2012, but before January 8, 2014 – the effective date that the 111(b) standards for new sources were re-proposed by EPA. Examples of such facilities include the following:

State	Plant	Summer Capacity (MW)[304]	Considered by EPA in building block 2?[305]	Commenced Construction Date
TX	Panda Sherman Power Station	717	no	Nov 2012[306]
TX	Panda Temple Power Station	717	no	Sep 2012[307]
TX	Thomas C Ferguson	510	no	Apr 2012[308]

303 "Goal Computation Technical Support Document." June 2014. EPA
304 "Proposed Units." EIA-860. 2012. www.eia.gov/electricity/data/eia860/
305 "Goal Computation Technical Support Document." EPA. June 2014.
306 www.pandafunds.com/broadcast/news-releases/sherman-groundbreaking/ &www.kten.com/story/25042685/construction-at-panda-sherman-power-nears-completion
307 www.bechtel.com/2012-09-06.html
308 www.turbomachinerymag.com/blog/content/san-marcos-partner-lcra-new-540-mw-ferguson-power-plant-project

d. EPA incorrectly accounts for NGCC units commissioned during 2012 in their calculation of potential redispatch amounts

EPA overstates the amount of redispatch available from NGCC units commissioned in 2012 because it does not weigh the commissioning date into its calculation. In other words, when calculating redispatch, EPA assumes that all of these units were available to operate throughout 2012 even though some of these units were not commissioned until later in the year. This faulty assumption means that these new units are calculated to have an artificially low capacity factor, which produces an artificially high amount of NGCC redispatch. The end result is a state emission rate goal that is biased low. For example, two of the five existing NGCC units in Ohio were commissioned in 2012.[309] The table below compares baseline capacity factors for these two facilities if calculated based on their in-service date versus EPA's assumption that they were available for the entire year.[310]

						EPA Method		
	In Service Date	2012 Net Gen (MWh)	Potential Operation Hours	Summer Net Capacity (MW)	Capacity Factor	Nameplate Capacity (MW)	Potential Operating Hours	Capacity Factor
Dresden	01/31/12	2,599,011	8,064	540	**60%**	678.3	8,784	**44%**[311]
Fremont	01/20/12	2,582,396	8,328	667.3	**46%**	739.5	8,784	**40%**

In the state goal calculation, EPA uses the following steps to determine the amount of NGCC capacity to be redispatched:

(1) Determine the total net generation from all existing NGCC units in 2012

(2) Calculate the "potential" NGCC capacity that could be redispatched if the entire NGCC fleet in the state operated at a 70% capacity factor as follows:
Potential Redispatch Capacity (MWh) = (existing NGCC capacity) * (8784 hours/yr) *70%
[Note EPA incorrectly uses nameplate capacity in this calculation]

(3) Calculate the amount of NGCC redispatch to be used in building block 2 as follows:
State NGCC redispatch (MWh) = "Potential" NGCC capacity at 70% - 2012 NGCC net generation

[309] Dresden was commissioned 01/31/12 per Appalachian Power Company filing to the VaSCC on 03/20.12; Fremont was commissioned on 01/20/12 per AMP, Inc. filing to the Ohio Power Siting Board on 02/23/12.
[310] Net Generation data per 2012 EIA-923 report. Summer and Nameplate Capacity per 2012 EIA-860 report.
[311] 44% is based on the correct 2012 net generation value for Dresden. As discussed in the comments that follow EPA used an incorrect net generation value for Dresden, which would have indicated an 8% capacity factor for the facility using EPA's methodology.

Thus, the amount of redispatch that EPA computed for certain states is inflated by the inclusion of the capacity that units did not generate (and were not available to generate) prior to being commissioned in 2012. If units commissioned during 2012 remain in the calculation of the "existing" category of units, then the potential redispatch for the existing NGCC fleet should be derived based on the historic capacity factor, *not* on the EPA approach of using historic generation. Using the historic capacity factor approach accounts for the fact that units were commissioned in 2012 and appropriately weighs the in-service date into the redispatch calculation. This calculation would involve the following:

(1) Determine the total net generation from all existing NGCC units in 2012

(2) Calculate the potential operating hours for each existing NGCC unit in 2012 based on the date that each unit was commissioned
Potential operating hours for units in-service prior to 2012 = 8,784 hours
Potential operating hours for units commissioned in 2012 = 8,784 hours – (time prior commissioning)

(3) Calculate the maximum potential 2012 NGCC generation for each existing unit:
Maximum potential generation = potential operating hours (from step 2) * net summer capacity

(4) Determine the weighted potential net generation from existing NGCC units in 2012

(5) Calculate the weighted 2012 capacity factor for the state NGCC fleet
2012 NGCC capacity factor = 2012 net generation (step 1) / 2012 total potential generation (step 4)

(6) Determine the amount of redispatch as a % capacity factor:
Amount of redispatch (% capacity factor) = 70% capacity factor – 2012 NGCC capacity factor (step 5)

(7) Determine the amount of redispatch in MWh:
Amount of redispatch (MWh) = redispatch capacity factor (step 6) * net summer capacity * 8784 hrs.

Using this approach for the Dresden and Fremont Plant, along with the correction of other errors noted throughout the comments would reduce the amount of NGCC redispatch calculated for Ohio from 5,793,981 to 439,452 MWh – a 92% reduction from EPA's calculated amount.[312] Consider another example, the H.F. Lee Plant, which is a 920 MW NGCC unit commissioned on December 31, 2012. The unit was available to operate *for only one day in 2012*, yet EPA's calculation assumes that the unit was available for the entire year. EPA used the nominal nameplate capacity (1,068 MW) to determine that approximately 6,548,976 MWh (equivalent of a 70% capacity factor) was available to be redispatched from this facility because it would have had a near 0% baseline capacity factor in 2012 by EPA's logic.[313] These

[312] A summary of the revised Ohio calculations is provided in Appendix B.
[313] Estimate Redispatch = 6,548,976 MWh = 1,068 MW (nameplate capacity from EIA860) * (8784 hours/yr – 24 potentially in-service) *70%

6,548,976 MWhs represent over 20% of the total redispatch calculated for the state of North Carolina – even though the H.F. Lee plant had not been commissioned until the last day of the year![314] The North Carolina goal is made even more unrealistic by the commissioning of another NGCC unit at the Dan River plant on December 10, 2012. If the associated "redispatch" capacity from Dan River is considered as well, then nearly 40% of the redispatch capacity calculated for North Carolina was from units that had not been commissioned or available to operate for most of the year. Other examples of this issue are as follows:

State	Plant	In-Service Date	Potential Operating Hours (based on in-service date)	EPA Calculated Potential Operating Hours	% Difference In-Service vs. EPA Operating Hours
OH	Fremont[315]	01/20/12	8,328	8,784	-5%
OH	Dresden[316]	01/31/12	8,064	8,784	-8%
GA	Jack McDonough[317]	04/26/12	6,000	8,784	-32%
TN	John Sevier[318]	04/30/12	5,904	8,784	-33%
MS	Moselle[319]	~05/01/12	5,928	8,784	-33%
ID	Langley Gulch[320]	06/29/12	4,464	8,784	-49%
SD	Deer Creek[321]	08/01/12	3,672	8,784	-58%
CA	El Centro[322]	10/05/12	2,112	8,784	-76%
CA	Tracy[323]	11/01/12	1,464	8,784	-83%
CA	Lodi[324]	11/01/12	1,464	8,784	-83%
MS	Moselle[325]	~11/01/12	1,464	8,784	-83%
NC	Dan River[326]	12/10/12	504	8,784	-94%
NC	H.F. Lee[327]	12/31/12	24	8,784	-99.7%

[314] EPA Calculated 31,918,596 MWh of NGCC redispatch. "Goal Computation Technical Support Document – Appendix 1." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602. (6,548,976 MWh H.F. Lee / 31,918,596 MWh North Caroline = 20.5%)
[315] Fremont was commissioned on 01/20/12 per AMP, Inc. filing to the Ohio Power Siting Board on 02/23/12.
[316] Dresden was commissioned 01/31/12 per Appalachian Power Company filing to the VaSCC on 03/20.12.
[317] www.prnewswire.com/news-releases/georgia-power-completes-plant-mcdonough-atkinson-conversion-to-natural-gas-176265521.html
[318] www.tva.com/sites/johnsevier_cc.htm
[319] www.hattiesburgamerican.com/story/news/local/2014/05/22/officials-give-media-tour-plant-moselle/9456577/
[320] www.transmissionhub.com/articles/2012/07/idaho-power-brings-online-300-mw-langley-gulch-gas-plant.html
[321] https://puc.sd.gov/Dockets/Electric/2009/el09-015.aspx
[322] www.energy.ca.gov/sitingcases/all_projects.html
[323] www.energy.ca.gov/sitingcases/tracyexpansion/
[324] www.energy.ca.gov/sitingcases/lodi/
[325] www.hattiesburgamerican.com/story/news/local/2014/05/22/officials-give-media-tour-plant-moselle/9456577/
[326] www.bizjournals.com/triad/prnewswire/press_releases/North_Carolina/2013/01/03/CL36348
[327] Id.

EPA's proposed 111(b) rule for new units included a technical support document for combustion turbines that was designed to evaluate potential differences in emission rates due to various unit-specific factors. The evaluation focused on NGCC units that were commissioned from 2000 through 2010. With respect to new NGCC units that were commissioned after 2010, EPA noted that:

> Although new NGCC units came online in 2011, none are included here as *they lacked sufficient data* to calculate a 12-month rolling average, *the basis for determining a standard of performance.*[328]

EPA should apply this same rationale and exclude units commissioned in 2012 from the calculation of existing NGCC units to be redispatched. These units could then be separately included in the "under construction" category of units within building block two calculation. At a minimum, EPA must at least revise the state goal calculations to properly account for the date that new units were commissioned in 2012.

4. EPA must resolve significant data quality issues

A number of data quality issues have been identified in the building block two calculations related to the reported CO_2 emissions and net generation reported for various units. One of the most significant data quality errors pertains to the 2012 net generation data that EPA considered for the AEP Dresden NGCC unit in Ohio. EPA relied upon the 2012 EIA-923 report for generation data, which incorrectly reported the generation for the Dresden NGCC unit as 470,486 MWh, instead of the 2,599,011 MWh the unit actually generated. In reviewing the error, it was determined that AEP had correctly reported the generation to the EIA, however a publication error by EIA led to the 923 report only reporting generation data for November and December of 2012. AEP notified EIA of this publication error on August 21, 2014. At the request of EIA, AEP resubmitted the 2012 generation data for the Dresden plant on August 27, 2014. Subsequently, AEP followed up with EIA on September 3, October 16, and most recently on November 19, 2014, regarding the status of revising and republishing the 2012 EIA-923 report with the corrected information. EIA's most recent response on November 20, 2014 indicates that the agency is targeting "mid-January" of 2015 for the revision.

[328] Combustion Turbine Standard TSD. EPA. 2014. Docket #: EPA-HQ-OAR-2013-0495-0082. p.2.

Another data quality concern pertains to EPA's confusion regarding the configuration and operation the AEP Arsenal Hill and J. Lamar Stall ("Stall") generation units in Louisiana. The Arsenal Hill plant is a natural gas steam boiler unit that was commissioned in 1960. The Stall plant is a natural gas combined cycle unit commissioned in 2010 that consists of two combustion turbine and heat recovery steam generator trains that supply steam to a common steam turbine. The Stall plan is co-located at the Arsenal Hill facility. Both units are covered under the same Title V operating permit, which identifies the Arsenal Hill unit as 5A and the two Stall combustion turbine units as 6A and 6B.[329] The Clean Air Markets Division database identifies CO_2 emissions from the units using a common Arsenal Hill facility name (e.g. Arsenal Hill 5A, Arsenal Hill 6A, and Arsenal Hill 6B). This nomenclature led to emissions from the facility being incorrectly considered in the Louisiana state goal calculations. A summary of the error and the correct values are provided in the table below.

Data Source:	EPA eGRID Database	AEP	EPA eGRID Database	EPA CAMD	Calculation eGRID-CAMD
	Plant / Unit	Unit Type	2012 CO2 (tons)	2012 CO2 (tons)	Difference
	Arsenal Hill 5	Gas Steam Boiler	1,484,758.0	38,301	1,446,457
	J. Lamar Stall 6A	NGCC (Comb Turbine)	431,511.0	759,793	
	J. Lamar Stall 6B	NGCC (Comb Turbine)	431,511.0	686,664	
	J. Lamar Stall 6STG	NGCC (Steam Turbine)	600,363.1	none (not applicable)	
		Stall Total =	1,463,385.1	1,446,457.0	16,928.1

Accordingly, CO_2 emission data used by EPA to calculate the proposed Louisiana state goal should be updated to accurately reflect the emissions associated with the Arsenal Hill and Stall units.[330] Specifically (if EPA continues to use the building block approach and 2012 data), the CO_2 emissions data for Arsenal Hill should be revised to 38,301 tons (from 1,484,758 tons). For the J. Lamar Stall facility, the CO_2 emission data should be revised to 1,446,457 tons (from 1,462,385.1 tons).

A summary of other data discrepancies identified is detailed in Appendix B. EPA must correct these issues and perform a thorough quality assurance check of all the data inputs and calculations used to calculated the state goals.

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[329] Title V Permit #0500-00008-V2. Louisiana Department of Environmental Quality. June 7, 2010.
[330] EPA should correct CO_2 data listed in Appendix 7 of the Goal Computation Technical Support Document.

5. Building block two calculations are incorrect for all states identified by EPA as having applicable NGCC units

The data quality issues and methodological errors detailed above are not limited in scope, but are present in the building block two calculations for every state with NGCC capacity. The impact of these concerns is significant. For example, correcting these errors was determined to reduce the amount of NGCC redispatch that EPA calculated by 51% in Louisiana and 92% in Ohio.[331] While not a complete analysis, the matrix that follows at the end of this section highlights the scope of building block two calculation issues, alone, that have been identified for each state with NGCC capacity.

6. EPA must revise all aspects of the proposed rule that are impacted by the data quality and methodological issues identified for building block 2

Any attempt to correct the litany of concerns or determine how these corrections impact state goal calculations, "flexible" compliance strategies, reliability evaluations, and cost-benefit analyses is too complex to complete within the public comment period. Given the egregious nature and scope of concerns to be resolved in building block 2 alone, EPA must withdraw the current proposal, address these issues, and publish a new proposed rule for public comment.

I. Building Block 2 Comments related to EPA's NODA

1. Phased Implementation of Building Block 2

EPA requested comment on whether or not the building block 2 should be phased-in to prevent the possibility of early unit retirements and related potential reliability issues. Aside from the legal, technical, and practical concerns with building block 2, a phased-in approach would offer additional flexibility for states to attempt to address these concerns in developing an state plan within the aggressive implementation schedule proposed by EPA.

2. Consideration of Minimal NGCC Utilization in the BSER

EPA requested comment whether the BSER determination should include a minimum utilization of natural gas in all states and assumes that states that are below that minimum utilization would either build new NGCC to facilitate additional redispatch or would co-fire gas at existing coal-fired boilers. Such an approach would be arbitrary and infringe on state energy planning and regulation authority. It also disregards the remaining useful life of the coal units

[331] The revised redispatch calculations for Ohio and Louisiana are detailed in Appendix B.

located in those states. Therefore, the BSER determination should not include a minimum natural gas utilization assumption.

With respect to natural gas co-firing, EPA initially dismissed it from the BSER on the basis of cost by noting that "that other approaches could reduce CO_2 emissions from existing EGUs at lower cost."[332] EPA's estimated costs of avoided CO_2 from co-firing are "approximately $83 to $150 per metric ton," which is significantly more than other options analyzed within the BSER building block determination and subsequent IPM analysis.[333] The agency also notes that significant lateral pipeline expansion could be required to supply gas to co-firing facilities. These costs can be extremely significant for units that are located some distance from pipelines or pipelines with excess capacity. Furthermore, the ease and capital cost associated natural gas co-firing is highly dependent on a multitude of unit-specific technical factors. As such, EPA cannot make broad generalizations of co-firing costs or achievability and therefore cannot include co-firing as part of a BSER determination

3. Regional Approach to Building Block 2

EPA requested comment on whether NGCC redispatch should be viewed from a regional perspective. While the electric sector operates in a regional context and a regional view is important in assessing impacts of this proposed rule, it is unclear how a state could be apportioned an emission reduction requirement based on the utilization of out-of-state resources. Also, drawing this regional distinction would be difficult to accomplish without robust analysis of the supporting infrastructure that would make such dispatch feasible. As previously noted, even at the state level, significant constraints exist to NGCC redispatch. A regional approach could exacerbate these limitations. While such an approach could help to levelize the required emission reductions by removing artificial state boundaries in the redispatch determination, any regional determination would be also arbitrary, given the number of factors that influence feasibility. As such, a regional approach to redispatch is not warranted under this proposal.

[332] 79 Fed. Reg. 34857 (June 18, 2014)
[333] Id.

Summary of Methodology & Data Quality Issues (observations to date only, not a comprehensive review)

	Incorrect Use of Nameplate Capacity	"Existing NGCC" includes units that are not NGCC units or affected sources	Incorrect Consideration of NGCC units commissioned after 2011	Incorrect Consideration of Cogeneration units	Data Quality issues identified or air permit limits that affect redispatch
Alabama	Yes			n/a	
Alaska	Yes	Yes	Yes	n/a	
Arizona	Yes			Yes	
Arkansas	Yes			Yes	
California	Yes	Yes	Yes	Yes	
Colorado	Yes		Yes	Yes	Yes
Connecticut	Yes			Yes	Yes
Delaware	Yes			n/a	
Florida	Yes	Yes	Yes	Yes	Yes
Georgia	Yes		Yes	Yes	Yes
Idaho	Yes		Yes	n/a	Yes
Illinois	Yes			Yes	
Indiana	Yes	Yes		Yes	
Iowa	Yes			n/a	Yes
Kentucky	Yes	n/a	Yes	n/a	n/a
Louisiana	Yes	Yes	Yes	Yes	Yes
Maine	Yes			n/a	
Maryland	Yes			n/a	
Massachusetts	Yes			Yes	Yes
Michigan	Yes			Yes	Yes
Minnesota	Yes			Yes	Yes
Mississippi	Yes		Yes	n/a	
Missouri	Yes			n/a	
Nebraska	Yes			n/a	
Nevada	Yes			Yes	
New Hampshire	Yes			n/a	
New Jersey	Yes			Yes	
New Mexico	Yes			n/a	
New York	Yes			Yes	Yes
North Carolina	Yes		Yes	n/a	Yes
Ohio	Yes		Yes	n/a	Yes
Oklahoma	Yes			Yes	
Oregon	Yes			Yes	
Pennsylvania	Yes			Yes	
Rhode Island	Yes			n/a	Yes
South Carolina	Yes			Yes	
South Dakota	Yes		Yes	n/a	
Tennessee	Yes		Yes	n/a	
Texas	Yes		Yes	Yes	
Utah	Yes	Yes	Yes	n/a	
Virginia	Yes		Yes	Yes	Yes
Washington	Yes			Yes	
Wisconsin	Yes			Yes	Yes
Wyoming	Yes	n/a	Yes	n/a	n/a

VII. Building Block 3 is unachievable

The inclusion of renewable energy in the determination of the best system of emission reductions is fundamentally flawed due to a number of legal, technical, economic, and practical issues. These concerns are related to EPA having:

- overstated its regulatory authority and interpretation of applicable requirements;
- mischaracterized and misapplied state renewable portfolio standards and experience;
- insufficiently evaluated the technical potential and cost of renewable options;
- failed to fully evaluate or provide sufficient guidance on interstate considerations;
- used arbitrary assumptions to develop renewable energy regions and state goals; and
- ignored development challenges related to the expansion of both intra- and interstate transmission resources, regulatory processes, cost allocation, and timing.

A. Renewable resources must be excluded from the determination of the best system of emission reductions for existing fossil fuel electric generating units

1. Renewable resources are not affected sources under 111(b) and therefore cannot be regulated under 111(d)

As detailed extensively above, EPA's authority is constrained by the clear language of section 111 to establishing guidelines that will assist the states in developing performance standards for "designated facilities" that would be subject to a federal standard "if they were new."[334] EPA's January 2014 proposal applies to EGUs that are currently regulated under Subparts Da and KKKK of 40 CFR Part 60, with certain slight modifications. Nothing in the CAA gives EPA the authority to reach outside the listed source category and base its determination of the BSER on the continued operation and future expansion of facilities that not only are outside the listed source category, but that emit no pollutants at all, and therefore are not regulated under the CAA. EPA's recent discovery of this broad-ranging regulatory authority in the word "system" is the kind of legislative interpretation that the Supreme Court has affirmed will be greeted with skepticism, because it would bring about an "enormous and transformative expansion of EPA's regulatory authority without clear Congressional authorization."[335] EPA must eliminate building block 3 from its proposal.

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[334] 42 U.S.C. §7411(d).
[335] *UARG v. EPA*, 134 S.Ct. at 2444.

2. EPA has infringed upon States Tenth Amendment Rights

Not only does the CAA itself constrain EPA's authority and preclude the inclusion of renewable energy resources in a section 111(d) standard, but the expansion of EPA's regulatory authority in this way directly infringes upon powers reserved to the states, contrary to the Tenth Amendment to the U.S. Constitution. Few industries are as heavily regulated as the utility industry, precisely because of the importance of adequate and affordable supplies of electricity to the national economy. But the balance between federal and state authority was drawn long ago, and is codified in the Federal Power Act. While there is a sufficient national interest to justify federal regulation of interstate sales of electricity and the operation of the bulk electric system, states are granted the authority to regulate the generation of electricity, including determining the type, size, location and design of individual generating resources.[336] As outlined in UARG's comments, the FPA's long history of implementation, since its enactment in 1935, has maintained this clear distinction between state and federal authority.[337]

Moreover, the CAA itself directly addresses the interrelationship between EPA and other federal agencies, and EPA and the states. Section 310 of the CAA states that the CAA "shall not be construed as superseding or limiting the authorities and responsibilities, under any other provision of law, of . . . any other Federal officer, department, or agency."[338] Congress also expressly recognized that "air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments...[339] Sections 110 and 111 reflect that assignment of primary responsibility to the states, and EPA cannot reinterpret words that have long been understood to require control of pollution at the source to authorize broader control over the entire scope of energy production and use.

Federal courts have repeatedly rejected attempts by EPA to compel states to enact or administer a federal program without express Congressional authorization. Yet here, on the basis of a dictionary definition that strains the meaning of "system" beyond any reasonable bounds, EPA asserts the authority to usurp state legislative authority and mandate measures that

[336] 16 U.S.C. §824(a) and (b).
[337] *See also Fed. Power Comm. v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964) (Congress meant to draw a bright line easily ascertained, between federal and state jurisdiction . . .).
[338] 42 U.S.C.§7610(a).
[339] 42 U.S.C. §7401(a)(3).

reach far beyond the regulated source category, into the exclusive province of state energy policy decisions, by creating a system where without the inclusion of zero-emitting generation in its compliance calculus, a state has no hope of developing a plan that actually complies with the goals established by EPA.

In *Maryland v. EPA*, the Fourth Circuit rejected EPA's attempt to require the state to enact a specific transportation control plan, stating that, "if there is any attribute of sovereignty left to the states it is the right of their legislatures to pass, or not to pass, laws."[340] Congress itself has tried and failed to enact federal renewable portfolio standards on numerous occasions.[341] EPA's authority under Section 111(d) simply is not capacious enough to support a system of state goals that would, in effect, require the state to legislate such standards in order to successfully implement EPA's guidelines.

B. EPA's use of existing renewable portfolio standards to determine state renewable energy targets is fundamentally flawed

EPA developed building block 3 goals based on an arbitrary assignment of states into regions that presume that neighboring states will have similar opportunities for the development of renewable resources. The agency then used an average of mandatory state renewable portfolio goals in these regions to assume that what may be technically and economically achievable in terms of renewable development and generation in some states will be achievable by all states within each respective region. This approach is flawed in that EPA:

- mischaracterized the design and overstated the stringency of existing state RPS;
- incorrectly assumed that existing RPS represent achievable targets for renewable resource development in other states;
- ignored the renewable energy experience and perspectives of states with no RPS;
- did not fully consider significant geographic and economic differences between states in a region; and
- relied upon "effective" 2020 renewable energy targets that have not been adequately demonstrated and may not be representative of specific RPS requirements.

[340] 530 F.2d at 225. *See also, Brown v. EPA*, 521 F.2d 827 (9th Cir. 1975); *District of Columbia v. Train*, 521 F.2d 971(D.C. Cir. 1975).

[341] *See, e.g.*, S. 1567 (10th Congress, 2007); S. 741 (112th Congress, 2011); H.R. 983 (109th Congress 2005); H.R. 5756 (107th Congress, 2002) ; each of these bills would have amended the Public Utility Regulatory Policy Act and provided for a renewable portfolio standard to be administered by the Secretary of Energy.

1. EPA has mischaracterized and overstated the renewable energy development associated with existing renewable portfolio standards

Based on a review of the mandatory RPS that EPA considered, it is readily apparent that the design of state programs varies significantly and represents an assortment of different provisions. The individual and cumulative impact of these unique provisions reduces the "effective" amount of renewable resources that EPA can reasonably rely on as equivalent to its renewable energy goals. EPA ignored these factors in the proposed rule, but must fully consider and correct for the impact of these nuances if building block 3 remains a component of the final guidelines. Below is summary of the factors that impact the stringency of state renewable energy goals:

Hydroelectric Generation

Most state RPS include existing and/or new hydroelectric generating units as eligible resources for demonstrating compliance.[342] The contribution of existing hydroelectric units is included in the "effective" 2020 RPS rates that EPA used to calculate the renewable energy goals for each region. However, in using these regional targets to develop regional growth rates and individual state renewable goals in building block three, EPA relies on baseline renewable generation from 2012 that excludes hydroelectric generation:

> For the purpose of calculating a baseline level of RE generation in each state, the EPA adopted a broad interpretation of RE generation to include any non-fossil renewable type, with the exception of generation from existing hydroelectric power facilities.[343]

In other words, state RPS targets designed to *include* existing hydro units are unfairly used to establish regional renewable energy goals in building block 3 that *exclude* existing hydro generation units.

Biomass Generation

As with hydroelectric generation, many state RPS are designed to include the contributions from biomass resources. EPA uses the contribution of biomass resources to determine the baseline renewable generation for each state that is then used to develop the building block 3 goals. However, EPA had not made a determination of whether states would be able consider biomass

[342] Database of State Incentives for Renewables & Efficiency. U.S. DOE. www.dsireusa.org/rpsdata/RPSspread042213.xlsx
[343] "GHG Abatement Measures TSD." EPA. June 2014. p.4-5. (emphasis added)

for compliance purposes at the time of its proposal. On November 19, 2014, EPA released its second draft of the *Framework for Assessing Biogenic Carbon Dioxide Emissions from Stationary Sources,* [344] and anticipates seeking further review of the *Framework* through the Science Advisory Board and public comment.[345] However, EPA must be consistent in accounting for biomass emissions, both in its state goal calculations and in its regulations for compliance demonstrations, by either adjusting the "effective" 2020 RPS rate to exclude biomass, or to definitively affirm that states can rely on biomass as a carbon neutral resource in developing implementation plans. The revised *Framework* does not provide definitive answers on these issues, only proposed calculations that require detailed inputs in order to determine whether, and to what extent, biogenic energy sources may be relied on to reduce CO_2 emission rates or mass emissions in the context of the proposed CPP. At present, all EPA has committed to do is to second-guess state plan submittals based on criteria that it has not clearly defined.

<u>Unique Eligible Resources</u>

Some RPS apply to renewable resources that are unique in that state, and which may have limited or no applicability to other states in the regions defined by EPA in building block 3. Including the potential contribution from these uniquely defined and limited resources in the calculation of the renewable energy average for the regions creates an unrealistic expectation that other states without such resources can achieve a comparable level of renewable development. Some of these uniquely eligible resources contained in existing RPS include:

- ocean tidal and ocean thermal resources (i.e. Delaware)
- offshore wind energy (i.e. Maryland)
- energy efficiency (i.e. North Caronia, where up to 40% of RPS can met with EE)
- energy recovery from swine and poultry waste (i.e. North Carolina, ~10% of RPS must be met from these resources)
- coal mine methane (i.e. Pennsylvania)
- "clean coal" (i.e. Ohio)
- municipal solid waste (i.e. Michigan)
- "advanced nuclear" (i.e. Ohio)

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[344] Revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources,* Second Draft, November 2014.
[345] Memorandum from Janet G. McCabe, Acting Administrator, Office of Air and Radiation to Air Directors, Regions 1-10, *Addressing Biogenic Carbon Dioxide Emissions form Stationary Sources* (November 19, 2014).

- “densified fuel pellets” (i.e. Wisconsin)
- pyrolysis of municipal solid waste (i.e. Colorado)
- solar light pipes (i.e. Wisconsin)
- compressed air, fly wheel, and battery storage (i.e. Montana)
- solar pool heating (i.e. Nevada)

Credit Multipliers

Credit multipliers are designed to incentivize specific technologies or programs to be developed. For instance, if a specific renewable resource is constructed within a state, then each MWh produced by that resource would be counted as 2 MWh. As a result of the multiplier, the actual state RPS targets are less stringent that the absolute percentage target would indicate. A variety of such provisions were identified in the review of existing RPS programs, including renewable resources that are:

- located within state boundaries;
- using equipment manufactured within the state;
- constructed by state residents or by an “approved apprenticeship program;”
- constructed by a specific date;
- using specific technologies;
- operated during peak demand periods; or
- qualified as “community-based” projects.

Out-of-State Renewable Energy Credits

Most state RPS accept out-of-state renewable energy credits (“RECs”) as part of the compliance demonstration program. For instance, the state of North Carolina allows for up to 25% of its RPS requirements to be met by out-of-state resources, while Ohio now allows up to 100% of the renewable energy used to satisfy its requirements to come from outside the state. EPA acknowledges the dependence state RPS compliance on out-of-state resources by noting that:

> [EPA’s] approach applies the...growth factors and regional RE targets to state-level generation, where as the state-level RPS requirement upon which they are based are not necessarily applied in practice to generation that is produced within the relevant state.[346]

[346] “GHG Abatement Measures TSD.” EPA. June 2014. p.4-19.

Alternative Compliance Payment (“ACP”) programs

Many existing state RPS contain provisions that establish alternative compliance payment programs if the regulated entity is unable to secure or develop the renewable resources required by the program. These programs were created largely to protect consumers if renewable energy supplies become uneconomic or unavailable. Such ACP programs are designed so that entities pay a $/MWh amount for any shortfall of renewable energy obligations. The use of ACP programs to demonstrate compliance is indicative of the difficulty that some states envisioned for meeting RPS even with the subsidies provided in the form of federal production tax credits (“PTC”) and investment tax credits (“ITC”). EPA should adjust state targets where ACP has historically or can reasonably be predicted to reduce the amount of renewable energy that is actually deployed under the RPS in the future.

Cost Mitigation Measures

Several state RPS programs contain cost mitigation measures whereby the state has established caps on the impact to retail rates associated with the cost of renewable resources. For instance, if retail rates increase by a certain amount (i.e. 1 or 2%), then the RPS is effectively lowered for that compliance year to avoid excessive consumer cost impacts. Absent additional governmental subsidies which expired at the end of 2013 (PTC) and will expire at the end of 2016 (ITC), it is more likely that these existing RPS caps will be triggered as additional resources are added to achieve future RPS requirements. EPA should not include renewable goals for any state that can reasonably be predicted to exceed the retain rate caps already in effect in those states.

Reliability Mitigation Measures

Some states have included exit ramps from RPS to address potential reliability concerns regarding the impacts of increased capacity from intermittent resources. EPA should consider including such a provision to allow state to issue variances if reliability impacts would otherwise occur.

Retail Sales vs. Capacity Based Standards

The targets for most state RPS are based on the percentage of retail sales in the state. However, some RPS programs, such as in Kansas, are designed as a generating capacity-based standard. EPA failed to account for these differences in the design of state standards in terms of the percentage reduction targets for individual states. Although EPA recognized these differences, it incorrectly noted that it "did not include targets that were capacity-based" in the building block 3 calculation of regional goals. In fact, the Kansas RPS was the sole basis for developing the goal for the South Central region.[347]

RPS based on State Sales vs. Block 3 Goal base on Total Generation

Nearly all the state RPS programs are designed around targets related to a percentage of state retail sales. EPA calculated regional renewable energy goals based on these retail sales-based RPS, but then applied that calculated rate to 2012 total generation, not retail sales, for that state. This creates an "apples and oranges" comparison that may translate into unrealistic expectations for what a specific region or state may or may not be able to achieve. In particular for energy-exporting states, retail sales may be a better estimation of in-state usage, while wholesale sales often represent energy exports. As such, the state is unable to influence customer behavior, or require addition of renewable resources to meet customer demand for the portion of generation that is exported to other states. EPA should examine this "disconnect" between the state-established RPS standards and its proposed imposition of a goal based on a wholly different base. This kind of adjustment would also allow EPA to take into account in setting goals the ownership of generating facilities by multi-state utilities, or by multiple partners, some of whom may be located in adjacent states.

State RPS Implementation Schedules

The implementation schedule for state RPS programs is generally less aggressive than the proposed schedule for implementing the Clean Power Plan. States structured their programs in this fashion in part to allow for a more gradual, cost-effective, and practically achievable ramp rate for increasing renewable resources. Based on the review of the RPS considered by EPA, the implementation period was commonly 15 to 18 years for most states, but up to 20 years in Montana, versus the 10-12 year period envisioned by EPA, depending on the approval date for state plans. Additionally, EPA has assumed that states would ramp up renewable generation in advance of final state plans being approved, but has not clarified if and how such activities would receive credit under the final guidelines. While EPA has requested comment on how

[347] Id. p.4-10.

early actions could be taken into account in determining compliance, its proposal appears to give credit only for renewable generation that is provided to the grid in a specific year, and does not allow for flexible systems like banking renewable credits for use in future years.

<u>Revisions State RPS</u>

Most existing RPS have been revised several times in order revise expected targets, alter the design of the program or extend the compliance schedule based a number of factors, including more realistic expectations on the cost-effective development of new resources. In some instances such as Ohio, the state has reduced the stringency of the RPS and increased compliance flexibility. In 2014, Ohio did both by freezing the ramp-up schedule of its RPS program and by expanding the program to allow of out-of-state resources to be used to fully meet the Ohio RPS, if necessary.

If renewable energy programs remain a part of the final guidelines, EPA must recognize the need for flexibility as an approved part of state plans, and allow for mid-course revisions, banking of excess credits, and other mechanisms that already exist as part of many of the standards EPA used as the basis for its proposal. In the absence of such mechanisms, there is no basis for EPA's assertion that these programs represent a level of performance that has been "adequately demonstrated" as required by the CAA. As shown below, 23 of the 27 programs examined by EPA have been revised, 19 of them multiple times, over the course of their implementation. Below is a summary of revisions made to the RPS considered by EPA:[348]

[348] "Renewables Portfolio Standards in the United States: A Status Update." Barbose. G. Lawrence Berkeley National Laboratory. Sept 22, 2014. www.cesa.org/projects/state-federal-rps-collaborative/rps-resource-library/resource/renewables-portfolio-standards-in-the-united-states-a-status-update-galen-barbose

State	Year RPS First Enacted	Number of Revisions Since RPS first Enacted	Most Recent RPS Revision
Delaware	2005	4	2011
D.C.	2005	2	2011
Maryland	2004	6	2013
New Jersey	1999	5	2012
Ohio	2008	2	2014
Pennsylvania	1998	2	2007
North Carolina	2007	1	2011
Kansas	2009	0	2009
Michigan	2008	0	2008
Minnesota	1994	6	2013
Missouri	2008	0	2008
Illinois	2007	4	2014
Wisconsin	1998	4	2014
Connecticut	1998	6	2013
Maine	1997	2	2009
Massachusetts	1997	5	2014
New Hampshire	2007	1	2012
New York	2004	2	2012
Rhode Island	2004	1	2009
Arizona	1991	2	2006
California	2002	2	2011
Colorado	2004	4	2013
Montana	2005	1	2013
Nevada	1997	5	2013
New Mexico	2000	5	2013
Oregon	2007	2	2014
Washington	2006	0	2006

2. EPA's methodology for calculating renewable energy goals is flawed

EPA's calculation of renewable energy goals in building block 3 is fundamentally flawed because it:

- excludes consideration of states without mandatory RPS programs;
- is premised on "effective" 2020 rates calculated by EPA that do not reflect the specific requirements within those existing RPS programs;
- relies upon renewable energy targets that have not been adequately demonstrated; and
- ignores individual state determinations in favor of regional renewable energy benchmarks that are arbitrarily assigned.

EPA calculated renewable energy goals for six agency-defined regions by averaging the "effective" 2020 targets of the existing mandatory RPS programs in that region. For states without mandatory RPS, the agency made no effort to investigate or defer to prior state determinations of the adequacy or cost-effectiveness of integrating renewable resources into their generation portfolios. Had EPA done so, there would have been no reason to deviate from the conclusions reached by these state legislatures and regulators, nor is there any reason to attempt to impose more stringent requirements in the establishing the BSER. Instead, EPA ignored the decision of those states without an RPS in the calculation of the regional average renewable energy goals because the agency did not deem them to be "*leading states*."[349] The agency failed to consider that perhaps these states have previously evaluated renewable energy opportunities and determined that they were not currently technically feasible or cost-effective. Instead, EPA's process forces states to conform to the policies developed by other states that are based on different considerations of feasibility, cost, and public interest.

Louisiana is an example of one state that has evaluated opportunities for renewable energy and determined not to implement an RPS program. In 2010, the Louisiana Public Service Commission approved a Renewable Energy Pilot Program for the state with the goal of determining whether an RPS is suitable for Louisiana. As part of the program, an AEP subsidiary, Southwest Electric Power Company ("SWEPCO"), conducted an all-source Renewable Request for Proposal. Bids were received for 46 proposed renewable energy projects. Only 14 were for projects to be located in Louisiana (one wind, five solar, three waste

[349] "GHG Abatement Measures TSD." EPA. June 2014. p.4-1.

heat recovery, four biomass, and one landfill gas project). The balance of bids came from other states within the same RTO, the Southwest Power Pool ("SPP") states. The most practical source of renewables that could be secured to serve SWEPCO customers was from a portion of a wind project being developed in Kansas. Interestingly, the single wind project that was proposed to be located in Louisiana was more than three times the cost of the selected wind energy bid from Kansas. None of this experience was considered by EPA in the proposed rule, and Louisiana's decision to not to establish an RPS based on the current lack of cost-effective and technically feasible renewable resources is ignored in the calculation of the South Central region goal.

Comments submitted by the Virginia State Corporation Commission ("SCC") further highlight the concern that state decisions to not establish RPS programs has been ignored by EPA in the building block three calculations. The SCC notes that:

> The fact that Virginia does not have a mandatory RPS requirement is not considered at all in EPA's calculations or the extrapolation of other States' RPS requirements on Virginia...
>
> Even if the legislative process of one state could establish a level of renewable generation that has been demonstrated in Virginia, that would not justify giving less weight – indeed, not weight at all – to Virginia's legislative determination to not impose RPS requirements. EPA's math is wrong.[350]

The EPA's use of "effective" 2020 RPS requirements reflects rates that are overstated due to the failure to consider RPS provisions that reduce the overall stringency of individual state requirements. In addition, the future effective 2020 RPS rates have not been "*adequately demonstrated*," which the Clean Air Act defines is a necessary prerequisite for determining the "best system of emission reduction."[351] In the design of most RPS, states acknowledged the challenges associated with increased development and utilization or renewable resources by including provisions that gradually increase implementation over two decades, that allow for alternative compliance plans in lieu of renewable resource development, and that reduce the stringency of standards in order to mitigate retail cost (cost caps) or transmission reliability impacts. EPA acknowledges that full compliance to date has been challenging with RPS that are much lower that the effective 2020 rates considered in building block 3 by stating that:

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[350] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. pp. 32-33. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767

[351] Clean Air Act Section 111(a)(1).

> ...recent improvements in RPS compliance rates indicate to the EPA the reasonableness of current RPS growth trajectories. Weighted average compliance rates among all states have improved in each of the past three reported years (2008 - 2011) from 92.1 percent to 95.2 percent despite a 40 percent increase in RPS obligations during this period.[352]

EPA further acknowledges that these less than 100% compliance rates include considerations that are not accommodated by EPA's proposal:

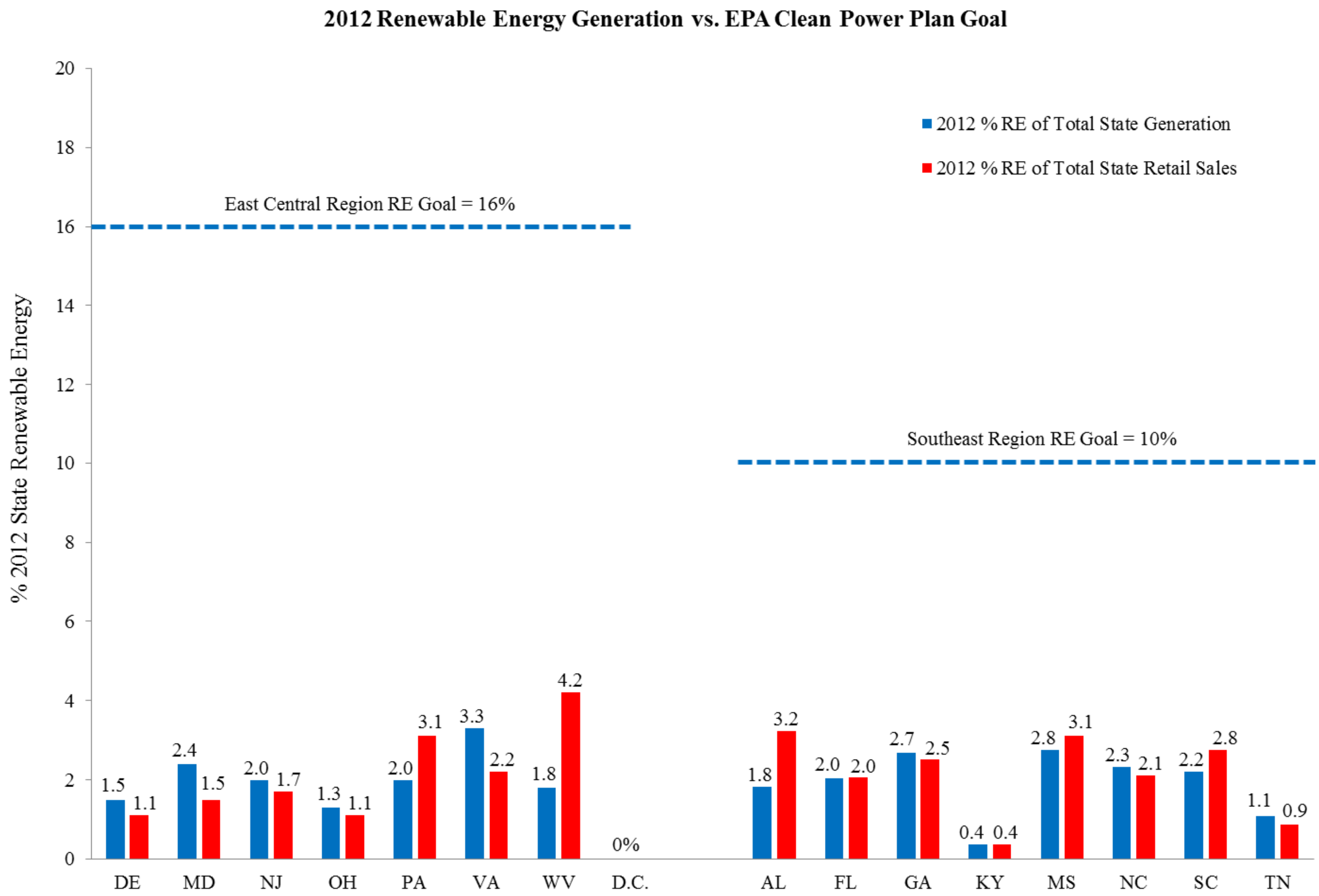
> The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.[353].

Regardless of how the percentage of historic renewable energy is calculated, the regional renewable goals developed by EPA have not been adequately demonstrated. For example, the agency calculated regional goals for the East Central and Southeast regions of 16% and 10%, respectively. However, the maximum renewable energy demonstrated in 2012 by individual states in those regions was 4.2% in the East Central Region and 3.2% in the Southeast Region – ironically, by states that *do not* have mandatory RPS programs. The table and graph below highlight this issue for both regions.[354]

[352] "GHG Abatement Measures TSD." EPA. June 2014. p.4-3.
[353] 79 Fed Reg. 34869
[354] Summary of calculations provided in Appendix C.

State	EPA Renewable Energy Region	2012 % RE of Total State Generation[355]	2012 % RE of Total State Retail Sales[356]	EPA Regional Renewable Energy Target
Delaware	East Central	1.5%	1.1%	16%
Maryland	East Central	2.4%	1.5%	16%
New Jersey	East Central	2.0%	1.7%	16%
Ohio	East Central	1.3%	1.1%	16%
Pennsylvania	East Central	2.0%	3.1%	16%
Virginia	East Central	3.3%	2.2%	16%
West Virginia	East Central	1.8%	4.2%	16%
D.C.	East Central	0.0%	0.0%	16%
Alabama	Southeast	1.8%	3.2%	10%
Florida	Southeast	2.0%	2.0%	10%
Georgia	Southeast	2.7%	2.5%	10%
Kentucky	Southeast	0.4%	0.4%	10%
Mississippi	Southeast	2.8%	3.1%	10%
North Carolina	Southeast	2.3%	2.1%	10%
South Carolina	Southeast	2.2%	2.8%	10%
Tennessee	Southeast	1.1%	0.9%	10%

[355] Calculated using 2012 Renewable Energy Generation divided by 2012 Total State Generation (both values per "GHG Abatement Measures TSD." EPA. June 2014. Table 4-1)
[356] Calculated using 2012 Renewable Energy Generation (per "GHG Abatement Measures TSD." EPA. June 2014. Table 4-1) divided by 2012 Total State Retail Sales (2012 EIA 861 Report).


2012 Renewable Energy Generation vs. EPA Clean Power Plan Goal
% 2012 State Renewable Energy
20
18
16
14
12
10
8
6
4
2
0
2012 % RE of Total State Generation
2012 % RE of Total State Retail Sales
East Central Region RE Goal = 16%
Southeast Region RE Goal = 10%
1.5
1.1
2.4
1.5
2.0
1.7
1.3
1.1
2.0
3.1
3.3
2.2
1.8
4.2
0%
1.8
3.2
2.0
2.0
2.7
2.5
0.4
0.4
2.8
3.1
2.3
2.1
2.2
2.8
1.1
0.9
DE
MD
NJ
OH
PA
VA
WV
D.C.
AL
FL
GA
KY
MS
NC
SC
TN

The Virginia State Corporation Commission also expressed concern that the regional renewable goals proposed by EPA had not been adequately demonstrated by noting that:

> Another fundamental problem with EPA's addition of future renewable generation into the calculation for Virginia's Mandatory Goals is that it does not establish what has been adequately demonstrated in Virginia, as required by the plain text of the Clean Air Act. For the eight States in the "East Central" region in which EPA places Virginia, EPA's data shows that the renewable generation in 2012 ranged between 1 to 3%, with Virginia at 3% for that year. This is the level of renewable generation that has been adequately demonstrated in Virginia. That other States have future legislative requirements – and no assurance that they will be met – does not change the reality in Virginia.[357]

The aforementioned concerns regarding the applicability of RPS programs from one state to another, as well as the methodology used to calculate state renewable energy goals are further exacerbated by EPA's arbitrary design of six regions in building block 3. In defining these regions, EPA incorrectly assumed that what may be achievable, but not yet demonstrated, in terms of renewable energy development and generation in some states (with the aid of subsidies from the Federal Production Tax Credit and from the investment of out-of-state utilities and customers) is achievable by all states within each respective region. EPA assumes that:

> States within each region exhibit similar profiles of RE potential or have similar levels of renewable resources[358]

However, EPA's rationale is not supported by the technical information referenced by the agency in the proposed rule or by the consideration of RPS in the regional calculations. Examples of conflict between EPA's characterization of individual state RPS and the technical data used to support EPA's proposal are provided below for the South Central, Southeast, and East Central renewable energy regions. In each region, an objective assessment of the existing state standards and technical data evaluating resource availability and cost would result in much lower targets than those established in EPA's guideline.

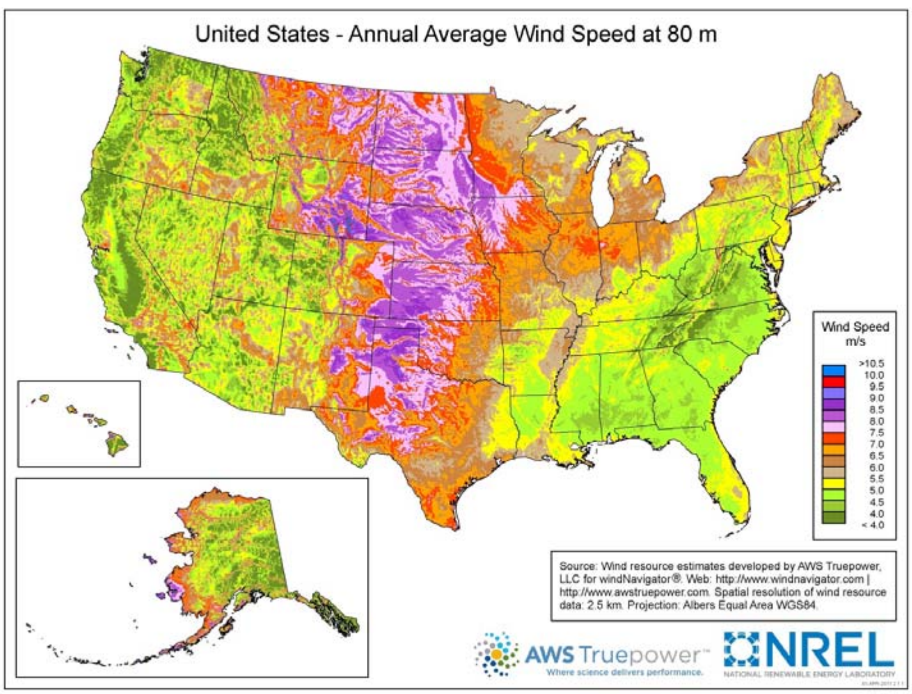
South Central Region

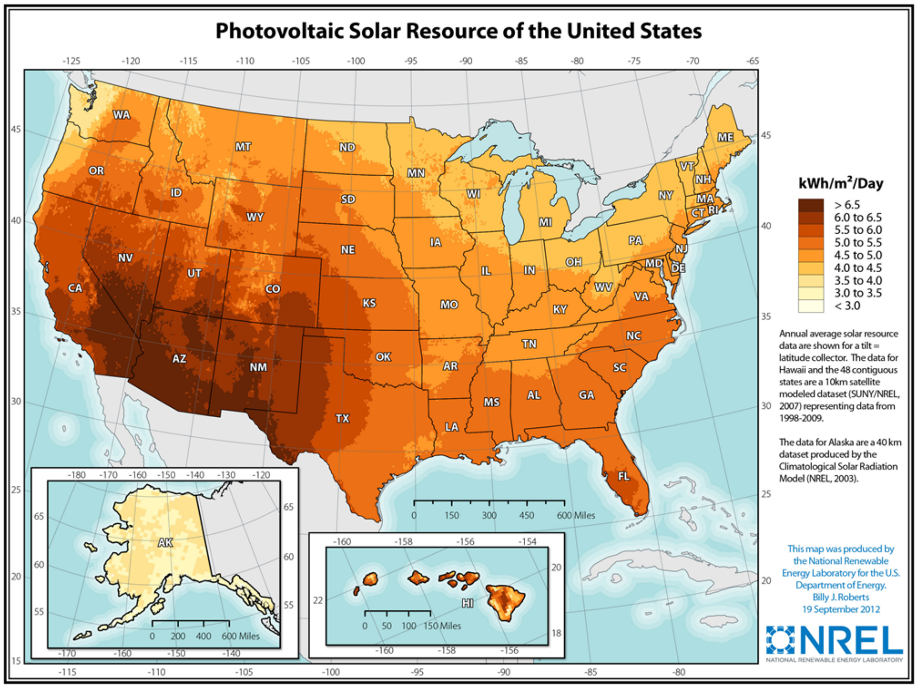
The South Central region is comprised of six states: Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, and Texas. The region is not homogenous in terms of potential renewable resources as four states have far superior resource potential, greater access, and lower cost

[357] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. p.33. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767
[358] "GHG Abatement Measures TSD." EPA. June 2014. p.4-12.

renewable development options. As a result, the remaining two states (Arkansas and Louisiana) are unfairly and inappropriately penalized and burdened with unrealistic goals that cannot be cost-effectively achieved through the development of in-state resources. To achieve their goals most cost-effectively, these states would have to rely on the development of out-of-state resources without certainty regarding if or how such projects would be treated by the host states.

In terms of differences in renewable resource potential, consider the average wind speed or solar resource across the region, a key variable in evaluating the feasibility of wind energy developments, and the availability of potential solar resources. The figures that follow from the U.S. Department of Energy National Renewable Energy Laboratory indicate that there is significant variability across the U.S. and within the South Central region, which indicates significant differences in the opportunities for developing wind energy and solar resources. Arkansas and Louisiana bear a far closer visual resemblance to the states in the Southeast region (Alabama, Florida, Georgia, Kentucky, Mississippi, Tennessee and the Carolinas) than they do to the states in the South Central region.





In addition, while EPA claims to have based its determination of "achievable" state goals based on average values for existing state programs, only one state in the EPA-defined South Central region, Kansas, has a mandatory RPS that was considered by EPA. Therefore, the Kansas RPS – and only the Kansas RPS – is the sole basis for determining the renewable energy goal for all states in the South Central region, regardless of differences in the geographic potential or cost-effectiveness for achieving such a goal among states in the region. EPA also gave no consideration to provisions within the Kansas RPS, such as implementation of cost mitigation measures and in-state renewable credit multipliers, that reduce the overall stringency of the program. As the Kansas Corporation Commission notes:

> Kansas' standard differs from other state's renewable portfolio standards in that it is based on gross generation capacity rather than total retail sales. In general, the gross generation capacity is the amount owned or leased by a utility minus the auxiliary power used to operate the facility.[359]

Based on EPA's own statement that it "*did not* [intend] *to include* [RPS] *targets that were capacity-based,*" the Kansas RPS *should not* have been considered in determining the renewable energy goal for the region, and the South Central region would have no qualifying RPS upon which to base a regional goal.

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[359] http://kcc.ks.gov/energy/res.htm (accessed 11/03/14).

Southeast Region

Similar to concerns identified for the South Central region, the calculation of the regional renewable energy goal for the Southeast region relies on the RPS of only one state – North Carolina. Thus, the North Carolina RPS – and only the North Carolina RPS – is the sole basis for determining the renewable energy goal for all states in the Southeast region, regardless of the unique design aspects of the North Carolina program or different geographic potential or cost-effectiveness for achieving such a goal among states in the region. The North Carolina RPS contains a number of unique elements that significantly affect the extent and types of specific renewable resources that may be applicable to other states in the region. Examples of these unique provisions include the following:

- Up to 40% of the standard can be met through energy efficiency measures;
- Up to 25% of the standard can be met by using out-of-state renewable credits; and
- ~10% of the standard *must be* met by energy recovery from swine and poultry waste.[360]

In fact, the U.S. Department of Energy's Database of State Incentives for Renewables & Efficiency ("DSIRE") describes the North Carolina standard as follows:

> Due to the combined circumstances that it 1) has fairly stringent per-account cost caps, 2) allows for energy efficiency and conservation measures to comprise 25% of General Requirement compliance through 2021 and 40% thereafter, North Carolina's REPS [Renewable Energy Portfolio Standard] can function in ways similar to an Energy Efficiency Resource Standard (EERS). However, since it does not require specific annual targets for efficiency and demand-side management, it is not formally considered by DSIRE to be an EERS.[361]

By including both energy efficiency measures and renewable resources in a single goal, North Carolina's standard is far different from the goals EPA claims to be establishing for groups of states on a regional basis. And EPA's methodology, which sets both energy efficiency and renewable goals as part of the state goals, effectively ignores the dual role those measures play in North Carolina, and has increased the state's standards.[362] EPA should have adjusted the actual

[360] www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC09R (accessed 11/03/14).
[361] Id.
[362] To further highlight the flaws of EPA's methodology for determining regional goals, consider Alaska and Hawaii, which are not included in a specific region. Rather their renewable goals are based on the lowest calculated regional goal – in other words the Southeast regional goal derived solely from the North Carolina RPS. Thus, for the state of Hawaii, which has vastly different geographic and cost-effectiveness considerations, *and* which already has a state RPS with future renewable energy targets of 25% (in 2020) and 40% (in 2030), EPA has proposed a

percentage to reflect this duality, and reduced the renewable portion of the North Carolina and Southeast regional goals.

East Central Region

The East Central region is comprised of Delaware, the District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. Six of the eight states have a mandatory RPS that was used by EPA to calculate the regional and state goals. Even though both Virginia and West Virginia have evaluated renewable energy opportunities and adopted RPS policies, EPA gives no consideration to this experience in calculating the regional goal. Interestingly, the RPS for the District of Columbia is included in the calculation of the regional average, but the District of Columbia had zero renewable generation in 2012, and its standard focuses on the utilization of out-of-state renewable resources as a percentage of sales. EPA has not proposed a state goal for the District, and should have excluded its RPS from the calculation of the East Central regional goal. EPA must also consider the renewable energy experience of Virginia and West Virginia, along with other geographic and cost-effectiveness differences for renewable energy development that exist across the entire region.

The Virginia State Corporation Commission also expressed significant concerns regarding EPA's methodology for developing the state renewable goals by noting that:

> EPA's own data demonstrates why a simple average for calculating a regional target is wrong. The States in EPA's "East Central" region that have higher future RPS requirements are those with relatively little generation compared to the others in this region. Delaware, D.C., Maryland and New Jersey generated approximately 111 million MWh in 2012 and are assigned "2020 Effective RE Levels" between 19 to 22%. In contrast, Pennsylvania, Ohio, Virginia, and West Virginia generated approximately 500 million MWH in 2012 and are either ignored in the calculation or assigned a "2020 Effective RE Level" no greater than 9%. There is no rational basis – legally or mathematically – for giving such undue and unintended influence to certain legislatures at the expense of others, including Virginia.[363]

renewable energy goal that is based on the North Carolina RPS that is premised on the use of out-of-state development, swine and poultry waste, and energy efficiency measures.

[363] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767

3. The state renewable goals calculated by EPA are flawed and inconsistent with the assessment and experience of individual states

EPA has ignored details that reduce the stringency of existing RPS, has not considered the renewable energy experience of states without mandatory RPS programs, and has failed to fully consider differences in the availability of potential renewable resources between states. As a result, the agency has derived state renewable energy goals in building block 3 that are technically and cost-effectively flawed, and that are inconsistent with the prior assessment of these resources by individual states.

Prior state experiences are claimed to be strongly valued by EPA in their development and application of renewable energy targets in the calculation of state goals. For example, the agency notes:

> The proposed approach is derived from state experience with policies that drive investment in RE... EPA focused on state-level RE policy... These state-level goals and requirements have been developed and implemented with technical assistance from state-level regulatory agencies and utility commissions such that they *reflect expert assessments of RE technical and economic potential that can be cost-effectively developed for that state's electricity consumers*.[364]

Ironically, EPA ignores these "expert assessments" of state regulators in establishing the renewable energy goals for states that have mandatory RPS or that have previously evaluated potential opportunities for developing renewable resources. A review of the renewable energy goals that EPA used to develop building block 3 reveals that EPA's goals are more stringent than the effective 2020 RPS goals for 14 states, while for 12 of these states the building block 3 goal is less than the RPS target derived from its own expert assessment.

With respect to states that have previously evaluated opportunities to develop renewable resources and decided that a state RPS was currently not feasible and/or economic, EPA has ignored that state experience and applied renewable energy goals that may not be technically or cost-effectively achievable with in-state resources. As an example, Louisiana evaluated opportunities for renewable energy and determined not to implement an RPS program. In 2010, the Louisiana Public Service Commission ("LPSC") approved a Renewable Energy Pilot Program for the state with the goal of determining whether an RPS is suitable for Louisiana. The program ended in 2013 with the LPSC concluding that while the program "was a useful means of

[364] "GHG Abatement Measures TSD." EPA. June 2014. p.4-2. (emphasis added)

gaining valuable information and experience with renewable resources," "a mandatory RPS is not warranted at this time...[because] the levelized cost of renewable technologies exceeds the cost of conventional resources."[365] Despite this experience and these conclusions from the LPSC, EPA utilizes as 20% renewable energy target in calculating the proposed state goal for Louisiana. Ironically, but consistent with the findings of the LPSC, EPA's Alternative Approach found that the technical potential for additional renewable energy in Louisiana is very small, and that even when modeled with a $30/MWh advantage over other available resources, no new renewable capacity would be added in Louisiana by 2030.

The Commonwealth of Virginia has also considered opportunities for renewable energy development, but has not established a mandatory RPS program. The Virginia State Corporation Commission ("VSCC") has expressed concern that EPA did not consider this experience in establishing the renewable energy goals for Virginia, by noting:

> The renewable levels assigned to Virginia are the highest in the East Central region. Thus, even though EPA relies on the legislative determinations of States with renewable requirements to determine what is achievable across a region, the final result of EPA's calculation is that States with such requirements are actually expected to achieve less than Virginia, which has no renewable requirement. In fact, for the States with renewable requirements, EPA's formula sets renewable levels for those States that are lower than the figures built into the regional target that was then applied to Virginia"

and

> The results of EPA's formula are illogical: Virginia is expected to achieve renewable levels that are calculated based on other States renewable requirements that the EPA's formula does not ultimately expect those States to achieve.[366]

The state of Arkansas is another example of one that does not have a mandatory RPS, and for which EPA has applied a renewable energy target in the state goal calculation that is premised on the standards established for the state of Kansas that has superior potential renewable resources that could be developed more cost-effectively. The renewable energy target applied to Arkansas in building block 3 is one example of the absurd results produced by EPA's flawed methodology. EPA includes Arkansas in the South Central region, which EPA determined has a 20% renewable energy target and annual growth rate of renewable resources of

[365] General Order of the Louisiana Public Service Commission for Docket No. R-28271 Subdocket B. Aug 21, 2013. pp.2-3.
[366] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. pp.34-35. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767

8.3%.[367] If Arkansas would have instead been included in the Southeast region (that has a lower regional target of 10%), one would expect that Arkansas would have a lower renewable energy goal. However, the Southeast region has a lower baseline level of renewable generation relative to its regional target, which translates into an annual renewable energy growth rate for states in the region of 13.4%.[368] Thus, in this example, Arkansas would move to a region with a lower renewable energy target (from 20% to 10%), but would have a more stringent renewable energy growth rate (from 8.3% to 13.4%) leading to a higher 2030 renewable energy goal.

Another example of the absurd outcomes from EPA's flawed methodology is that the required expansion of renewable energy resources does not necessarily occur in the states with the most abundant renewable resources and the most cost-effective opportunities. For example, in the South Central region, the state of Kansas has the second largest amount of renewable energy potential in the region, but increases their renewable energy generation by the lowest amount of any state in the region.[369] Meanwhile, states such as Arkansas and Louisiana, with the least abundant and more expensive renewable energy resources, are required to increase their renewable energy development and generation the most. In fact, EPA's goal calculations assume that only 0.03% of the potential generation from renewable resources in Kansas would be developed, with no additional increases occurring after 2023. Further, despite the fact that Louisiana has only 16% of the potential renewable resources of Kansas, EPA's goal presumes that Louisiana would increase its annual renewable generation by 830 GWh more than the increase assumed for Kansas. Below is a summary these issues for the South Central region.

[367] "Data File: Proposed Renewable Energy (RE) Approach (XLS)." EPA. June 2014. www2.epa.gov/sites/production/files/2014-06/20140602tsd-proposed-re-approach.xlsx
[368] Id.
[369] "Alternative Renewable Energy (RE) Approach TSD." EPA. June 2014. p.20.

	NREL Renewable Technical Potential[370]	**2012** Renewable In-State Generation[371]	2029 Existing & Incremental Renewables[372]	% 2012 Renewables of Potential Renewables	% Final Goal of Potential Renewables	2012 to 2029 Increase in Renewables	2012 to 2029 Increase in Renewables
	GWh	GWh	GWh	%	%	GWh	%
AR	5,038,242	1,698	4,709	0.03%	0.09%	3,011	177%
KS	25,607,687	5,253	8,885	0.02%	0.03%	3,632	69%
LA	4,171,209	2,430	6,892	0.06%	0.17%	4,462	184%
NE	17,137,893	1,347	3,819	0.01%	0.02%	2,473	184%
OK	15,981,649	8,521	15,579	0.05%	0.10%	7,059	83%
TX	67,627,415	34,017	85,963	0.05%	0.13%	51,946	153%

4. EPA should utilize more robust data as the baseline for building block 3

EPA used 2012 data as a baseline to establish individual state goals in building block 3. But a single year can be an anomaly, and EPA should have used a more robust set of data in calculating its goals. Increased generation from renewable resources coupled with changes in the total generation produced in 2013 and 2014 impact both the regional growth factor calculated by EPA and the resulting individual state renewable goals. Using 2013 generation data would decrease the regional renewable energy growth rate calculated by EPA. The table below summarizes this decrease for three regions as an example:

	Renewable Generation Growth Rate Based on 2012 Data	Renewable Generation Growth Rate Based on 2013 Data[373]
East Central	17.3%	15.9%
South Central	8.3%	6.8%
Southeast	13.4%	12.9%

The change in the growth rate using 2013 data can have a significant impact on the renewable energy goal that EPA calculates for state goals. For instance, utilizing 2013 data reduces the interim and final renewable energy goals for Arkansas by 15% and 22% respectively. Likewise, for Louisiana the interim and final renewable energy goals are reduced by 10% and

[370] "Alternative Renewable Energy (RE) Approach TSD." EPA. June 2014. p.20.
[371] "Data File: Proposed Renewable Energy (RE) Approach (XLS)." EPA. June 2014. www2.epa.gov/sites/production/files/2014-06/20140602tsd-proposed-re-approach.xlsx
[372] Id.
[373] See Appendix C for detailed calculations.

17% if using 2013 as a baseline.[374] EPA's selection of 2012 as the single baseline year in its goal calculation efforts is unreasonable and arbitrary.

C. EPA's alternative approach for calculating renewable energy goals is fundamentally flawed

The proposed alternative approach for calculating renewable energy goals is based on an evaluation of the technical and market potential of renewable resource development in each state. The lower of these two projections forms the basis for developing the state-specific renewable goals. EPA's methodology and the results of its analysis are fundamentally flawed in that they are premised on incomplete, unsubstantiated assumptions regarding the rate at which states can develop renewable resources and the future costs of those technologies.

1. EPA overstates the technical potential of state renewable resources and calculates growth rates for renewable energy development that are flawed

EPA attempts to determine the technical potential of state renewable resources by relying on a 2012 NREL report. This report by design only represents resource potential, with some caveats. However, as the report notes:

> The estimates do not consider...economic or market constraints, and therefore do not represent a level of renewable generation that might actually be deployed.[375]

The report indicates that these "economic or market constraints" include technology and fuel costs, policy considerations, regulatory limits, and regional competition with other energy sources.[376] EPA also acknowledges the significant limitations of this study by stating:

> technical potential data is typically unconstrained by grid limitations, costs associated with development, quality of resource, and may overstate electricity production potential because a given site cannot produce RE simultaneously from multiple technology types.[377]

Other factors that impact the amount of the technical potential resources that can actually be developed include seasonal impacts, transmission considerations, state regulatory processes, and project siting rules and limitations associated with certain endangered species and other environmental programs. Clearly, these issues present technical, cost, regulatory, and practical

[374] Id.
[375] "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis." NREL. July 2012. p. iv.
[376] Id. p.1.
[377] "Alternative RE Approach TSD." EPA. June 2014. p.2

challenges that can and do limit actual opportunities for developing these potential resources. Yet, EPA did not consider these factors in deriving the technical potential or assumed development rate for each resource.

Based on the technical potential of state renewable resources, EPA calculated the level of renewable energy development on a state- and renewable energy-specific basis using the amount of renewable generation produced in 2012. The agency then calculated a benchmark development rate for each renewable technology based on the arbitrary average of the top 16 states for each resource. The benchmark rates from this limited number of states are then incorrectly applied to all states.

EPA's approach is fatally flawed as the agency incorrectly assumes that the technical potential and experience of 16 states is sufficient for establishing renewable energy goals for all other states. EPA's reliance on historic renewable energy development in only the top 16 states disregards the fact that experience of these limited states may not be applicable or achievable by other states, as the top performing states are typically those with the greatest renewable generation potential, greatest access to transmission, and have lower development costs. In addition, EPA made no attempt to evaluate the quality of the resources developed, the manner in which they were funded (out-of-state entities, federal tax credits, grants, etc.), or other drivers for development that may not be applicable to other states. Given that subsidies such as the federal production tax credit and investment tax credit have already expired or are scheduled to expire before the states even file their compliance plans, it is not reasonable to expect that past development of renewable resources is necessarily indicative of future development potential as experienced in recent years when these tax benefits were available. Further, EPA did not consider whether existing renewable resources represent opportunistic or nuanced circumstances for development that cannot be readily replicated or expanded.

The NREL report acknowledges these state differences by estimating potential renewable resources based on varying assumptions on the capacity factors that would be expected from each technology. For example, NREL provides state-specific estimates of capacity factors for photovoltaic resources. For the states in the EPA-defined South Central region, the capacity factors for photovoltaic resources ranged from 19.6% (Louisiana) to 23.8% (Kansas). Thus, EPA does not consider that the development rates derived from the top performing states may not be achievable by other states that are not able to utilize their resources at the same rate due to differences in the availability of the resource.

The agency has provided no rationale for why it is appropriate to assume that the development achieved to date by select states, with different technical, cost, and policy considerations, is replicable and represents what is achievable by all states going forward. Nor has EPA provided any rationale for using prior growth rates as an indication of achievable future growth, particularly given the technical challenges associated with incorporating increased renewable energy into the power supply system, such as the need for additional transmission investment.

2. EPA uses unsubstantiated assumptions on future costs to estimate the market-based potential for state renewable energy development

EPA also used its Integrated Planning Model to evaluate renewable energy development assuming a $30/MWh reduction in the cost of all types of new renewable resources. However, EPA failed to provide any basis that supports this rate of reduction or its broad-brushed applicability to all types of renewable resources. The factors that impact future costs are specific to each resource and must consider technology advances, permitting and regulatory issues, energy market considerations, and the availability or need for transmission updates, among other factors. Further, cost trends for one renewable technology are independent of the trends for other resources, and will vary by location and by the maturity and use of the technology. For example, onshore wind resources in the interior of the country are approximately $35/MWh less expensive than they are in the western U.S.[378] EPA's attempt to apply renewable energy goals that must be achieved by all states based on limited, region-specific data is flawed. Instead, EPA should use state, regional, and technology-specific costs in its modeling approach as opposed to a broad average that is assumed to be achievable by all renewable energy resources, regardless of location and/or the continued availability of federal subsidies for certain renewables.

Further, EPA provides no evidence regarding if, when, or how its assumption that renewable energy technologies, as a whole or individually, would be reduced by $30/MWh could be achieved. Nor does the agency provide any details regarding the baseline cost from which the $30/MWh rate was reduced. The cost of renewable resources is strongly influenced by public

[378] "2013 Wind Technologies Report." U.S. DOE. Aug 2014. http://energy.gov/eere/wind/downloads/2013-wind-technologies-market-report

policies. As the NREL study notes, tax credits greatly influence the development of renewable energy.[379] Lazard, an independent financial advisory and asset management firm, notes the impact of federal subsidies on the levelized cost of energy (LCOE) for renewable technologies in their annual LCOE analysis. The cost reduction due to subsidies varies by technology, but can be as much as $42/MWh on a levelized basis.[380] Given that subsidies such as the federal production tax credit and investment tax credit have already expired or are scheduled to expire before the states even file compliance plans, it is not reasonable to expect costs to continue to decline at the same level as experienced in recent years when these tax benefits were available. In addition, tariffs on imported solar panels[381] and tightening supply may slow the decline in price of solar panels in the near term.[382,383]

The cost of any technology depends on many factors, and EPA provided no information about how these factors were considered in determining that $30/MWh is a reasonable cost reduction estimate. Accordingly, it is not clear that EPA accounted for technology- and region-specific factors and trends. If EPA finalizes its alternate proposed approach, it must provide sufficient data and analysis to justify this number. If no such analysis is available, then EPA must remove the estimate from any calculation of state RE targets altogether. Specifically, EPA should not adjust IPM results by any assumed future subsidies.

3. The alternative methodology produces absurd results as applied to state emission rate goal

By using a combination of an arbitrary renewable cost reduction and integrated modeling process, some states are forecast to have a dramatic increase in renewable energy under the proposal. As two prime examples, Kansas is expected to have a target for renewable energy equivalent to 115% of 2012 generation (excluding hydroelectric sources) by 2029 and South Dakota has a target equal to 159% of 2012 generation. If these numbers were applied to state emission rate goals, this would significantly reduce the CO_2 emission rate goal for the states and

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379 Owen Zinaman et al., *ReEDS Modeling of the President's 2020 U.S. Renewable Electricity Generation Goal* at 12 (May 2014)
380 Lazard, *Levelized Cost of Energy Analysis (*Sept. 2014),
381 U.S. Department of Commerce, *Commerce Preliminarily Finds Counteravailable Subsidization of Imports of Certain Crystalline Silicon Photovoltaic Products from the People's Republic of China* (June 2014)
382 Munsell. M., *New Tariffs on Chinese Solar Modules Will Raise US Prices by 14%, GreenTechSolar* (June 20, 2014).
383 Press Release, IHS, US to Dodge Shortage This Year Even Amidst Fines on Chinese Module Suppliers. Apr. 17, 2014

likely force out any fossil resources necessary to provide firm energy to support this level of renewable development. Furthermore, as this level of renewable energy would be in excess of in-state needs, these states would be legally required to produce emissions reductions that could only be achieved by extreme penetration of renewable energy without any requirement that other states share the cost burden. This would subject in-state ratepayers to the potential for enormous cost increases while other states would likely see displacement of fossil resources at no cost. This illustrates that this alternative methodology creates significant winners and losers at the state level by parsing state-based results from an integrated national model.

D. Building Block 3 Comments related to EPA's NODA

1. The alternative approach proposed in NODA is flawed

EPA requested comment on a regional approach to defining state renewable energy target levels. This approach would allow EPA to establish regional targets for renewable energy and apportion out requirements to individual states based on a state's share of regional retail sales or generation. This approach is substantially flawed for a number of reasons. First, this approach could effectively force states to rely upon generation resources outside their boundaries and, beyond their jurisdiction, making compliance subject to a multitude of factors outside of state control. Second, utilizing a regional approach as applied to just this building block is highly arbitrary. While arguably all of the other building blocks have regional attributes to their application, none of the other building blocks were examined or calculated within a similar regional context, presumably based on the fact that states are required to develop and implement these programs by statute. Third, any use of regions that do not correspond to small and distinct electric transmission control areas would ignore significant transmission constraints that must be addressed in order to accommodate regional renewable development. It seems that EPA is contemplating a much broader definition of "region." Fourth, EPA has not provided any clear guidance within the proposal regarding how renewable credits could be treated within a rate-based compliance approach given differences between the states' goals, nor would this approach be facilitated by using a mass-based compliance program as out-of-state resources might not displace in-state emissions. Absent clear guidance on interstate issues, EPA's identification of this alternative in the NODA provides no basis for informed comments.

The final and most serious concern related to the alternative process based on regional renewable targets is that the outcomes for individual states are not reflected in any definitive way. The only other proposals from EPA are the primary and alternative calculations of renewable energy goals associated with the initial proposal. Both of those methodologies are deeply flawed. Applying a variation of that same flawed analysis to a broader region, and then using an unidentified process for allocating individual state responsibilities under this option, would be arbitrary and capricious, and has no foundation in the materials placed in the record for this rulemaking.

2. State Goal Calculation Method for Building Block 3 and 4.

EPA requested comment on whether the goal-setting calculation should “back-off” fossil generation in response to the addition of the renewable energy and energy efficiency building blocks. AEP strongly disagrees with this modification as this change would artificially place additional emission reductions on many states and thus result in further stress to the electrical system. While renewable energy and energy efficiency have some implications for the utilization of existing sources they also play a key role in offsetting the need for new generating sources, and thus a determination that these building blocks would solely displace existing fossil generation is not practical.

EPA has not attempted to evaluate how such an approach would affect the operation and reliability of the grid as *dispatchable* fossil resources are needed to support voltage, frequency, capacity needs and enable renewable technologies to be deployed. Under the proposed revision to the state goal calculation, some states (e.g. Washington, Idaho, Oregon, Maine) would be left with *zero* fossil fuel-based generation, which significantly impairs the ability of operators to maintain reliability. If this proposal was expanded further as contemplated within the NODA, and building blocks 3 and 4 were applied to reduce fossil-steam generation preferentially, such as is done with building block 2, all fossil-steam generation would be lost in 21 states - even while existing NGCC capacity would be assumed to run at a fixed capacity factor. EPA has not performed any analysis to suggest that the grid could function without these critical capacity resources. As such, this potential alternative goal calculation approach should be rejected.

E. EPA did not fully consider transmission issues that impact the feasibility, cost, and timing for developing additional renewable resources

As discussed in the comments below on reliability, the increased development and utilization of renewable energy resources introduces a number of concerns regarding the need to upgrade and/or expand the existing grid. The concerns become more significant when coupled with the impact of all the building blocks on the grid in terms of changes to the location and capabilities of generation versus load centers. NERC has identified a number of issues that must be addressed in order to accommodate the increased development of renewable resources. For example, NERC's 2013 Long-Term Reliability Assessment notes that:

> Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro)...will require significant changes to traditional methods used for system planning and operation... Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS [bulk power system] reliability. Operators will require new tools and practices, including potential enhancements to NERC Reliability Standards or guidelines to maintain BPS reliability.
>
> Accommodating higher levels of variable resources requires cooperation and coordination within each interconnection—especially between BPS and non-BPS entities. Frequency stability, frequency response, energy imbalance, and increased and dynamic transfers must be addressed at all levels. Specifically, increasing amounts of solar photovoltaic (PV) generation leads to decreased system inertia and frequency response capabilities that could potentially result in reliability impacts on the BPS.
>
> Wind generation is often located substantial distances from the point of interconnection to the transmission system, which creates additional reliability implications. In many cases, the location of these variable resources only meets the minimum voltage support requirements.
>
> The addition of significant amounts of variable generation to the BPS changes the way that transmission and resource planners develop their future systems to maintain reliability.[384]

EPA has not seriously considered any of these technology, economic, and regulatory challenges related to integrating additional renewable generation into the interconnected power supply system. However, these issues introduce significant uncertainty regarding the feasibility, cost, and timing of increasing renewable resources.

[384] 2013 Long-Term Reliability Assessment. NERC. Dec 2013. pp. 22-24.

F. EPA does not fully consider the technical, cost, regulatory, and practical challenges of increasing renewable resources

A number of state-specific factors impact not only the amount of potential renewable resources available, but also impact the feasibility and rate at which such resources may be developed. These factors include geography, topology, energy markets, seasonal differences, transmission considerations, state regulatory processes, and project siting rules associated with certain endangered species and other environmental programs. A summary of the development challenges that EPA must consider follows below:

Implementation

As discussed in the comments that follow related to implementation, generation (and related transmission) planning involves input and decisions from a number of entities, such as various state regulators, regional transmission organizations, and independent system operators. As proposed, the state goals are based on states increasing renewable generation beginning in 2017 – the earliest date that a state would have a final, approved compliance plan, and before regional plans would be submitted to EPA for approval. As such, the proposal would not allow sufficient time for the design, approval, and implementation of state and/or regional compliance strategies needed to achieve the proposed renewable energy goals. The implementation comments also discuss significant concerns and uncertainties pertaining to the mechanics of implementing and managing interstate issues associated with how states that support the development of out-of-state renewable resources obtain credit for such resources in their compliance plans.

Regulatory Considerations

EPA did not evaluate the impact of regulatory processes on the timing and feasibility of developing renewable energy resources. Timing related challenges are introduced by the number of regulatory agencies that must evaluate and approve the addition of renewable resources, including the necessary arrangements to connect those new generating resources to the grid, as well as by the number of agencies that evaluate and balance the impacts of multiple projects across multiple jurisdictions. This includes agencies whose obligations are very diverse, including cultural and historic resource agencies, marine, fish and wildlife services, aviation authorities, state and federal land management agencies, and others.

G. EPA should exclude nuclear energy from state goal calculations

Nuclear energy should be excluded from the state goal calculations, but should remain an option for states to consider in developing their state plans to meet the proposed goals. Consideration of at-risk and new nuclear generation unnecessarily introduces uncertainty into the goal setting methodology and compliance planning due to concerns regarding the short- and long-term viability of EPA's assumptions regarding the continued operation of the existing nuclear fleet and with respect to if/when the under construction nuclear capacity actually is commissioned. The implementation section identifies additional concerns for developing compliance requirements for nuclear capacity within state plans that further warrant excluding nuclear energy from the goal calculation.

H. Recommendations regarding building block 3.

In summary, renewable energy and nuclear energy should not play any role in establishing the BSER for existing fossil fuel fired electric generating units. If EPA decides to allow states to introduce additional flexibility in achieving broad state goals through measures considered in this building block, then the inclusion of renewable energy in calculating the state plans should be based on the state-specific technical potential and cost-effectiveness of renewable resources, and state-specific growth factors that take into account all of the issues identified in this section. Such considerations might minimize or eliminate this component for many states and especially those states that have already evaluated and determined that opportunities for renewable energy development are limited. In order to fully assess the feasibility and potential costs of implementing the types of renewable goals envisioned in the proposed rule, more information is needed regarding:

- the final level of renewable energy to be considered in establishing the state goal;
- the mechanisms available to resolve interstate issues regarding the "credit" for renewables procured in one state for the benefit of customers in other states;
- the mechanisms that will be acceptable to the states and EPA for purposes of demonstrating compliance; and
- the location, size, and design of new renewable capacity must be known to adequately evaluate the cost of transmission improvements necessary to support those facilities and to assess whether additional generation resources are needed during periods when the renewable resources are not available.

VIII. Building Block 4 Comments

As discussed above, EPA does not have the authority to consider energy efficiency ("EE") measures adopted by customers when determining the BSER.[385] In addition, EPA has failed to demonstrate that the EE standard is achievable or has been adequately demonstrated. Specifically, EPA ignores the expert evaluations of the majority of states regarding a reasonably achievable level of EE, the pace of increase in EE achievement, and a reasonable level of costs to achieve those proposed EE levels. Further, the data and methodology that the agency used in establishing these levels for all states in a one-size-fits-all manner ignores many fundamental differences between the states that affect the nature and scope of achievable EE measures and rates of growth. EPA did not use a transparent process in estimating the costs of the proposed EE levels, did not consider all cost elements of EE, and did not give adequate consideration to the effect of such costs on customers. EPA's failure to specifically identify the evaluation, measurement and validation ("EM&V") methods required for a satisfactory state plan, and its failure to assess whether such EM&V measures are currently applied in the programs identified as "best practice standards," provide an inadequate basis for commenters to determine the actual impact of the proposed guidelines. Accordingly, EPA should withdraw this aspect of the proposed guidelines.

To the extent that EPA allows states to rely on EE measures to satisfy a portion of their obligations in any state plan, EPA should give deference to the states' determination of a reasonable level of EE achievement considering the costs, non-air environmental impacts, and other factors outlined in section 111(d). Each state could then use that level of EE potential as it deems appropriate. If, however, EPA retains EE as part of the portfolio of options to be considered by the states, it should re-evaluate the stringency of the portion of the state goals based on such measures in accordance with the following comments.

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[385] Indeed, in the context of EPA's authority under section 169 of the CAA to specify what is the "best available technology" for regulated pollutants in a new source review ("NSR") permit, the Supreme Court noted with approval that, "BACT may not be used to require 'reductions in a facility's demand for energy from the electric grid,'" and that "BACT should not require every conceivable change that could result in minor improvements in energy efficiency, such as the aforementioned light bulbs." Rather, the Court confirmed that BACT can only be required for pollutants that the source itself emits, and that permitting authorities should consider whether the proposed regulatory burden outweighs any emission reductions that can be achieved. *UARG v. EPA*, 134 S.Ct. at 2448.. These same principles should apply to the BSER, which, as demonstrated above, is based on technology that can be applied to emission from the regulated source, and must satisfy the statutory balancing of costs, other environmental affects, and the emission reductions actually achieved.

A. Flaws in EPA's EE Achievability Analysis

There are several flaws in the analysis used by EPA to establish the level of EE measures to be used in the calculation of state goals. The cumulative effect of these flaws is that EPA has substantially overstated the amount of EE that could be achieved by states

1. Base data inconsistencies

The source of the base data that EPA relied upon for EE achievement data is not reliable. EPA uses EIA Form 861 data as the baseline level of the amount of EE achievements by utility EE programs. EPA acknowledges the consistency and quality issues with EIA Form 861 data, as utilities rely upon differing methodologies in measuring the net impact of their EE programs; however EPA does not fundamentally address this issue.

2. Invalid extrapolations

Extrapolation of EE achievement levels between states results in invalid comparisons. EPA suggests that a certain level of EE can be achieved by all states based on its evaluation of "best practices" achieved in certain states. The assertion that the experience in these states can be easily replicated in others is based on simplistic assumptions, not detailed analyses. There are fundamental flaws in such extrapolations when inherent real-world differences among the states are properly considered.

a. Relative size of customer classes not comparable

The relative size of the different classes of customers (industrial, commercial, and residential) is substantially different between states and across utility service territories; and the relative potential and costs to achieve EE savings across these customer classes varies substantially. Many states (such as those in the Midwest) deliver a much higher percentage of their electricity to industrial and manufacturing facilities. Others (such as those in the Northeast) have a much larger percentage of commercial and service-based entities in their customer mix. States with higher industrial and manufacturing activity tend to have higher overall electricity consumption levels. Because the EE target levels are based on total retail sales, this increases the EE target levels as well. In addition, implementing utility-sponsored EE at these industrial and manufacturing facilities can be much more challenging and costly, as they tend to be facility-specific measures that are based on unique circumstances, such as replacing pumps, motors, and drives in manufacturing equipment with more efficient models.

b. Commercial and industrial opt-out provisions not considered

Many states have determined that larger commercial and industrial customers should be not be required to participate in the utility-sponsored EE programs, because these customers typically have the sophistication and resources available to implement their own EE measures, have better access to capital, and better rates, and are generally better informed as to their EE options. In these instances, EPA should exclude commercial and industrial sales, or allow the requirement for EE implementation to be placed directly on those customers. In any event, as discussed above, the expected penetration rate for required EE programs should be consistent with the base of sales that can be addressed by those programs.

c. Customers subject to section 111 of the CAA should be excluded.

Certain industrial customers are also in industrial categories that are themselves subject to standards of performance under section 111 of the CAA, including steel, glass, paper, and chemical manufacturing, refineries, and other industries. For such customers, requiring efficiency improvements under an electric utility standard is not justified, when additional requirements may be imposed as part of a future section 111 standard for their source category. To the extent that any portion of the state goals is based on customer end use efficiency measures, the degree of manufacturing and industrial load that forms a part of the customer base must be considered, and appropriate adjustments made to exclude all or at least the portion of such load that is subject to a separate section 111 standard.

d. Average temperatures and electricity consuming devices are not comparable

The average temperatures and relative use patterns for specific electricity consuming devices among many of the states used to define "best practice" for EE are fundamentally different from the average temperatures and use patterns in other states. Foremost among these differences is the significant variation in space heating and cooling requirements and their relative contribution to electricity loads. Space heating and cooling are by far the largest energy-consuming loads in most households and many commercial establishments. EPA's failure to account for these differences leads to a flawed assessment of the percent of EE reductions that can be achieved across different states.

Regarding electricity consumption for space cooling, the differences are stark. For instance, Massachusetts has significantly fewer cooling degree days than Texas.[386] In Massachusetts, electricity used for space cooling accounts for only 1% of average household electricity consumption; over 20% of homes have no air conditioning; the majority of the remainder use smaller window/wall units sparingly; and only 20% having larger central air conditioning units. In contrast, in Texas electricity used for space cooling accounts for 18% of average household electricity consumption; over 80% of homes have central air conditioning; and those units are used much more extensively throughout a longer cooling season. As such, electricity needs for space cooling are significantly higher in Texas than in Massachusetts.

Regarding home heating, there are significant differences as well. Massachusetts experiences significantly more heating degree days than Texas.[387] However, a significant percent of residential heating is met using natural gas (>50%) and fuel oil (31%), while electricity is used very sparingly (10%). In contrast, in Texas electricity provides a significant portion of the energy to meet residential heating needs (50%), with relatively smaller percentages of natural gas usage (~42%) and virtually no heating oil. Therefore, due to a combination of average temperatures and prevalence and type of space heating and cooling equipment, households in Massachusetts rely on electricity significantly less than those in Texas to meet basic space heating and cooling needs of homes.

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[386] US NOAA / National Weather Service: (www.erh.noaa.gov/cle/climate/info/degreedays.html)
Q: What are degree days?
Heating engineers who wanted a way to relate each day's temperatures to the demand for fuel to heat buildings developed the concept of heating degree days.
To calculate the heating degree days for a particular day, find the day's average temperature by adding the day's high and low temperatures and dividing by two. If the number is above 65, there are no heating degree days that day. If the number is less than 65, subtract it from 65 to find the number of heating degree days.
For example, if the day's high temperature is 60 and the low is 40, the average temperature is 50 degrees. 65 minus 50 is 15 heating degree days.
Cooling degree days are also based on the day's average minus 65. They relate the day's temperature to the energy demands of air conditioning. For example, if the day's high is 90 and the day's low is 70, the day's average is 80. 80 minus 65 is 15 cooling degree days
Mean Cooling Degree Days in MA average 100-700, while in southern TX average 2500-3500.
US Dept of the Interior, US Geological Survey. http://nationalmap.gov/small_scale/printable/climatemap.html#list
[387] Mean Heating Degree Days in MA average 6000-9000, while in southern TX average 1000-2000.
US Deprtof the Interior, US Geological Survey. http://nationalmap.gov/small_scale/printable/climatemap.html#list

These phenomena are directly relevant to the issue of EE achievement potential. Lighting has historically been among the most widespread and successful utility-sponsored EE measures. But if the same EE lighting measure (such as a CFL light bulb) is installed in a low-electricity-use household in Massachusetts, it will contribute a far greater percent reduction in electricity usage than that same measure installed in a higher-electricity-use household in Texas. For example, all other things being equal, since household electricity consumption in Massachusetts is only about half that of Texas, the exact same EE measures installed in a typical Massachusetts household that resulted in a 1 percent reduction in electricity consumption would produce only a 0.5 percent reduction in a typical Texas household. If the identical types and levels of EE measures are implemented in a state that has double the energy consumption than another, the impact on a percentage-basis would be half that experienced in the original state.

These stark differences are particularly relevant because what EPA characterizes as EE is a misnomer. When EPA professes that a certain state has achieved a certain percent of energy efficiency, in actuality what is measured is the reduction in electricity consumption relative to the base of all electricity consumption. Other energy sources are completely ignored. For example, though the average household consumes only about one-half the electricity in Massachusetts as it does in Texas, when one compares the *total energy* consumption (on a British thermal unit "BTU" basis) the comparison is completely different. Massachusetts uses 22 percent *more* energy per household than the US national average, while Texas households use 14 percent *less* than the US average.[388]

e. Temporal considerations

In addition to these geographic differences, there are temporal challenges in extrapolating past EE achievements into the future. There has been a significant increase in overall baseline efficiency codes and standards, which will inherently reduce energy consumption irrespective of the impacts of utility-sponsored EE programs. The most significant changes have occurred in lighting EE efficiency standards, which have historically produced the greatest utility-sponsored EE achievements.

U.S. appliance efficiency standards and building codes have become increasingly more stringent. DOE has issued numerous new EE standards over the last few years, which will affect

[388] Source: US Energy Information Administration, Residential Energy Consumption Survey.

energy use as new homes are built and equipped with such appliances, and existing homes undertake replacement of appliances in the ordinary course. For instance, the Department of Energy ("DOE") has proposed new efficiency standards for commercial rooftop air conditioners that would reduce energy consumption by 30 percent, achieving the largest national energy savings of any standard ever issued. Over 30 years, it is estimated that this one standard could produce energy savings equivalent to one-half of all residential energy used in the U.S. in a single year.[389]

For any given EE measure, this increased baseline efficiency results in less EE savings opportunity for administrator/utility-sponsored programs. For instance, with this dramatic increase in efficiency standards for rooftop air conditioners, utility-administered EE achievements in this segment would become significantly more difficult and costly. Commercial customers would be achieving significant savings as a result of the standard, and less receptive to investing in more efficient equipment, as this equipment would come at a premium, but provide only marginally higher EE savings.

The impact of this phenomenon is most acute for lighting standards resulting from Energy Independence and Security Act (EISA) of 2007. Utility-sponsored EE programs have traditionally heavily relied upon lighting programs (most significantly residential CFL, and commercial T-8 fluorescent lighting programs) for a very significant portion of their EE achievements. While specific disaggregated data on program administrator reliance on lighting measures is typically not disclosed, indications are that many residential programs may have relied upon lighting measures for over half of their EE achievements in the past. One study conducted on the subject in the northeastern U.S. indicated that the two EE programs reviewed relied upon lighting for 94% of the EE achievements.[390]

With the adoption of the EISA 2007 lighting standards, standard incandescent bulbs and T-12 commercial lighting fixtures are no longer able to be manufactured or imported into the U.S. Therefore, this large and inexpensive market for utility-sponsored EE savings is being substantially eroded as the baseline efficiency level increases to the new standard. It is

[389] http://energy.gov/sites/prod/files/2014/09/f18/2104-09-18%20Issuance%20cauc_noticeofproposedrulemaking.pdf.
[390] *Benchmarking of Vermont's 2008 Electric Energy Efficiency Program*s, at p. 10, http://publicservicevermont.gov/sites/psd/files/Topics/Energy_Efficiency/EVT_Performance_Eval/Final%20VT%20BED%20Benchmarking%20Report.pdf

anticipated that by 2020 or soon thereafter, CFL devices will become the standard (or baseline), further limiting future efficiency improvements from these programs.

EPA utilized historic achievements built largely upon these low-cost and readily available EE lighting measures when making its projections for EE savings potential in future years. There are market potential studies that assert plentiful and inexpensive EE savings opportunities available from other EE measures in the future. However, there is no empirical evidence that any utility-sponsored EE programs relying upon these non-lighting measures can achieve EE levels even approaching those levels achieved through lighting programs. In the absence of further evidence of the availability of other programs that can deliver similarly substantial savings, EPA clearly fails in its requirement to demonstrate the technical achievability of its proposed standard under the EE codes and standards currently in effect.

f. Other options

Non-lighting measures have been aggressively pursued by many utilities; however capturing these savings is much more difficult. Non-lighting savings have not been achieved in significant quantities in any state, and most cost substantially more on a per-MWh basis. These measures are primarily comprised of thermal efficiency measures, such as heating, air conditioning, and other appliance efficiency upgrades, and weatherization measures. They are expensive, requiring a relatively large capital investment by customers for new appliances and equipment. This is problematic, as customers customarily avoid such large expenditures until a precipitating event occurs (appliance or equipment failure, etc.). Therefore, utilities would need to offer a much higher incentive payment to encourage customer participation. These are the types of EE measures that will need to be increasingly relied upon to achieve ongoing incremental improvements going forward as dependence on abundant an inexpensive lighting measures declines significantly.

3. Customer economic challenges

Many customers are challenged economically to invest in EE upgrades. AEP anticipates continued difficulty in motivating customers to pay premiums for such EE improvements due to much of its service territory being perpetually economically disadvantaged. AEP-served counties have household incomes that are approximately $9,000 less than the national average. Some of the counties it serves have average household incomes that are less than half the national average. The types of EE achievements proposed by EPA have not been historically demonstrated during a time of significant economic hardship, such as those being currently experienced (and likely to be exacerbated by imposition of the EPA rule) in manufacturing and coal mining dependent areas. When significant near-term economic performance is depressed and unemployment levels are high, customers postpone improvements that are not cost-justified in the short-term. Many customers are not willing or able to pay a premium to achieve a long-term economic benefit through investment in higher efficiency devices. Further, neither EPA, nor the states can force customers to achieve higher levels of EE. It is completely outside their control. EPA acknowledges that there are practical, economic, and market barriers to tracing the effects of EE deployment, but fails to fundamentally address these issues. Without addressing these issues, EPA has not shown that the proposed goals are achievable or adequately demonstrated.

4. Market potential studies

The Market Potential Studies ("MPS") that were relied upon to propose future levels of EE do not provide an adequate basis for use in establishing a regulatory compliance target. Much of the data and information was supplied by EE advocacy organizations and others with a similar focus, and was not subject to a peer review process. EPA notes that nearly all of these studies represent a "top-down, policy-based approach" and do not account for all of the practical factors that are necessary to build functioning EE programs. The metrics adopted by EPA largely comport with these findings, and differ substantially from the "bottom-up," engineering-based analysis that has been conducted on the topic. One study analyzed was conducted by Electric Power Research Institute ("EPRI") in 2014. EPRI's study used a conventional bottom-up engineering approach. As EPRI explains in their study, such an approach is "based on equipment stock turnover and adoption of energy efficiency measures at the technology and end-use levels" at a regional level "yielding detailed, granular results by division, sector, building type, end-use, and technology."[391] Notably, EPRI's estimate for average annual achievable potential EE based upon their engineering approach was 0.5% to 0.6% per year, while the top-

[391] EPRI, U.S. Energy Efficiency Potential Through 2035, p. vi, www.epri.com/abstracts/Pages/ProductAbstract.aspx?Product id=000000000001025477.

down policy approaches estimated EE potential many times higher at approximately 1.5%. Ultimately, EPA chose to use 1.5% as the "best practice level."

The MPS do not prove empirically that these levels of EE are achievable or sustainable. Much like the renewable resource studies referenced in EPA's analysis of alternative methods to develop state renewable energy goals, the MPS are not precise engineering analysis undertakings. Substantial differences in the models, assumptions, data sources, interpretations, etc. by various authors often make significant differences in the results. In a study conducted by the American Council for an Energy-Efficient Economy ("ACEEE"), 45 publicly available market potential studies performed since 2009 were reviewed, and ACEEE found that "for electricity, [the] average annual maximum achievable savings range [was] from 0.3% to 2.9%."[392] That is nearly a 1000% variation, depending on the assumptions and methodologies employed in the study.

There is a significant lack of transparency on major model inputs such as forecasting participation rates, incentive level estimates, impacts of codes and standards, emerging technologies, utility avoided cost estimates, and policy limitations. Even modest deviations from these point-in-time assumptions, estimates and projections, will compound over time and significantly affect the results. This is especially the case with projections made over 15 or more years, as EPA has done. Due to these factors, it is generally understood that MPS are most applicable to and best suited for short-term program planning rather than long-term policy application. EPA itself acknowledges the substantial variation in potential estimates, driven by lack of broad empirical evidence and significantly varying assumptions and methodologies. Regardless, EPA ignored these limitations, and instead proposed to set legally enforceable requirements based upon such studies. EPA must re-evaluate the basis for its proposed goals, and examine the full range of studies that have been performed, rather than selecting the highest projected rates and applying them indiscriminately across the country.

5. States used as proxies

The states used to demonstrate achievable EE levels are not representative of the varying experiences in other states. EPA used a set of top 12 states in terms of EE performance as

[392] ACEEE, *Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies, page v.*

measured by incremental savings as a percentage of retail sales (based on the 2012 reported data). EPA concluded that three states (Arizona, Maine, Vermont) have already achieved the highest level of performance, more than 1.5 percent annual incremental retail sales saving. Previous comments demonstrate the incomparability of these states to others as a whole. EPA notes that nine other states have EE policies in place that will bring their annual incremental savings levels to the 1.5 percent rate by 2020.[393] EPA cannot rely on speculative future EE targets as evidence that certain levels of EE are achievable or sustainable. Further, EPA ignored that two states they cited (both of which AEP serves, Indiana and Ohio) have recently taken legislative action to reconsider the degree of achievability of their long-term targeted EE requirements. Part of the reason for their concern is the potential rate impact that these programs are having on retail customers. Further, EPA asserts that states can sustain a level of 1.5% of incremental EE achievements indefinitely. EPA offers no justification for this assertion, and in fact there is no evidence of any program sustaining this level of EE achievement over the length of time covered by the proposed rule.

6. Illustrated example

One way to demonstrate the unachievable nature of the proposed rule is to review the participation levels and energy reductions that would be required. A 1.5 percent of retail sales EE achievement requires some combination of participation rate and savings rate, such that EE target = % participation x % reduction. Therefore, a 1.5 percent reduction equals:

- 10 percent participation with 15 percent savings, or
- 15 percent participation and 10 percent savings, or
- 2 percent participation with 30 percent savings, etc.

If an EE measure is targeted to replace older heat pumps with one that is 30 percent more efficient, and this would result in an overall reduction in household consumption by 10 percent, a utility would need 15 percent of its *entire* customer base to participate in the heat pump replacement program *every year* to meet the standard. But even if *all* customers had heat pumps, and they are replaced at failure every 15 years, only 6.7 percent of the total customer base would be in the market for an upgrade in any given year. Many utility-sponsored EE programs produce

[393] These nine other states are Colorado, Illinois, Indiana, Massachusetts, Minnesota, New York, Ohio, Rhode Island and Washington.

much lower efficiency gains. The higher efficiency gains like heat pump replacements are also accompanied by requirements for relatively high customer costs. Therefore, customer participation rates in such EE programs are currently a small fraction of what is described here.

7. EE growth estimates

EPA's 0.2% 'pace of improvement' (increase in incremental EE per year) is not reasonable. EPA utilizes increases in EE achievement experienced in a select set of states prior to 2011 as a proxy for what can be achieved in all states in the future. These states are not a representative set of states from which to develop a realistic rate of EE increase. Many of these states have had aggressive EE programs with supportive legislative and regulatory environments in place for 20 or more years to get to these best practice levels. Further, the 'pace of improvement' analysis relies upon a time where relatively large and inexpensive lighting measures were able to be counted as EE. As mentioned previously, the new EISA standard has limited, and will continue to limit, the potential of energy efficiency gains in the lighting sector. In addition, as the EPA notes, the pace of incremental EE savings slow over time as the sources of readily available and relatively lower cost EE dwindle (what is known as the "pincher effect"). EPA does not factor these considerations into their application of this pace of improvement to all other states.

B. Cost Estimates

EPA's proposal did not use a transparent process in estimating the costs of the proposed EE targets, did not consider all cost elements of EE, and did not give adequate consideration to the impacts of such costs on customers. Therefore, EPA has not adequately evaluated the cost-effectiveness of its proposed standard.

EPA's cost analysis is not transparent. EPA provides little information of the composition, elements, or methods of determining their Levelized Cost of Saved Energy (LCOSE) figures. Implementation of EE requires investment. The costs of such investment include:

- Utility costs to administer the program. These costs are generally recoverable in rates from customers in order to recompense utilities for their expenditures. These costs include:
    - Program administration expenses (advertising, fulfillment, tracking, etc.)

- Incentives to participants (various forms of rebates, buy-downs, etc.)
- Evaluation, measurement and verification (EM&V) activity (to check the validity of the EE impacts)
- Associated regulatory filings and other expenses.

- Recovery of lost-revenues (that portion of rates associated with fixed costs that are not avoided when energy use is reduced through EE programs). These costs are not addressed in EPA analysis. The consequences of not including this cost category in the EPA analysis could substantially change the resulting cost of compliance with the proposed rule.
- Administrator incentives. These costs are not addressed in the EPA analysis. The consequences of not including this cost category in the EPA analysis could also substantially change the resulting cost of compliance with the proposed rule.
- Customer investment in efficiency premiums. Customers pay a portion of the premium (sometimes matching the amount paid by the utility) associated with higher efficiency equipment.

C. Measurement and Accounting

The costs to implement EPA's aggressive schedule to achieve the EE levels envisioned by the proposal could be prohibitive. EPA's own estimates of the costs for implementation of the proposed EE requirements in the GHG Abatement Measure Technical Support Document (TSD) Supplemental Models show a substantial level of investments that would result in significant rate impacts on customers.

EPA has not defined the measurement and accounting protocols for EE so that the actual amount of contributions that such measures make toward the proposed standard is uncertain, and there are substantial and complex issues that have no current consensus solutions. Simply inviting comments on these issues does not provide an adequate basis on which to evaluate the goals or provide a basis on which its costs can be reasonably estimated.

1. Attribution

EPA suggests throughout the document that there is flexibility in how emission targets are achieved. As it relates to EE, this discussion extends to whether or not EE is required, what entity would have such responsibility (state, utility – integrated or distribution-only, independent program administrator, etc.), how such credits would be realized (state certificates, credits purchased by EGUs, etc.), in what market such credits are fungible (states, RTOs, trading regions, etc.) and so on. However, unless the states are given absolute discretion to resolve these issues to their own satisfaction, the uncertainties associated with these issues amount to a federal license to reject state submissions if all of the details of the state's EE programs do not conform to standards that EPA never clearly defined.

EPA's TSDs also discuss the challenges associated with attributing the resulting CO_2 reductions to specific generators, due the variety of ways that states could design their plans (especially for mass-based standards). In states with competitive generation supplies, there is no mechanism available to make utilities accountable for actual emission reductions at generation facilities that they do not control. Numerous other complicating variables exist, none of which have been resolved, including: allocation of EE measures for multi-state utilities; crediting excess EE measures for 111(d) compliance purposes; how differing market structures such as integrated utility operations or merchant plant ownership affect EE allocations; treatment of states that are net importers or exporters of power; how the particular load profile of utilities affects EE programs and resulting impacts on EGUs through merit order dispatch; and how those impacts evolve as generation profiles change over the compliance period. A full evaluation of these issues is also necessary to assess the effectiveness of any particular EE strategy, or design an effective state plan.

2. Evaluation, Measurement and Validation

EPA failed to establish Evaluation, Measurement and Validation ("EM&V") protocols that need to be relied upon by states to develop state plans. EPA's use of "expired savings", as outlined in the GHG Abatement Measures Technical Support Document, is an unorthodox and unjustified attempt to apply a one-size-fits all methodology that fails to recognize the very substantial variation in the duration of EE savings from particular measures (EE measure "life"). Among the many issues that need to be identified and addressed in the final guidelines before state plans can be proposed include: acceptable sources of EE; net-to-gross approaches; harmonization of differing state EM&V standards; recordkeeping requirements; and protocols for continuing credit from established measures. EPA's plan "to establish guidance for acceptable quantification, monitoring and verification" of EE measures for an approvable EM&V plan "in the coming years" is wholly inadequate. EPA has not even outlined a specific timetable for when it plans to develop this guidance. There is no assurance that EPA will begin its effort to develop guidance on acceptable EM&V methods in time for states to assess the cost and value of these options. If the EM&V methods required by EPA for compliance are significantly different from the EM&V methods already approved by a state PUC for established EE programs, there will be additional implementation delays associated with the development of new state laws and regulations to implement these unknown requirements. Ultimately, measurement affects the stringency of any standard, so without clarity on the measurement techniques that will be applied to these measures, interested parties have not had an adequate opportunity for comment, and EPA has not fulfilled its obligations under Section 307 of the CAA.

3. Impacts

While numerous approaches are discussed to remedy the difficult questions that arise in the area of EE attribution and EM&V, EPA proposes none and simply invites comments. All of these critical questions need affirmative answers or must be left to the states' discretion. Utilities have frequently been permitted to calculate EE savings based on the number of incentives issued, without extensive efforts to verify reductions in energy demand. If reasonable estimates of EE savings can be associated with specific measures and states can effectively track the number of such measures that have been implemented, EPA should deem the plan to satisfactorily comply with EPA's requirements. Otherwise, without definitive and timely guidance on these protocols, states will be second-guessed on the level of EE contributions associated with the proposed measures in their plans. Depending upon EPA's hindsight evaluation, the resolution to these questions, the relative contribution of EE to GHG reductions could be orders of magnitude greater or lesser, and plan approvals unreasonably delayed.

In addition, this uncertainty could lead to substantially underestimating the needed amount and types of EE (leaving the state short of meeting the needed contributions from EE) or overestimating the needed amounts and types of EE (needlessly increasing the overall costs of compliance). The "flexibility" built into this particular building block simply exposes the many substantive issues that remain unresolved, and to which EPA acknowledges it does not have readily available solutions. EPA must do more than simply "invite comments" or assert that there is "flexibility" and provide meaningful guidance on what will or will not be considered adequate EE measures.

D. Ancillary Issues

There are a number of other important issues that EPA needs to consider with respect to the proposed rule.

1. Electricity Suppliers

EPA established the state EE targets based upon the current retail sales of electricity in the state. Therefore, it is important to note that if these targets were to be proportionately allocated to the various electric suppliers, all such utilities (including investor owned utilities, municipalities, rural cooperative, and competitive retail suppliers) would need to implement EE programs to achieve the standard. Currently in many states only investor-owned utilities are required to implement such programs, while municipal utilities, rural cooperatives, and other suppliers oftentimes are not. Unless states find a way to proportionately share the responsibility to achieve whatever EE target is established, certain customers will be unfairly burdened.

2. Variety of EE sources

EPA should not consider limiting the wide variety of EE sources available to meet any proposed standard. Specifically, sources such as transmission and distribution line efficiency upgrades, design improvements, and operational practice improvements; combined heat and power (“CHP”); improved codes and standards, and other measures should all be eligible to contribute toward whatever EE achievement target is ultimately adopted. Restricting the use of any source of EE will reduce the ability of EE to contribute to the reduction of emissions, and ultimately increase the costs of compliance.

Specifically, transmission and distribution facility efficiency upgrades can be a significant component of any EE program. Distribution efficiency improvements such as Conservation Voltage Reduction (“CVR”), Volt Var Optimization (“VVO”), high-efficiency transformers, low loss conductors, voltage upgrades, phase balancing, and reactive power compensation and control can result in both energy and capacity savings and provide other operational benefits. Similarly, transmission equipment efficiency improvements and practices (such as voltage upgrade of transmission circuits, reduction of substation auxiliary power, low loss conductors, highly-efficient substation transformers, reduction of shield wire losses and corona and insulator losses, etc.), as well as enhanced transmission capacity and system utilization (such as through dynamic line ratings, use of high-temperature low-sag conductors in congested corridors, power routers and energy storage, smart controls, wide-area monitoring, high-performance computation clusters) can allow the grid to operate more safely and improve system utilization, thereby reducing emissions. These measures collectively could substantially contribute to EE achievements and should be creditable toward any reasonable EE targets that are established.

4. Cost-effective EE not included in base case

Regardless of the ultimate disposition of EPA's proposed rule, some states already have plans to continue existing utility-administered programs. EPA's analysis is flawed in that it doesn't recognize the future impacts of these existing EE programs, or future impacts of new (incremental) EE programs, both of which will occur regardless of the implementation of the rule. This has the effect of attributing all future EE achievements solely to this proposal, even though they would occur regardless of its implementation. Therefore, much of the benefit ascribed to the CPP's implementation is overstated, relative to business-as-usual. Further, this has the effect of overstating the EPA base case electricity costs and in turn substantially understating the incremental costs of the CPP (relative to this overstated base case). NERA, an economic modeling and consulting firm, has produced a report that provides a summary of EPA's cost-benefit analysis of the CPP, and highlights this significant bias in the analysis.[394] EPA should re-examine the RIA for this rule, and include the likely impact of ongoing implementation of existing state programs in its base case.

5. Beneficial use

The increased use of electricity in other sectors (*e.g.*, electric vehicles, port and off-road vehicle electrification) can produce many benefits, including reduced CO_2 emissions from those sectors. At the same time, these activities increase the demand for electricity (and in turn, can increase CO_2 emissions from regulated sources). Given that EPA acknowledges the importance of the role of electric vehicles in reducing emissions from the transportation sector in the future, the effects need to be considered in the proposed rule.

[394] NERA Economic Consulting, *Potential Energy Impacts of the EPA Proposed Clean Power Plan,* (2014), Appendix C.

6. Timing

Many states have established legislation and extensive regulatory processes that codify the EE practices of utilities in their jurisdictions. The resulting requirements related to achievement of standards, cost caps, evaluation processes, and ratemaking activities oftentimes have established schedules that are inconsistent with the proposed rule. Further, a portion of these processes have a direct bearing on the measurement and accounting issues identified earlier that the EPA will address "in the years to come." These specifics will need to be determined prior to the States initiating legislative or regulatory action to incorporate any such measures into a proposed state plan. Further, for some states (such as Texas), legislators meet every-other-year, therefore the ability to develop state plans may take more than 24 months. This leaves inadequate time to address numerous important issues prior to initiating activity to comply with EPA's proposed rule. In addition, EPA assumes a ramp-up in EE achievement starting in 2017, several years prior to the proposed rule becoming enforceable. EPA provides no justification for using a standard of performance that begins prior to the rule taking effect.

IX. EPA has failed to describe the mechanisms states can use to develop and implement a plan that will reliably demonstrate compliance.

EPA's description of the criteria for developing and evaluating state plans focuses primarily on issues related to federal enforceability and bureaucratic administration.[395] It spends no time evaluating whether the framework laid out in the CPP provides a reasonable foundation upon which states can build a plan that is achievable or will reliably demonstrate compliance. Indeed, the overall structure, the multiple "building blocks," and the independent factors that influence their achievability, make the task of designing and implementing a plan that can consistently deliver emission reductions year-over-year, as contemplated by EPA, a practical impossibility.

There are a number of legal, technical, and practical concerns and uncertainties that make implementation of the proposed rule unworkable. Many of these unknowns relate to the assumptions underlying each building block, regulatory strategies that are unproven, levels of implementation that are technically and practically unachievable, or interactions that are not feasible to design or enforce within the existing statutory and regulatory authorities of the states.

EPA acknowledges that some of these issues "introduce practical enforceability considerations under a state plan."[396] But instead of fully evaluating these issues, EPA relies exclusively on the purported "flexibility" that the agency believes states have to address any challenges associated with implementation. This claimed "flexibility" is illusory. There is no way for states to assure that individual generating units will achieve the emission reductions associated with block 1, and no technical basis upon which EPA can conclude that the projected emission reductions will actually occur, because EPA does not evaluate the extent to which such measures have already been implemented, and did not properly account for the heat rate increases associated with recent control equipment installations. There is no way for states to control system dispatch decisions that are entrusted to regional authorities, and simply attempting to "freeze" emissions from designated facilities in 2020 based on projected emissions and generation that accommodate the effects EPA hopes to achieve through building blocks 1 and 2 does not adequately account for the many factors that introduce variability into existing units' utilization and emissions, including weather patterns, unanticipated equipment problems,

[395] 79 Fed. Reg. at 34,900 – 34,911.
[396] "State Plan Considerations TSD." U.S.EPA. June 2014. p.10.

and changes in local load conditions. The output of renewable resources similarly is heavily influenced by weather conditions, equipment condition, and other factors that are neither controlled nor controllable by the designated facilities or the states, and EPA has misinterpreted existing state standards by ignoring the extent to which those standards are currently satisfied by participation in multi-state REC markets, the extent to which they are satisfied in whole or part through energy efficiency measures or alternative payments, and the extent to which they rely on unique resources whose status as "renewable" energy sources in any future section 111(d) plan is uncertain. These errors make EPA's cumulative targets unreasonable and arbitrary. Finally, EPA has no authority to regulate the behavior of consumers, and its simplistic evaluation of the potential for future energy efficiency measures ignores fundamental aspects of program design and achievability. There are errors in each and every one of the blocks upon which the state goal calculation is based that make the final result arbitrary and capricious. All of these errors inflate the prospects for future emission reductions, and simply shift the search for effective ways to meet the arbitrary goals from one building block to another and beyond, to measures EPA admits are not cost-effective, in a continuous loop of legally, technically, and practically flawed options that impairs the development of any workable compliance solution.

Further, the process and aggressive schedule to design, approve, and implement state compliance plans is unnecessarily disjointed and unachievable. While EPA attempts to analogize the CPP implementation process to the process of developing state implementation plans for ambient air quality standards, the two programs are significantly different. The CPP is an unprecedented effort to create an expansive framework that goes far beyond emission rates that can be achieved through control installations or changes in operational practices at designated facilities alone. It is unrealistic for EPA to expect the implementation timelines to be similar because the proposed CPP involves a unique scope and complexity of factors that requires extensive coordination among a broad number of state and federal regulatory agencies, the regulated community, and other interested parties. This requires a process that is methodical, collaborative, and well-informed – a process that requires a more extended schedule than that envisioned by EPA, even with the proposed extension options for states to develop plans.

A. Errors in EPA's state goal calculations impair their viability

In order to fully evaluate compliance options and attempt to develop viable implementation strategies, states must have an accurate and complete understanding of how the goals are calculated, and what impact changes in the calculation methodology will have on their compliance obligations. Such information is difficult to elicit from the technical resources placed in the docket, and would have been enhanced by including: (1) detailed output form EPA's IPM modeling runs; (2) clear background discussion of the alternative renewable energy goals and associated detailed year-by-year goal calculations; and (3) sample compliance calculations for multiple compliance years using a portfolio approach that illustrate the "flexibility" available to states in designing approvable programs. None of this information was available in the docket at the time of proposal, and much of it remains unavailable.

EPA's NODA, published on October 30, 2014,[397] increased, rather than decreased, the confusion and uncertainty regarding the goal calculation methodology, and added data to the record but failed to provide any insight on the impacts of using alternative base years, multi-year averaging, or changing the goal calculation by reducing fossil generation rates as renewable and energy efficiency measures are implemented during 2020-2029. Attached as Appendix D is a list of the issues upon which EPA requested comments in the initial proposal, as expanded by the NODA. As noted in the appendix, most of these requests propose alternative approaches or changes that affect the stringency of the state goals, but EPA provided no insight into what those impacts would be. The two exceptions to this general rule are the Option 2 state goals, and the goal calculations provided that rely solely on implementation of blocks 1 and 2, both of which were provided in the initial proposal. None of the alternatives described in the NODA have been used to calculate new state goals. There are multiple combinations of the alternatives proposed by EPA, and the outcome of each combination can result in unpredictable impacts on the ultimate obligations of the states - obligations that EPA says represent immutable standards against which any plan submitted by the state will be judged.[398]

AEP attempted to investigate how changes to the underlying information used to calculate the state goals would actually impact the goals. For example, EPA assigned states to

[397] 79 Fed. Reg.
[398] 79 Fed. Reg. at 34,892 ("As promulgated in the final rule following consideration of comments received, the interim and final goals will be binding emission guidelines for state plans.")

"regions" for purposes of identifying best practices and calculating the portion of the state goals attributable to development of renewable resources. However, based on the in-state resources available for development, certain regional average targets appear overly aggressive for certain states. AEP investigated the impact of "re-assigning" states to regions with more similar resource bases, and discovered that such re-assignments would actually *increase* the amount of renewable generation included in the calculation of the interim and final goals. Appendix C shows that if Arkansas and Louisiana were assigned to the Southeast region, which has a regional average target of 10 percent, instead of being included in the South Central Region, which has a regional average target of 20 percent, the amount of renewable energy included in the calculation of the interim goal would *increase* from 3,370,253 MWh to 4,848,761 MWh for Arkansas, and from 4,932,549 MWh to 7,282,579 MWh for Louisiana. This is a facially absurd result. Similarly, the base year upon which the goals are calculated makes a substantial difference, but the direction and extent of that difference are influenced primarily by local weather patterns, unit availability, and other unrelated factors.

AEP compared the renewable energy that would be included in the state goal calculations for states within the East Central, Southeast, and South Central Regions, using 2013 data, with the results of EPA's calculations using 2012 data. For all regions, changing the base year resulted in different goals and different rates of progress toward the regional goals. In certain regions, using 2013 data instead of 2012 data allowed the state to meet the regional target for 2020-2029. EPA's NODA suggests that other years may be used in the calculation of the final goals, without providing the kind of quantitative data necessary to evaluate the impact of such a change, and without explaining why any specific year or group of years is a more reasonable basis upon which to make such a calculation. EPA's inclusion of additional data in the record for this rulemaking at this late date does not cure the lack of notice and inability to effectively comment on alternatives that the agency itself has neither evaluated nor proposed, and cannot be used a means of securing *carte blanche* to perform additional calculations and derive an entirely new set of state goals that will appear for the first time in the final rule. Such tactics are fundamentally inconsistent with the agency's obligations under Section 307 of the CAA.[399]

Prior to promulgating a final rule, EPA should, at a minimum:

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[399] 42 U.S.C. § 7607(B); see also *Western States Petroleum Assoc. v. EPA,* 87 F.3d 280, 284 (9th Cir. 1996)..

- reconcile the extensive legal and technical issues that a have been identified regarding their interpretation, evaluation, and determination of the BSER;
- address the significant errors identified in the proposed state goal calculations;
- fully evaluate the broad scope of implementation issues that must be resolved and the corresponding regulatory agencies and other parties involved; and
- select a representative basis for the final guidelines, and present the information, data, sensitivity analyses, and a complete set of background information, and allow an opportunity for public comment on the proposal

B. Issues within each building block make implementation unworkable

As detailed in the specific comments for each building block, a number of issues have been identified regarding the underlying assumptions used by EPA. These issues create significant uncertainties that greatly diminish the potential for states to translate those assumptions into feasible requirements that can be implemented and enforced. A summary of these uncertainties and implementation concerns follows below.

1. Improvements made through building block 1 cannot be reliably projected or enforced.

As detailed in Section V above, it is unclear how EPA's assumptions within building block 1 could be implemented and enforced. Simply, it is infeasible to identify or develop a set of heat rate or CO_2 emission rate limitations that could be applied to all designated facilities within the regulated source categories, given the diversity of existing sources and the large number of known and unknown, controllable and uncontrollable variables that impact heat rate performance. AEP evaluated recent permits issued for both coal-fired and NGCC units across the nation, and found *no* examples of a permit where a heat rate standard has been imposed as an operating limit.[400] The lack of reliable information in the record upon which to assess the potential opportunities for improvement, the amount of potential improvement that may be realized, the sustainability of any improvement, and the lack of any real-time heat rate measurement technology capable of identifying and isolating the improvements associated with particular operating practices or equipment upgrades, support the development of a work practice standard. Such a standard could then be utilized by the states to evaluate future outage work and assure that the efficiency of the existing fleet is maintained and improved consistent with the

[400] See Appendix D

relevant factors that control a valid section 111(d) standard, including the remaining useful life of affected units. However, reliance on such a standard does not provide the states with readily quantifiable reductions that can be used to demonstrate achievement of a rate-based goal or mass emission cap. EPA must acknowledge these uncertainties and revise its criteria for approval of state plans to accommodate a reasonable work practice standard.

2. Building block 2 cannot require states to interfere with the economic dispatch or reliable operation of the grid.

Likewise for building block 2, it is unclear how EPA's assumed capacity factor could be effectively implemented and enforced because of various uncertainties related to whether the design, support infrastructure, and current permits and regulatory requirements for the existing NGCC fleet are sufficient for all units to sustainably achieve a 70% capacity factor. Even if all of these uncertainties were addressed, states cannot interfere with the existing regulatory authority and enforcement responsibility of the federally authorized agencies that control unit dispatch decisions and plan for the reliable operation of the electricity grid. Capacity factors at NGCC units will be influenced by a number of uncontrollable factors, including weather, local transmission constraints, fuel availability, performance of lower cost resources, and other factors. Further, it is unclear how EPA would envision a regulatory requirement be structured and enforced to achieve the types of redispatch assumptions that were used to derive the state goals. This includes the question of whether capacity factor is calculated using nameplate or summer capacity, but also, it includes uncertainties regarding how capacity factors are derived. AEP reviewed recent permits for NGCC units and other fossil units and found no examples of facilities that have an enforceable minimum capacity factor limit.[401] EPA's own modeled outputs indicate that the targeted 70 percent capacity factor used to create the state goals would not in fact be achieved by the proposed CPP. EPA must explain how states could develop a plan that produces results its own model refutes, or recognize that the proposal does not accurately reflect the operation of the electricity grid.

3. Building blocks 3 and 4 are not enforceable against designated facilities

EPA's proposal takes the form of a "portfolio approach" under which states would apply traditional "emission standards" to affected EGUs, and other requirements to other "affected

[401] See Appendix D.

entities" that, taken as a whole, will achieve the required level of emission performance.[402] Alternatively, EPA suggests that a "standard of performance" could be adopted by the states that places the entire burden of achieving the level of performance reflected in the state goals on affected sources. However, EPA also recognizes that states have varied regulatory frameworks for the electric industry that could impede their ability to enforce requirements related to building blocks 3 and 4 directly against many designated facilities. Certain owners and operators of EGUs are not subject to rate regulation or review of new resources, and have no retail customers. As such, they have no capability to require the addition of renewable resources within a state, and no ability to provide incentives for adoption of EE measures among retail customers. EPA proposes that states can create other "compliance entities" to assume those responsibilities,[403] but fails to explain how these entities (which emit nothing that is subject to regulation under the CAA) became subject to the jurisdiction of the environmental regulators, or how states could rely on activities by unrelated third parties to reduce emissions at independently operated facilities.

This framework raises a number of unanswered questions. Who is the entity being regulated? Who has enforcement responsibility? How are interstate considerations addressed with respect to credits for efforts within each block? What accounting processes will be required to assure no double counting of renewable energy credits and how will these interact with (or interfere with) existing markets and contractual rights? What EM&V requirements will apply to EE programs within and across state boundaries? Since EPA assumes that states will take early action prior to approval of their plans, what assurance can EPA give the states that credit that will be available for those efforts?

Separately, a number of concerns exist regarding the technical feasibility of potential opportunities to establish and expand renewable energy and EE programs, especially if these programs are implemented but fail to achieve the required reductions at affected units. Similarly, the consideration of nuclear units in the implementation plan raises issues regarding regulatory authority, enforcement responsibility, and compliance demonstrations if EPA intends the capacity factor assumptions used in calculating state goals to become an enforceable requirement

[402] 79 Fed. Reg. at 34,891.
[403] 79 Fed. Reg. at 34,901.

in order to claim a "credit" in the state's compliance demonstration. All of these issues are inadequately addressed in the proposal.

C. Uncertainties with the state plan development process and design options must be resolved before states can propose implementation plans to EPA

Separate from the concerns regarding the feasibility of developing requirements that represent the assumptions applied in each building block, there are a number of process related uncertainties regarding the steps required to design, approve, implement, and enforce state compliance plans. Detailed comments on these concerns follow.

1. EPA's Proposal to Allow State Plans to Include Federally Enforceable Obligations on "Affected Entities" Exceeds EPA's Statutory Authority.

In 2011, the U.S. Supreme Court provided an overview of the process by which EPA and the states must work together to craft greenhouse gas performance standards for existing sources:

> Section 111 of the Act directs the EPA Administrator to list "categories of stationary sources" that "in [her] judgment ... caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." § 7411(b)(1)(A). Once EPA lists a category, the agency must establish standards of performance for emission of pollutants from new or modified sources within that category. § 7411(b)(1)(B); see also § 7411(a)(2). And, most relevant here, § 7411(d) then requires regulation *of existing sources* within the same category.[404]

In other words, once EPA promulgates a section 111(b) NSPS, section 111(d) requires EPA to issue regulations under which the states will regulate existing sources <u>within that same category of sources</u>. In particular, section 111(d) directs EPA's Administrator to prescribe regulations that establish a procedure under which states submit plans that do only two things: (1) "establish[ ] standards of performance *for* [those] existing source[s]," and (2) "provide[ ] for the implementation and enforcement of such standards of performance."[405]

EPA, however, is "proposing to interpret CAA section 111 as allowing state plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources."[406] EPA's proposal explains that such an approach "could include enforceable CO_2

[404] *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537-2538, 2539, 180 L. Ed. 2d 435 (2011) (emphasis added) (footnote omitted).
[405] 42 U.S.C. § 7411(d)(1).
[406] 79 Fed. Reg. at 34,903.

emission limits that apply to affected EGUs [electric generating units] as well as other enforceable measures, such as RE [renewable energy] and demand-side EE [energy efficiency] measures, that avoid EGU CO_2 emissions and are implemented by the state or by another entity."[407] In other words, a "portfolio" plan would "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."[408] EPA offers four primary arguments in support of its theory that state plans could impose federally enforceable obligations on third-party "affected entities," none of which survives a facial review.

EPA's first argument "is based, in part, on CAA section 111(d)'s requirement that states set performance standards 'for' affected sources."[409] EPA argues that RE and EE measures are "for" EGUs because "they would have an effect on affected sources by, for example, causing reductions in affected EGUs' CO_2 emissions by decreasing the amount of generation needed from affected EGUs."[410] This argument is contrary to section 111 in at least two ways. First, as EPA itself states (but then immediately disregards), section 111(d) plans are supposed to "establish[ ] *standards of performance*" for existing sources.[411] Renewable energy generating technologies and demand-side energy efficiency measures (such as "energy efficiency programs, building energy codes, state appliance standards ..., tax credits, and benchmarking requirements for building energy use")[412] are not "standards of performance." A "standard of performance" is "a standard for emissions of air pollutants"[413] or "a requirement of continuous emission reduction."[414] Thus, no matter how one defines "for," RE and EE are not "standards of performance for any existing source" for purposes of section 111(d)(1). Second, the Act makes clear that "standards of performance *for* any existing source" must be standards that are applied *to* those existing sources, and not merely standards that "*have an effect on*"[415] those sources. There are only four sentences in section 111(d), and two of those sentences make this conclusion crystal clear:

[407] 79 Fed. Reg. at 34,837.
[408] 79 Fed. Reg. at 34,851.
[409] 79 Fed. Reg. at 34,903.
[410] 79 Fed. Reg. at 34,903.
[411] 42 U.S.C. § 7411(d)(1).
[412] 79 Fed. Reg. at 34,872.
[413] 42 U.S.C. § 7411(a)(1).
[414] 42 U.S.C. § 7602(l).
[415] 79 Fed. Reg. at 34,903 (emphasis added).

> Regulations of the Administrator under this paragraph shall permit the State *in applying a standard of performance to any particular source* under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of *the existing source to which such standard applies*. ... In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives *of the sources* in the category of sources *to which such standard applies*.[416]

Thus, viewing the phrase "standards of performance for any existing source" in context, as Supreme Court precedent requires, section 111(d) standards of performance are standards that apply *to* sources in the relevant source category, not just requirements that *affect* such sources. EPA's proposal to broaden section 111(d)(1) to include measures that are not "standards of performance" and do not apply to a regulated "existing source" is flatly contrary to the clear language of the statute.

EPA's second argument is that section 111(d) does not explicitly "prohibit[ ] states from including measures other than performance standards and implementation and enforcement measures," and that "the principle of cooperative federalism ... supports providing flexibility to states to meet environmental goals ... ."[417] This argument is fundamentally inconsistent with the fact that EPA is "a creature of statute," and has "only those authorities conferred upon it by Congress."[418] In section 111(d), Congress conferred authority on EPA to prescribe regulations under which states would submit plans that include (1) "standards of performance" and (2) "[provisions] for the implementation and enforcement of such standards of performance."[419] Congress did not authorize EPA to prescribe regulations under which states may submit plans that include measures *other* than performance standards and implementation and enforcement measures. Because Congress did not give EPA that authority, EPA does not have that authority. And, while it is true that states may choose to pass their own laws to reduce the CO_2 emissions of electric generating units in those states, such laws would not be part of any Section 111(d) plan if they did not constitute performance standards, or implementation and enforcement measures for performance standards.

As a third argument, EPA suggests that renewable energy and energy efficiency measures might qualify under the act as "implementation" measures. EPA explains: "if the state's plan

[416] 42 U.S.C. § 7411(d)(1) and (2).
[417] 79 Fed. Reg. at 34,903.
[418] *Michigan v. EPA*, 268 F.3d at 1081.
[419] 42 U.S.C. § 111(d)(1).

achieves the emission performance level through rate-based emission limits applicable to the affected sources, coupled with a crediting mechanism for RE and demand-side EE measures, we propose that RE and demand-side EE measures may be included in the plan as 'implement[ing]' measures because they facilitate the sources' compliance with their standards of performance."[420] This position assumes that "implementation" can be understood to mean "facilitation." It cannot, by any common understanding of the word "implement." WEBSTER'S defines "implement" to mean "to carry out"; "to give practical effect to and ensure of actual fulfillment by concrete measures[.]"[421] This is consistent with EPA's use of the word "implement," in proposed Subpart UUUU, to mean "carry out."[422] EPA's argument also misreads the statute. A state's section 111(d) plan must, again, "(1) "establish[ ] standards of performance" and (2) "provide[ ] for the implementation and enforcement *of such standards of performance*."[423] The Clean Power Plan's "emission performance levels," or "state goals,"[424] are not "standards of performance." Standards of performance are what the states would use to "*achieve* [t]he emission performance level."[425] Thus, the fact that RE and EE measures might help states achieve their emission performance levels could mean, at most, that such measures help the states "implement" *those emission performance levels*; it does not mean that those measures would help *EGU*s achieve their *standards of performance*. EPA acknowledges that RE and EE measures "are not directly tied to emission reductions that affected sources are required to make through emission limits" and "are not intended or designed to assist affected EGUs in meeting the performance standards."[426]

Finally, and in the alternative, EPA suggests that the state emission performance levels (*i.e.*, the "state goals") *could* be considered "standards of performance," "because it is in the nature of a requirement that concerns emissions and it is 'for' the affected sources because it

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[420] 79 Fed. Reg. at 34,903.
[421] WEBSTER'S THIRD NEW INTERNATIONAL DICTIONARY 1134 (1981).
[422] *See*, *e.g.*, Proposed 40 C.F.R. §§ 60.5710 ("you must submit a state plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart.") and 60.5720 ("If you do not submit an approvable state plan the EPA will develop a Federal plan for your state according to § 60.27 to implement the emission guidelines contained in this subpart.").
[423] 42 U.S.C. § 7411(d)(1) (emphasis added).
[424] *See* 79 Fed. Reg. at 34,903.
[425] *See*, *e.g.*, 79 Fed. Reg. at 34,851 (emphasis added); *see also id.* at 34,853 ("[E]ach state must develop a plan to achieve an emission performance level that corresponds to the state goal. The state plans must establish standards of performance for the affected EGUs and include measures that implement and enforce those standards.").
[426] 79 Fed. Reg. at 34,903.

helps determine their obligations under the plan."[427] EPA does not explain this point, but the agency presumably intends to argue that if the state goals are "standards of performance," then EE and RE measures would be "implement[ing] measures that could be included in the state plans. This argument, like the first three arguments, suffers from obvious flaws. "Standard of performance" does not mean "a requirement that concerns emissions"; it means, again, "a standard for emissions of air pollutants"[428] or "a requirement of continuous emission reduction."[429] A standard of performance is *for* an existing source only if it is applied *to* that source. The state goals cannot be standards of performance because, as EPA has explained, the state goals "are *not* requirements on individual electric generating units."[430] The state goals cannot be "standards of performance" because EPA has no authority to set standards of performance; it is the state plans that establish the standards of performance.[431]

For all of these reasons, states could not adopt a portfolio approach that includes *federally* enforceable obligations on third-party "affected entities" when establishing their section 111(d) plans. Such an approach would be directly contrary to the clear commands of section 111(d) and, as such, would be unlawful. This does not mean, however, that states could not use state renewable energy or energy efficiency requirements as a method to help the states achieve their emission performance levels. AEP agrees with those stakeholders who suggested "that states could rely on RE and demand-side EE programs [that are enforceable under state law] as complementary measures to reduce costs for, and otherwise facilitate, EGU emission limits without including those measures in the CAA section 111(d) state plan."[432]

2. EPA's Proposal to Regulate States or State Agencies as "Compliance Entities" Is Inconsistent with the Clean Air Act's Premise of Cooperative Federalism and Raises Serious Enforceability Concerns

The building block assumptions relate to both emission sources that have historically been regulated by the Clean Air Act, as well as other entities who, until this proposed rule, would

[427] 79 Fed. Reg. at 34,903.
[428] 42 U.S.C. § 7411(a)(1).
[429] 42 U.S.C. § 7602(l).
[430] EPA, *Fact Sheet: Clean Power Plan / National Framework for States – Setting State Goals to Cut Carbon Pollution* (June 13, 2014) (*available at* http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-setting-goals.pdf).
[431] *See* 42 U.S.C. § 7411(d)(1).
[432] 79 Fed. Reg. at 34,902.

have not been subject to the Act or to regulation by state environmental agencies. EPA refers to this expanded scope of regulated entities by noting that:

> a mix of entities might have enforceable obligations under a state plan. This includes owners and operators of affected EGUs subject to direct emission limits, as well as electric distribution utilities, private or public third-party entities, and state agencies or authorities that administer end-use energy efficiency and renewable energy deployment programs or are subject to portfolio requirements.[433]

And further comments:

> responsible entities in an approval state plan may include an owner or operator of an affected EGU, other entities with responsibilities assigned by a state, or the state itself. Other entities might include an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity. State responsibility might include obligations that are assumed directly by a state agency, authority, or other state entity to carry out aspects of the state plan. While this approach provides states with broad discretion to develop plants that best suit their circumstances and policy objectives, assigning responsibility to other parties regulated by the state, private or public third-party entities, or state entities *raises enforceability considerations*.[434]

Various provisions of EPA's proposed Clean Power Plan rely on the assumptions that states themselves may take responsibility for obligations under a section 111(d) plan, and that such states would be subject to citizen suit if they failed to fulfill those obligations. For example, EPA solicits comment on a "state commitment approach" to section 111(d) plans, under which states would commit to implement, say, RE and demand-side EE programs "that would achieve a specified portion of the required emission performance level on behalf of affected EGUs."[435] EPA explains that those commitments would not be part of the state plan, per se, and would not be federally enforceable.[436] Nonetheless, EPA asserts, states "fail[ing] to achieve the expected emission reductions ... could be subject to challenges – including by citizen groups – for violating CAA requirements and, as a result, could be held liable for CAA penalties."[437] Alternatively, EPA suggests, states could "impose the full responsibility for achieving the emission performance level on the affected EGUs, but ... credit the EGUs with the amount of emission reductions expected to be achieved from, for example, RE or demand-side EE measures" and "then assume responsibility for that credited amount of emission reductions ...

[433] Id. p. 10.
[434] Id. p. 13. (emphasis added)
[435] 79 Fed. Reg. at 34,902.
[436] *Id.*
[437] *Id.*

."[438] EPA's proposal ignores important restrictions on the ability to sue state agencies under the Clean Air Act's citizen suit provisions.

Section 304 of the Clean Air Act authorizes "any person" to commence "citizen suits" against "any person (including ... any ... governmental instrumentality or agency to the extent permitted by the Eleventh Amendment to the Constitution) ... who is alleged to have violated ... or to be in violation of" certain requirements of the Clean Air Act.[439] The relevant provisions of section 304 would permit suit only for violations of "an emission standard or limitation" or "an order issued by the Administrator or a State with respect to such a standard or limitation."[440] "Emission standard or limitation under this chapter" is defined, in section 304(f)(3), to include "any requirement under section 7411 or 7412 of this title (without regard to whether such requirement is expressed as an emission standard or otherwise)[.]"[441] Section 304 does not, however, provide citizens the ability to sue state agencies for failure to administer section 111 requirements. In *Sierra Club v. Korleski*, the U.S. Court of Appeals for the Sixth Circuit held that "§ 7604(a)(1) does not permit citizen suits against state regulators *qua* regulators. Instead," the court held, "§ 7604(a)(1) is only a means by which "parties may enforce the substantive provisions of the [CAA] against regulated parties[.]"[442]

Consequently, any proposal in EPA's Clean Power Plan that would impose legal responsibility on a state or state agency to undertake measures to comply with the state emission performance goals would be unreasonable, as it would be effectively unenforceable by citizen suit plaintiffs.

The assumptions applied to the building blocks involve regulating entities, operations, and programs that exceed the existing regulatory jurisdiction of state environmental agencies. It is unclear who has, could have, or should have the authority to establish and enforce limits for the assumptions that extend beyond the current authority of state environmental agencies. Further, the process and time required for individual states to evaluate, design, and establish such authorities is unclear. EPA acknowledges these issues regarding regulatory authority by noting that:

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[438] *Id.*
[439] 42 U.S.C. § 7604(a)(1).
[440] *Id.*
[441] 42 U.S.C. § 7604(f)(3).
[442] *Sierra Club v. Korleski*, 681 F.3d 342, 351 (6th Cir. 2012), quoting *Bennett v. Spear*, 520 U.S. 154, 173, 117 S. Ct. 1154, 137 L. Ed. 2d 281 (1997).

> ...due to differences in state utility regulatory structure, a portfolio approach implemented in a restructured state with retail competition will likely look quite different from one implemented in a state with vertically integrated, regulated electric utilities. This includes the process for developing the portfolio approach, the mechanics for implementing it, the responsible parties, and the regulatory and legal relationships among parties and state regulators.

and

> ...state public utility commissions (PUCs) often do not regulate these utilities [municipally owned utilities or utility cooperatives]. As a result, implementation of a portfolio approach by these utilities would introduce practical enforceability considerations under a state plan.[443]

EPA alludes to these same concerns and in some cases suggests the need for state legislation to establish the regulatory authority and to potentially fund the implementation of such programs by noting that:

> [A] legal arrangement that might be applied under this scenario is legislation directing state executive branch actions, or actions by independent state authorities under the plan, if obligations are not met. Depending on the form of legislation, this could also provide citizens with the ability to compel state action under state law, if obligations are not met under a state plan. An additional consideration is whether such legal arrangements, if related to a renewable energy or end-use energy efficiency deployment program, should also specify a stable budget authority or funding source through the plan performance period, or other provisions, to ensure that programs are implemented as projected under the state plan.[444]

The willingness of states to undertake such legislative initiatives and the timing required for states to successfully enact such initiatives is a significant unknown, especially in context with extensive concerns regarding the nature and scope of existing state regulatory authorities that may be ceded to EPA.

EPA is correct that the construct of the proposed rule "raised enforceability considerations." EPA's proposal attempts to regulate entities that are not subject to the Clean Air Act, do not own assets that are emission sources (i.e. distribution only companies), or that do not own any assets associated at all with the generation or delivery of electricity (i.e. state agencies responsible for energy efficiency programs). These concerns will impede state plan development, because they exceed EPA's authority and the authority of state agencies under the CAA.

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[443] Id. pp.9-11.
[444] "State Plan Considerations TSD." U.S.EPA. June 2014. pp.17-18.

3. Uncertainties Affect Plan Development Due to Reliability Issues

EPA projects that implementation of the proposed rule will result in significant changes in how and where electricity is generated. The agency estimates that as a result of implementing the proposed rule up to 49 GW of existing coal-based generation will retire by 2020, that existing NGCC units will be utilized more, and that new renewable energy development and energy efficiency programs will be implemented. Each of these outcomes must be evaluated by utilities, state utility commissions, and regional transmission organizations in order to assess and to mitigate potential reliability issues. The process for performing such evaluations for an individual state alone could be extensive. Given the fact that the transmission grid crosses state boundaries, and that multiple entities may be responsible for regional grid operations within a single state, the process of evaluating reliability concerns in context with proposed implementation strategies from multiple states, which may or may not be collaborating together, becomes significantly more complex and time consuming. As a result, the need to evaluate and respond to reliability issues creates significant unknowns regarding the process and time required for completing such analyses.

4. Uncertainties Regarding Multi-State Plans

The proposed rule presents the option for states to collaborate to develop multi-state plans. But such plans will require coordinated action by multiple state legislatures and regulatory agencies to come to fruition, and may even require Congressional approval before multi-state plans become a viable option for compliance.[445] The process and time required to develop an acceptable multi-state framework, coordinate plans by individual states, provide for adequate review by regional transmission authorities or other reliability organizations, and secure approval by Congress and EPA is not adequately considered or addressed in the EPA proposal. EPA has not adequately disclosed the consequences if one state is unable to meet all of its obligations, but others subject to a regional plan are in compliance. Unknowns also exist regarding the ability and process for states to exit multi-state plans and the corresponding impacts on all parties involved. For all of these reasons, EPA's proposal lacks sufficient detail to allow states to proceed with the development of multi-state plans.

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[445] *See* 42 U.S.C.§ 7402 (a), (c) (although Congress expressly encouraged the Administrator to facilitate interstate cooperation, and authorized states to negotiate and enter into agreements or compacts, no such agreement or compact is binding on a state until it has been approved by Congress).

D. EPA has overstated the degree of implementation "flexibility" available to states

Throughout the proposed rule, EPA refers to states having flexibility in the design of implementation plans. In reality, the purported flexibility is insufficient for developing any workable compliance solution. As previously discussed, significant flaws have been identified in EPA's assumptions and goal calculations for both blocks 1 and 2 Correcting these assumptions should reduce the stringency of the state goals, as there are significantly fewer opportunities for heat rate improvements available, and significantly less NGCC capacity is available for redispatch. Similarly, EPA's evaluation of the opportunities for increasing renewable energy and EE are seriously flawed. As a result, states ultimately have very little flexibility in developing plans, and no guidance on how alternative measures will be "credited" if they are relied on. These omissions must be addressed if states are to be equipped to investigate and adopt alternative measures as part of their state plans.

1. Potential compliance options referenced by EPA outside of the building blocks do not provide additional "flexibility"

EPA notes that other options outside of the building block assumptions may be available that would provide additional "flexibility" to states in developing implementation plans. These other options include the potential use of partial carbon capture and storage ("CCS") technologies and technologies to improve the efficiency of the transmission system, both of which are unproven, insufficient, and/or are not cost-effective solutions for achieving the proposed state goals. As noted in the extensive comments that AEP provided on the proposed 111(b) standards for new sources, CCS technologies have not been adequately demonstrated to be technically feasible or cost-effective for fossil fuel-fired generating units.[446] With respect to measures to improve the efficiency of the transmissions system, technologies do exist to improve performance. However, significant concerns remain regarding the broad application, cost, and performance of such technologies.[447]

2. EPA's proposed alternative mass-based program does not provide additional compliance flexibility

EPA has proposed basic guidelines for states/regions to convert emission rate guidelines into a binding mass-based emission cap. EPA guidance is largely based on a prospective

[446] See Appendix G for relevant AEP comments of CCS that were submitted on the proposed 111(b) rule. 2014.
[447] Id

modeling of emissions to demonstrate that a mass-based system is “at least as stringent” as EPA's rate-based goals for affected sources.

However, the measures that EPA has considered as part of an adjusted emission rate goal may or not directly displace emissions from affected sources in the same manner EPA has proposed due to the interconnected nature of the electric grid and the fact that under a least cost dispatch approach, emissions are always reduced from the marginal generating units at a specific point in time. (e.g. increased use of renewable energy or energy efficiency measures could at times displace emissions from out of state generation or gas-fired generation which would either not affect emissions from affected sources within a state or at a minimum not to levels EPA has assumed.) Therefore, states may be disadvantaged in setting a mass-based target even though they offer enormous benefits in terms of simplicity in implementation and market design.

Further, EPA’s conversion guidelines are also inadequate as it is unclear what modeling assumptions may be acceptable to EPA for approval of mass-based plan. While EPA has subsequently released a Technical Support Document discussing an “illustrative” approach for translating the emission rate-based carbon dioxide goals into mass-based goals, states may wish to take another approach to deriving their goals. EPA should still provide further guidance on what could be a workable system outside of the "illustrative" approach. Furthermore, EPA needs to make an explicit determination that mass-based goals could be codified within a SIP or SIPs and approved with no further need for review.

E. EPA must not infringe on the statutory authority granted for developing state plans, including consideration of the remaining useful life of existing sources.

EPA relies upon its claims of the “inherent flexibility” in the design of the proposed CPP to explain away its disregard for the elements Congress expressly entrusted to the states’ discretion in developing “standards of performance” under section 111(d). But EPA cannot write its own authorizing legislation, and must follow the clear prescription laid out in the statute.[448]

Section 111(d) unequivocally places the responsibility and authority for developing enforceable standards of performance for existing sources with the states. And Congress described the latitude EPA *must* provide to the states as follows:

[448] *UARG v. EPA*, 134 S.Ct. at 2446.

> "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies."[449]

The facilities and equipment to which the proposed guidelines apply are capital-intensive, long-lived assets, many of which have historically operated for 50 to 60 years. In addition, at most of these facilities, significant additional investments have recently been made to comply with other environmental regulations. Such investments have been made due to programs like the MATS rule[450] and the Regional Haze program "best available retrofit technology" or BART requirements.[451] In analyzing the cost-effectiveness of controls under the BART guidelines, EPA has often used the "remaining useful life" of a source as an input to that analysis, and its default assumption is that existing sources will continue to operate for 20 years after completing the retrofit of such controls.[452]

However, for purposes of this rulemaking, EPA assumes that all existing coal-fired sources that will be operating in 2020 and beyond should gradually reduce their generation and be replaced by lower or non-emitting generation or EE measures over a fifteen-year period. The most egregious example of this scenario is in Arizona, where EPA's model predicts that all coal-fueled EGUs will disappear before the final goals become effective in 2030. However, EPA's IPM outputs demonstrate that the integrated operation of the four building blocks would result in the retirement of many additional sources, none of which have reached the end of their "remaining useful life."

The magnitude of the recent investments in the existing fleet is staggering. AEP alone has spent approximately $3.5 billion to upgrade its existing units, and several compliance projects are still underway. Nowhere does EPA take into account the loss of these assets, and their potential impact on customer rates. Nor does EPA explain how it can override the discretion Congress specifically vested in the states to avoid such adverse economic impacts. EPA must address these costs, and revise its proposal to allow states the latitude to design

[449] 42 U.S.C. § 7411(d)(1).
[450] 40 CFR Part 63, Subpart UUUUU.
[451] 40 CFR §51.308.
[452] *Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans*, EPA-R09-OAR-2012-0021, 77 Fed. Reg. 42,833 at 42,854.

programs that do not result in the confiscation of assets, or prematurely force retirements rather than preserving the remaining useful lives of these units.

F. EPA cannot regulate affected sources under both 111(b) and 111(d)

AEP supports the comments of UARG, EEI and other organizations, which demonstrate that EPA's proposal to subject units that are modified or reconstructed after the effective date of a state or federal plan under Section 111(d) to the requirements of *both* programs is inconsistent with the plain language of the Clean Air Act. A unit is a *new* unit, or it is an *existing* unit; but it cannot be both simultaneously. If a unit is "modified" or "reconstructed" before such a plan is approved, none of the requirements for "existing" sources should apply. If that change occurs after state plan approval, the unit will no longer be subject to ongoing requirements for "existing" sources. While this could "change the equation" for a state or regional plan as currently envisioned by EPA's existing source proposal, this is simply one more change in the host of changes that will undoubtedly occur over the course of the administration of the program, and one on which EPA needs to provide clear guidance for the states.

G. EPA's proposed implementation timeline is unachievable

As illustrated above, the challenges confronting states are many, and EPA's proposal lacks the clarity necessary to guide the development and approval of state plans within the very aggressive time frame outlined in the proposal. The CAA does not set a specific time for the submission of state plans, nor does it establish a rigid compliance deadline for the designated facilities that are to be governed by the plans. EPA should reassess its schedule, given the realities of the tasks it has set before the states.

First, as explained in detail in many of the comments submitted by state agencies, even if EPA substantially revised its proposal to be consistent with the authorities granted by Congress, state regulatory development processes, including the public hearings and other processes required by the CAA, will take more than 13 months to complete. States are ordinarily provided with much more time to develop plans under section 110.[453] RTOs and others have indicated that they see a need for an option to review state plans, consistent with their long-term planning

[453] 42 U.S.C 7410(a) (providing three years for SIP submissions).

responsibilities for the bulk electric system.[454] Since the current planning processes at the RTOs can take up to a year to complete, allowing time for these essential reliability safety checks suggests that a minimum of two years may be necessary to develop sound state plans.

Multi-state planning efforts will take even longer to complete. The Regional Greenhouse Gas Initiative states devoted five years to the planning, legislative, and regulatory development efforts necessary to establish their program. EPA has provided no real world examples to support its time schedule for the development of state or regional plans, and must re-evaluate the time frames included in its proposal.

The second matter of grave concern is the interim compliance goals. EPA has assumed that all of the measures required under building blocks 1 and 2, as well as initial steps to implement block 4 and ongoing renewable energy development efforts, can be completed by 2020, and that assumption significantly affects a state's ability to demonstrate compliance with the 2020-2029 goal. These assumptions are unfounded, and create a "compliance cliff" in many states, as additional coal generation is projected to retire, natural gas pipeline capacity is assumed to be constructed, and all of the transmission additions and mitigation necessary to accommodate these vast changes in the make-up of the bulk electric system cannot be completed within this time frame.[455] The result, according to NERC, is widespread concern over the integrity of the bulk electric system.[456]

EPA has given no reasoned explanation of why it believes the transformation it seeks can be accomplished in less than five years after the final guidelines are published. Its assumptions are inherently unreasonable because they are based upon significant changes in investments occurring without sufficient regulatory certainty to support those changes. EGUs are in large measure regulated entities whose significant investments (whether they be generation, transmission or distribution assets) are subject to the oversight of state regulatory commissions, and are regularly examined in careful detail so as to protect the interests of utility customers. Since this process of regulatory oversight and approval typically occurs at the time the assets are placed in service, utilities must be prepared to demonstrate that the investments were prudently made, or risk disallowance of recovery for all or a portion of the investment. Therefore, until

[454] Comments of the Southwest Power Pool in Docket No. EPA-HQ-OAR-2013-0602, *filed* October 9, 2014 ("SPP Comments").
[455] NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan,* November 2014.
[456] *Id.*

utilities are reasonably confident that the proposed investment is consistent with the contents of a state plan that will not be disapproved by EPA and replaced by a federal plan, they will have no incentive to take measures to implement these requirements. EPA's proposal assumes that there will be as little as 6-18 months between the final approval of a plan by EPA and the initial compliance date in 2020. Such a short period for implementation is arbitrary, unreasonable and unlawful.

EPA has also offered no legal justification for the interim goals. EPA's implementing regulations state that guideline documents shall include, among other information:

> An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.[457]

EPA has said that its "state goals form the EPA's emission guidelines."[458] Thus, EPA's regulations would allow the agency to take into consideration "the time within which compliance with emission standards ... can be achieved" when setting its state goals. As the D.C. Circuit recognized in 1973, whether a particular degree of emission reduction is "achievable" depends on whether the system of emission reduction on which it is based is available, and "the question of availability is partially dependent on 'lead time,' the time in which the technology will have to be available."[459] The regulations would also allow EPA to "specify different [state goals] or compliance times or both for different sizes, types, and classes of designated facilities ... ." They would not, however, authorize EPA to specify different state goals *for different compliance times*, which is what EPA is attempting to do with its interim goals.

Nor are interim state goals necessary under EPA's implementing regulations. State plans under section 111(d) must include compliance schedules.[460] "Compliance schedule" is defined to mean "a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific emission standards contained in a plan or with any

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[457] 40 C.F.R. § 60.22(b).
[458] Legal Memorandum at 16.
[459] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).
[460] 40 C.F.R. § 60.24(a).

increments of progress to achieve such compliance."[461] Additionally, if compliance will take more than 12 months (which it would, under the CPP), state compliance schedules must include "legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities."[462] The increments of progress in state plans would ensure that states, affected EGUs, and/or affected entities would stay on track to achieve required CO_2 emission reductions. Nothing in section 111(d) or Subpart B, however, authorizes EPA to impose its own increments of progress up-front, in the form of interim state goals.

Lastly, EPA's state interim goals may be unnecessary to some extent. EPA has asserted that states and affected EGUs are already undertaking many or most of the measures that make up EPA's proposed BSER. EPA has said, for example, that "[a]verage deployment of RPS-supported renewable capacity from 2007-2012 has exceeded 6 GW per year."[463] EPA reports that "[i]n 2012, RE accounted for more than 56% of all new electrical capacity installations in the U.S."[464] EPA also reports that, according to a study by the Lawrence Berkeley National Laboratory, "efficiency programs are 'posed for dramatic growth over the course of the next 10 to 15 years[.]'"[465] If these studies and projections are correct, states are moving towards increased RE and demand-side EE even without the proposed command-and-control goals of the CPP.

If EPA finalizes a proposal that includes all or significant portions of the building blocks, EPA should eliminate the interim goal and provide states with true flexibility to design a glide path toward compliance.

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[461] 40 C.F.R. § 60.21(g).
[462] 40 C.F.R. § 60.24(e)(1).
[463] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants – GHG Abatement Measures, at 4-3 (June 10, 2014).
[464] *Id.* at 4-7.
[465] *Id.* at 5-19.

X. EPA Failed to Conduct An Adequate Reliability Analysis, and Does Not Provide Adequate Time in Its Implementation Schedule to Address Electric Infrastructure Needs

The U.S. transmission grid has evolved over the past 100 years to become the intricate system it is today. While flexible and adaptable to small changes in generation or load, the transmission grid is not prepared to accommodate the sweeping changes in the generation portfolio that would result from the CPP. As generation supplies of an electric system change, an evaluation of potential impacts to the transmission infrastructure used to deliver the energy is necessary to ensure reliable operation for the public good. The CPP is not based on any detailed reliability analysis, and would create an unprecedented change to the existing generation fleet through coal retirements and the addition of substantial new renewable generation. The plan essentially forces this sophisticated system to evolve and operate in an entirely different way than its current design, without considering the planning, analysis, and other activities that must precede such changes.

For utilities, cooperatives, balancing authorities, and many others, keeping the lights on is job #1. Changes to the mix of generation resources, even in isolation, require a full assessment of the capabilities of the transmission grid to be able to withstand the proposed changes in the generation fleet. As was demonstrated during implementation of the Mercury and Air Toxics Standards ("MATS") rule,[466] regional transmission authorities played a critical role in protecting the grid from the unintended consequences of generator retirements. Generators provided notice of their compliance plans to state authorities and RTOs, and together identified the activities and construction projects necessary to maintain reliability in those new configurations. In many cases, these assessments indicated the need for additional time, and states worked with generators to provide the needed flexibility in scheduling.

The number of retirements projected to occur as a result of EPA's CPP proposal far exceeds those projected to occur as a result of MATS implementation, and is estimated at between 46 and 49 GW of largely baseload coal-fired generation.[467] Recent assessments by individual RTOs, the National Electricity Reliability Corporation (NERC), and others indicate that new generation and transmission expansion will be necessary to maintain regional reliability standards under this new paradigm. Without this expansion, the CPP would result in widespread

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[466] 40 CFR Part 63, Subpart UUUUU.
[467] RIA, Section 3.7.4

reliability concerns, including the potential for blackouts. This kind of widespread service interruption, and the damages associated with it, has a significant negative impact on public health and welfare. Failing to adequately evaluate reliability impacts, or simply ignoring them, is not consistent with EPA's obligation to engage in reasoned decision-making, and renders the proposed CPP arbitrary and capricious.

A. EPA Lacks the Tools and Expertise to Assess Transmission Reliability

NERC is the regulatory authority entrusted with ensuring the reliability of the bulk power system in North America.[468] NERC's authority was enhanced following the 2003 blackout that interrupted electric service throughout the northeastern U.S. and parts of Canada. While the public most often associates service interruptions with dramatic weather events, the regular aging of transmission infrastructure, and relatively minor incidents resulting in loss of load or generation can disrupt the operation of the power grid, must be planned for and considered. This is a challenge even under business-as-usual scenarios. The changes contemplated as part of the CPP presents a multitude of uncertainties and complications that increase the risk of extensive disruptions to the grid.

Computer models are maintained per NERC requirements by utilities and RTOs/ISOs that represent intricacies of the physical transmission grid and its complex operation. These models are used to assess reliability by simulating the electrical performance of the grid during real-time operations, as well as to evaluate contingencies, and to plan potential future operating scenarios. These assessments help to identify conditions that may result in violations of reliability standards, and allow utilities to identify the measures necessary to mitigate potential reliability issues before they arise.

The analyses used to determine reliability impacts are commonly known as load power flow studies and stability studies. These analyses are performed to ensure that the grid operates within its physical and electrical limitations. Power flow studies balance supply and demand, and assess whether or not the power carrying capacity of lines and equipment is exceeded, and if the resulting voltages remain within specified voltage standards. Violations of these standards cannot be ignored, because sustained operation outside of the voltage thresholds will result in

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[468] FPA

loss of load or broad system outages. In the most severe cases, the models cannot solve, which is an indication of severe issues and a high risk for a major blackout.

NERC standard TPL-001-4 governs the analysis that must be performed by transmission planners (e.g., utilities) and planning coordinators (e.g., RTOs or other NERC-approved Regional Entities) to evaluate reliability on near-term and long-term bases.[469] This standard specifically states that the analysis must consider a number of anticipated factors, including load forecasts, expected service dates of new transmission facilities, reactive resource capabilities, and generation additions, retirements, or other dispatch scenarios. Each building block within the proposed CPP has a tremendous effect on one or more of these factors. NERC, transmission planners, and planning coordinators will therefore all be required to perform short –term and long-term analyses to determine the reliability impact of the proposal.

NERC has already confirmed this conclusion. In its preliminary review of the CPP, released on November 5, 2014, NERC identified several aspects of the CPP that impact grid reliability and require further analysis.[470] Specifically, NERC identified the projected changes in generation resources, and the increased reliance on renewable resources, concentration of particular types of generating resources (NGCC) as aspects of the proposed CPP that will strain essential reliability services and require electric transmission expansion. NERC also noted that more time is needed to evaluate and implement necessary grid reliability enhancements and recommended that flexibility mechanisms be available to sustain reliability during the transition.[471] NERC recommended that it continue to assess the reliability implications of the proposed CPP, and that regional and multi-regional industry planning groups and

In contrast to the evaluation provided by NERC, EPA released an 11-page technical support document entitled "Resource Adequacy and Reliability Analysis" in June 2014. According to EPA, for this analysis it utilized the Integrated Planning Model ("IPM") to analyze "the ability to deliver the resources to the loads, such that the overall power grid remains stable."[472] However, IPM is an economic model that is not suited to analyzing reliability.

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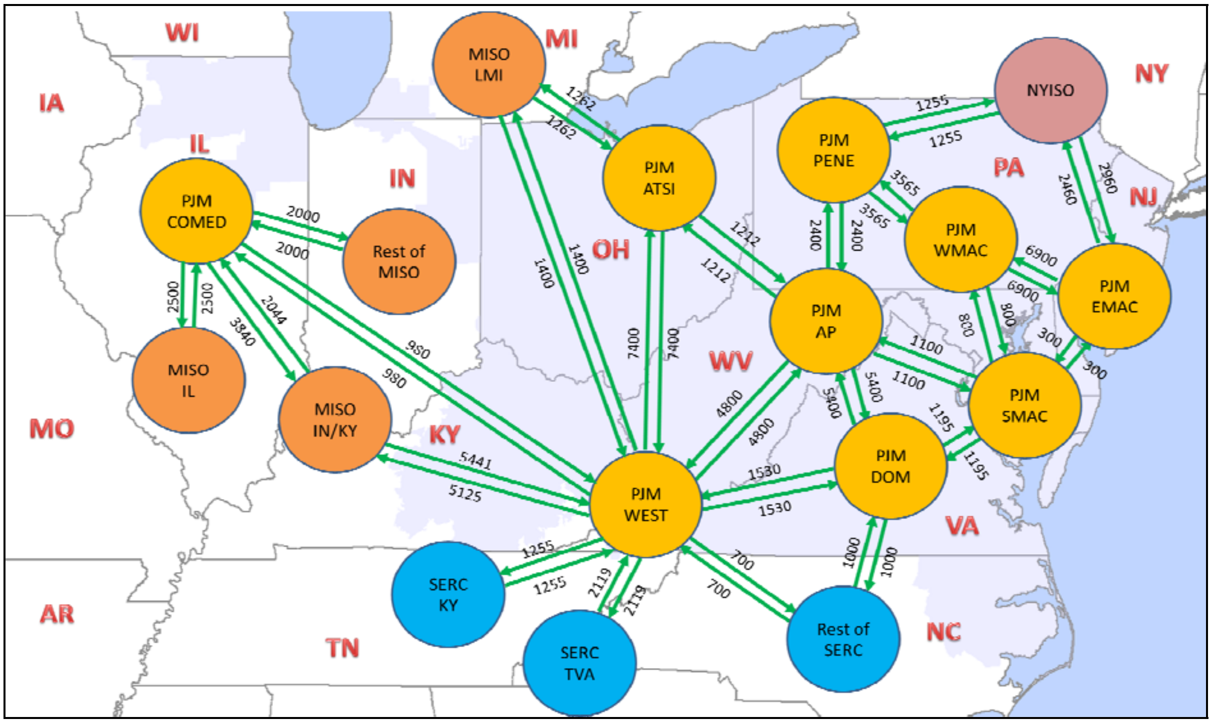
[469] www.nerc.com/files/TPL-001-4.pdf
[470] www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf
[471] Id at p.2.
[472] "Technical Support Document: Resource Adequacy and Reliability Analysis" USEPA. June 2014. p.1

In its description of the model, EPA states, “IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints.”[473] However, the IPM model is not capable of assessing transmission reliability because, as EPA admits, “Within each model region, IPM *assumes* that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region.”[474] In other words, EPA suggests there will be no impact to the transmission grid inside the regions, despite dramatically altering the generation resources within them.

EPA’s analysis is merely an economic assessment that does not consider reliability impacts or NERC standards. In IPM, as in many economic models, the transmission system is equalized into large “pipes” providing a gross representation of the power transfer capability between “bubbles”, or broad regions (typically RTO or utility regions). The IPM model utilized by EPA includes just 64 regions to represent over 16,000 electric transmission substations and over 450,000 circuit miles of transmission lines. This can be appropriate for high-level economic assessments, but should not be mistaken for a model that can be used to assess transmission reliability. The figure below is a depiction of the IPM economic model’s representation of the transmission system.

[473] Id.
[474] Id. p.2. (emphasis added.)



PJM Transmission According to the EPA Model

Economic models are used to estimate values like production costs, fuel consumption, capacity factors, emissions and emission costs. An economic model does not take into consideration the voltage/reactive power requirements of the transmission grid or the full range of possible contingency events. Unlike a load power flow analysis, only a small number of outage events are considered. Consequently, the results of economic analyses cannot be used to determine reliability impacts, nor should they be considered a substitute for load power flow or stability studies.

EPA, its own words, merely assumed that adequate transmission capacity would be available to deliver resources seamlessly and reliably.[475] However, this assumption may not even be valid for the system that will exists in 2016, after all MATS retirements have occurred, and certainly cannot be assumed to be the case once all other recommended changes introduced by the CPP take place.

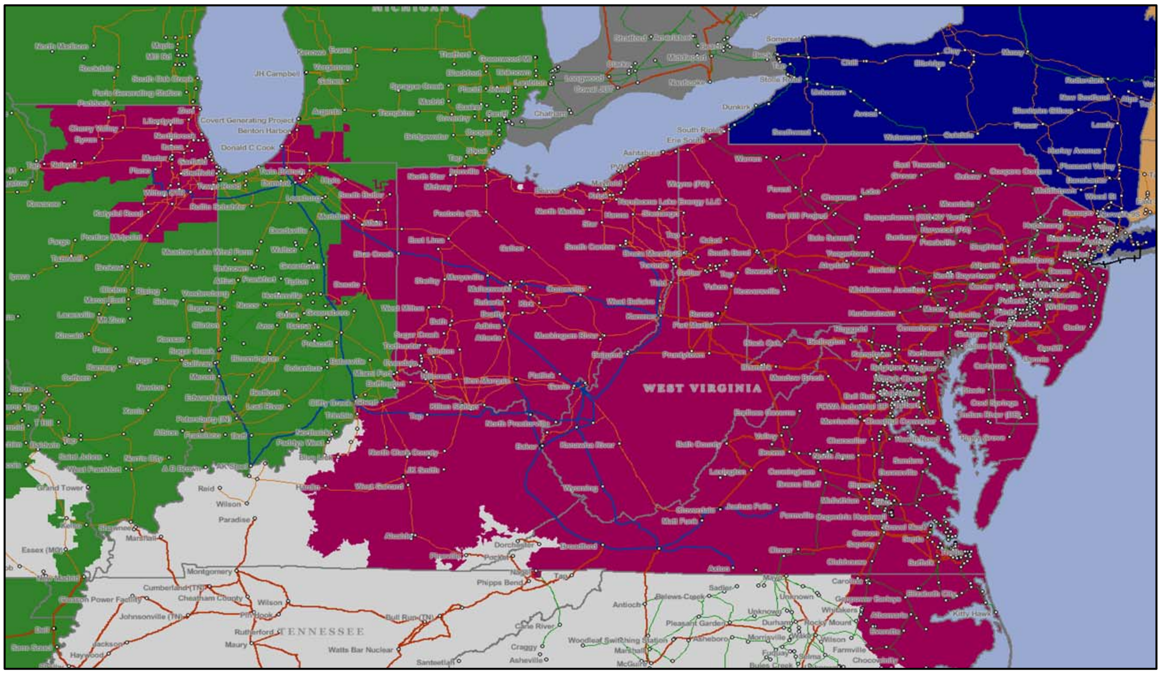
[475] *Resource Adequacy and Reliability Analysis,* p. 2.

B. AEP and Industry Analyses Demonstrate Real Reliability Concerns

AEP has performed preliminary power flow analyses for the transmission systems in PJM and SPP based on EPA's modeled unit retirements in 2020. These studies identified severe, widespread reliability concerns in both regions.[476] The problems consist of thermal overloads, low voltages, and voltage collapse leading to cascading outages. The study results are likely to be conservative, as they did not include an analysis of inter-regional impacts, or the effects of adding substantial amounts of new renewable generation. It is anticipated that the reliability issues identified would require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation, and to support the dispatch of the system in a manner significantly different from historical operations.

As mentioned, NERC and RTOs have echoed the concerns AEP's analysis has demonstrated. In SPP's reliability assessment published on October 9, 2014, their study findings "…make it very clear that new generation and transmission expansion will be necessary to maintain reliability during summer peak conditions if EPA's projected generator retirements occur."[477] Additionally, MISO's recent assessment uncovered hundreds of non-converged (unsolved) contingencies that indicate severe reliability violations.[478] The figure below is the actual transmission system that must be evaluated for reliability purposes, and can which was used, along with the proper tools, in performing AEP's analysis and those performed by SPP.

[476] See model outputs in presentation attached as Appendix E.
[477] www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf
[478]www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20141112/20141112%20PAC%20Item%2002b%20Preliminary%20Assessment%20of%20Transmission%20Reliability%20Impacts.pdf



The Actual PJM Transmission Grid (230 kV and above only)

AEP's reliability analysis that shows there are significant reliability problems *within* many of the 64 IPM model regions. Additionally, the assumed ratings of the interfaces ("pipes") between the IPM regions are negatively impacted by the changes to the generation fleet. The method in which these interface ratings are established using power flow models, and often they are limited by voltage limitations as opposed to transmission line capacity. AEP's analysis shows that the capacity of key interfaces within PJM could be reduced by as much as 20% due to a reduction in voltage support following retirement of coal generating plants. Thus, EPA's assumption that transmission is adequate within or between regions is flawed and unsubstantiated.

C. CPP Compliance Plans Are Not Viable without a Regional Transmission Analysis

EPA provides only scant acknowledgement of potential reliability issues when it states "Although there can be local grid reliability issues in replacing some units, these can be managed within the normal reliability planning and management time frames provided by the flexible resource options and time frames in the rule."[479] EPA has provided no analysis to validate this

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[479] *Resource Adequacy and Reliability Analysis, p. 5*

claim, and completely ignores the reality that developing the transmission necessary to address reliability in time to achieve the reductions EPA assumes can be fully implemented by 2020 (those associated with building blocks 1 and 2) is not achievable.

In addition, the current CPP is predicated upon state-specific plans. However, the interconnected electric power system functions as a single, large, dynamic machine – extending thousands of miles. Any modifications to electric generation or transmission in one state will inevitably impact surrounding states. Therefore it is imperative that reliability analyses be performed, at a minimum, by RTOs and other regional entities, on state plans, and on the comprehensive collection of plans that will impact the reliability of the electric grid. It will be impossible for states like Indiana, Michigan, Arkansas, Texas, Kentucky, and Louisiana, for example, that have facilities in multiple RTOs, to develop a compliance plan without interregional coordination.

The CPP will force such significant changes to the electric supply that a comprehensive assessment of reliability on a regional and interregional basis should be mandated. Additionally, the time required to determine the generation scenarios, perform the assessments, and determine solutions must be factored into the time line for development, submission, and approval of state plans. Accommodations must then be made that will allow time to construct necessary transmission projects before reliability is threatened. Only by performing a comprehensive transmission assessment prior to approval of state plans will it be possible to identify potential reliability threats, and the measures necessary to address them. However, EPA must then provide the time necessary to develop the infrastructure that will be required to support the transformation envisioned by the proposed CPP.

D. Interim Goals Incompatible with Transmission Infrastructure Requirements

The EPA technical support document related to transmission adequacy and reliability states that:

> Although not the focus of this document, it is important to recognize that this proposal provides flexibility in the context of state plan development that preserves the ability of responsible authorities to maintain electric reliability. For example, relevant planning authorities (such as ISOs and RTOs) may consult with states during the formulation of a state plan. ISOs and RTOs have also expressed interest in discussing the facilitation of emission control requirements under multi-state approaches. The flexibility of meeting the state goal over time also allows short-term variation in CO_2 emissions that may occur

> as certain generators run for short periods of time to maintain system reliability. While not discussed further here, these facts further support this document's demonstration that the implementation of this rule can be achieved without undermining resource adequacy or reliability.[480]

However, the reality of the situation is that the combination of targets and timelines removes any level of flexibility EPA purports to have included in the plan. Given EPA's assumptions on the retirements that would occur by 2020, it would be impossible to plan, engineer, site and construct transmission is this time frame that would provide for reliable operation of the grid.

Time lines currently contemplated for compliance are simply misaligned with transmission realities. Implementation of approved state plans will take time, as will potential mitigation measures to address unacceptable system conditions to accommodate retirements. The identification of new transmission needs, engineering, siting and construction will take anywhere from 5 to 10 years following development of the compliance plans. Figure 3 below highlights the major components of a typical transmission line project schedule.

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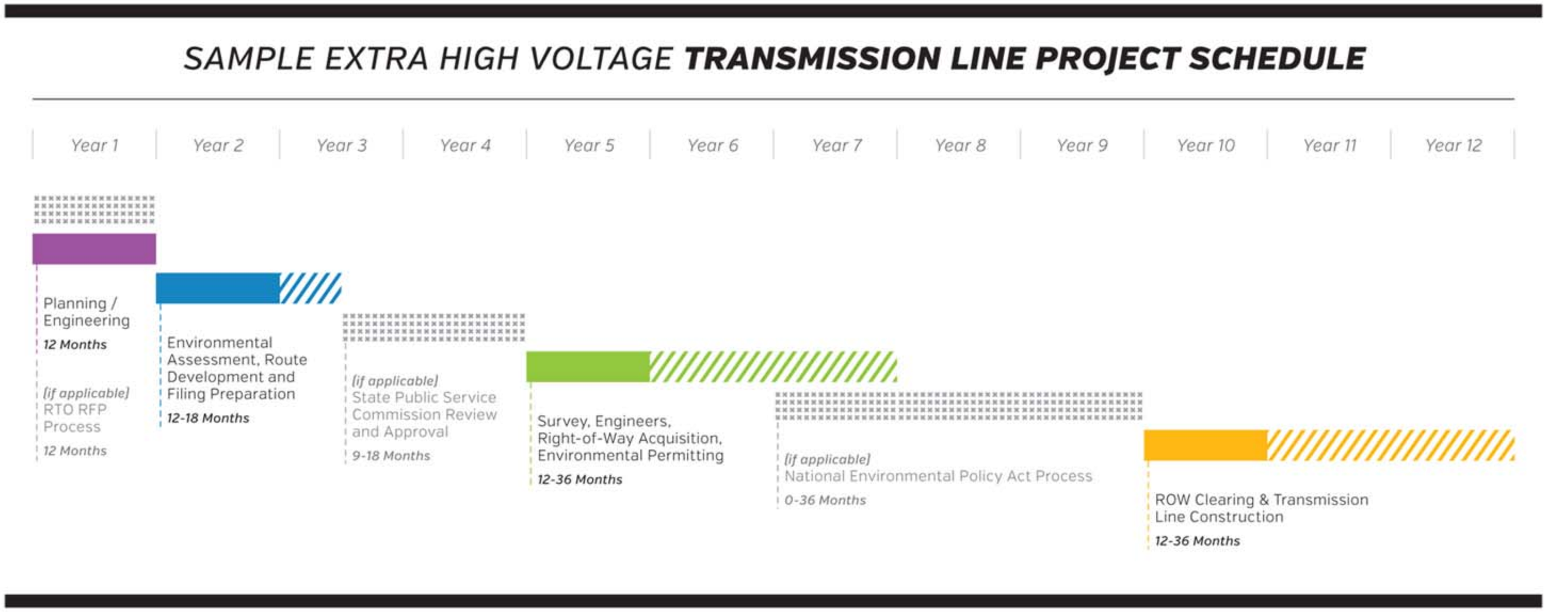
[480] Id. p. 1.



Sample Transmission Project Schedule

A transmission project lifecycle can vary significantly depending upon the type of project and where it is being built. The nature of the project (for example, its voltage and length), trigger different regulatory processes in different areas. Some, but not all, states review applications and issue permits for construction. Environmental issues, necessary permits and crossing public lands widely affect the process. Additionally, projects that require a National Environmental Policy Act review can plan on adding one to three years, or more, to the process. In AEP's own experience, a 90-mile line can take 16 years to complete.

As indicated previously, reliability studies must accompany the CPP's implementation and be incorporated into the compliance time frames. One of the few studies to date that could be considered comparable in scope to that required to assess the impact of EPA's CPP is the Eastern Interconnection Planning Collaborative (EIPC). This DOE-sponsored initiative was a first-of-its-kind effort to involve planning authorities in the Eastern Interconnection to model the impacts of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. Even this analysis, which did not consider the full range of NERC reliability standards, took over two years to complete, and ultimately did not result in an actionable plan.

Even after transmission requirements are identified, developers must be given the authority to construct quickly. The time line to plan and build upgrades to the transmission infrastructure will extend several years beyond the date resource plans are identified, and the current time lines for compliance with the CPP are insufficient for the necessary infrastructure to be built. Accomplishing this may require policy changes that sanction RTOs and other planning authorities to take action by approving necessary solutions sufficiently in advance of compliance deadlines and streamline siting and permitting activities.

Finally, the magnitude of the necessary transmission grid enhancements is expected to be substantial. However these grid enhancements cannot all be constructed at the same time. The new transmission infrastructure will need to be staged and constructed in a manner that allows the grid operators to schedule necessary facility outages while continuing to maintain reliable operations and keep the lights on. The need to stage the construction activities will increase the time frame required to fully implement the CPP.

E. Assumptions for Renewable Expansion Must Also Consider Transmission Requirements

Another aspect of the CPP that affects transmission is the integration of renewable resources. While this aspect was not directly considered as part of AEP's reliability analysis, it is well documented that connection and reliable delivery of new renewable resources requires transmission expansion. Even if states were to rely on existing RPS requirements to fulfill obligations under the CPP, the transmission grid is ill equipped to meet those objectives. PJM recently hired GE Energy Consulting to perform a renewable integration study for the region[481]. This study indicated the need for at least $3.7 billion in transmission upgrades to support a 14% regional RPS, and this figure could reach $13.7 billion under higher penetration scenarios. While these figures may pale in comparison to the total cost of implementing the CPP, the reality is that these transmission facilities would be in addition to the upgrades required to mitigate reliability impacts of coal unit retirements. Since much of the renewable generation capacity is located in remote locations far from load centers, much this infrastructure would be new facilities that require significant time to plan, permit, site, and construct.

F. Transmission Recommendations

A robust and adaptable transmission grid is essential to diversifying the generation portfolio and accommodating large changes to generation resources. The CPP will force significant changes to the electric generating plants, which will have clear ramifications on a transmission system designed for an entirely different supply paradigm. Transmission modernization can provide significant benefits, and should be considered an essential and complimentary element of the CPP.

For states to adequately develop an implementation plan, they will need to evaluate long-term options that involve unit retirements, multi-year contracts, e.g., power purchase agreements, or the requirement for the utilities to build new power plants. These decisions will drive the need for enhancements to the transmission grid and, conversely, transmission needs may affect states' decisions on generation resources. If enacted, the following recommendations are considered the minimum steps necessary to facilitate the evolution of the transmission system to accommodate these complex regulations:

[481] http://pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx

- A comprehensive assessment of reliability on a regional and interregional basis should be mandated and included as part of the CPP. RTOs, under the guidance of NERC, should commission detailed reliability studies to evaluate the impacts of both retiring generation and integration of new generation resources.
- RTOs should facilitate development of transmission upgrades necessary to sustain reliability and ensure the integrity of the transmission grid is maintained during the implementation period.
- The time required to determine the generation scenarios, perform the detailed analytical assessments, and identify the required grid enhancements and construct the necessary transmission infrastructure must be factored into the time line for compliance to ensure reliability is not threatened.

XI. Assessment of Regulatory Impact Analysis

EPA's Regulatory Impact Analysis ("RIA") of the proposed rule does not provide an adequate administrative record to allow for proper evaluation of the proposed rule and subsequent public comment. Furthermore, the methodology for assessing both costs and benefits is deeply flawed where information is present to be evaluated. The following areas have been identified as having either inadequate and incomplete information or information which was misinterpreted and/or misused within EPA's assessment of the potential cost, impacts and benefits of the proposed rule:

- Lack of Information on State Compliance Actions
- Conflicts Between Results and Purported BSER Elements
- Incomplete and Improper Assessment of Compliance Actions, Infrastructure Timing and Costs
- Incomplete Assessment of Employment Impacts
- Improper Treatment of Energy Efficiency
- Improper Use of Social Cost of Carbon
- Incomplete Assessment of Alternative Futures
- Misrepresentation of Energy Efficiency Expenditures/Costs

In light of these inadequacies, EPA should withdraw the current rule and re-propose at a later date, while addressing the previous legal and technical comments, in addition to the comments provided below.

A. Lack of Information on State Compliance Actions

The Integrated Planning Model (IPM) was used to support the RIA, however the IPM output files provided by EPA do not allow for a proper evaluation of the suite of measures that states and affected sources are projected to utilize under the proposed rule. EPA has provided the IPM "parsed" model output files only for one select model compliance year for each of the cases run. This does not allow for a full evaluation of state-by-state compliance actions across the full timeline the proposal encompasses. Furthermore, the model year provided is not consistent between the cases run. Additionally, the outputs for the IPM model run consisting of only building blocks 1 and 2 appears to be based on a single integrated model compliance year which does not allow for proper assessment of the emission caps as utilized by EPA. Full outputs and documentation are critical to the evaluation of the rule, particularly as the state agencies responsible for rule administration do not possess the tools or resources to assess potential electric sector compliance strategies.

B. Conflicts Between Results and Purported BSER elements

From the IPM results that are publically available, there are considerable inconsistencies between the modeled outcomes and what EPA has suggested as the BSER for the "building block" approach to calculating state goals. As a prominent example, EPA concludes that the existing NGCC fleet will only achieve annual capacity factors of 50-57 percent while the BSER determination suggests that 70 percent capacity factor is achievable. As the IPM model is a least-cost optimization, the fact that NGCC units do not reach 70 percent capacity factor in aggregate suggests there are unaccounted for significant economic and or physical barriers to increased utilization. This calls into question the robustness of EPA's initial BSER determination.

Another example of an inconsistency between the IPM modeled outcomes and building block determinations is in the deployment of renewable energy resources. EPA's modeling suggests a relatively small amount of new renewable energy development; for wind energy, the dominant source of renewable energy additions, there is only an 11 to 12 percent increase in generation in the policy cases for Option 1, as compared to the base case. Additionally, the renewable energy capacity additions appear to be centered in a few select states and regions, which is contrary to the view that renewable energy additions are cost effective across all states. In light of these inconsistencies, EPA should revise its BSER determination to reflect the amounts of renewable energy that are economically justified.

C. Incomplete and Improper Assessment of Compliance Actions, Infrastructure Timing and Costs

EPA has not provided a proper assessment of the timing and costs of associated infrastructure needed to implement this rule within the RIA. As currently utilized, the IPM model is an optimization of economic outcomes without regard to physical or practical realities. The model improperly assumes that compliance actions related to existing generating assets and construction of new generating assets could be deployed in 2016, which would assume an even earlier compliance evaluation and planning process. This is well in advance of when state plans would be developed, and does not consider the time necessary to put in place accompanying regulatory, legislative and compliance decisions. It is thus completely inconsistent with how the electric system is planned and managed.

EPA has a statutory duty to "tak[e] into account the cost of achieving such reduction" when determining the "best system of emission reduction."[482] The most centrally relevant costs are the costs to the existing sources required to make the emission reductions mandated under section 111(d). EPA has failed to identify, much less consider, those costs. Instead, EPA has estimated macroeconomic net costs to the entire nation. Under EPA's proposal, virtually all of the reductions in CO_2 emissions from affected EGUs come from reduced utilization of coal-fired EGUs. EPA must, at a minimum, determine the diminution in asset value to the owners of those existing sources, and the local and regional economic disruption and unemployment that would result from the proposal.

As an example, under its assessment of Option 1, EPA projects that an incremental 41 to 44 GW of generation will be taken offline in 2016 relative to the Base Case. Many of the units projected to retire are currently in the process of making multi-million dollar investments in emission controls to comply with MATS. EPA has therefore assumed billions of dollars of stranded investment associated with current retrofit projects and existing plant, property and equipment, which may not be fully depreciated. In regulated jurisdictions, these costs will be passed on to customers in the form of higher rates. In deregulated jurisdictions, these stranded investments will result in a loss of shareholder value.

In addition, EPA has failed to identify and consider the costs of the proposed transformation of the existing electricity systems, such as additional transmission facilities, additional natural gas pipeline capacity, additional transmission support capacity, additional financing costs of intermittently used generating capacity, and additional maintenance, repair and replacement due to increased ramping up and down of dispatchable generation. It is implausible to interpret the mandate to consider cost in section 111(d) as excluding the costs pinpointed on specific existing sources and specific local and regional economic disruption and unemployment. EPA's proposal is deficient and arbitrary in its omission of: 1) any analysis of the direct cost impacts to owners of existing coal-fired EGUs that would be expected or forced to shut down or reduce utilization; and 2) any analysis of the full costs of ensuring a reliable bulk power supply system in a rapid transition to lower carbon and intermittent electricity generation.

[482] 42 U.S.C. § 7411(a)(1).

EPA uses a separate Retail Price Module developed by ICF to estimate the impacts of the rule on retail electricity rates. However, it is unclear that this model incorporates stranded costs or ancillary transmission and other investment costs into its projections of electricity rates impacts. Stranded costs are capital expenses made by cost-of-service based utilities that are not fully recovered from customers by the end of a facility's useful life. As these plants would be prematurely deemed uneconomic, many of these plants would have associated capital costs that have not been fully recovered from ratepayers. Thus, ratepayers would still be required to pay the costs associated with these retired units in addition to the costs of any other measures that would have to be deployed in response to the rule. These consumer costs must be included in projections of rate impacts.

Notwithstanding the improper accounting of costs, there still remains the fact that compliance decisions related to existing assets will not be made until well after state compliance plans are approved. In the case of multi-state plans with one-year extensions at the state level, this approval could come mid-2019 or later. This is completely inconsistent with the assumption in EPA's modeling that compliance decisions related to both the disposition of existing assets and investment in new assets could be made to effectuate changes in the 2016 generating mix. A similar argument applies to the construction of new renewable energy efficiency measures and energy efficiency programs. Additional comments on this subject are also included within the Implementation section of AEP's comments.

The economic selection of unit retirements and new generation in the 2016 model year artificially skews the cost assessment of the proposal lower by assuming premature economic actions without a firm regulatory basis. Economic compliance decisions cannot be made and will not be made until well after state plans are approved. Due to this fact, in the IPM model assumptions, EPA must assume that any changes in the electric generating mix cannot occur until at least 2020 and then factor in the relevant development timelines for the various generating technologies. Using this realistic assumption for technology deployment would thereby limit any changes in the electric generation mix until well into next decade, which is reasonable given the timeline for state plan development, regulatory action and compliance determinations.

EPA has also not included any assessment of the need for firm gas delivery to support higher utilization of NGCC units. As units would be required to run additional hours to replace higher emitting generating sources, there would be increased hours of the year in which they would need delivered gas. However, in peak months, natural gas may not be available without a firm delivery contract. A firm delivery contract results in a higher delivered gas price, as the gas must be paid for whether used or not. This cost also needs to be factored into the cost assessment.

D. Incomplete Assessment of Employment Impacts

EPA's assessment of labor impacts ignores the largest labor impacts, which are the indirect jobs impacted as a result of higher energy costs. Higher electricity rates will arise in response to this proposal, discounting EPA's improper assumptions regarding energy efficiency and other factual modeling errors, as generators will be forced to internalize carbon costs and invest in compliance strategies that would otherwise be uneconomic absent the proposed rule. Higher natural gas prices will also be realized as electric generators consume more natural gas, driving domestic natural gas demand higher. Higher natural gas prices and electric rates will result in the economic dislocation of some industries, particularly those industries that are energy intensive, as they are unable to fully pass thru the higher cost of electricity and natural gas to their consumers and customers. This economic disruption will result in businesses curtailing output or relocating, with the loss of employment and tax income. EPA must consider these indirect job impacts in the RIA.

E. Improper Treatment of Energy Efficiency

The methodology used to evaluate the cost and benefits of energy efficiency (EE) are completely disjointed from a practical and economic reality. For purposes of cost-benefit analysis, EPA's assumptions on EE were "[hard wired] into the illustrative compliance scenarios. This approach is taken because the EPA has determined, as discussed previously, that EE is cost-effective at the established EE goal levels."[483] However, notwithstanding AEP's objections to the EE methodology, if the projected levels of energy efficiency are deemed to be exogenously economic, they should also be included in the Base Case projection of electric demand as these activities should occur organically absent this rulemaking and thus should already be factored into the electric load forecast. EPA makes no effort to rationalize why either EPA or EIA has not

[483] *Technical Support Document on GHG Abatement Measures*, at 5-49.

included these types of projections within the reference load forecast or what EPA models as a "base case."

The proposed rule does not require states to target any specific level of energy efficiency, nor is it within EPA's authority to require a set level of efficiency, the inclusion of the energy efficiency measures only in the policy cases artificially skews the costs of the program downward by assuming less generation is needed to meet electric demand and that avoided costs are greater than EE program costs. As EPA has reached a conclusion that the proposed levels of EE are economic under prevailing market conditions, EE measures must be included in both the base case and policy cases to ensure a proper, fair and transparent assessment of costs that are directly attributable to this proposal.

F. Improper Use of Social Cost of Carbon

EPA uses the Social Cost of Carbon (SCC) to characterize potential carbon benefits associated with the proposed rule, even though it is widely acknowledged that these cost estimates are inaccurate, uncertain, and highly speculative. EPA acknowledges in the RIA that "any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional."[484] As such, these calculations cannot form the basis of an adequate RIA. Additionally, according to guidance provided by the Office of Management and Budget (OMB), costs and benefits must be examined on a domestic, not global, basis. The current methodology for assigning a cost to carbon is based on a global value and therefore is both inconsistent with OMB guidance and EPA assessments of costs, which are only on a U.S. basis. As a result, EPA is offering an "apples-to-oranges" comparison of costs and benefits within the RIA.

As an example of how the flawed geographic scope of cost-benefit evaluation skews the results, one can examine the conclusions reached through EPA's IPM modeling of the rule. As projected by EPA's modeling, domestic coal prices will decline and natural gas prices will rise as a result of the proposed rule. Basic economics suggests that this change in prices would encourage increased exports of coal due to its lower cost basis and decreased exports of natural gas due to its higher cost basis. Because of this likely change in exports, international CO_2

[484] "RIA for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants." USEPA. June 2014. p. 182.

emissions will rise through increased international use of coal and decreased international use of natural gas, thus diminishing the purported benefits of the rule. Additionally, increased electricity and natural gas prices as a result of the rule could shift more manufacturing overseas to less efficient facilities to take advantage of lower energy costs, which could also result in increased CO_2 emissions. These potential increases in global CO_2 emissions, which would result in carbon costs, have not been quantified in any form, even though the benefits of the rule are calculated on a global basis. Due to this inherent and incorrect dichotomy, EPA must recalculate and evaluate any climate "benefits" associated with this proposal solely on the basis of domestic carbon value.

AEP also has considerable other concerns with the current methodology used to develop the Social Cost of Carbon (SCC) and has previously submitted detailed comments on the development of SCC values and their use. These comments are attached as Appendix F to this document.

G. Incomplete Assessment of Alternative Futures

EPA has not adequately accounted for the potential impacts of the proposed rule under a full range of possible future market conditions, effectively hiding the true potential costs of the proposed rule. Instead of robust scenario analysis, which would incorporate plausible alternative assumptions, EPA has overly relied upon "one-off" calculations and comparisons in making key determinations as to cos- effectiveness of technologies and programs. Policymakers and the general public need to be fully informed of the potential costs of this proposed rule through a comprehensive and well-informed analysis.

EPA has used a single model run in its analysis of options 1 & 2. However, while EPA conducted sensitivity analyses on a number of the assumptions going into the BSER determinations in an one-off approach, there was no effort to test the robustness of assumptions within the regulatory impact analysis of the rule. As the proposal assumes that BSER measures are available to the same extent they are used in the calculation of state targets, there is no proper assessment of the potential implications of one or more of the "building blocks" being either less available in quantity or less economic. As the BSER determination is structured on the "best system," unavailability of one of the building blocks would leave a state or region with limited options to reduce emissions elsewhere. EPA needs to provide alternative scenarios assuming some variance of the achievable rate of energy efficiency, heat rate improvements, and renewable developments, to paint a full picture of the potential costs of this proposed regulation.

It has been well understood and documented within the electric power sector that natural gas supply and prices play a pivotal role in determining both the current and projected future electricity mix, as well as electricity costs. EIA, whom EPA relies upon for a number of key data points, routinely produces alternative scenarios in its Annual Energy Outlook to examine some of these alternative futures given the importance. However, EPA has not evaluated any variance in natural gas supply or pricing under this proposal. This variable also needs to be further explored through sensitivity analysis and reporting of potential costs.

H. Misrepresentation of Energy Efficiency Expenditures/Costs

EPA misrepresents Energy Efficiency (EE) expenditures within the RIA by choosing to report and tabulate annualized EE costs in-lieu of first-year EE costs. As a result of the error, the total cost of the proposed rule is dramatically understated in both annual and present value terms. Energy efficient programs are typically funded on the basis of O&M expenditures for utility program costs and out-of-pocket expense for participant costs. As EE utility program costs are typically expensed, not capitalized within a rate-base, a first-year cost is the appropriate measure to evaluate the true cost, as this is the cost that directly flows to customer rates. Furthermore, participant costs are typically not financed, but rather represent a one-time out-of-pocket expenditure. Even to the extent some programs are financeable; the lending term is likely to be significantly less than the 20 year measure life assumed by EPA. As such, both participant and utility costs should be reported on an annual first-year cost basis.

As a result of EPA relying on annualized EE costs, the annual cost of the Clean Power Plan is dramatically understated in the early portions of the program, by more than $20 billion and almost $15 billion in 2020 and 2025, respectively. This has an enormous impact on the overall cost analysis for the proposed rule as the difference in cost reporting is accentuated under a calculation of present value cost. Use of annualized EE costs results in enormous discounting of total EE costs given an assumed 20 year EE measure life. Proper actuarial treatment would result in significantly higher present value costs as first-year costs would be discounted less to the present year.

In the calculation of retail rate impacts EPA appropriately recognizes utility program costs on a first-year cost basis. This first-year cost basis also needs to be applied to EE programs within the total cost assessment to allow for a proper assessment of the proposed rule's costs and benefits.

I. EPA must consider costs associated with transmission improvements required to implement the proposed rule and maintain reliability

As discussed in Section X above, EPA failed to conduct an adequate reliability analysis to determine the extent of potential improvements that are needed to existing transmission system in order to maintain reliability with the implementation of the proposed rule. Based on AEP modeling and concerns express by regional transmission organizations and NERC, the amount of improvements to the transmission grid may be extensive. As summarized in Appendix E, AEP's analysis indicates up to $2 billion in potential improvements may be necessary on the AEP transmission system alone as a result of the proposed rule. EPA must thoroughly evaluate and weigh costs associated with transmission upgrades in the RIA for the proposed rule.

XII. Miscellaneous

A. EPA Cannot Regulate Sources in a Category Subject to a Standard Under Section 112.

AEP adopts by reference, as if fully set forth herein, the arguments made in comments submitted by UARG, EEI, and 17 states' Attorneys General,[485] that the clear language of section 111(d) prohibits EPA from regulating emissions under that section when the "source category ... is regulated under section [112]."[486] EPA admits that a literal reading of the codified statute has this result,[487] but relies on a conforming amendment that was excluded from the code as justification for departing from the plain language of the law. EPA cites no support for this unique method of construing conflicting provisions of amendments made to a complex piece of legislation, and none exists. Instead, the conforming amendment should be disregarded, and the substantive amendment reflected in the U.S. Code should be given full effect.[488] As noted in UARG's comments, the conflicting amendments here do not create "ambiguity," they create conflict, and conflict can only be resolved by legislative choices, that is, by Congress.[489] Here Congress clearly acted by later passing the House bill, which contains the codified language prohibiting duplicative regulation of sources already regulated under section 112. Having made its choice to regulate EGUs under section 112,[490] EPA cannot now assert authority to regulate the same sources under section 111(d).

B. The Proposed Guidelines Constitute Uncompensated Takings.

For all of the reasons set forth above in Section IV, EPA cannot require reduced utilization or shutdown of existing EGUs as a "standard of performance" under section 111. However, to the extent that the proposed guidelines would result in the shutdown or reduced utilization of an existing unit with remaining useful life, particularly those units that have made substantial investments to comply with other recent rulemakings from the Administrator, the proposal would constitute an unlawful taking without just compensation, prohibited by the Fifth Amendment to the U.S. Constitution. The economic value of an EGU lies in its ability to generate electricity.

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[485] Comment from the Attorneys General of the States of Oklahoma, West Virginia, Nebraska, Alabama, Florida, Georgia, Indiana, Kansas, Louisiana, Michigan, Montana, North Dakota, Ohio, South Carolina, South Dakota, Utah and Wyoming, Docket No. EPA-HQ-OAR-2013-0602, submitted November 25, 2014.
[486] 42 U.S.C. § 7411(d)(1)(A)(i).
[487] *Legal Memorandum* at p. 26.
[488] *See, e.g.,American Petroleum Inst. V. SEC*, 714 F.3d 1329, 1336-1337 (D.C. Cir. 2013);
[489] *Scialabba v. Cuella de Osorio*, 134 S.Ct. 2191, 2214 (Roberts, C.J. concurring) (2014).
[490] 40 CFR Part 63, Subpart UUUUU.

The government must protect the investment-backed expectations that are embodied in the concept of "property," and provide just compensation if regulation goes so far as to rob citizens of the beneficial use of their property.[491] AEP incorporates by reference, as if fully set forth herein, the arguments made by UARG regarding this issue.

C. EPA Cannot Simultaneously Regulate Units Under Sections 111(b) and (d).

EPA proposes that units that become "modified" and therefore "new" sources after a state plan is adopted and goes into effect will remain subject to the requirements of the state plan, and at the same time be required to comply with the recently proposed standards under section 111(b). This result is precluded by the plain language of the statute, which contains definitions for "new" and "existing" sources that are mutually exclusive.[492] EPA's proposal would result in duplicative and overly burdensome regulation for the sources and confusion regarding the obligations of state permitting authorities. This purported "ambiguity" arises solely as a result of EPA's decision to invert the nature of the proposed standards, seeking far more aggressive emission reductions from existing sources than those that would apply if a source became "new" as a result of a modification. There is no basis for EPA's duplicative regulatory proposal, and it conflicts with the clear language of the statue and is invalid.

D. EPA's Proposal Omits Critical Information About Title V Requirements.

EPA's proposal omits critical information about the Title V requirements applicable to "affected entities" potentially included in state 111(d) plans, contrary to EPA's Title V regulations. The definition of "applicable requirement" for Title V permitting purposes includes "any standard or other requirement under section 111 of the Act, including section 111(d)."[493] The Title V regulations require a Title V permit for "[a]ny source, *including an area source*, subject to a standard, limitation, or other requirement under section 111 of the Act."[494] The regulations then provide: "In the case of non-major sources subject to a standard or other requirement under ... section 111 ... of the Act after July 21, 1992 . . , the Administrator will

[491] *Lingle v. Chevron USA, Inc.,* 544 U.S. 528,537 (2005); *Lucas v. South Carolina Coastal Council,* 505 U.S. 1003, 1019 (1992).
[492] 42 U.S.C. § 7411(a)(2) and (6).
[493] 40 C.F.R. § 70.2.
[494] 40 C.F.R. § 70.3(a)(2).

determine whether to exempt any or all such applicable sources from the requirement to obtain a part 70 permit at the time that the new standard is promulgated."[495]

EPA has not made any proposed determination of whether to exempt any or all non-major (area source) "compliance entities" subject to a standard or other requirement under the proposed Clean Power Plan from the duty to obtain a Title V permit. However, as discussed above, it is clear that making certain types of entities "compliance entities" results in an unauthorized expansion of EPA's authority, and will present unresolvable issues for state permitting authorities. The applicability or non-applicability of Title V permitting requirements also determines the enforcement mechanisms available to the states for section 111(d) plan requirements applicable to "compliance entities," and illustrates the absurd results that would follow from making the state itself, other governmental entities, or non-emitting generators subject to the enforcement provisions of the Title V permitting program. To the extent EPA continues to rely on its "portfolio approach" to developing section 111(d) plans, EPA's final rule must clarify the application of Title V's permitting requirements to "compliance entities," and avoid the absurd results that would ensue if section 111(d) were interpreted to encompass a broad range of entities far beyond the "affected facilities" that are within the listed source categories and can legitimately be subject to a 111(b) standard.

E. EPA Failed to Consider the Implications of Proposed Changes to the Ozone Standard.

The preamble to EPA's proposed section 111(d) rulemaking contains a discussion of the implications of other EPA rules on the proposal.[496] However, the proposal and its basis and purpose are completely devoid of any mention of another rule, the proposed revision to the ozone NAAQS, due to be published the same day comments are due on the section 111(d) proposal. EPA is under a court order to propose appropriate revisions to the current ozone standard (75 ppb, set in 2008) by December 1, 2014. The OAQPS August 2014 Policy Assessment finds the current standard insufficiently protective and recommends a more stringent standard in the range of 60 to 70 ppb.[497]

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[495] 40 C.F.R § 70.3(b)(2).
[496] *See* 79 Fed. Reg. at 34,928 - 34,931.
[497] *See* EPA., Office of Air and Radiation, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards, at ES-5 (Aug. 2014) (*available at* www.epa.gov/ttn/naaqs/standards/ozone/data/20140829pa.pdf).

A more stringent ozone standard would have a material impact on the sources subject to the proposed section 111(d) rules. For example, a more stringent ozone standard would impact the timing and permitting obstacles to construction of new NGCC capacity necessary to replace dispatchable coal-fired capacity required to reduce utilization or retire as a result of the proposed section 111(d) rules and other EPA requirements, including the Mercury and Air Toxics (MATS) rule. A more stringent ozone standard would impose resource demands on states required to develop implementation plans, at the same time they must address the proposed Clean Power Plan. Also, a more stringent ozone standard could complicate the states' obligations under proposed 40 CFR § 60.5740(a)(6), to demonstrate that each emission standard in the state's §111(d) plan is "non-duplicative" with respect to an affected entity (*i.e.,* will reductions in CO_2 emissions or electricity demand resulting from compliance with revised ozone standards be deemed "non-duplicative"?) and would complicate States' evaluations of the optimum mix of "building blocks" for achieving the mandatory section 111(d) "state goals." However, only EPA knows the nature of its proposed revisions to the ozone standard, and the interactions between a more stringent ozone standard and its section 111(d) proposal. It is for EPA to address in the first instance the implications of a revised ozone standard on the proposed section 111(d) rules.

At a minimum, EPA should address the interactions between its proposed section 111(d) rules and any proposed revisions to the ozone standard, and provide adequate time for comment in this rulemaking on those interactions before finalizing the proposed section 111(d) rules.

F. EPA's October 30, 2014 NODA Fails to Satisfy EPA's Obligations Under Section 307 of the CAA.

EPA's proposed rulemaking on CO_2 emission guidelines for existing fossil-fueled EGUs is so saturated with alternatives, and such a multiplicity of major legal interpretations and policy considerations (often inconsistent or inchoate), spanning such a vast range of inadequately analyzed data and assumptions regarding electricity planning, generation, transmission, pricing, financing, and use, that it frustrates public participation and judicial review. All things large and small are open for comment, so much so that there is not a coherent statement of basis and purpose underlying an intelligible proposed legislative rule. The very grandiosity of the proposal itself should have been a clue to EPA that its interpretation of the Clean Air Act as allowing for such widespread economic regulation has led it astray.

The June 18, 2014 proposal, for example, is accompanied by a 19-page spreadsheet titled "Listing of U.S. Environmental Protection Agency Requests for Comment."[498] The spreadsheet lists 204 separate "categories" for which EPA is requesting comments. Many of the categories float in the ether, unconnected to any proposed regulatory language or discernable consequences to the proposed BSER determination, the obligations imposed on the states, or the impact on other "affected entities." EPA solicits comment on different rationales for reaching a single conclusion, or different conclusions that could follow from a single rationale. Some issues for which comments are requested could have a material impact, or a domino effect, on some of the most basic elements of the proposed state CO_2 goals.

The October NODA compounds the scattershot nature of the original June proposal by introducing a whole host of new issues on which EPA solicits comment. The NODA further obscures the intelligibility of the proposed rule. EPA asks for comment on issues that could make the state goals more or less aggressive, the time deadlines more accelerated or longer, and the formula for determining compliance or noncompliance with the state goals more stringent or more malleable. EPA seeks input regarding the baseline for computing state CO_2 goals and the possible reformulation of state compliance criteria to include yet-to-be-constructed natural gas pipelines and new nuclear and NGCC generating capacity. The NODA simply highlights that EPA has failed to gather essential data and complete the pertinent analyses, even more than four months after the proposal, on how the proposal will impact the reliability and resiliency of the bulk power grid – matters of paramount public interest and an absolute prerequisite to reasoned decision-making.

In many ways, the June 18, 2014 notice of proposed rulemaking, even more so the October 30, 2014 NODA, is more like an advanced notice of proposed rulemaking than a notice of proposed rulemaking. Ironically, the NODA asks for comments on "the potential changes identified in this document in terms both of the rationale for these changes and their effects on the stringency of the state goals, as well as ways in which the potential changes interact with each other."[499] How could such questions remain unanswered by EPA? With so many moving parts and independent and dependent variables in EPA's proposal, how can a commenter know

[498] *See* EPA, Proposed Clean Power Plan for Existing Power Plants, Listing of U.S. Environmental Protection Agency Requests for Comment, www2.epa.gov/sites/production/files/2014-08/documents/clean-power-plan-comment-categories.pdf.
[499] 79 Fed. Reg. at 64,544, col. 2.

how they interact with each other if EPA does not? Four months after its notice of proposed rulemaking, EPA solicited comments on "ideas" (but no regulatory language) on such basic fundamentals of the proposal as "alternative approaches for the goal-setting equation and alternative uses of data in calculating the goals."[500] There are too many gaps in the data and analyses, too many unanswered questions about the underlying basis and purpose, and too many alternative rationales, conclusions, and regulatory possibilities to constitute a proper foundation for informed public participation and reasoned decision-making.

The October NODA also illustrates the extent to which EPA's proposal to transform the electricity sector is outside the zone of the Agency's core technical expertise. Without any proposed regulatory language or identification of regulatory consequences, and without any EPA analysis of the nature and effect of its proposed action on electric costs and reliability, EPA is asking for information on the "technical, engineering, and infrastructure limitations or other considerations" associated with shifting from coal-fired to NGCC generation as calculated under building block 2, and how building block 2 "may limit cost-effective options for emission reductions."[501] EPA is likewise asking for information on threshold issues such as "the time required to improve natural gas pipeline infrastructure in some states" and the need to "stop operating by 2020" even recently constructed coal-fired units, and coal-fired units for which recent significant capital investment has been made for EPA-required pollution control retrofits.[502] This is information is of utmost relevance and importance to EPA's proposal.

The concern is not that EPA is asking for this information. The concern is that EPA is not the electricity regulator, and even if it were, EPA was not ready to issue the type proposed rule it did in June without first analyzing this and other information, and then disclosing the results of that analysis in its notice of proposed rulemaking, including the data, technical evaluations, and resulting proposed regulatory language, together with a statement of its basis and purpose. EPA's failure to do so violates section 307(d) of the Clean Air Act,[503] and is unlawful and unreasonable.

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[500] 79 Fed. Reg. at 64,545, col. 2.
[501] 79 Fed. Reg. at 64546, col. 1.
[502] 79 Fed. Reg. at 64546, col. 2.
[503] 42 U.S.C. §7607(d)(3).

XIII. Recommendations

Electricity serves as the foundation of our nation's safety, security, and prosperity. EPA must take the time to carefully consider all of the comments submitted, and to issue guidelines that strike the appropriate balance between environmental protection and economic well-being. EPA should develop and issue for comment a proposal that includes the following elements:

(1) Heat rate improvements can be cost-effective ways to reduce CO_2 emissions, or to mitigate increases in CO_2 emissions, over the life of a fossil-fueled generating unit, regardless of fuel type or unit design. However, given the inherent variability in heat rate due to duty cycles and other uncontrollable factors, and the lack of an effective real-time heat rate measurement technique, it is infeasible to establish traditional emission limitations or standards based on improved heat rates. EPA should collect sufficient information about the techniques that could potentially be adopted to varying degrees at existing units (considering costs, lack of physical space, degree of prior adoption, remaining useful life, and other factors) and formulate a proposed guideline for a work practice standard that would allow for periodic evaluation of cost-effective heat rate improvement opportunities on a unit-specific basis, that can then be integrated into regularly planned outages across the existing fleet. Such a measure would ensure sustained adoption of available efficiency improvements within the existing fleet, which is the "best system of emission reduction" for these designated facilities.

(2) Encouraging reduced utilization of certain existing units and increased utilization of others is not authorized as a "means of emission limitation" under Section 302, and is inconsistent with the authorities granted to the Federal Energy Regulatory Commission (FERC) and the regional reliability organizations under the Federal Power Act (FPA). Section 310 of the Clean Air Act clearly states that EPA's authorities cannot be interpreted in such a way as to intrude upon the implementation of security constrained economic dispatch of the bulk electric system through the mechanisms FERC has developed under the FPA. However, future emission reductions will occur through the natural aging of the existing fleet, and plans could be established based on the remaining useful life of existing units consistent with the express language of section 111(d). EPA should allow states to examine the emission reductions that will occur within the existing fleet as units near and reach the ends of their useful lives, and establish a glide path to lower total mass emissions from the existing fossil fleet. EPA should allow states to calculate the "degree of emission reduction" achieved through such a procedure, and to develop the path for reductions that is consistent with the energy and economic needs of the states. EPA has no authority to dictate arbitrary "interim" goals that the states must meet.

(3) Nothing in the Clean Air Act gives EPA the authority to specify the types of new generation resources that should be constructed to fulfill a utility's obligation to serve. This authority has been specifically reserved to the states under the FPA, and no Congress has yet passed laws to establish national renewable portfolio standards. However, EPA should allow states to examine the planned additions of renewable and other low- or non-emitting resources under existing integrated resource plans and other siting or certification requirements, and

use any approved, cost-effective resource additions as creditable emission reductions, to facilitate the transition of the existing fleet to a cleaner, more modern system.

(4) Energy efficiency targets and goals have also been used by state utility regulators and state energy resource planning agencies as a means to delay the need for additional capital-intensive base-load generating resources, and to manage peak loads. States should be given the option to take credit for these efforts if they prove to be cost-effective, and as new technologies develop. However, EPA is not an energy planning expert or rate regulator, and these measures can only be developed consistent with the reserved power of the states for retail energy rate regulation. There is no single "best practice" that can be established for all states. Each state should be allowed to incorporate its energy planning strategy into a plan under section 111(d) to the extent it determines is appropriate.

Like the Clean Power Plan, the four recommendations listed above are not mandatory or federally enforceable requirements; they are merely guidelines to be used by the states as one of many factors that will contribute to the development of final state and regional plans. States would be free to identify other measures in their plans, if they are more cost-effective or better suited to individual state policies and resources. EPA’s backstop authority under Section 111(d) would permit it to develop a federal implementation plan if a state fails to submit a satisfactory plan, but it could be based on only the first two recommendations, which directly control emissions from the regulated sources. Additional measures based on recommendations three and four would help states accommodate needs for increased flexibility, such as allowing the states to address units that have no cost-effective options for heat rate improvements due to site-specific factors, or where replacement of existing resources will require a longer compliance time frame due to the need for transmission mitigation or reinforcement, or other infrastructure additions.