From: Ex. 6 - Personal Privacy, Gina McCarthy
To: Samy, Kevin
Sent: 5/31/2014 11:19:33 AM
Subject: FW: EO12866_EGU GHG Existing Source 2060-AR33 Proposal_051514_May 28 2014_1030pm gm(2).docx
Attachments: EO12866_EGU GHG Existing Source 2060-AR33 Proposal_051514_May 28 2014_1030pm gm(2).docx

Here it is. Pages 342 start the flexibilities summary.

From: Ex. 6 - Personal Privacy, Gina McCarthy
Sent: Friday, May 30, 2014 11:49 AM
To: McCabe, Janet
Subject: EO12866_EGU GHG Existing Source 2060-AR33 Proposal_051514_May 28 2014_1030pm gm(2).docx

I made come – hopefully very limited – comment on the executive summary only. Some of my highlights are for me to share with Kevin because they are great ways to explain the rule – as you will see in the comment. I can walk you thru these pretty quickly.

From: Wachter, Eric
To: (b)(6)-Administrator McCarthy
Sent: 5/8/2014 3:51:07 PM
Subject: FW: new report: Clean Air Act - Section 111(d) and electric reliability
Attachments: Tierney - Electric Reliability & GHG Emissions CAA 111(d) 5-8-2014.pdf

From: Tierney, Susan [mailto:STierney@analysisgroup.com]
Sent: Wednesday, May 07, 2014 6:41 PM
To: Mccarthy, Gina; McCabe, Janet; Goffman, Joseph; Tsirigotis, Peter; Beauvais, Joel; Kurlansky, Ellen; Culligan, Kevin
Subject: new report: Clean Air Act - Section 111(d) and electric reliability

Dear Madame Administrator, Madame Air Administrator, Senior Advisor, and other key EPA advisors on CAA Section 111(d):

I wanted to send you a copy of the paper that I've just written on the electric system reliability issues associated with EPA's guidance under the CAA 111(d). The bottom line of my report is that the inherent flexibility of the Clean Air Act's Section 111(d) will provide useful ways for EPA and the states to assure reliability while the system transitions to a lower GHG footprint.

Please let me know if any of you would like to discuss any of this. Hope all of you are doing very well.

Best –

Sue

Sue Tierney | Senior Advisor
Analysis Group, Inc. | Economic, Financial, and Strategy Consulting
111 Huntington Avenue, Tenth Floor, Boston, MA 02199
617-425-8114 (direct) | 617-425-8000 (main) | 617-901-6921 (mobile)
www.analysisgroup.com

This e-mail message and any attachments are confidential and may be privileged. Unless you are the intended recipient (or authorized to receive this message for the intended recipient), you may not use, copy, disseminate or disclose to anyone the message or any information contained in the attachments. If you are not the intended recipient, please notify the sender immediately by replying to this message, and then destroy any copy of the message as well as any attachments. Thank you.

Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act:

Options to Ensure Electric System Reliability

Susan F. Tierney, Ph.D.

Analysis Group, Inc.

May 8, 2014

Table of Contents

Introduction and Executive Summary 1

Regulating GHG Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act 7

How does Section 111(d) of the CAA work? 9

The likely character of EPA's guidance under CAA Section 111(d) 13

Section 111(d) Differs from Other Recent EPA Regulations Affecting Power Plants 16

The MATS Rule 16

How Section 111(d)'s Framework Differs from the MATS Rule 18

Power plants that are subject to CAA Section 111(d) 20

Context for Industry Compliance with CAA Section 111(d) Requirements 23

Natural gas, coal and existing power plants 23

Outlook for electricity demand 28

Availability of zero-carbon supply from nuclear generators 34

Responses to EPA MATS regulations 38

New Generating Capacity Proposals 43

Implications of the Changing Electricity Resource Mix 44

Planning for Compliance with EPA Guidance Under Section 111(d) of the CAA 46

Breadth of Options Available to the States in Developing Section111(d) SIPs 46

Inside the Fence Options 47

Outside the Fence Options 49

Outside-the-Fence Models Approaches: Examples to ensure reliable and economic compliance in states with different electric industry structures 56

Outside-the-Fence Models Approaches: Collateral policies 65

Conclusions 66

Introduction and Executive Summary

In June 2014, the U.S. Environmental Protection Agency ("EPA") is expected to propose guidance to the states for reducing greenhouse gas ("GHG") emissions from existing fossil-fuel power plants. Final guidance is expected a year later, with requirements that each state develop and submit a state implementation plan ("SIP") for how the state would prefer to achieve such emissions reductions at the power plants in its state. While the Clean Air Act's Section 111 identifies many criteria for setting the emissions standard and for states' development of SIPs to achieve it, an important additional objective not mentioned in the Act but still important for the nation is assuring that such plans will not jeopardize electric system reliability.

This paper addresses whether EPA's actions to regulate GHG emissions from existing power plants will give rise to electric system reliability problems,[1] and explains why it will not.

Industry participants have often raised concerns about potential electric system reliability impacts from major new EPA regulations affecting power plants. This was a major issue in 2010 to 2012, for example, in many parties' comments on EPA's proposals to control mercury and air toxic emissions (the "MATS" rule). Reliability concerns have already been raised in relation to EPA's upcoming regulation of GHG emissions from existing power plants.[2]

Electric system reliability:

"The degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service."

Energy Information Administration.

[1] The North American Electric Reliability Corporation ("NERC") further explains the adequacy component of reliability: "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." In this paper, I focus on reliability in the bulk-power system, which NERC defines as: "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy….The bulk power electric system is routinely planned and operated so as to perform reliably under normal and abnormal conditions." http://www.nerc.com/files/glossary_of_terms.pdf.

[2] See, for example, hearings held on November 14, 2013, before the House Energy and Commerce Subcommittee on Energy and Power, and comments made by panelists at the February 12, 2014 meeting of the National Association of Regulatory Utility Commissioners ("NARUC").

Historically, the reliability red flag[3] has tended to be raised with regard to concerns that compliance with a new environmental rule would require a large portion of generating capacity to be simultaneously out of service to add control equipment, to retire permanently, or otherwise to become unavailable to produce power.[4] To date, implementation of new environmental rules has not produced reliability problems, in large part because the industry has proven itself capable of responding effectively. A very mission-oriented industry, composed of electric utilities, other grid operators, non-utility energy companies, federal and state regulators, and others, has taken a wide variety of steps to ensure reliability.[5]

Regarding the upcoming EPA regulations of GHG emissions from existing power plants, reliability concerns are misplaced. It is broadly understood – including by President Obama[6]

---

[3] In recent years, many Congressional hearings have addressed the implications of EPA regulations for electric system reliability. For example: hearings before the House Energy and Commerce Subcommittee on Energy and Power (December 5, 2013; May 9, 2012; and September 14, 2011); the November 1, 2011 hearing before the House Oversight and Government Reform Committee; and the June 30, 211 hearing before the Senate Environment and Public Works Subcommittee on Clean Air and Nuclear Safety. In 2010/2011, NERC published major assessments of electric system reliability and EPA regulations. .

[4] This, for example, was how the issue came up in discussions of EPA's acid rain regulations in the early 1990s and in proposals for how Northeast states would reduce sulfur dioxide ("SO2"), and nitrogen oxides ("NOx") emissions from existing power plants. In such cases, key questions were whether the electric industry (and its supply chains) could respond in a timely way to regulatory requirements while also ensuring that the lights stay on at all times in every part of the affected regions of the U.S. This was the framing of reliability concerns in recent years when EPA agency proposed the combination of regulations affecting cross-state transport of NOx (e.g., the "Cross-State Air Pollution Rule" ("CSAPR") and toxic air pollution (e.g., the MATS rule)).

[5] For example, the Federal Energy Regulatory Commission ("FERC") has authority under the Energy Policy Act of 2005 to ensure reliability in the bulk power systems, and has delegated to the NERC (as the National Reliability Organization) the responsibility for setting reliability standards. For decades, states have supervised – and continue to do so – utilities and others' planning for long-term resource adequacy. I previously described these processes, norms, requirements, and other elements of the mission-oriented culture of the industry: "The U.S. electric industry has a proven track record of doing what it takes to provide the reliable power supplies. Regulated electric utilities, competitive electric companies, grid operators, and regulators have a strong mission orientation, along with regulatory requirements, which together ensure that reliable electricity supply is a priority. For many decides, the U.S. electric industry has developed institutions, operating and planning requirements, system plans, operating approaches, emergency response protocols, and billions of dollars of investment to assure reliable electricity supply. The industry is keenly aware that the American economy and standard of living depend upon reliable power supplies…. With some notable exceptions, utilities and other electric companies and their workers, investors, and suppliers, have provided what Americans take for granted and what public officials insist upon: that electricity be reliably available around the clock, with increasing levels of environmental performance to assure worker and community safety and public health. ….The electric industry has responded well in prior periods (such as the mid-1990s) when Clean Air Act requirements led to investments in new pollution-control equipment and new additions to generating capacity. There were no reliability problems arising from those actions, in spite of concerns raised that there would be equipment shortages and difficulties adding control equipment on so many power plants in a constrained period of time." Testimony of Susan Tierney, Before the U.S. Senate Environment and Public Works Committee. Subcommittee on Clean Air and Nuclear Safety, June 30, 2011 (Oversight Hearing: Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR)).

[6] The June 35, 2013 "Presidential Memorandum -- Power Sector Carbon Pollution Standards" states that "In developing standards, regulations, or guidelines … {EPA] shall ensure, to the greatest extent possible, that you: …(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses…"

and the EPA's Administrator[7] – that regulatory actions to reduce threats to public health and the environment from power generation cannot occur at the expense of reliable power supply.

Moreover, EPA will be relying on a portion of the Clean Air Act ("CAA") – Section 111(d) – to regulate GHG emissions from existing power plants. Section 111(d)'s regulatory framework creates an entirely different and potentially much wider set of compliance and implementation options compared to other recent federal regulatory initiatives applicable to the electric industry. Section 111(d)'s 'cooperative federalism' model provides for much more compliance flexibility and creativity than was possible for the many unit-specific regulations issued by EPA in the past two decades. This is core to understanding why EPA's regulation of GHG emissions from existing power plants will not jeopardize electric system reliability.

In the recent MATS rule, for example, EPA set uniform national standards to reduce emissions from different categories of existing coal- and oil-fired power plants. No trading or averaging is allowed across different generating stations. There is no possibility of purchasing credits resulting from over-compliance at other sources, or to credit emissions reductions resulting from end-use efficiency or zero-carbon energy sources.

By contrast with MATS, Section 111(d) inherently allows greater opportunities for different pathways to compliance. Section 111(d) relies on the SIP process. This means that EPA will provide states with guidance allowing considerable and wide-ranging latitude in how they plan to meet EPA's requirements. EPA's guidance will not likely impose a standard that must be met solely by actions taken at each affected unit. Rather, EPA is likely to establish standards specific to each state, based on the "degree of emission limitation achievable through the application of the best system of emission reduction," which may vary across states in light of their own particular circumstances. And in its SIP, each state will have flexibility to propose its own preferred actions to accomplish the targeted reductions, as long as the plan provides reductions across the facilities in the state that are at least as effective as EPA's approach.[8] This language "supports the use of market-based mechanisms" and other alternatives in ways that

[7] See, for example: Statement of Gina McCarthy, Nominee for the Position of Administrator of the EPA, Before the Environment and Public Works Committee, U.S. Senate, April 11, 2013; Testimony of Gina McCarthy before the FERC, Reliability Technical Conference, Docket Number AD12-1-000, November 30, 2011.

[8] Section 111(d) directs EPA to "prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan…." As explained in Section 110 (a)(2)(A) of the Act, a SIP shall (among other things), "(A) include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter."

are not possible under the statutory language governing MATs, which required each affected generating station to have emissions at or below the allowed emissions rates.

If a state has concerns about the reliability implications of compliance with EPA guidance, the state can take that fact into account as it designs its SIP and its schedule/timetable for individual units' compliance so long as the overall emission reduction required by the guideline has a firm deadline and is achieved. For example, a state could propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow for deeper reductions at one unit in exchange for lighter reductions at another. Thus, the inherent authority within Section 111(d) removes the reliability red flag in this case, as long as the EPA, the states, and the industry take appropriate and timely steps.

States may consider diverse options as they plan for cost-effective emissions reductions while also ensuring electric system reliability. Some of the options may take place "inside the fence" of generating units covered by Section 111(d), while others might focus more on interactions of those plants' emissions in light of changes in power demand, transmission and generation:

- *Inside the fence*: Examples include: heat-rate improvements; fuel switching; averaging of emissions within a single station; and changes to the operating permit of existing power plants to limit emissions over some averaging period.
- *Outside the fence:* Examples include: emission reductions achieved through changes in the overall dispatch of existing generating resources and/or level of demand on the system: emission-averaging among multiple power plants; state carbon budgets with an emissions cap-and-trade program; multi-state electric-system dispatch practices of grid operators; demand-side reductions; adoption of clean energy standards; and/or transmission upgrades to open up access to underutilized, low-carbon facilities.

Other factors also allow for cost-effective emissions reductions at Section 111(d) units in ways that do not adversely affect system reliability. A significant amount of existing generating capacity is underutilized. For example, output at natural-gas fired combined-cycle power plants averaged approximately 50 percent in 2012. There is the potential to reduce overall demand through energy efficiency, thus reducing the need to dispatch plants with relatively high emission rates. There is potential to add additional low or zero-carbon electricity supply (e.g., wind and solar; combined heat and power; nuclear uprates). Actions also can be taken to extend the life of, or increase the output from, well-performing generating units that produce no emissions at the facility (e.g., hydroelectric resources, nuclear plants). These various resources

offer significant flexibility and optionality to states as they prepare a SIP suited to their own circumstances and conditions (including reliability concerns).

As they develop SIPs in response to the EPA's Section 111(d) guidance, the states start from a position of great diversity in their electric power industries. These differences show up in the character of the power plants located in each state, the electric industry structure, the CO_2 emissions from existing power plants, renewable energy potential, reliance on in-state versus out-of-state power resources, the outlook for demand growth, mix of public policies affecting power plants, and many other differences. This will likely lead to varied approaches in SIP designs. (See the Appendix 2 for the generating units in each state that are directly affected by Section 111(d) requirements, along with information about other generating resources and their capacity factors in 2012.)

To envision how differently situated states might shape their compliance strategies to assure both electric system reliability and compliance with upcoming EPA guidance, this paper concludes with a handful of examples representing ways that states could consider shaping their SIPs to suit their own conditions. The examples address options for states with traditionally regulated electric industries, and for states whose electric companies participate in an organized interstate wholesale electric market managed by a regional transmission organization ("RTO"). The GHG control options include: inter-facility emissions trading for plants owned by a common owner in a single state or in multiple states with traditional electric industry structure; inter-state trading among plants owned by multiple owners in traditionally regulated states; reliance on a state-wide emissions budget combined with other mechanisms to allow emissions averaging across plants located within a single-state or multi-state RTO; and use of collateral programs to support cost-effective emissions reductions (such as clean energy standards, renewable portfolio standards, energy efficiency programs, transmission enhancements, and others). All of these provide extensive opportunities for innovative SIP elements that can accommodate cost-effective environmental compliance, alignment with economic principles underpinning electric industry structure and market design, while maintenance of electric system reliability.

The bottom line: there is no reasonable basis to anticipate that EPA's guidance, the states' SIPs and the electric industry's compliance with them will create reliability problems for the power system, as long as EPA and the states plan appropriately and take timely actions to assure electric-system reliability in their plans. Section 111(d) affords states considerable latitude to mitigate and otherwise resolve reliability concerns.

To explain how I reached this conclusion, this paper covers the following topics:

- the federal/state regulatory framework under Section 111(d) of the CAA;
- how Section 111(d)'s reliance on the preparation of SIPs makes this regulatory framework inherently different from other recent environmental regulations affecting existing power plants, and provides more compliance options and greater flexibility;
- the types of power plants directly affected by the GHG reduction policies, with differences among fleets in various regions of the country;
- conditions in the electric industry (such as the outlook for demand, fuel prices, plant additions and retirements) that set the stage for the industry's future compliance with GHG regulations for existing plants;
- the breadth of tools that may be available to the states as they consider what to include in their SIPs;
- the factors that states may take into account to assure electric system reliability as part of their compliance strategies;
- examples of ways to design compliance strategies in different industry contexts; and
- the overall implications of Section 111(d) compliance for maintaining electric system reliability.

Regulating GHG Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act

Under the CAA, the control of GHG emissions from existing power plants fits within a larger framework in which EPA regulates air pollution from mobile and stationary sources. Section 111(d) sets forth the process through which EPA will regulate GHG emissions from existing power plants, which account for 40 percent of total CO_2 emissions in the U.S.,[9] and one out of every 15 tons of CO_2 emitted anywhere in the world.[10]

Much has been written about the overall framework under which GHG emissions may be regulated under the CAA.[11] These analyses depict the process now underway:

---

[9] Based on 2011 data, the most recent available in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011," April 12 2013, Table 2-3 (Recent Trends in U.S. Greenhouse Gas Emissions and Sinks) and Table 2-4 (Emissions from Energy).

[10] The U.S. emitted 5,433,056 kt of CO_2, out of the total 33,615,389 kt of CO_2 emitted globally in 2010. The U.S.'s CO_2 emissions were 16 percent of the global amount. http://data.worldbank.org/topic/climate-change. Assuming electric power accounts for 40 percent of U.S. CO_2 emissions (from the EPA GHG Inventory data), then electric power production in the U.S. accounted for 6.5 percent of global CO_2 emissions in 2010.

[11] For example, see: Dan Lashof, et. al., "Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants, Delivering Health, Environmental, and Economic Benefits," NRDC, March 2014; Clean Air Task Force, "Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants," February 2014, with accompanying analysis (Bruce Phillips, The Northbridge Group," Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," February 27, 2014); Comments of the Attorneys General of New York, California, Massachusetts, Connecticut, Delaware, Maine, Maryland, New Mexico, Oregon, Rhode Island, Vermont, Washington, and the District of Columbia on the Design of a Program to Reduce Carbon Pollution from Existing Power Plants, December 16, 2013; White Paper to EPA from 18 State Attorneys General, "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act," November 2013; Megan Ceronsky and Tomas Carbonell, "Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants," Environmental Defense Fund, October 2013; Christopher Van Atten, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Plants," MJ Bradley & Associates, October 2013; James McCarthy, "EPA Standards for Greenhouse Gas Emissions from Power Plants: Many Questions, Some Answers," Congressional Research Service, September 30, 2013; National Climate Coalition, "Using EPA Clear Air Act Authority to Build a Federal Framework for State Greenhouse Gas Reduction Programs," September 2013; Scott Schang, ed., *Old Laws, New Tricks: Using the Clean Air Act to Curb Climate Change* (Environmental Law Institute, August 19, 2013); Kyle Danish, Stephen Fotis, Doug Smith, Ilan Gutherz, "EPA Regulation of Greenhouse Gas Emissions from Existing Power Plants: Issues and Options," Van Ness Feldman, June 27, 2013; Daniel A. Lashof, et. al., "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013; Nicholas Bianco and Franz Litz, "Reducing Greenhouse Gas Emissions in the United States: Using Existing Federal Authorities and State Action," World Resources Institute, February 2013; Jeremy Tarr, Jonas Monast and Tim Profeta, "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, Limits, and Impacts," Nicholas Institute, Duke University, January 2013; Georgetown Climate Center, "Issue Brief for the States: EPA's Forthcoming Performance Standards for Regulating Greenhouse Gas Pollution from Power Plants (Clean Air Action Section 111)," September 2011; Gregory E. Wannier, Jason A. Schwartz, Nathan Richardson, Michael A. Livermore, Michael B. Gerrard, and Dallas Burtraw, "Prevailing Academic View on Compliance Flexibility under § 111 of the Clean Air Act," Resources for the Future, July 2011; Pew Center on Global Climate Change, "GHG New Source Performance Standards for the Power Sector: Options for EPA and the States," March 17, 2011.

- The U.S. Supreme Court's 2007 holding that "greenhouse gases fit well within the [Clean Air] Act's capacious definition of 'air pollutant'."[12]
- The EPA Administrator's finding in 2009 that current and projected concentrations of GHGs "in the atmosphere threaten the public health and welfare of current and future generations."[13]
- The President's 2009 pledge at the United Nations Climate Change Conference that by 2020, America would reduce its GHG "emissions in the range of 17 per cent by 2020" compared with 2005 levels.[14]
- The President's 2013 Climate Action Plan and Presidential Memorandum directing the EPA to take steps under Section 111(d) authority to reduce carbon pollution from existing power plants,[15] and to do so through engaging directly with the states ("as they will play a central role in establishing and implementing standards for existing power plants") and other stakeholders.[16]

[12] 549 U.S. 497 (2007).

[13] 74 Fed. Reg. 66496 (December 15, 2009) (Environmental Protection Agency, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act).

[14] White House Press Release, Remarks by the President in the Morning Plenary Session of the United Nations Climate Change Conference, Copenhagen, December 18, 2009.

[15] The President's Climate Action Plan, June 2013; White House, Presidential Memorandum -- Power Sector Carbon Pollution Standards, June 25, 2013.

[16] "Carbon Pollution Regulation for Modified, Reconstructed, and Existing Power Plants. To ensure continued progress in reducing harmful carbon pollution, I direct you to use your authority under sections 111(b) and 111(d) of the Clean Air Act to issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector." White House, Presidential Memorandum -- Power Sector Carbon Pollution Standards, June 25, 2013. The Memorandum also directs that EPA "(ii) consistent with achieving regulatory objectives and taking into account other relevant environmental regulations and policies that affect the power sector, tailor regulations and guidelines to reduce costs; (iii) develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities; (iv) ensure that the standards enable continued reliance on a range of energy sources and technologies; (v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses; and (vi) work with the Department of Energy and other Federal and State agencies to promote the reliable and affordable provision of electric power through the continued development and deployment of cleaner technologies and by increasing energy efficiency, including through stronger appliance efficiency standards and other measures."

How does Section 111(d) of the CAA work?

Regulation of one third of the nation's GHG emissions (i.e., from existing fossil power plants) will take place through a portion of the CAA that is used infrequently. Section 111(d) only applies to pollutants (like GHGs) not regulated elsewhere in the law. Most air pollutants emitted from power production – including emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and air toxics like mercury – are specifically covered by other parts of the CAA. The electric industry, the states and many other stakeholders have become familiar with regulatory approaches related to those other pollutants over several decades.

Section 111(d) has only been used to control emissions for five categories of existing sources of emissions[17] and never for a pollutant that is so pervasive (as CO_2) in the U.S. and globally. Thus it is thus relatively 'new' to the EPA, as well as to the regulated industry and the states.

Clean Air Act:

Section 111(d) Standards of performance for existing sources; remaining useful life of source [excerpts]

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued …, and (B) provides for the implementation and enforcement of such standards of performance. 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.

Section 111(a) Definitions [excerpts] For the purposes of this section:

(1) The term "standard of performance" means 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 (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…..

(See Appendix 1 for additional statutory language from Section 111 of the CAA)

That said, the upcoming regulatory process is not entirely unfamiliar to the states. Section 111(d) calls for EPA to use "a procedure similar to that provided by section 110." Section 110 is a well-established "cooperative federalism" framework that has been relied upon for decades to ensure that EPA's National

[17] Section 111(d) has been used previously for regulating: landfill gases from municipal solid waste landfills; acid mist from sulfuric acid plants; flourides from phosphate fertilizer plants; flourides from primary aluminum plants; and total reduced sulfur from kraft pulp plants. Source: "Overview presentation of Clean Air Act Section 111," http://www2.epa.gov/carbon-pollution-standards/what-epa-doing.

Ambient Air Quality Standards ("NAAQS") are met and maintained for six common air pollutants (known as 'criteria pollutants'). Under Section 110, "EPA uses its expertise to determine *what* the NAAQS should be, and the states are delegated the authority to determine *how* the NAAQS will be achieved."[18] In essence, the 'cooperative federalism' framework of Section 111(d) can be thought of one in which EPA identifies the destination (e.g., ambient air quality), and states determine what route they want to take to get there.[19] In the past, the states (typically through their state air regulatory agency) have developed SIPs to demonstrate how they will address ground-level ozone (smog), particulate emissions, SO_2, NOx, and other criteria pollutants to meet the national air standards.[20] Thus, state air regulators have considerable experience with such SIP processes.[21]

In various presentations, statements and other documents, EPA has provided strong indications of how it intends to move forward under the Section 111(d) framework. The process is expected to involve the following steps and elements:[22]

- **EPA Guidance**: EPA issues guidance to the states with respect to the "best system of emissions reductions" ("BSER") from existing power plants. This guidance will likely establish the target CO_2 tonnage reductions, or reductions in CO_2 emission rates per megawatt-hour ("MWh"), that each individual state must achieve at affected generating units through its SIP.

[18] Jonas Monast, Tim Profesta, Brooks Rainey Pearson, and John Doyle, "Regulating Greenhouse Gas Emissions from Existing Sources: Section 111(d) and State Equivalency," 42 ELR 10206, March 2012 (hereinafter "Monast et. al. (2012)").

[19] Susan Tierney, "Section 111(d) of the Clean Air Act: Drivers of Power Sector CO_2 Reductions," presentation to the Bipartisan Policy Center Workshop on GHG Regulation of Existing Power Plants under the Clean Air Act: Policy Design and Impacts, December 6, 2013.

[20] The States "develop a general plan to attain and maintain the NAAQS in all areas of the country and a specific plan to attain the standards for each area designated nonattainment for a NAAQS. These plans, known as State Implementation Plans or SIPs, are developed by state and local air quality management agencies and submitted to EPA for approval." http://www.epa.gov/oar/urbanair/sipstatus/index.html

[21] See, for example, EPA's website that tracks the status of each state's SIP for each criteria pollutant. As is apparent there, SIPs include elements that are added or changed over time. http://www.epa.gov/oar/urbanair/sipstatus/reports/map_s.html.

[22] This description is drawn from various documents, including from the EPA's website and its "Overview presentation of Clean Air Act Section 111"(http://www2.epa.gov/carbon-pollution-standards/what-epa-doing); EPA Office of Air and Radiation, "Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants," September 23, 2013 version (hereinafter "EPA Design Considerations 2013"); EPA, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act," October 2013, http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf; EPA, Office of Air Quality Planning and Standards ("OAQPS"), "Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units," Tribal Consultation, May 2011 (hereinafter "OAQPS GHG Presentation").

- Guidance will be developed through EPA's normal rulemaking process with a notice-and-comment period (including a Regulatory Impact Assessment), and with "binding requirements that states are required to address when they develop plans to regulate existing sources in their jurisdictions."
- The guidance will come first in proposed form (by June 1, 2014), and then in final form (by June 1, 2015).
- The Presidential Memorandum requests that EPA guidelines require that States submit to EPA their SIPs by no later than June 30, 2016.
- EPA's guidance will likely set the target reductions for states to use in developing their implementation plans with performance standards that apply to the power plants subject to Section 111(d) (the "affected sources" of GHG emissions). Consistent with prior Section 111(d) rules, "EPA believes that its guidelines should identify for sources and states the required level(s) of performance prior to plan submittal."[23] Based on prior EPA guidance under Section 111(d), the GHG guidance is likely to contain:[24]
    - A description of BSER that has been adequately demonstrated for a particular category of sources (taking into account feasibility, cost, emissions reductions, and technology development issues);[25] the degree of emission limitation achievable, costs and benefits, and environmental impacts of application; and a goal for reductions based on the BSER analysis.
    - No specific prescribed technologies that must be used to comply.

[23] EPA Design Considerations 2013.

[24] Sources for these points: EPA, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act," October 2013, http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf; "Overview presentation of Clean Air Act Section 111"(http://www2.epa.gov/carbon-pollution-standards/what-epa-doing); OAQPS GHG Presentation; Monast et. al. (2012).

[25] Senior EPA officials have stated that the *particular* BSER the agency adopts for existing sources of GHG emissions will not be the same as the one it adopted for new power plants, although the BSER *criteria* EPA takes into account are similar. (See the statement of Acting Administrator for Air and Radiation Janet McCabe before the House Energy and Commerce Subcommittee on Energy and Power (November 14, 2013)). The application of the criteria to new versus existing power plants is what would lead to different BSER targets. In EPA's proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" (dated September 2013), EPA explains the factors that are to be considered in identifying the BSER: "For this rulemaking [under Section 111(b)], the following factors are key: feasibility, costs, size of emission reductions and technology. **Feasibility …**whether the system of emission reduction is technically feasible. **Costs…**whether the costs of the system are reasonable. **Size of emission reductions**…the amount of emissions reductions that the system would generate. **Technology**…whether the system promotes the implementation and further development of technology." Page 25 of the signed prepublication version of 40 CFR Part 60 [EPA-HQ-OAR-2013-0495; FRL-9839-4] RIN 2060-AQ91, EPA, Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, September 20, 2013 (hereinafter "EPA 2013 Proposed GHG Standards for New EGUs").

  - A stated performance standard using a rate of allowed emissions that is met on a facility-by-facility basis (although EPA has discretion to set performance standards for classes of power plants based on an allowed rate of emissions (e.g., pounds of CO_2 per MWh) or a total mass of emissions (e.g., a CO_2 tonnage budget for a state)).[26]
  - Timelines for implementing its guidelines.
  - "Different guidelines or compliance times (or both)…for different sizes, types, and classes of designated facilities when costs, physical limitations, geographical location, or other factors make sub-categorization appropriate."
  - Proposed model rules or a "model approach" to facilitate development of SIPs, but the states need not adopt any particular approach.

- **State SIPs**: States prepare their plans and implement the elements of approved SIPs:

  - In parallel with EPA's development and issuance of proposed and final guidelines, a state may begin to plan its SIP, informed by increasingly more concrete information provided through the process and adopted in the final EPA guidance.
  - A state's SIP, due to be filed at EPA one year after EPA finalizes its guidance, will describe how the state proposes to satisfy the EPA guidance, either through adopting the EPA approach (if one is provided) or through a program that would provide equivalent emissions reductions achieved via elements preferred by the state.
  - A SIP may need to contain, for example:
    - "Emission standards and compliance schedules 'no less stringent than emission guidelines'," [27] with the regulations (under Section 110) allowing for equivalency where the resulting emission limit is quantifiable, accountable, and enforceable, and (based upon replicable procedures) is equivalent to the SIP limit.[28]
    - Methods and procedures for determining compliance.[29]
    - Enforceable increments of progress for compliance schedules longer than 12 months.[30]

[26] Megan Ceronsky and Tomas Carbonell, "Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants," Environmental Defense Fund, October 2013.

[27] OAQPS GHG Presentation.

[28] 57 Fed. Reg. 13567-68.

[29] OAQPS GHG Presentation.

[30] OAQPS GHG Presentation.

- A SIP may propose to "adopt less stringent emission standards or longer compliance schedules than those set out in the guidelines where the State demonstrates"":[31]
    - "Unreasonable cost of control due to age, location or basic process design"
    - "Physical impossibility of installing necessary control equipment"
    - "Other factors specific to the facility or class of facility that make application of a less stringent standard or final compliance time significantly more reasonable."
- A SIP may adopt more stringent standards or shorter compliance schedules than those contained in the guidelines.
- States will need to adopt laws, rules and/or other administrative mechanisms as part of their demonstration that their SIPs will be effective and enforceable.
- If a state does not file a satisfactory SIP or fails to enforce an approved SIP, then EPA has the authority to issue and enforce a Federal Implementation Plan ("FIP").

The likely character of EPA's guidance under CAA Section 111(d)

Until the EPA publishes its proposed Section 111(d) guidance in June 2014 and finalizes it by the following year, observers cannot be sure what that final guidance will contain. There are clues, however, in statements from EPA, as well as analyses prepared by many observers. These clues provide a reasonable basis for states and the affected industry to begin their planning (as many states have already done).

In its September 2013 document posing "questions to the states," for example, EPA identified two "different options available for addressing carbon pollution from existing power plants… A source-based approach evaluates emission reduction measures that could be taken directly at the affected sources—in this case, the power plants. A system-based approach evaluates a broader portfolio of measures including those that could be taken beyond the affected sources but still reduce emissions at the source."[32]

EPA has typically adopted a source-based approach in other Section 111 regulations.[33] In developing its proposed GHG emission standards for *new* fossil power plants under Section 111(b), for example, EPA relied upon a source-based approach, expressed as a limit on pounds

[31] OAQPS GHG Presentation.

[32] EPA Design Considerations 2013.

[33] EPA, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act," October 2013, http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf;

of CO_2 emitted for each MWh of generation. The proposal has one CO_2/MWh rate for new Electric Utility Steam Generating Units ("EGUs") that propose to use a solid fossil fuel (e.g., coal-fired boilers) and integrated gasification combined cycle ("IGCC") units,[34] and another rate for natural-gas-fired combustion units.[35],[36]

Many parties outside of EPA have made recommendations and proposals for the form of regulations they prefer to see EPA adopt in its guidance. In terms of the design and stringency of the requirement, these proposals differ in two dimensions (as described recently by Bruce Phillips/Clean Air Task Force[37]): "(1) Whether the rule establishes separate emission standards for covered coal and natural gas-fired generation or a blended emission standard for all covered fossil generation (both coal and natural gas). (2) Whether the emission standards are expressed as an emission rate (in pounds of carbon emissions per unit of generating output) or a mass-based standard (in tons of carbon emissions). As shown in the following table, these two basic design elements characterize the policy proposals and concepts offered to date."

[34] EPA has proposed standards of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage ("CCS") as the BSER. "There are two limits for fossil fuel-fired utility boilers and IGCC units, depending on the compliance period that best suits the unit. These limits require capture of only a portion of the CO2 from the new unit. These proposed limits are: (a) 1,100 lb CO2/MWh gross over a 12-operating month period, or (b) 1,000-1,050 lb CO2/MWh gross over an 84-operating month (7-year) period. All standards are in pounds of CO2 per megawatt-hour (lb CO2/MWh gross)." EPA Fact Sheet, "Reducing Carbon Pollution From Power Plants Moving Forward On the Climate Action Plan," September 20, 2013; EPA 2013 Proposed GHG Standards for New EGUs, pages 15-16.

[35] "EPA is proposing two standards for natural gas-fired stationary combustion units, depending on size. The proposed limits are based on the performance of modern natural gas combined cycle (NGCC) units. These proposed limits are: (a) 1,000 lb CO2/MWh gross for larger units (> 850 mmBtu/hr); and (b) 1,100 lb CO2/MWh gross for smaller units (≤ 850 mmBtu/hr)." All standards are in pounds of CO2 per megawatt-hour (lb CO2/MWh gross." EPA Fact Sheet, "Reducing Carbon Pollution From Power Plants Moving Forward On the Climate Action Plan," September 20, 2013; EPA 2013 Proposed GHG Standards for New EGUs, page 16.

[36] I do not mean to suggest that the *particular* form or level of the CO_2/MWh standards proposed in the Section 111(b) rulemaking for *new* power plants will be the same form or level of standards applicable to *existing* power plants. Indeed, EPA has stated that the particular CO_2/MWh standards proposed in the rulemaking for new power plants will *not* be the same standards applicable to existing power plants: "In September [2013], the EPA announced its new proposal. The proposed standards would establish the first uniform national limits on carbon pollution from future power plants. They will not apply to existing power plants." Opening Statement of Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, EPA, Hearing on EPA's Proposed GHG Standards for New Power Plants and H.R. __, Whitfield-Manchin Legislation, Subcommittee on Energy and Power, Committee on Energy and Commerce, U.S. House of Representatives, November 14, 2013.

[37] Bruce Phillips, The Northbridge Group, "Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," prepared at the Request of the Clean Air Task Force, February 27, 2014 (hereafter, "Phillips/CATF 2014").

Table 1 TAXONOMY OF ALTERNATIVE POLICY DESIGNS[38]		
	Blended Fossil Standard	**Separate Coal and Gas Standards**
Rate-Based	**Blended Fossil Emission Rate** [one rate for all fossil sources] • NRDC [*Natural Resources Defense Council*] (trading with uncovered sources)[39]	**Coal Emission Rate & Gas Emission Rate** • CATF [*Clean Air Task Force*] 1.0 • NCC [*National Climate Coalition*] (trading with uncovered sources)[40]
Mass-Based	**Fossil Budget** (ceiling on total amount of emissions from covered fossil fuel units) • RGGI [*Regional Greenhouse Gas Initiative*] • California AB 32 [*Cap-and-Trade Program*] • CATF 2.0 Fossil Alternative	**Coal Budget & Gas Emission Rate** • CATF 2.0 Coal Budget/Gas Rate Alternative (with an emission rate standard for natural gas)

EPA reports[41] that commenters have suggested that Section 111(d) guidelines be drafted to accommodate multiple emission-reduction options for state SIPs,[42] including:

- Averaging of emissions from covered units, through tradable credits. "Units would be given emission rate targets. If they emit below the targets, they would generate credits

[38] I have reproduced the overall structure of the original table in Phillips/CATF 2014 (page 8), but have annotated it [in bracketed italics text] to provide full names for the acronyms in the original table, and with other information as provided in the explanatory text of Phillips/CATF 2014 regarding the table. Note the perspective of Phillips/CATF 2014 (page 8) that "Although the coal budget/gas rate approach is less familiar than the fossil budget approach, there are several advantages. It provides similar compliance flexibility and cost effectiveness to the fossil approach, and during the initial years of a 111(d) power plant policy results in lower emission credit prices, wholesale market prices and potentially lower retail rate impacts. Also, it is fundamentally quite similar to the sulfur dioxide (SO2) trading program established by the CAA Amendments of 1990 and successfully operated since then. Coal plants produce virtually all of the electric sector's SO2 emissions, while natural gas emits only trace amounts. Consequently, the SO2 trading program is effectively a type of mass-based coal regulation. Given these characteristics and advantages, the mass-based coal approach deserves close consideration."

[39] Footnote in the original: Dan Lashof et al., NRDC, "Closing The Power Plant Loophole: Smart Ways The Clean Air Act Can Clean Up America's Climate Polluters, December 2012.

[40] Footnotes in the original: "The NCC policy concept calls for renewable and demand side efficiency crediting to play a critical role in the rule." National Climate Coalition, "Using EPA Clean Air Act Authority to Build a Federal Framework for State Greenhouse Gas Reduction Programs." September 2013. Phillips/CATF 2014, page 7-8.

[41] EPA Design Considerations 2013.

[42] EPA has also indicated that although it has historically issued a model rule, the agency is "exploring whether and how to develop a 'toolbox' of decision-making and implementation resources for states that might include information about state programs and measures that reduce electricity sector CO2 emissions. Examples of information in the decision-making toolbox might include criteria for demonstrating how system-wide actions can meet the level of performance in the emission guidelines; a compendium of existing state energy and GHG policies, programs, and measures that includes information about key design attributes and how the states are estimating energy savings and emission reductions; and links to tools that help quantify energy savings and emissions reductions from state programs and measures." EPA Design Considerations 2013.

for each MWh generated. If they emit above the targets, they would still be able to comply if they obtained credits to offset emissions above the target."

- "Generation performance standards," which EPA depicts as similar to emissions averaging "but would include all generating sources (e.g., renewables, nuclear, etc.)."
- "Intrastate emission trading programs with GHG limitations."
- "Other programs that impact a State's generation mix and could lead to reductions in emissions from covered sources such as renewable portfolio standards, clean energy standards," or "increases in end-use efficiency and demand-side management."

These clues provide a reasonable basis to expect that the final rule will give states many options to meet CO_2 reductions cost-effectively and reliably and in ways tailored to the generation mix and policy preferences of the particular state.

Section 111(d) Differs from Other Recent EPA Regulations Affecting Power Plants

The character of Section 111(d)'s regulatory framework creates an entirely different and potentially much-wider set of compliance and implementation options compared to other federal regulations that have affected the electric industry in recent memory. The 'cooperative federalism' model embedded in Section 111(d) provides for much more compliance flexibility and creativity than was possible for the many unit-specific regulations issued recently by EPA. This is core to the conclusion that EPA's regulation of GHG emissions from existing power plants will not raise electric system reliability concerns.

The MATS Rule

For example, one of the most recent EPA regulations affecting existing fossil-fuel power plants – the MATS rule – differs in fundamental ways from Section 111(d). In the MATS rule, EPA set uniform, national standards to reduce emissions of mercury and other toxic air pollutants from approximately 1,100 coal-fired EGUs and 300 oil-fired EGUs located in the U.S.[43], [44] The regulations set limits on allowable emissions that could occur at each affected unit by the compliance dates.

[43] The 12-16-2011 MATS rule also adopted standards for new power plants, which were updated in March 2013.

[44] EPA, "Reducing Toxic Pollution from Power Plants: Final Mercury and Air Toxics Standards (MATS)," December 2011 presentation, page 11.

EGUs generally have up to four years (and in a limited number of instances, a fifth year) to comply with MATS,[45] through a range of compliance strategies to be undertaken at the specific generating units covered by the regulation. "Many existing sources will comply with the MATS by controlling their emissions, while others (typically older, smaller, less efficient units) may choose to cease operations rather than install control technologies."[46] No trading or averaging is allowed across different generating stations. There is no possibility of purchasing compliance credits from over-compliance at other generating stations.

A vibrant public debate took place during the 2010-2012 period about the ability of the electric industry to maintain electric system reliability while also complying with MATS, because those EGUs not yet in compliance would either have to invest in pollution-control technology to comply with MATS, or shut down.[47],[48] Reliability concerns focused on the fact that such a large portion of the nation's generating fleet would be affected, and on whether the systems in which they were located could respond appropriately (and reliably) given those regions' heavy reliance on coal-fired generation. Other concerns focused on whether pollution-control equipment manufacturers and installers could absorb the simultaneous demand for work orders from the owners of so many affected units, and whether the rule would force coal units to retire and create shortages of generation capacity in some regions.

To address such concerns, the EPA took the unusual step in December 2011 (when it finalized its MATS regulation) of issuing a specific statement of enforcement policy to explain that, "where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with

[45] MATS includes a 3-year compliance period, with an extension of the compliance deadline for a 4th year for units able to demonstrate to state permitting authorities that additional year is needed for installing technology. In some cases a 5th year may be allowed, in light of EPA intention to allow use of administrative orders "with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented [electric] reliability concern." EPA December 2011 MATS Enforcement Policy Letter. This would extend MATS compliance deadlines from April 2015 to April 2016 for certain units.

[46] EPA December 2011 MATS Enforcement Policy Letter.

[47] Note that many generating units covered by the MATS rule were already compliant with the emissions limits as of the issuance of the MATS rule. See M. Bradley, S. Tierney, C. Van Atten, and A. Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," Fall 2011 Update, November 2011.

[48] During the two-year period of 2010 and 2011, countless industry reports and analyses, conference presentations, financial analyst calls, media articles, congressional hearings, and other public reviews focused on the question of whether the EPA's adoption of the mercury and air toxics rules, either alone or in conjunction with other potential EPA regulations affecting existing power plants (including CSAPR, the coal-ash rule, and the cooling water intake structure rule (Section 316(b) of the Clean Water Act)) that were being considered at the time, would introduce local or regional electric system reliability issues. Note one of my own analyses on this topic from early 2011: S. Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," January 18, 2011. http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

environmental standards while addressing genuine risks to reliability in a manner that protect public health and welfare."[49]

At present, the industry is proceeding with its planning in light of the final MATS regulation. (See further discussion, below, on how MATS compliance affects the conditions under which the states and the industry will develop their responses to EPA guidance under Section 111(d).)

How Section 111(d)'s Framework Differs from the MATS Rule

There several reasons why the types of reliability concerns raised during the discussions of the MATS rule in 2010-2011 are not relevant to the Section 111(d) regulations. First, Section 111(d)'s reliance on the SIP process means that EPA will be able to provide states with guidance allowing considerable and wide-ranging latitude in how they plan to meet EPA's requirements. EPA's guidance will not likely impose a common emission standard that must be met solely by actions taken at each affected unit. Rather, EPA is likely to establish standards specific to each state, based on the "degree of emission limitation achievable through the application of the best system of emission reduction," which may vary across states given their own particular circumstances. Each state will have flexibility to propose its preferred actions that accomplish the targeted reductions, as long as the SIP provides reductions across the facilities in the state that are at least as effective as EPA's approach. As EPA Acting Administrator for Air and Radiation told state regulators recently, "We get it that states are in very different positions and that they're thinking about these issues in their own context."[50]

Second, if a state has concerns about the reliability implications of potential temporary or permanent outages of units needed to respond to EPA guidance, the state can take that fact

[49] EPA December 2011 MATS Enforcement Policy Letter, pages 1, 4: "The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations temporarily (until controls can be installed) or indefinitely (through deactivation of a unit). …Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability. In the event that such sources are interested in receiving a schedule to come into compliance while operating, the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO [Administrative Order] to bring a source into compliance within one year….Any such AOs would be issued on or after (not before) the MATS Compliance Date and would be limit to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another units has had such a delay."

[50] Remarks of Janet McCabe, Acting Administrator for Air and Radiation, presented to the National Association of Regulatory Utility Commissioners, February 11, 2014.

explicitly into account as it designs its SIP. For example, a state may propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow emission averaging or emission-credit trading that achieve deeper reductions at one unit in exchange for lighter reductions at another. (The many options available to states in developing their SIPs are discussed below, in the section on "Planning for compliance with EPA guidance.")

Third, the Presidential Memorandum directing EPA to use its Section 111(d) authority explicitly calls for the agency to "develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities" that are not possible under the statutory language governing MATS. The Presidential Memorandum further directs EPA to develop its standards, regulations or guidelines to:

> identify and use the best, most innovative, and least burdensome tools for achieving regulatory ends…[and to] propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor its regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.[51]

Thus, the inherent authority within 111(d), combined with these Presidential directives, invites (if not requires) EPA to implement a flexible framework that will allow states to propose SIPs that take into account the need to assure electric system reliability. As such, the reliability red flag is mainly useful as a spur toward advanced planning, and to motivate states to prepare SIPs with elements addressing (and mitigating) such concerns. (See further discussion below.)

[51] This language is from Executive Order 13563, reflecting the Presidential Memorandum direction that EPA develop its guidance in a manner "consistent with Executive Orders 12866 of September 30, 1993, as amended, and 13563 of January 18, 2011." The latter Executive Order is "13563: Improving Regulation and Regulatory Review."

Power plants that are subject to CAA Section 111(d)

EPA has previously indicated that its Section 111(d) regulations will apply specifically to existing EGUs:[52] all grid-connected steam generators that use fossil fuel and are over 25 megawatts ("MW") in size. It is sensible to presume, too, that Section 111(d) will also apply to natural-gas-fired combined-cycle ("NGCCs") generating units, in light of the fact that the Section 111(b) proposal (affecting new power plants) applies to such units as well.[53]

Together, these categories represent a large subset of all of the nation's power plants, and cover most but not all existing fossil-fuel generating units. It does not include either non-grid connected or very-small steam generating units, or simple-cycle peaking units. EGUs and NGCCs represent classes of technologies which may be owned by investor-owned utilities, publicly owned utilities, rural electric cooperatives, non-utility generating companies, and others.

Based on current information about power plants from SNL Financial for 2013, I calculate that there are 3,084 EGUs and NGCC units likely to be directly affected by EPA's upcoming regulations.[54] (See Table 2.) These generating units represent approximately 532.4 GW of generating capacity,[55] with 292.4 GW of coal-fired power plants (mainly EGU capacity), 216.6

---

[52] "The regulations would apply to each EGU capable of combusting more than 250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel: *Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts electric (MWe) output to any utility power distribution system for sale. *Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat." OAQPS GHG Presentation.

[53] This is based on two assumptions: First, CAA Section 111(d) will apply to EGUs as defined by the EPA (see, for example, the OAQPS GHG Presentation from 2011). Second, Section 111(d) will apply to any categories of existing emission sources that, if they were new sources, would be regulated under Section 111(b). Under EPA's 2013 Proposed GHG Standards for New EGUs, Section 111(b) includes not only fossil-fuel steam generating units but also natural-gas combined-cycle units: "Utility announcements about the status of coal projects, IRPs [integrated resources plans], and EIA projections suggest that, by far, the largest sources of new fossil fuel-fired electricity generation are likely to be NGCC units. The EPA believes, therefore, that it is also appropriate to set a standard for stationary combustion turbines used as EGUs. These units are currently covered under subpart KKKK (stationary combustion turbines). The EPA also proposes to maintain the definition of EGUs under the NSPS that differentiates between EGUs (sources used primarily for generating electricity for sale to the grid) and non-EGUs (turbines primarily used to generate steam and/or electricity for on-site use). That definition defines EGUs as units that sell more than one-third of their potential electric output to the grid. Under this definition, most simple cycle "peaking" stationary combustion turbines, which typically sell significantly less than one-third of their potential electric output to the grid, would not be affected by today's proposal." Page 24 of EPA 2013 Proposed GHG Standards for New EGUs.

[54] The actual number of EGUs as of early 2014 is 1,929 units in light of data for grid-connected steam generating units over 25 MW in size and using coal, natural gas or oil for fuel. In early 2014, there were 1,176 generating units associated with combined cycle technologies, most of which burn natural gas. Source of data: SNL Financial.

[55] Net summer capacity.

GW of natural-gas-fired plants (mainly combined cycle units), and 23.7 GW of plants that burn oil (mainly EGUs).[56] This represents approximately half of total generating capacity in the U.S. as of the first quarter of 2014 (with the rest being primarily nuclear, hydro and wind), and 70 percent of U.S. fossil generating capacity. (See Appendix 2.)

Table 2
Existing Power Generation Capacity in the U.S. as of 3-2014:
All Power Plants and Power Plants Likely to be Subject to Clean Air Act 111(d)

	Generating Units Likely to Be Directly Covered by Section 111(d)* (# Units)	(GW of Capacity)	Total Grid-Connected Generating Capacity in the U.S. (GW)	111(d) Capacity as a Share of Total Capacity (%)
Coal	1204	292.4	303.7	96%
Natural Gas	1,636	216.6	414.3	52%
Oil	244	23.7	38.2	61%
Nuclear	0	0	98.0	0
Hydro	0	0	99.0	0
Wind and Solar	0	0	68.9	0
Other**	0	0	21.7	0
Total	3,804	532.4	1042.4	51%

Source of data: SNL Financial, March 2014. "GW" reflects net summer capacity of the generating units.
* This reflects existing grid-connected EGUs over 25 MW and NGCCs.
** This includes biomass, geothermal, and generation from other fuels not listed above.

Figure 1 shows the location of all U.S. fossil power plants by fuel type. Given the different fuel/technology mixes of power plants across the states, Section 111(d) will impact the states in different ways:

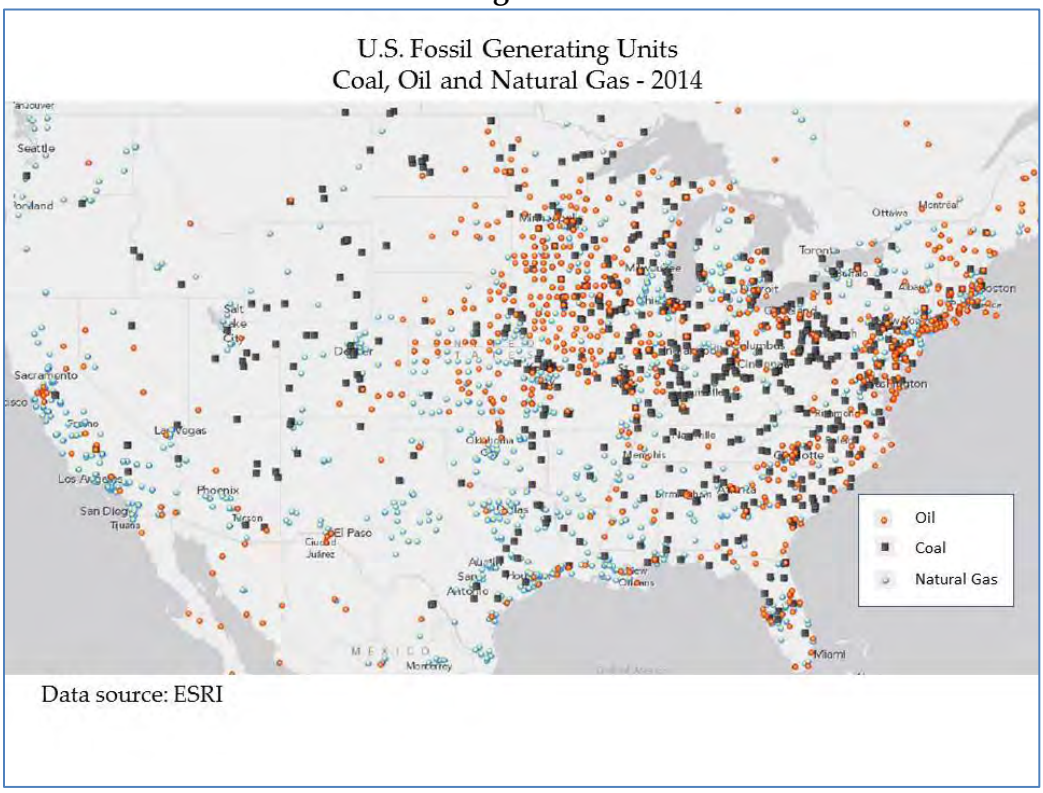
- States with half of their in-state generating capacity likely to be subject to Section 111(d) are (ranked by percentage of total capacity in the state): West Virginia (highest at 88 percent), Utah, Wyoming, Kentucky, Indiana, Louisiana, Delaware, Ohio, New Mexico, Oklahoma, Texas, Missouri, North Dakota, Missouri, Arkansas, Rhode Island, Massachusetts, Maryland, Wisconsin, Florida, Nebraska, Michigan, Alabama, Pennsylvania, and Hawaii (with 50 percent).

[56] These estimates are based on the primary fuel of plants, some of which may burn a second fuel.

- States with a relatively high share of the nation's total generating capacity affected by Section 111(d) are as follows (ranked by highest percentage of total capacity in the U.S.): Texas (12 percent), Florida, California, Pennsylvania, Ohio, Indiana, Georgia, Illinois, Louisiana, Alabama, New York, Michigan, Kentucky, Oklahoma, West Virginia, North Carolina, and Missouri (3 percent).

Appendix 2 provides state-specific information about power plant capacity and units likely to be directly subject to 111(d), along with other capacity in the each state's electric generating fleet. Forty-nine of the 50 states will need to prepare a SIP to show how the state plans to bring its generating facilities into compliance with EPA guidance.

Figure 1



Roughly one quarter of that Section 111(d) capacity (and 28 percent of the units) entered service prior to 1970, and is thus at least 43 years old. Approximately 352 EGUs (with a total capacity of 43.2 GW) are older than 53 years. Owners of 119 of the old (pre-1970) EGUs (with a capacity totaling 16.7 GW) have announced that they intend to retire the unit in a year prior to the end of

2016.[57] These tend to be much smaller units, two-thirds of which are coal-fired EGUs and one-fourth oil-fired EGUs.

Approximately three percent of the directly affected EGU and combined-cycle capacity (18.8 GW) operating at the start of 2014 has a planned retirement occurring between 2013 and 2016 – well before the compliance period for SIP implementation[58] (and roughly consistent with the date by which existing coal-fired and oil-fired EGUs will have had to comply with the EPA's MATS rule[59] or retire). Using this information as a proxy for upcoming retirements, approximately 523 GW of capacity nationwide would be subject to Section 111(d) after 2016. (See further discussion below regarding power plant retirements.)

Context for Industry Compliance with CAA Section 111(d) Requirements

Several trends affecting the electric industry set the stage for the roll-out of new regulations. Foremost among these trends are: the 'shale gas' revolution and its implications for coal plant economics (including the availability of higher levels of output from existing natural-gas power plants); relatively flat demand for electricity; growth in development of renewable energy; the availability of supply from zero-carbon nuclear generation; the announcements of retirements of coal-fired generating capacity that result from these factors and the EPA's MATS rule; and proposals to build new power plants. These trends set the context for EPA and the states preparing to address GHG emission reductions. And they affect the factors that states will need to consider as they plan for electric-system reliability as part of that process.

Natural gas, coal and existing power plants

Until the past few years, energy market fundamentals favored use of coal for power generation in many parts of the U.S. The recent shale gas revolution has fundamentally changed that

[57] Analysis based on SNL Financial data.

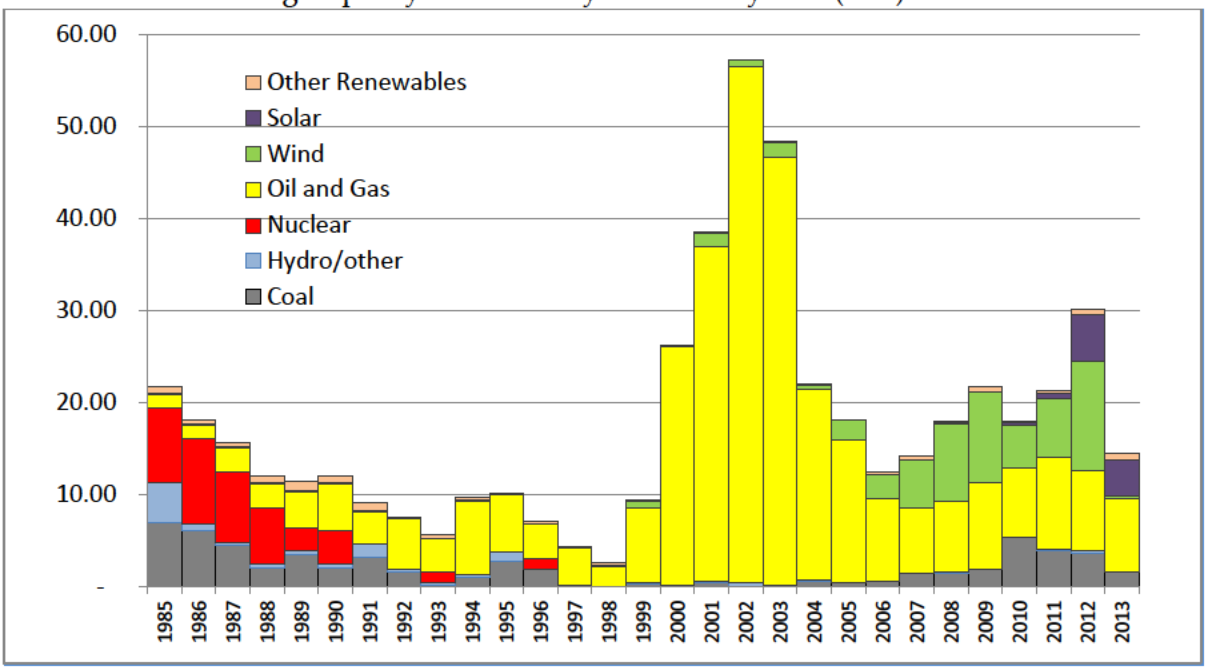
[58] The Presidential Memorandum requests that EPA's 111(d) guidelines require states to submit their SIPs by no later than June 2016. Assuming this optimistic time frame and taking into account time for EPA review and state implementation, compliance would actually likely begin no earlier than late 2017. (See, for example, the schedule showing an estimated compliance period for Section 111(d) spanning roughly late 2017 through 2020, as presented by Jennifer Macedonia, Bipartisan Policy Center, "Clean Air Act Regulation of Power Plants: Greenhouse Gas Performance Standards," September 2013, page 4.)

[59] See December 16, 2011, letter of Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance, EPA, re: the EPA's "Enforcement Response Policy for Use of Clean Air Act Section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxics Standard" (hereafter, "EPA December 2011 MATS Enforcement Policy Letter").

situation. Low natural gas prices over the past few years[60] have put economic pressure on coal facilities. Natural-gas-fired power plants increased their output (from 22 percent of U.S. power production in 2007, to 28 percent in 2013), while coal-fired generation decreased (from 49 percent in 2007 to 39 percent 2013).[61] Fuel-switching and re-dispatch of existing power plants was possible in light of the significant amount of gas-fired generating capacity that had been added in the U.S. since 2000 (Figure 2) and that had been underutilized for many years.

Figure 2

Generating Capacity Additions by Year and by Fuel (GW): 1985-2013



Source: EIA, Annual Energy Outlook 2013, Figure 78.

Low gas prices resulted from a combination of lower demand for energy (from the U.S. economic downturn and other factors[62]), and generally lower production costs associated with unconventional gas production. (See Figure 3 for wellhead prices of natural gas and in Figure 4 for prices of natural gas futures.) Market pressure resulting from low natural gas prices led to

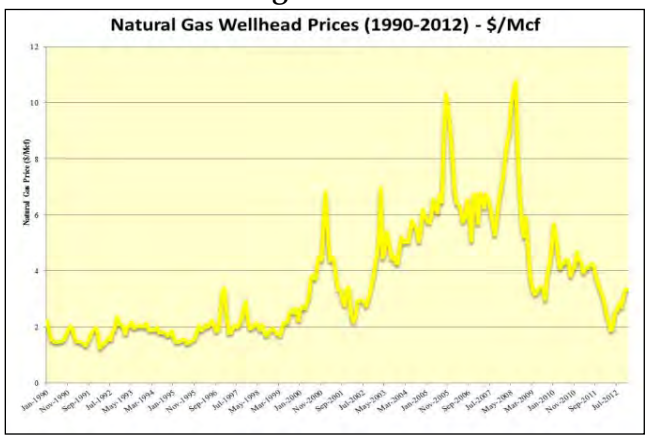
[60] Note that natural gas commodity prices spiked in many parts of the U.S. where extremely cold weather occurred in December 2013 and mid-January 2014. See SNL Financial.

[61] Source: EIA, Electric Power Monthly, Table 1.1. Net Generation by Energy Source: Total (All Sectors), 2003-November 2013. Information for 2013 is for the 11 months (January through November).

[62] Including states' promotion of increased funding for energy efficiency programs and stronger appliance efficiency standards.

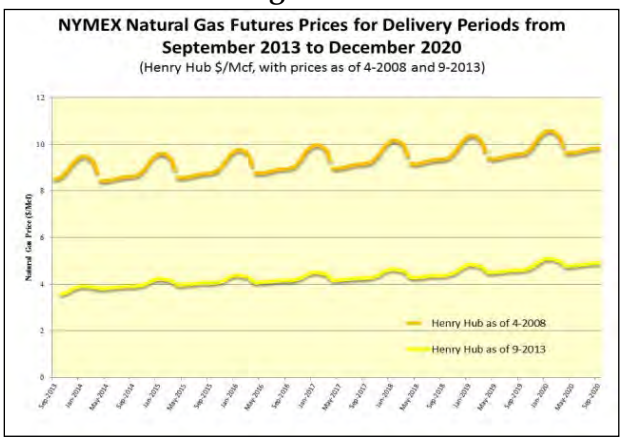
announcements of retirements of some of the oldest, smallest and least-efficient coal plants, as discussed previously.[63] Figure 5 shows the cumulative amount of coal-fired generating capacity (a total of 25.4 GW) that retired without reliability problems in the 2008-2013 period, in various regions of the U.S. It also shows the amount of capacity (an additional 20 GW) that has been announced to retire between 2014 through 2018. Most of the retiring capacity is located in the RFC and SERC regions – areas with substantial coal-fired generation and underutilized natural gas capacity.

Figure 3



Source: EIA

Figure 4



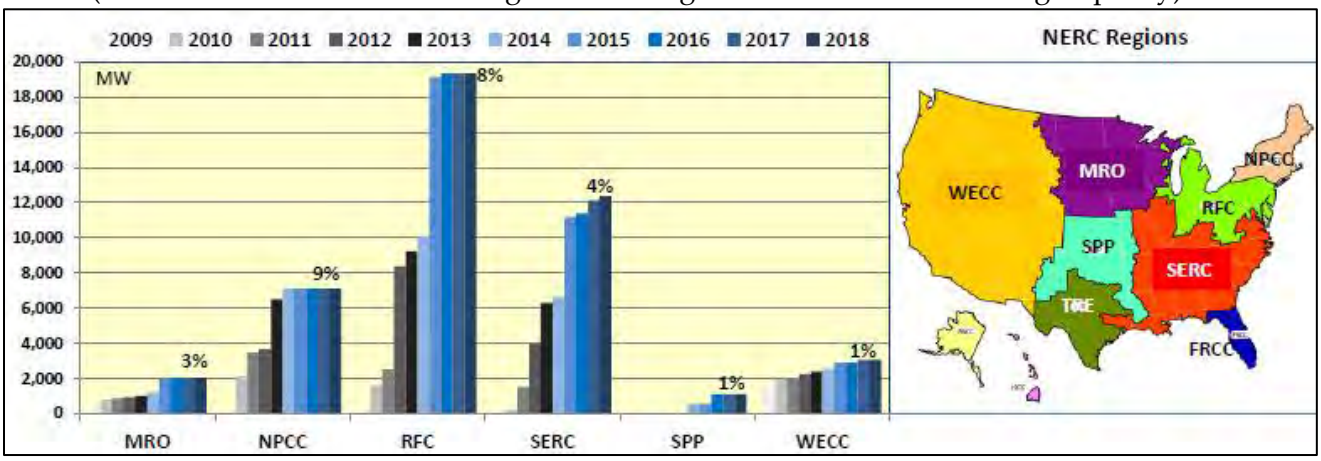
Source: SNL Financial

Given the significant amount of natural-gas-fired generating capacity added since 2000, these plants have not operated at full capacity, even as natural gas prices dropped in recent years and made it more economical to operate gas-fired plants.[64] This underutilized gas-fired capacity represents existing capacity that could operate more and could supply consumers' power requirements in the event of retirements of other power plants, operating restrictions on other high-emitting plants, and/or increased costs to run coal-fired power plants.

[63] A longer explanation of such market changes is in my February 2012 paper called "Why Coal Plants Retire: Power Market Fundamentals as of 2012."

[64] This is particularly true compared to prior years (e.g., during the period from roughly 2001 through 2008), when gas prices were relatively volatile and high (compared to most of the period since then, as shown in Figure 3).

Figure 5
Generating Capacity Associated Actual Coal-Plant Retirements (2009-2013) and Planned Coal Capacity Retirements (2014-2018) by NERC Region
(With Retirements as a Percentage of Each Region's Total 2012 Generating Capacity)

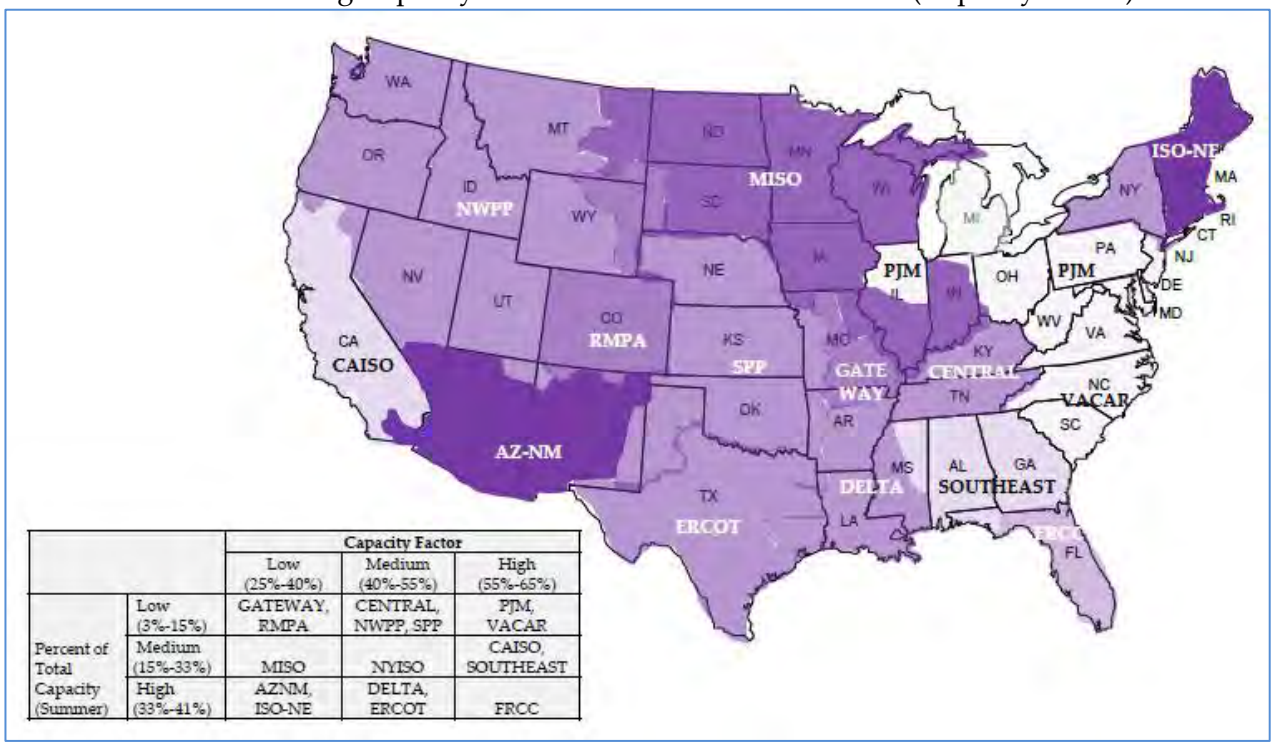


Source of data: SNL Financial, March 25, 2014. "NERC Region" refers to NERC's reliability regions (shown on the map). Note that there are no actual or planned retirements during the 2008-2018 period for TRE and FRCC.

The states and regions vary with respect to their reliance on natural gas capacity (e.g., NGCC capacity as a percentage of total capacity in the region) and their dispatch of NGCCs (i.e., their capacity factors, or the percentage actual output relative to their potential to produce power). Figure 6 shows the various regions, with shading indicating the extent to which there is significant under-utilized NGCC capacity that could be dispatched to meet power requirements in the event of restricted output at or retirement of coal plants. A lighter-shaded color indicates that the region's electric mix has relatively low reliance on NGCC capacity, but operates them relatively frequently. A darker-shaded color indicates that that region has relatively high reliance on NGCC capacity but with low capacity factors at those plants.

Figure 6

Regional Reliance on Natural Gas-Fired Combined Cycle in 2012 as a Percentage of Total Generating Capacity and in terms of Asset Utilization (Capacity Factor):



		Capacity Factor		
		Low (25%-40%)	Medium (40%-55%)	High (55%-65%)
Percent of Total Capacity (Summer)	Low (3%-15%)	GATEWAY, RMPA	CENTRAL, NWPP, SPP	PJM, VACAR
	Medium (15%-33%)	MISO	NYISO	CAISO, SOUTHEAST
	High (33%-41%)	AZNM, ISO-NE	DELTA, ERCOT	FRCC

Source of data: SNL data (on NGCC power plants and capacity factors) by NERC subregion as of 2012. NERC regions and subregions are shown in Appendix 3. Note: There were no regions with less than 3 percent or more than 41 percent reliance on NGCC capacity (as a percentage of total summer capacity in 2012). No regions had an average NGCC capacity factor lower than 25 percent and higher than 65 percent in 2012. In all but one region (NWPP), the average 3-year capacity factor (2011-2013) was lower than the capacity factor in 2012, due to various factors including relative price of natural gas and coal, availability of hydro and/or wind, nuclear outages and/or retirements, coal-plant retirements). The 3-year average was less than 5 percent lower for some regions (i.e., ERCOT, FRCC, ISO-NE, NYISO, RMPA, VACAR), between 5-10 percent lower for others (AZNM, DELTA, and SOUTHEAST), between 10-15 percent lower (CAISO, CENTRAL, PJM, and SPP), and 15-30 percent lower (in GATEWAY and MISO).

This under-utilized NGCC capacity provides an opportunity in most states to incorporate policies and actions in their SIPs that encourage redispatch of existing power plants. For example, the recent Phillips/CATF 2014 analysis indicates that a combination of

> approaches would reduce emissions through a mix of compliance actions: by reducing the heat rates (and consequently the emission rates) of coal units; displacing high emission rate coal generation with lower emission rate gas generation through an emission credit trading program; retiring

> coal generating capacity; and reducing electric demand through customer response to higher electric prices. Of these, the emission reductions from fossil dispatch represent the largest single source of reductions, in both cases approximately 70 percent of total compliance. This is due to the large size and intermediate capacity factors of the existing NGCC fleet (even under current and expected market conditions) and the relatively narrow spread between delivered coal and natural gas prices, especially in the eastern and central regions of the country."[65]

This existing, under-utilized existing capacity provides grid operators with generating resources to dispatch to meet operating requirements reliably. As noted in Figure 6, every region has some existing under-utilized NGCC capacity, and there were no regions with average NGCC capacity factors lower than 25 percent and higher than 65 percent in 2012. As shown in the Appendix 2, a handful of states (Hawaii, Kansas, Kentucky, North Dakota, Vermont, West Virginia, and Wyoming) did not have any NGCC capacity operating in 2012; of these, most of them either have NGCC capacity under construction in their state as of March 2014 (as is the case for Kansas, Kentucky, North Dakota, and Wyoming) and/or are part of a region with significant under-utilized NGCC capacity (as is the case for all of these states besides Hawaii).

Outlook for electricity demand

GHG emissions from fossil fuel power plants are also strongly tied to overall electricity use. Electricity demand has been relatively flat in recent years, with a gradual return to 2007 levels anticipated by next year.[66] Beyond then, EIA estimates that demand will grow approximately 1.5 percent per year through the end of this decade.[67] The current forecast for 2020 is approximately the level of demand anticipated for 2013 before the economic downturn. This provides a degree of breathing room for managing changes in the generation mix.

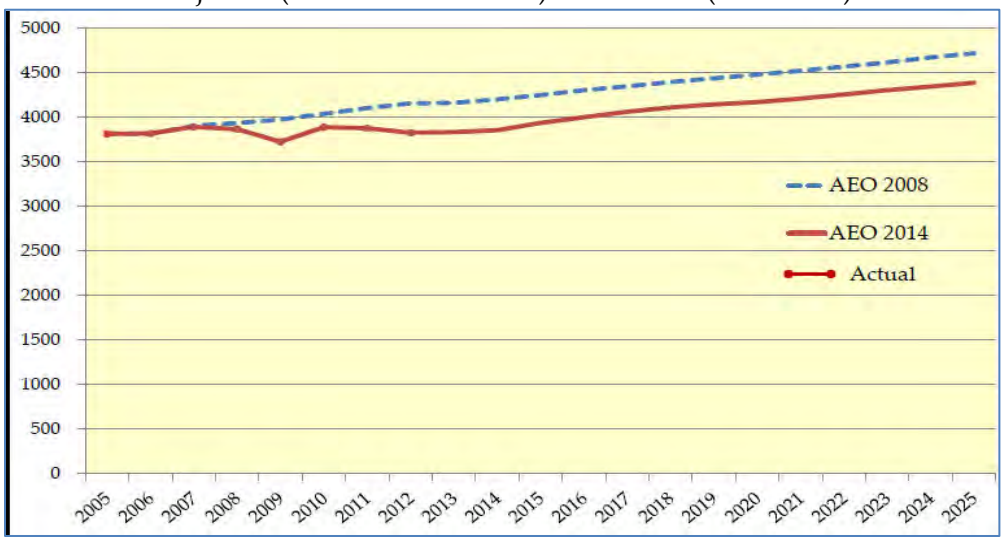
---

[65] Phillips/CATF 2014, page 21. See also the Appendix in that report.

[66] EIA, Annual Energy Outlook 2014 (Early Release) (hereafter "EIA AEO 2014ER"), and AEO 2008, with actual data from Electric Power Monthly.

[67] The EIA's estimates of demand does not take into account the demand met by on-site renewable generation (e.g., roof-top photovoltaic systems).

Figure 7
Electricity Demand through 2025:
Projected (as of 2008 and 2014) and Actual (2005-2012)



Source of data: EIA, AEO (2008, 2014), and Electric Power Monthly

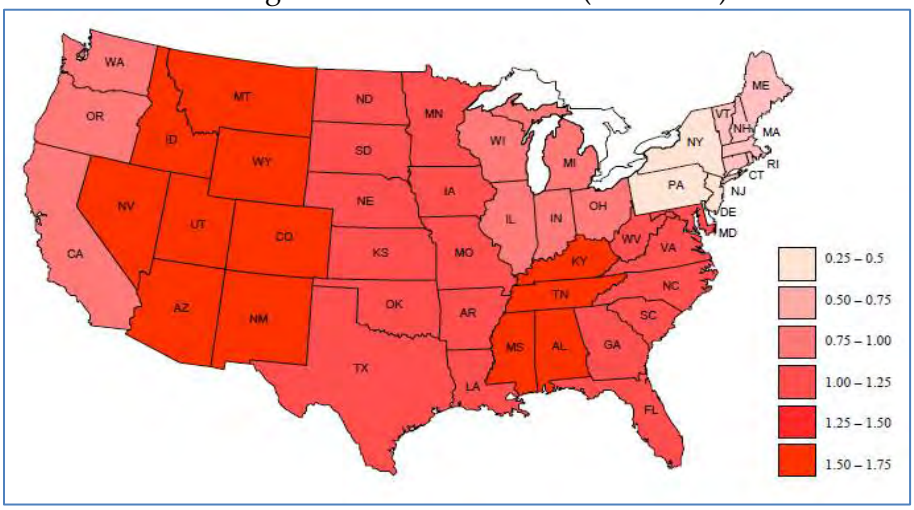
EIA projects different growth rates by region of the country.[68] Regions anticipated to grow faster than the U.S. average are the Mountain states, the Plains states, Texas, and the Southeast.[69] By contrast, EIA projects slower growth for the Pacific states, East North Central states, the Mid-Atlantic, and New England regions.[70] (Figure 8.)

[68] EIA AEO 2014ER, Tables 1-30. http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm, Tables.

[69] West North Central (1.0%/year); South Atlantic (1.1%/year); West South Central (1.2%/year); Mountain (1.7%/year); East South Central (1.7%/year). EIA, AEO 2014ER.

[70] Middle Atlantic states (0.3%/year); New England (0.6%/year); East North Central (0 8%/year); Pacific states (0.8%/year). EIA AEO 2014ER.

Figure 8
Projected Growth in Demand for Electricity by Region:
Average Annual Growth Rate (2012-2020)



Source of data: EIA, AEO 2014ER

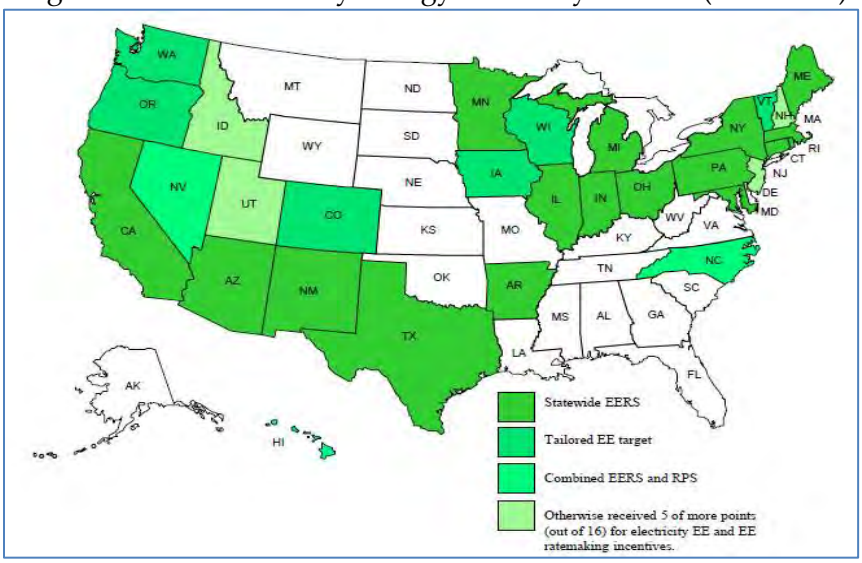
States' growth trends reflect not only different economic activity but also the effect of policy. Many states have adopted energy efficiency policies that enable greater energy productivity through policies such as utility-sponsored energy efficiency programs, building codes, ratemaking incentives for meeting efficiency targets, and an Energy Efficiency Resource Standard ("EERS"). According to the American Council for an Energy Efficiency Economy ("ACEEE"), 26 states "have adopted and adequately funded an EERS, which sets long-term energy savings targets and drives investments in utility-sector energy efficiency programs,"[71] and which "aim explicitly for quantifiable energy savings."[72] Figure 9 shows states with an EERS and other programs promoting efficiency savings in electricity use.

[71] ACEEE, "The 2013 State Energy Efficiency Scorecard," ACEEE Report E13K (hereafter "ACEEE 2013 Efficiency Scorecard"), page vi. The states with a "statewide EERS" as of 2013 are: Arizona, Arkansas, California, Connecticut, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, and Texas. The states with a version of an EERS that ACEEE calls a "tailored target" are Colorado, Iowa, Oregon, Vermont, Washington, and Wisconsin. And the states that combine a renewables and energy efficiency standard are Hawaii, Nevada and North Carolina. ACEEE 2013 Efficiency Scorecard, page 19.

[72] "Twenty-six states now have fully funded EERS that establish specific energy savings targets through customer energy efficiency programs. These policies set multi-year targets for electricity…, such as 1% or 2% incremental savings per year or 20% cumulative savings by 2025.[fn in the original.] EERS policies aim explicitly for quantifiable energy savings, reinforcing the idea that energy efficiency is a utility system resource on par with supply-side resources. These standards also help utility system planners more clearly anticipate and project the impact of energy efficiency programs on utility system loads and resource needs. Energy savings

Figure 9

States with a Energy Efficiency Resource Standard or With Relatively High Scores for Electricity Energy Efficiency Policies (as of 2013)



Source: Data from the ACEEE 2013 Efficiency Scorecard, Table 8. This table includes all states considered having an EERS (by ACEEE) and otherwise receiving at least 5 of 16 points for electricity energy efficiency ("EE") or EE ratemaking incentives for utilities.

Even states with a strong history of pursuing cost-effective energy efficiency have further opportunities to improve energy productivity in the future.[73] Tapping such opportunities can help states reduce some of the GHG emissions associated with electricity production.[74]

State policies relating to renewable energy

Another factor affecting the outlook for GHG emissions at existing fossil units is the widespread adoption of policies by states to promote use of renewable generation. As shown in Figure 10,

---

targets are generally set at levels that push efficiency programs to achieve higher savings than they otherwise would have, typically based on analysis for the energy efficiency savings potential in the state that ensures the targets are realistic and achievable. EERS policies maintain strict requirements for cost-effectiveness so that efficiency programs are guaranteed to provide overall benefits to consumers." ACEEE 2013 Efficiency Scorecard, Page 18.

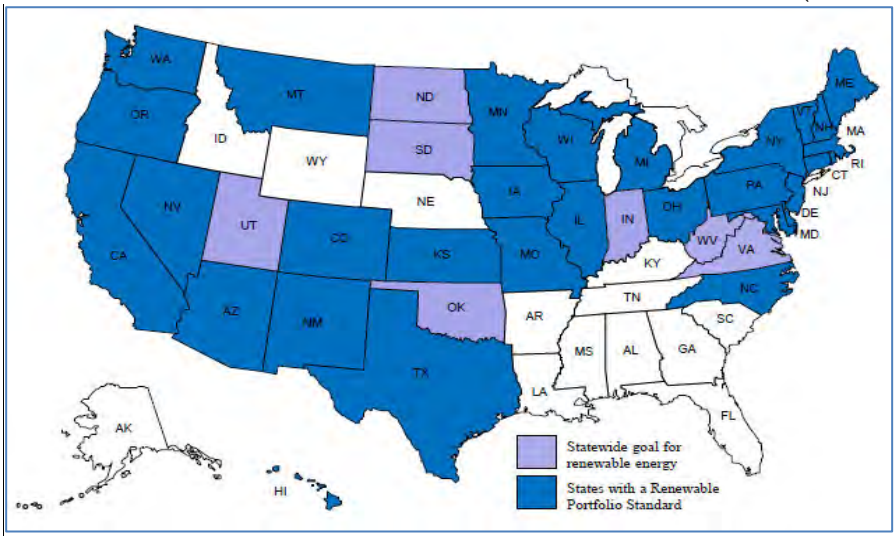
[73] See, for example, the February 7, 2013 report of the Alliance Commission on National Energy Efficiency Policy, "Doubling U.S. Energy Productivity by 2030."

[74] Paul Hibbard and Andrea Okie, "Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments: Recommended Framework for Proposed Guidance on Quantifying Energy Savings and Emission Reductions in Section 111(d) State Plans Implementing the Carbon Pollution Standards for Existing Power Plants," March 2014. http://www.edf.org/sites/default/files/eemv-111d-recommended-framework.pdf.

most states have either a Renewable Portfolio Standard ("RPS") that requires that a certain percentage of electricity sold at retail be sourced from renewable energy generation, or a goal for development and use of renewable supplies. Some of these states' RPS policies have been in place for many years, leading to growth in renewable generation in recent years. Figure 11 shows the percentage of states' 2012 generation that came from renewable energy (including wind, solar, geothermal, hydro, wood, wood waste, municipal waste, landfill gas, and other biomass). This output tends to displace output that would otherwise come from fossil generation with GHG emissions.[75]

Figure 10

States with a Renewable Portfolio Standard or Renewables Goals (as of 2013)



Source: Database of State Incentives for Renewables and Efficiency ("DSIRE")

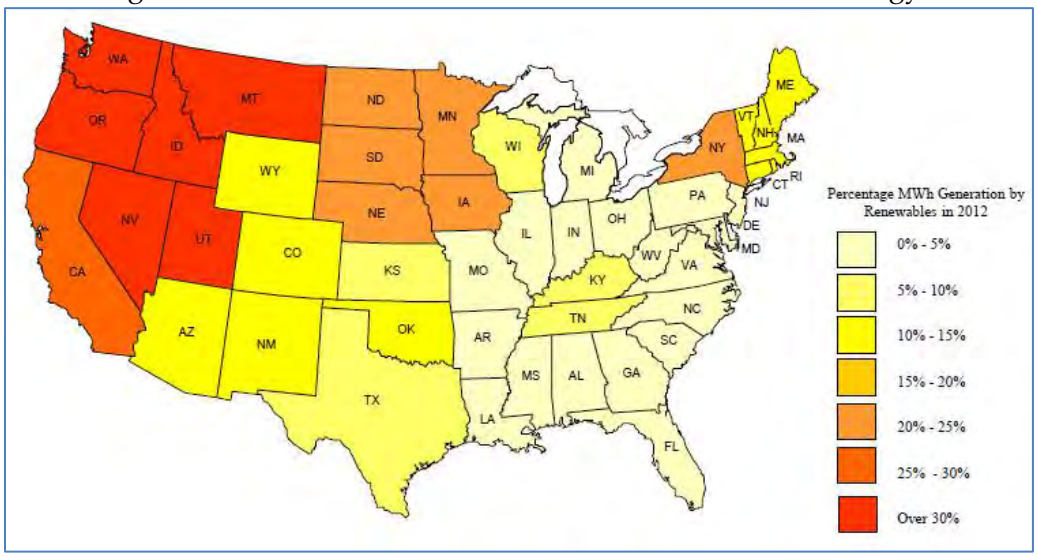
[75] In the U.S. overall in 2012, renewable generation accounted for 14 percent of total electricity supply. Of this renewable generation, the sources of power production were as follows:

Renewable Generation in the U.S. – Percentage Shares by Fuel/Resource in 2012	
Conventional Hydro	55%
Wind	28%
Wood and Other Biomass	7%
Municipal Wastes	4%
Geothermal	3%
Solar (not including off-grid PV systems)	2%
Total Renewables	100%

EIA, AEO 2014ER, ref2014.d102413a, Table 120.

Figure 11

Percentage of States' Total Power Generation from Renewable Energy in 2012

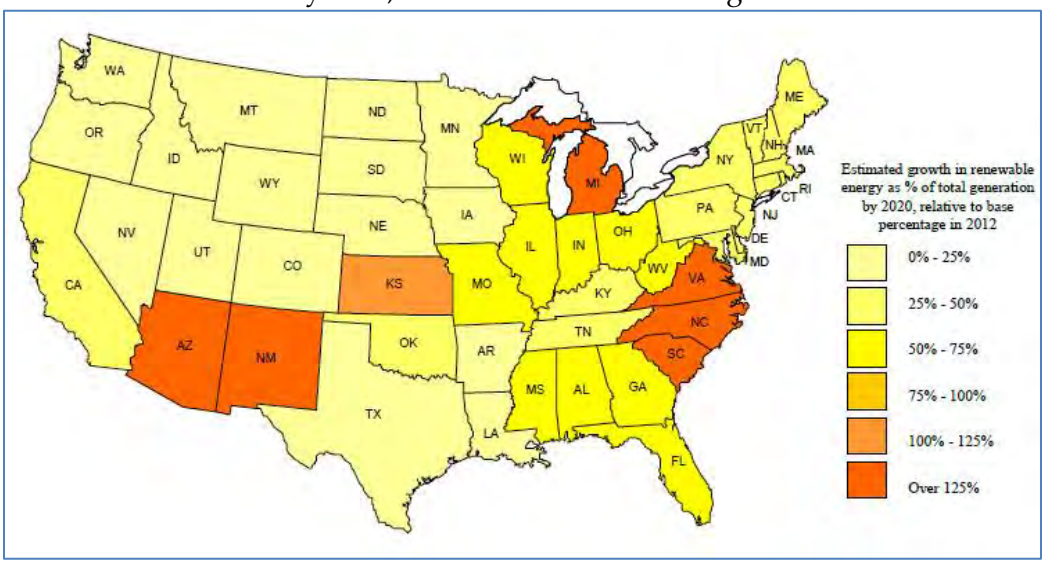


Source of data: EIA, AEO 2014ER, ref2014.d102413a, Table 96. States' output shown on the map above is based on their location within EIA's Electricity Market Module Regions. For states in more than one region, a state has been assigned to the particular region in which the majority of the state is located (by land, not necessarily load). "Renewables" includes wind, solar, geothermal, conventional hydro, wood, wood waste, municipal waste, landfill gas, and other biomass.

EIA projects that in several parts of the country where renewable generation was a relatively small share of total power supply in 2012, there will be substantial growth in renewable output. Figure 12 shows information related to such growth, with the color indicating each state's renewable generation in 2020, as a percentage increase from that state's base of renewables in 2012. The additional renewable supply will come from both utility-scale and distributed renewable energy projects (i.e., facilities located 'behind the meter' on customers' premises). These projections, based on current policy assumptions, provide a reasonable basis for assuming that in the future, renewables will allow for displacement of some of the output from fossil generation in many regions of the country (e.g., the Southeast and Florida, Arizona and New Mexico, Virginia and the Carolinas, Michigan and other parts of the Midwest) in the years ahead. States may be able to plan for such as part of their SIPs, and will likely need to address

operational/integration issues that may become more urgent with higher penetration of renewables (although the availability of flexible NGCC will help with this integration).[76]

Figure 12
Projected Growth in States' Renewable Generation
by 2020, Relative to 2012 Percentage



Source of data: EIA, AEO, 2014ER, ref2014.d102413a, Table 96. The information in this chart is based on a comparison of the MWh of generation in 2012 with the projected generation in 2020, with the difference reflecting the percentage change in renewables generation over that period. States with a darker color represent a higher percentage growth in that state. States' output shown on the map above is based on their location within EIA's Electricity Market Module Regions. For states in more than one region, a state has been assigned to the particular region in which the majority of the state is located (by land, not necessarily load). "Renewables" includes wind, solar, geothermal, conventional hydro, wood, wood waste, municipal waste, landfill gas, and other biomass.

Availability of zero-carbon supply from nuclear generators

For nearly two decades, one fifth of the nation's electricity supply has been generated at nuclear power plants.[77] The currently operating 100 nuclear reactors are located in 31 states, as shown in Figure 13.

[76] See, for example, the recent study performed to examine the operational, cost, emission, and other implications of a 40-percent and 50-percent RPS requirement in California: E3, "investigating a Higher Renewables Portfolio Standard in California, January 2014; and Dan Arvizu, Severin Borenstein, Susan Tierney, and Stephen Wright, "Report of the Independent Advisory Panel Regarding the Five California Utilities' Study of Integration of Renewable Energy into California's Electric System: 'Investigating a Higher Renewables Portfolio Standard in California'," January 2014.

Figure 13

Location of Existing Nuclear Power Plants and Regional Transmission Organizations (RTOs)

Source: World Nuclear Association, http://www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/. Overlay of RTOs (Analysis Group). Note that this map shows the San Onofre (California), Crystal River (Florida), and Kewaunee (Wisconsin) units – all of which were retired as of 2014.

In the past two years, owners of several existing nuclear units have either retired or announced an impending retirement of the plants. The actual retirements include units located in California, Wisconsin, and Florida. A unit retirement will occur in Vermont at the end of 2014. These particular retirements are due to a variety of reasons, including costly repairs and low wholesale power prices.[78]

---

[77] EIA, Annual Review of Energy, 2013, Table 7.2b Electricity Net Generation: Electric Power Sector.

[78] San Onofre Units 2 and 3 in California (and totaling 2150 MW) retired in 2013 after being shut down for an extended outage related to a damaged steam generator at the unit, with its owner reporting it would be uneconomic to repair and restart the units, in light of market conditions; Kawanee, a 566-MW unit in Wisconsin shut down in 2013 due to lower power prices in wholesale markets; Crystal River, a 860-MW unit in Florida that was shut down permanently in 2013 down after a decision not to repair the previously damaged station; and Vermont Yankee, a 604-MW unit announced to be retired at the end of 2014 due to unfavorable economics, in spite of a 90+ percent capacity factor. Sources: EIA Generator Y2012 data (860 database on power plants); EIA, "Lower power prices and high repair costs drive nuclear," July 2, 2013; Matthew Bandyck, "UPDATE: Entergy says Vermont Yankee nuke closure shows design flaws in wholesale markets," August 27, 2013.

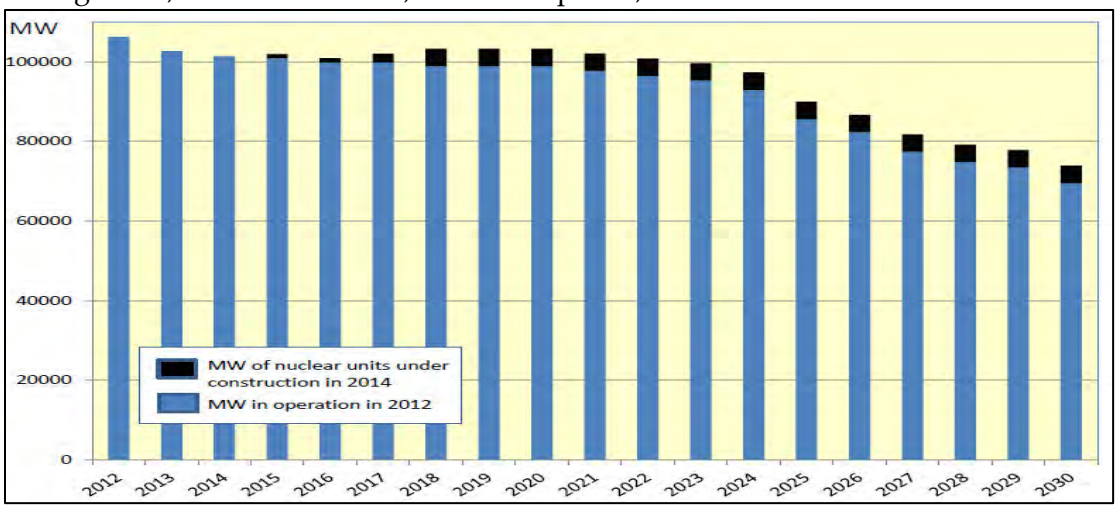
Many of the nation's best-performing nuclear units – including those that operate on a non-utility 'merchant' basis – are under significant economic pressure. Merchant nuclear plants operating in the 'organized' wholesale power markets (shown on Figure 13's shaded regions) have suffered slim profit margins in recent years. This results from many factors, including low natural gas prices, wholesale power-market design flaws, flat electricity demand, rising capital costs, and public policies that favor some low-carbon resources but not others.[79]

Figure 14 shows total nuclear generating capacity, taking into account the effect of recent nuclear retirements, new nuclear units under construction, new capacity uprates, and other nuclear plants retiring at the end of their currently approved operating licenses.

Figure 14

Nuclear Generating Capacity: 2012-2030

(Existing Units, Unit Retirements, Planned Uprates, and Units Under Construction in 2014

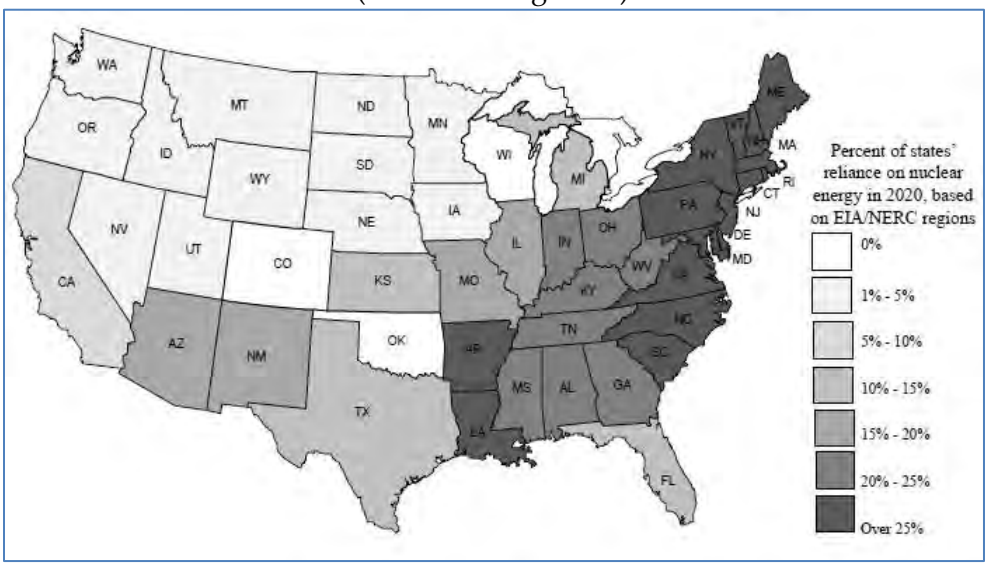


Source: EIA, AEO 2014ER.

Taking these retirements into account, along with the projected addition of the five nuclear generating units under construction in the Southeast, EIA projects that regions will continue to rely on nuclear plants to produce a considerable share of power supply by the year 2020 (as shown in Figure 15), with declining zero-carbon nuclear generating capacity beyond then (see Figure 14).

[79] See my forthcoming paper: S. Tierney, "Today's Nuclear Fleet: What Role in the Nation's Clean, Affordable and Reliable Power Strategy?"

Figure 15
Projected Regional Reliance on Nuclear Energy 2020
(NERC Subregions[80])



Source of data: EIA, AEO 2014ER, ref2014.d102413a, Table 96. Note that because these projections are based on NERC subregions rather than state-specific generation estimates for 2020, there may be no nuclear units in some states with that show shading (rather than being a white color). Compare Figure 13 to this one, for the location of nuclear units by state. Note that NERC regions and subregions are shown in Appendix 3.

When a nuclear plant retires, its output tends to be replaced (at least in the near term) with generation from plants that burn natural gas, oil or coal. Loss of nuclear units leads, therefore, to higher CO_2 emissions. Reportedly, California's CO_2 emissions increased by 10 percent after the recent loss of the output from the two San Onofre units that shut down in early 2012.[81]

The need to replace zero-carbon generation at any additional nuclear plants that shut down could increase the pressure on states to include Section 111(d) SIP elements addressing this

[80] States' output shown on the map above is based on their location within EIA's Electricity Market Module Regions. For states in more than one region, a state has been assigned to the particular region in which the majority of the state is located (by land, not necessarily load). There may be no nuclear units in some states with a shading (i.e , not white color), in light of the market sub-regions used in EIA modeling.

[81] The California Air Resources Board has reported that CO_2 emissions in the state increased from 2011 to 2012, "primarily due to emission increases from California electricity generation using natural gas as a fuel", which in turn were tied to low hydro conditions, higher demand as a result of warmer weather and a recovery economy, and the shutdown of the San Onofre nuclear station in early 2012. World Nuclear News, "Greenhouse gas emissions from power plants in California increased by 35% in 2012, partly due to the early closure of the San Onofre nuclear power plant," November 5, 2013.

situation. For example, EPA should consider requiring states with existing nuclear plants to demonstrate in their SIPs mechanisms to assure retention of such zero-carbon electricity supply and/or address the potential loss of resources with no GHG emissions. Additionally, the states located in regions with (a) deep reliance on nuclear generation (Figure 15), (b) merchant nuclear plants located in ERCOT, PJM, MISO, NYISO, ISO-NE (Figure 13), and (c) significant coal retirements (Figure 5, and discussion in the following section) should consider including elements in their SIPs to create incentives to retain safely operating zero-carbon generating capacity and/or to recognize the potential to generate electricity with no carbon emissions as a result of any planned nuclear capacity uprates.

Responses to EPA MATS regulations

Owners of many existing coal-fired power plants are planning for their future in light of the EPA's MATS regulations issued at the end of 2011. EGUs affected by the MATS rule will need to be in compliance by 2016, with some exceptions as noted by EPA.[82]

In anticipation of these regulations and in light of market fundamentals, many of the older and less-efficient coal plants may retire before the MATS compliance deadlines. (See Figure 5.) (Various observers have estimated the expected amounts of retirements, but comparisons among them are hard because they reflect different time periods for their baseline generating capacity and forward period for retirements.[83]) Some of the coal plant capacity has already retired (e.g., 25.4 GW from 2008 through 2013, as shown in Table 5), leaving 303.7 GW of coal-fired capacity as of the beginning of 2014. Because owners of plants affected by the MATS rule have until roughly 2016 to comply with the rule's requirements, the retirements occurring before then can be viewed as heavily affected by current power market pressures. In addition to the 25.4 GW already retired, another 18.4 GW has been announced to retired through 2016, with most of that retiring by the end of 2015 and located in the RFC (Midwest) and SERC (Southeast) regions (see Figure 5).

---

[82] See EPA December 2011 MATS Enforcement Policy Letter.

[83] "Over 52 GW (about 16% of the existing coal fleet) of coal-fired electric generating capacity has been announced for retirement by 2025. Of this, about 45 GW will retire by 2016." Amlan Saha, "Review of Coal Retirements," MJ Bradley Associates, April 2013. SNL has recently reported that owners of 47 GW (roughly 14.6 percent of the 323 GW of coal-fired generating capacity operating as of 2012) have announced the retirement of such units before 2016. Jesse Gilbert and Andrew Gelbaugh, "Coal under fire: Assessing risk factors and market impacts for upcoming coal retirement decisions," SNL Financial, December 2013 (hereafter "SNL 2013 Coal Retirement Study"), page 14.

A December 2013 SNL study analyzed the combined economic pressures from MATS compliance and other factors (including low natural gas prices, wholesale power prices and demand forecasts). SNL estimates that an additional 16.9 GW is 'at risk" of retirement, with that amount decreasing to 15 GW if average natural gas prices are 50 cents/MMBtu higher than the base case and increasing to 22.3 GW if average natural gas prices are 50 cents/MMBtu lower than in the base case [by 2016].[84] Most of the coal-fired capacity identified as 'at risk' of retirement by SNL is located in parts of the Midwest and the Southeast, as shown in Figure 16, reproduced from the SNL study. These 'at risk' units are older, smaller and worse performing compared to the average coal fleet overall. This capacity has an average unit size of 102 MW, an average age at retirement of 51 years old, and an average capacity factor of 51 percent.[85]

[84] SNL's report identified 323 GW, but included the 9 GW that had been retired in 2012. As of the start of 2013, SNL identified 314 GW of coal plants in operation as of the beginning of 2013. Of this capacity, 13 GW are not "EGUs," and therefore are not subject to MATS regulations. SNL identified 113 GW of existing coal-fired capacity "which appear to need some retrofits for MATS compliance but have neither announced specific plans for major retrofits nor firm retirement plans." SNL 2013 Coal Retirement Study, page 12-16.

SNL's analysis of announced retirements plus capacity at-risk of retirement is generally consistent with February 2014 study published by the Brattle Group, which identifies additional announced retirements totaling 25 GW in 2014 through 2016, as a result of the combined effects of low wholesale electricity prices and the cost of compliance with pollution-control equipment. This report summarized coal-plant retirements by year: Actual retirements in 2012 (9.0 GW) and 2013 (6.0 GW), totaling 15 GW. Announced additional retirements in 2014 (3.5 GW), in 2015 (16.9 GW), and 2016 (4.6 GW, for a total of 25 GW between now and the end of 2016. Martin Celebi, Brattle Group, "Coal Plant Retirements and Market Impacts," February 5, 2014.

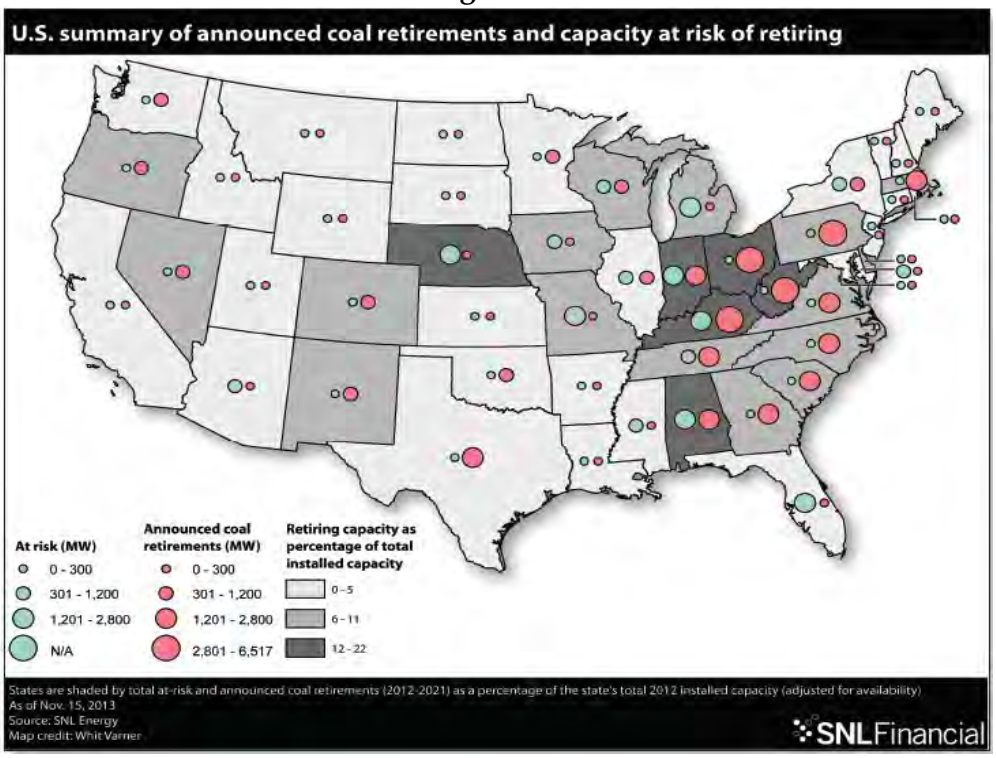
[85] SNL 2013 Coal Retirement Study, Figure 22.

Table 4
Operating Statistics for 'At-Risk" Coal Retirements for Select Regions

	2011 Capacity Factor	Average Heat Rate	Average Age at Retirement	Average size (MW)
MISO (Midcontinent)	52.29	11,598	51	75
PJM (MidAtlantic and Midwest)	40.51	11,414	53	67
Southeast	38.11	10,527	50	169
AZ/NM (Arizona and New Mexico)	65.15	10,953	39	192
SPP (Southwest)	61.44	11,065	48	97
Central	64.79	10,679	60	144
All regions	51.19	11,138	51	102

Source: SNL 2013 Coal Retirement Study, Figure 22.

Figure 16



Source: SNL 2013 Coal Retirement Study. The note on the bottom of the chart reads: States are shaded by total at risk and announced retirements (2012-2021) as a percentage of the state's total 2012 installed capacity (adjusted for availability), as of Nov. 15, 2013.

By now, electric companies and grid operators affected by these retirements have been planning to assure compliance as well as system reliability for many years.[86] According to EIA, as of the end of 2012, "70% of the U.S. coal generating capacity already had the appropriate environmental control equipment to comply with the MATS and allow their operation past 2016. Another 6% plan to add control equipment, while 8% have announced plans to retire. Owners of the remaining 16% are faced with the decision of upgrading or retiring their plants."[87]

[86] See, for example, M. Bradley, S. Tierney, C. Van Atten, and A. Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," Fall 2011 Update, November 2011; NERC, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations," October 2010.

[87] EIA, "Coal-fired power plant operators consider emissions compliance strategies," March 28, 2014.

The most recent long-term reliability assessment published by NERC indicates that reserve margins will be adequate in upcoming years in all parts of the country, with two notable exceptions: ERCOT (the TRE reliability region in Texas) and the MISO region.[88]

In ERCOT, for example, relatively near-term resource adequacy issues have been headline news for several years, with different parties expressing views about the need for changes in the wholesale power market design (which is an "energy-only" market) to assure new investment in generating capacity.[89] This debate is separate from the state's response to the MATS rule. In its recent analysis of at-risk generating assets, SNL found "no units in ERCOT were identified as at risk under the SNL base case…"[90] ERCOT's regulators, grid operator and stakeholders are working on solutions to address these low-reserve-margin issues, including instituting additional market-design changes, demand-response and other actions.

At the end of 2013, MISO issued a report summarizing power plant owners' plans for unit retirements, and indicated that "25 coal-fired units, representing 8.2 GW of capacity, or about one-eighth of the MISO coal fleet capacity, have yet to determine whether they need an additional year to comply with MATS."[91] MISO's summary indicated a potential shortfall of capacity by 2016 but only if all of that capacity retired and no significant steps end up being taken to increase additional demand-response, energy efficiency, incremental generating capacity, and/or transmission additions. The SNL analysis of 'at risk' capacity identifies 6 GW in MISO, with that capacity at small, old, and inefficient units.[92] Some have offered suggestions

[88] NERC, "2013 Long-Term Reliability Assessment," December 2013, page 2 and Figure 2 (page 6).

[89] For example, "ERCOT projects that reserve margins will fall to 9.8% by 2014, substantially below its current reliability target of 13.75%. Reserve margins will decline even further thereafter unless new resources are added. Generation investors state that a lack of long-term contracting with buyers, low market heat rates, and low gas prices in ERCOT's energy-only market make for a uniquely challenging investment environment. In response to these concerns, the Public Utility Commission of Texas (PUCT) has implemented a number of actions to ensure stronger price signals to add generation when market conditions become tight…. The key question is whether market prices will be high enough to support entry at an acceptably high reserve margin and associated reliability level." Samuel Newell, Kathleen Spees, Johannes Pfeifenberger, Robert Mudge, Michael DeLucia, Robert Carlton, "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012.

[90] SNL 2013 Coal Retirement Study, page 17.

[91] MISO s "3rd Quarter 2013 EPA Survey Update," November 13, 2013, as reported by Jonathan Crawford, "More than 8 GW of MISO coal capacity still undecided on compliance path for EPA mercury rule," SNL Exclusive, November 18, 2013. "An additional 24 coal-fired units in MISO, accounting for 4.1 GW, that were listed as needing a one-year extension to meet the MATS emissions limits were identified as not having submitted an extension request to regulators for approval. The survey had a participation rate of 98.5%, with 1 GW of MISO s total 66 GW of coal capacity not included in the results….. On the positive side, the survey showed that 35 coal-fired units in MISO, accounting for 11.7 GW, were approved for a one-year extension to comply with MATS. That is out of 84 coal units, representing 24 GW, which could possibly need a one-year extension….This is consistent with calls by the EPA that state regulators be liberal in granting approval of the compliance deadline extension requests."

[92] See prior table. SNL 2013 Coal Retirement Study, Figure 19.

about steps that could be undertaken by parties in the MISO region and states in the near term to ensure adequate reserve margins in 2016.[93] These include: improving joint planning and coordination with neighboring regions with very-high reserve margins (e.g., SPP); increasing the notice that generators must give of their intention to close temporarily or permanently (beyond the current 6-months' notice requirement); and encouraging states to coordinate their plans (e.g., for energy efficiency, demand response) with MISO's.

MISO is taking steps to assuring resource adequacy in light of MATS regulations. MISO is also actively planning for the cost and reliability implications of upcoming Section 111(d) regulations (e.g., for additional retirements beyond those likely to occur before Section 111(d)'s implementation). For example, MISO has recently refreshed its analysis of the impacts of region-wide versus more zonal approaches that MISO states might choose to take with respect to managing their future compliance with Section 111(d), and concluded that a more flexible, region-wide approach may lower the overall cost of compliance.[94] This latter analysis does not specifically assess reliability implications of compliance strategies, but it nonetheless invites cooperative approaches to design compliance schedules and pathways in light of the realities of interstate electricity market operations and reliability considerations.

In both MISO and ERCOT (as elsewhere in the nation), there are at least five years before the full effect of implementation of Section 111(d) will occur. States will have many tools and flexible approaches to use in planning for compliance with GHG emission limits, and addressing reliability and other concerns. For example, MISO and ERCOT have significant amounts of underutilized natural gas combined-cycle capacity whose more-frequent dispatch could absorb some of the generation needed in those regions to comply with Section 111(d). (See Figure 6.) Many states in the MISO region rely on integrated resource plans to assure resource adequacy, and these states can take steps in near-term planning cycles to assure both adequate capacity and generation that emits lower CO_2 emissions. As a single state RTO, ERCOT and Texas regulators have demonstrated an ability to take aggressive action to implement policies deemed to be important for the state.[95]

---

[93] For example: John Moore, NRDC, "We Can Have Both a Reliable Grid and a Cleaner Environment," December 9, 2013. http://switchboard.nrdc.org/blogs/jmoore/we_can_have_both_a_reliable_gr.html.

[94] MISO, "Refresh of MTEP-10 Carbon Analysis," presentation to PAC Meeting, February 19, 2014.

[95] Note that Texas/ERCOT undertook steps in the past decade to create incentives for investment in renewable energy and high-voltage transmission facilities. Today, Texas has the highest amount of wind power capacity (12,355 MW as of the 4th quarter of 2013). It has more wind capacity than the combined amount in the two states with next-highest amount of wind generating capacity

New Generating Capacity Proposals

Given the relatively low price of natural gas, the "fuel of choice" for new power generation capacity planned and under construction by electric utilities and independent power producers has shifted to natural gas and renewable power plants, and away from coal. Figure 17 shows the location of capacity under construction (by state). Half of the power plant capacity under construction is at gas-fired power plants, with another fifth at renewable facilities. There are five new nuclear reactors under construction in the Southeast. Of the other projects in advanced development (e.g., well along in permitting but not yet under construction), approximately one-third of the capacity is at gas-fired power plants, and another 42 percent is at renewable projects. Figure 18 shows the expected net changes in generating capacity from 2013 through 2017, by fuel type and by NERC region. These data reflect the effect of new plants under construction or planned (especially natural gas-fired capacity and renewable projects), as well plant retirements (especially coal, oil, and nuclear retirements).

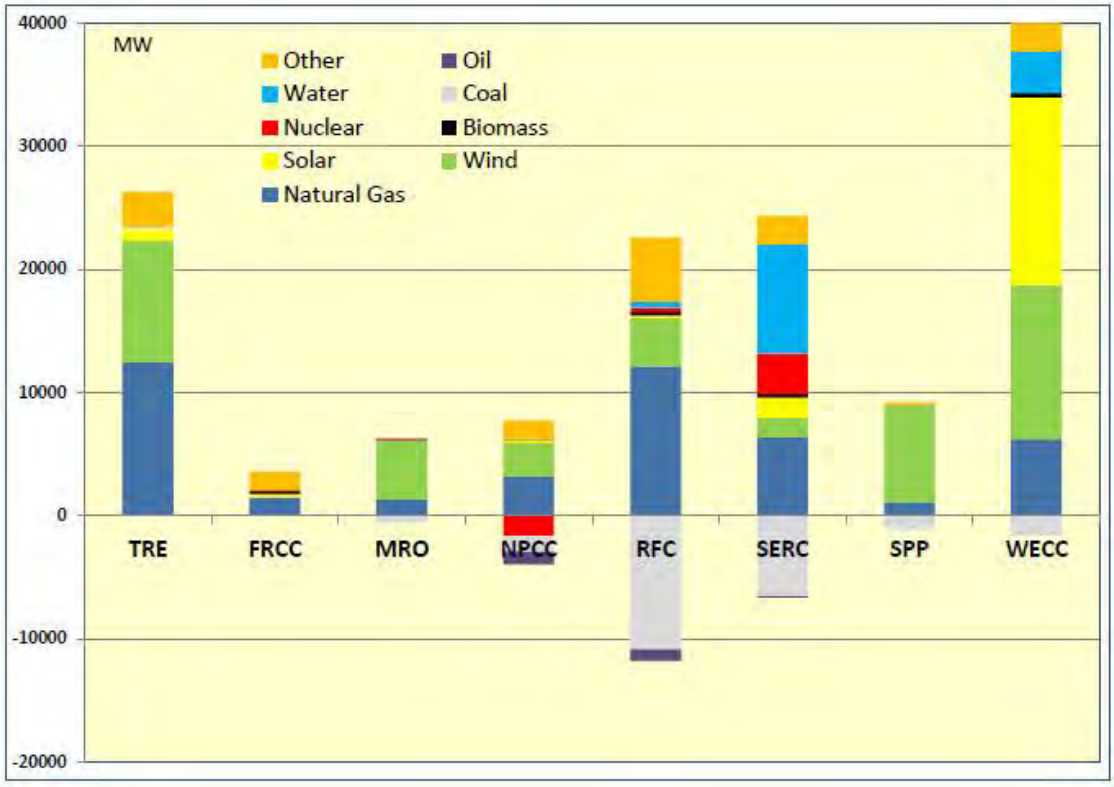
Figure 17

Generating Capacity Under Construction by State as of March 2014

Source of data: SNL Financial

(California, with 5,830 MW, and Iowa, with 5,178 MW). American Wind Energy Association, "U.W. Wind Industry Fourth Quarter Market Report, 2013," page 6. Since 1999, when Texas restructured its electric industry, there has been $14.3 billion investment in transmission, with 9,141 new circuit miles of transmission improvements, with another 2,558 circuit miles and $3.7 billion of planned transmission. ERCOT Quick Facts, 2014. Currently, Texas has 5,833 MW of power plants under construction, and another 1,671 MW in advanced development, most of which is scheduled to come on line in 2014 and 2015. Of this, 3,940 MW is gas-fired capacity. Charlotte Cox, "Nearly 6 GW of capacity under construction in ERCOT, with 42 GW planned," SNL Data Dispatch, February 26, 2014.

Figure 18
Changes in Capacity by Fuel and by NERC Region from 2013 to 2017
(Showing Capacity Additions and Retirements)



Source of data: SNL Financial (as of March 2014)

Implications of the Changing Electricity Resource Mix

The significant changes underway in the electric industry (and described above) set the stage for states' planning for compliance with Section 111(d). To a large degree, many of these changes create breathing room for compliance with upcoming GHG regulations while also maintaining electric system reliability.

Around the country, the changing conditions reflect the combined effects of low natural gas prices, significant under-utilized capacity at existing gas-fired power plants around the country, relatively slow demand growth, continuing opportunities for cost-effective energy efficiency, retirements of older and less efficient coal-fired generating capacity, new natural-gas-fired and

renewable energy capacity under construction, and substantial progress toward compliance with MATS by 2016.

The conditions create opportunities for states to maintain system reliability as they plan for compliance with Section 111(d). For example, the presence of under-utilized capacity at existing gas-fired power plants and the outlook for relatively low natural gas prices allow for a relatively affordable pathway to lower GHG emissions, but doing so must be accompanied with advanced planning to assure that natural gas supplies can be delivered and/or stored reliably as electric systems increase their reliance on natural gas. (New England has already had to accelerate its planning to respond to this type of situation while assuring reliable system operations.[96]) Federal regulators and policy makers, grid operators, and many others are focusing on this question of gas-deliverability and harmonization of electric and gas markets.[97] Continued attention to this issue will be important for reliability, regardless of the implementation of Section 111(d).

Similarly, new gas-fired power plants, new renewable projects, and new nuclear capacity additions will further support reliable compliance with Section 111(d). That said, states (and the federal government) should not assume that zero-carbon generating capacity at existing nuclear stations will automatically be available in the future, especially at merchant nuclear plants located in organized markets which are facing significant financial pressure to remain in operation.[98] Planning for reliable and affordable compliance with Section 111(d) should proactively address market reforms and other policies (including design of SIPs) to retain zero-carbon electricity supplies.[99]

In the parts of the country – like MISO and ERCOT – with pre-existing reliability challenges, Section 111(d) will only exacerbate that situation if nothing is done to address them. Clearly,

---

[96] ISO-NE has for the past two years focused attention on ways to ensure winter reliability in an electric system with high reliance on natural gas, pipeline capacity constraints, and lack of incentives in the market design to ensure gas-fired generators have fuel to allow them to operate.

[97] See, for example, NERC, "2013 Long-Term Reliability Assessment," December 2013, page 2 and Figure 2 (page 6); Questions of the leadership of the House Energy and Commerce Committee to MISO, PJM, NYISO, and ISO-NE, March 27, 2014; FERC notice of proposed rulemaking on Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, 146FERC¶61,201, 18 CFR Part 284, Docket No. RM14-2-000, March 20, 2014; Testimony of Acting Chair Cheryl LaFleur and Commissioners Philip Moeller, John Norris and Tony Clark before the House Energy & Commerce, Subcommittee on Energy and Power, valuating the Role of FERC in a Changing Energy Landscape, December 5, 2013.

[98] See my forthcoming paper: S. Tierney, "Today's Nuclear Fleet: What Role in the Nation's Clean, Affordable and Reliable Power Strategy?"

[99] See further discussion below on "outside the fence" actions to reduce GHG emissions.

the industry, state and federal regulators, grid operators, and many other stakeholders are working to address these pre-existing reliability challenges, through a wide range of solutions. These options include potential market reforms, new power plants, new power lines, new gas transmission, more efficient use of existing transmission and distribution systems for electricity and gas, increased investment in demand-side measures, and other things.

Section 111(d)'s compliance period is far enough in the future that there will be time for states and regions to transition toward lower GHG emissions while retaining electric reliability. And, as described previously, Section 111(d) affords broad flexibility to the states to respond to upcoming GHG emissions requirements in a way that preserves electric system reliability.

Planning for Compliance with EPA Guidance Under Section 111(d) of the CAA

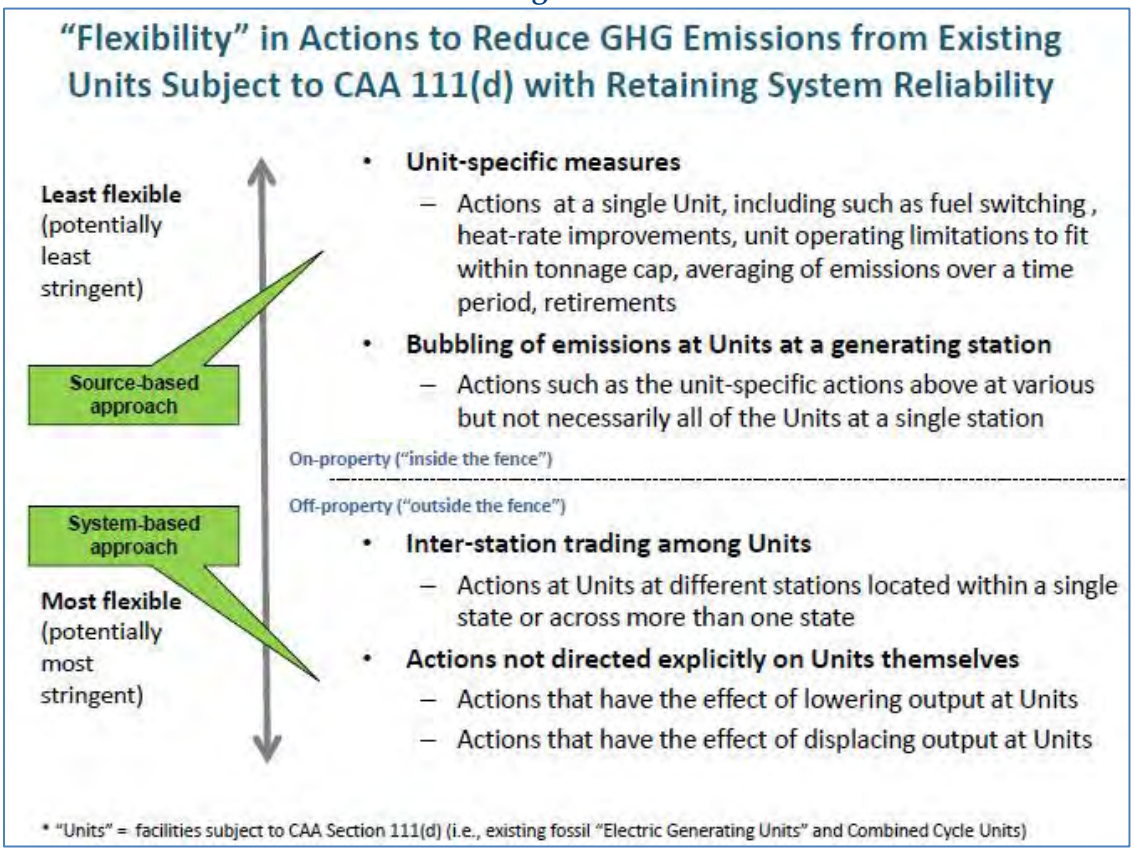
Breadth of Options Available to the States in Developing Section111(d) SIPs

Even in advance of EPA's proposed guidelines (June, 2014), it is already clear that states will have discretion to consider and propose a wide range of options as part of their plans. EPA officials have signaled their intention to allow each state to submit a SIP that enables them to comply with EPA's guidance and tailor their approach to meet multiple state-specific goals, including affordable and reliable electricity supplies.[100]

It is likely that as long as a state is able to demonstrate that its SIP is at least equivalent to EPA's guidance (in terms of reducing GHG emissions from affected power plants), then that state will have significant flexibility in developing its preferred package of policies. For example, SIPs may create incentives for EGUs and NGCCs to reduce emissions "within the fence" line of the covered units themselves. SIPs may include elements that affect actions occurring "outside the fence," where there is a strong connection between those actions and emission reductions at plants covered by Section 111(d). (See Figure 19.) This combination of options creates significant opportunities to plan for reliability while also planning for cost-effective GHG emissions reductions.

[100] For example, remarks of Administrator Gina McCarthy, Acting Administrator for Air and Radiation Janet McCabe and Senior Air Advisor Joseph Goffman at the meeting of the National Association of Regulatory Utility Commissioners, February 7th and 11th, 2014.

Figure 19



Inside the Fence Options

"Inside the fence" actions differ in terms of engineering, cost and feasibility of potential GHG reductions. For example, Dr. James Staudt has identified two categories of actions that can accomplish GHG emissions reductions at existing coal plants: (a) heat rate improvements at the units, which improve the efficiency of the boiler and/or steam plant (in terms of the amount of fuel it needs to burn to generate a unit of electricity), or reduce auxiliary loads at the station; and (b) conversion to a less carbon-intensive fuel, by fuel-switching, co-firing and/or reburn approaches.[101] These engineering-based approaches all focus on reducing a plant's rate of GHG emissions relative to its production of electricity.

[101] Dr. James Staudt, "Reducing CO2 Emissions from Fossil Fuel Power Plants," presented to the Bipartisan Policy Center workshop on Section 111(d), December 6, 2013. Dr. Staudt has identified the various engineering options for reducing CO_2 emissions from existing coal plants: (1) "Potential Approaches for HR [heat rate] Improvement: Coal Drying (esp., lignite coals); Variable Speed

States seeking these types of engineering approaches could require each affected EGU or NGCC to reduce its emissions by a certain percentage, or meet a maximum emission rate for CO_2/MWh. A state could impose a common standard to all plants in a category of EGUs, or it could tailor the requirements to particular conditions at different plants (reflecting, for example, their remaining useful life, or their role in providing local reliability).

The Department of Energy's National Energy Technology Laboratory ("NETL") has studied the opportunities for "inside the fence" power-production efficiency improvements, and has estimated that they could improve power plant performance (and thereby reduce coal combustion and GHG emissions) in the range of 1 percent to as high as 12 percent, depending upon the particular set of engineering actions taken at different coal-fired facilities.[102]

Other SIP approaches that could lead to "inside the fence" GHG reductions at EGUs and NGCCs would include modifications to the operating permit of particular plants so as to limit the dispatch and generation output of one or more units. It is not uncommon for power plants to have certain operational limits. Sometimes these limit the unit's overall annual output to an amount equivalent to 30 days of output at full power.[103] Or the unit may be dispatched only when local system reliability requirements demand operation of the generating unit (such as shortage events in the summer or winter period).[104] Such inside-the-fence operating constraints

---

Drives; Centrifugal to Axial fan conversion; Steam turbine modifications; Intelligent soot-blowing system; New APH seals; Repair boiler casing and duct in-leakage; Condenser cleaning. [2] Using less Carbon-Intensive Fuels: Conversion (convert to 100% gas), with a capital cost of ~$80/kW (with gas on site); Cofiring/Reburning (10-15% gas) Modest cost (somewhat higher for reburn), assuming gas is on site, with co-benefits from reducing NOx emissions as well."

[102] A recent study by the NETL evaluated four efficiency improvement projects, the three of which are 'off-the-shelf' technologies: 1. Coal Pulverizer Improvement; 2. Condenser Improvement; 3. Steam Turbine Upgrade; and 4. Solar Assisted Feedwater Heaters. NETL's analysis found opportunities to reduce GHG emissions in the range of 1.7 to 6.9 percent, with the highest reduction potential at less-efficient power plants. NETL, "Options for Improving the Efficiency of Existing Coal-Fired Power Plants," DOE/NETL-2013/1611, Final Report, April 1, 2014, pages 1-4. Prior NETL studies examined the effect of efficiency improvements: NETL, "Reducing CO2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet," DOE/NETL-2008/1329, July 23, 2008. By examining the efficiency of the top performing coal-fired power plants relative to the efficiency level of the fleet on average, NETL calculates that if changes could be made across the fleet to bring all of the plants up to the top 10 percent performance level, then the CO2 emissions associated with a constant level of MWh generated could be reduced by approximately 12 percent. This conclusion was further examined in NETL, "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions" (DOE/NETL-2010/1411), April 16, 2010. NETL concluded that the use of a combination of aggressive refurbishment and improved operation and maintenance at existing coal plants could improve the average fleet's overall efficiency.

[103] This approach was used in the air permit approvals issued in 1999/2000 by the Massachusetts Department of Environmental Protection for capacity expansion at Mystic Station, in which a new 1500-MW NGCC was permitted to operate in conjunction with imposition of 30-day operating limits on several other older generating units that also existed at the same station.

[104] For example: Several years ago, Exelon Corporation decided to retire units at two generating stations in Pennsylvania (the Eddystone and Cromby units) due primarily to economic factors. In its analysis to determine whether such retirements would lead to system reliability problems, the grid operator (PJM) determined that in the absence of transmission upgrades, retirements of

would affect the terms and conditions of plant dispatch, causing the grid operator (e.g., the local vertically integrated utility, or the RTO) to dispatch other power plants to make up for power it might otherwise have wanted to generate at the restricted unit. A state (or an owner of multiple power plants within the state) might find it economically preferable to impose operating limits on Unit A (with relatively high GHG emissions per MWh) and to dispatch Unit B (with higher operating costs but lower GHG emissions per MWh), than to require both Unit A and Unit B to invest in engineering actions leading to heat rate improvements at both. The permit limitation on Unit A would be the action inside the fence of that plant, and the electricity requirements for the system could be satisfied by electricity generation at Unit A and B.

In theory, a state could identify plants that provide some form of important functionality to the system but produce GHG emissions that are relatively expensive to control through one of the types of actions above. The state could introduce a limitation on that unit's output over an annual period of time such that its MWh and GHG emissions would be capped, while retaining its availability during high load periods, and with its MWh replaced at cleaner unit(s) during periods of low or medium electric demand. The latter approach would be one type of tool that states could use to assure that the compliance pathways demonstrated in their SIPs take into account both GHG emissions reductions and reliability concerns.

Outside the Fence Options

A much wider set of cost-effective emissions reductions could result from SIP elements involving actions in the electric system occurring outside the fence of a specific unit subject to Section 111(d).[105]

---

those units would lead to violations of security standards. Exelon entered into agreements with PJM and with the state air regulatory office so that the plant could remain on line pending those transmission upgrades, but allowing the units to be dispatched by PJM only when needed for reliability purposes. Prepared Testimony of Kathleen L. Barrón, Vice President, Federal Regulatory Affairs and Policy Exelon Corporation, before the FERC, Reliability Technical Conference Docket No. AD12-1-000 (etc.), November 11, 2011. This agreement was referenced by CATF in its 2011 proposal for "reliability-only dispatch": "to minimize health risks, we propose limiting the operation of any such units to the brief periods when required to preserve reliability, *i.e.*, when no other resource is available to meet the electricity need. Such a targeted "Reliability---Only Dispatch" approach can serve the goals of both the Federal Power Act's reliability framework and the Clean Air Act's express concern for near term reductions of air toxics and maximum protections for public health and the environment…. Through such customized solutions to identified reliability issues and tailored to specific, local circumstances, the Cromby---Eddystone example demonstrates that when a plant must continue to operate for some period due to reliability needs, it can be limited to running only to meet those reliability needs." John Hanger, "Reliability Only Dispatch: Protecting Lives & Human Health While Ensuring System Reliability," Clean Air Task Force, pages 5, 23.

[105] In the example above, Unit B's redispatch to replace power that would otherwise have come from Unit A is an example of an outside-the-fence counterpart action to the inside-the-fence action at Unit A.

Emission Averaging and Carbon Budgets

Many observers have examined the economic and emissions trade-offs associated with engineering-approaches versus more market-based compliance approaches. For example, Dallas Burtraw and Matt Woerman compared the cost to achieve a ton of CO_2 emission reduction through inside-the-fence actions versus outside-the-fence options enabled through a 'tradable performance standard.' Starting with estimates of the cost to accomplish the types of inside-the-fence options, they determined that with the money it would take to accomplish 4 percent reductions in GHG emissions inside the fence, it would be possible to achieve four times the amount of total emissions reductions if power plants were allowed the flexibility to trade emissions reduction opportunities.[106]

They and others[107] have analyzed variations on this approach of allowing a state to comply with EPA guidance by creating a rate-based or mass-based tradable currency, either of which could allow units with a higher level of GHG emissions per MWh to trade with those having a lower-than-average level of GHG emissions per MWh.

The Philips/CATF 2014 study explains how the use of a mass-based standard (converted from an original rate-based standard) has numerous benefits because it overcomes certain market distortions that might arise with use of a rate-based standard alone. "First, the positive price on carbon emissions and lack of production incentives means they would diminish or avoid the previously described emission rebound, seams and longer term regulatory transition concerns associated with most rate-based approaches. Also, they would give states another proven, practical compliance pathway and greater flexibility than if every state were restricted to complying through a mandatory emission rate standard. …Further, the accounting rules required to reflect the impact of new

[106] A "specific emissions rate improvement averaged over a larger set of generators reduces the actual emissions change. A marginal abatement cost criterion to compare policy designs suggests cost-effectiveness across sources. This criterion can quadruple the emissions reductions that are achieved, with net social benefits exceeding $25 billion in 2020, with a 1.3 percent electricity price increase." Dallas Burtraw and Matt Woerman, "Technology Flexibility and Stringency for Greenhouse Gas Regulations," Resources for the Future, July 2013, executive summary.

[107] For example, Phillips/CATF 2014; Christopher Van Atten, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Plants," MJ Bradley & Associates, October 2013; National Climate Coalition, "Using EPA Clear Air Act Authority to Build a Federal Framework for State Greenhouse Gas Reduction Programs," September 2013.

renewable facilities, energy efficiency programs and nuclear uprates, would be much more straightforward under a mass-based system than a rate-based system."[108]

More generally, mass-based standards can be translated into a total amount of GHG emissions "budgeted" or allowed to occur in a state. A budget could apply to all units collectively within a state, or to groups of units within a state, or to the units in multiple states that have compacted with each other. Chris Van Atten has described how a state budget approach might work: "In proposing a state budget approach, EPA could still develop a rate-based performance standard and then translate that performance standard into state budgets, giving each individual state the choice in terms of whether to impose a rate-based performance standard or state-wide emissions budget. In guidance to states, EPA could: define the appropriate baseline period (i.e., the MWh data used in converting the lbs./MWh standards to tons); determine whether and how future economic growth should be factored into the calculation of the budgets; and define trading rules for states that elect to allow trading as a compliance mechanism."[109]

Demand-side and non-carbon emitting options

States could take action to create incentives specifically aimed at adding and/or retaining zero-carbon electricity supply through adoption of a tradable emission standard ("TES") or clean

[108] Also, "Rate-based approaches…are typically established so that some covered generating sources have emission rates above the standard and others have rates below the standard. Generating sources with emission rates above the standard must undertake actions to come into compliance. Generating sources with emission rates below the standard have a financial incentive to increase their production, assuming an emission credit trading program, because every additional unit of generating output "earns" that generator additional emission credits which have a financial value under the trading program. In the case of a single blended fossil rate standard covering both coal and gas generation, NGCC units would typically be awarded emission credits whenever they generate output. This would allow gas units to sell power for less than their direct variable fuel and O&M costs. The value of the credits earned by generating additional output partially offsets the unit's variable cost of production, reducing the marginal cost of dispatch and making the unit more competitive with other sources of generation in that power market without comparable production incentives. Such production incentives can lead to unintended adverse consequences….. create what often are referred to as "seams" conflicts at the borders of mass-based trading programs such as RGGI and other mass-based programs, emissions "rebound", and greater difficulty in transitioning to longer term national carbon policies." Phillips/CATF 2014 (pages 8-9, 18).

[109] Also: "States would … have the flexibility to determine their preferred method for meeting their assigned budget, including the option of relying on a system of transferable emissions permits. If states elected to implement a trading program, power plant operators would track their CO2 emissions and surrender an emissions permit for each ton of CO2 released to the atmosphere….. For example, a state could propose to give each company operating in the state a set number of emission permits. Under such a scenario, a regulated utility might advocate for a company-wide emission budget that it could reflect in its integrated resource plan." Christopher Van Atten, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Plants," M. J. Bradley & Associates, October 2013, pages 17-18.

energy standard ("CES"). When applied to owners of generating units in an area, the TES could be a mechanism through which generation of zero- and low-carbon electricity by suppliers (old and new) would create carbon-free electricity credits, for sale to others. For example, a state (or a group of states) could set assign a common target CO_2/MWh to *all* generating units in the state, and then allow generators with different CO_2/MWh emissions rates to buy/sell their CO_2-emission permits. A provider of energy efficiency or demand-side measures could similarly generate CO_2-emission permits. It would be important that such a standard be at or below the emissions rate achievable by NGCCs so as to avoid potential wholesale price distortions that would result from natural gas units generating rate credits by offering a price below their variable cost of generation (as could arise as described above by Phillips/CATF 2014).

By contrast, a state could apply the CES to sellers of retail power supply (e.g., load serving entities ("LSEs")) to demonstrate that their overall supply portfolio satisfies a standard emissions amount (in much the same way that an RPS requires LSEs to include renewables as a percentage of their supply portfolios). A CES could cover all existing and new generation, thus allowing sellers of zero-carbon supply to find revenue streams to remain in and/or enter the market.

Allowing zero-carbon resources to capture the economic value of that attribute through efficient market-based transactions with other generators provides the state with the ability to arrive at a least-cost, reliable pathway toward overall electric system compliance.

RTO Dispatch Constraint

Another recent variation on the outside-the-fence approach has been suggested for one multi-state RTO (or Independent System Operator ("ISO")) region. In this approach, the RTO would expand the criteria it uses to determine the dispatch of power plants so that in addition to security-constrained economic dispatch, it would also use a total system-wide constraint on CO_2 emissions. As described by its authors, this concept includes the following elements:

> Translate EPA requirements into ISO-level targets on CO_2 emissions, ideally with a single long-term target (*e.g.* X% reduction over 2000 level, by 2030). Short/ intermediate term targets may be necessary to guide the "emissions path," but could limit flexibility of meeting the targets and possibly be less cost effective.
> ISO sets an initial path of "carbon values," that are used in dispatching (based on

> emissions profiles and bid offers) to reach the expected regional target. Plant dispatch minimizes total cost while meeting reliability and CO_2 constraints. The resulting power market prices, paid by load, reflect the emission constraints. Generators are charged the per-unit carbon value for their CO_2 emissions. Revenues collected are returned to load on a non-variable basis (maintaining proper price signals for demand-side resources). ISO adjusts carbon value path carefully when updated projections of emissions deviate significantly from original assumptions.[110]

These various mass-based approaches allow for cost-effective and administratively efficient means to reduce GHG emissions across the power plants dispatched in a system. And they allow for system conditions, such as reliability considerations, to factor into the manner in which the grid operator dispatches its plants to meet system requirements in regions with organized wholesale electricity markets.

Figure 20 shows (with color shading) the parts of the U.S. where an RTO (or ISO) is the grid operator and administrator of an organized wholesale market.[111] In these areas, the RTO has responsibility for centrally dispatching power plants that are owned or controlled by market participants (e.g., utilities (including investor-owned, coops, publicly owned utilities) and IPPs) in that region.[112] In states (or parts of states) which are not part of an RTO, the utility typically is responsible for centrally dispatching the power plants it owns or controls. In some states with a traditional vertically integrated electric industry structure, most if not all of the generating capacity is owned by utilities. The states with more than two-thirds of their generation produced at utility-owned power plants are shown with a pattern (dotted) on Figure

---

[110] Judy Chang, Jurgen Weiss, Yingxia Yang, Jon Brekke, and Will Kaul, "A Market-based Regional Approach to Implementing EPA's GHG Emissions Regulation," Brattle Group and Great River Energy, January 2014.

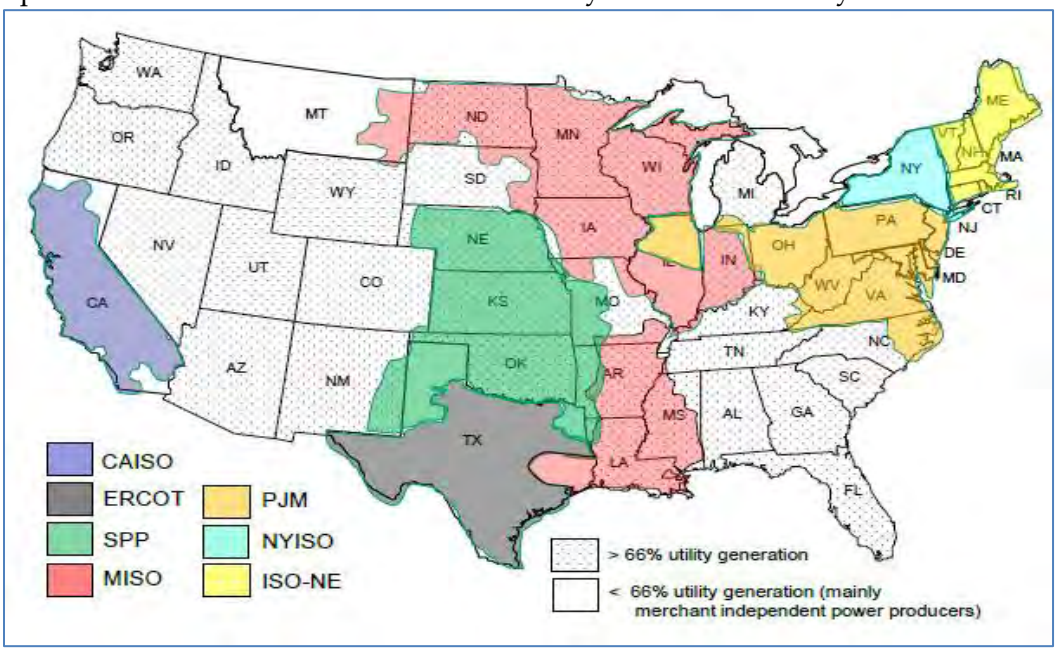
[111] "Presently, RTOs/ISOs geographic footprint covers approximately 2/3rds of the nation, encompassing regions that cover all or parts of 38 of the 50 states plus the District of Columbia. ISOs/RTOs serve approximately 75% of national demand." ISO/RTO Council, "EPA CO_2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals," January 31, 2014.

[112] "ISOs/RTOs centrally dispatch power plants within their footprint based on the marginal cost of operation of each individual unit as reflected in bids submitted to the ISO/RTO on a day ahead basis.[fn] By dispatching generation resources across the I ISO/RTO footprint based on the marginal cost to produce the next MW of electricity, the economic efficiencies of the generation fleet is maximized for each hour of the operating day across the entire RTO footprint.[fn] Supply bids submitted by generators effectively internalize environmental compliance costs while still ensuring least cost compliance with environmental requirements.[fn] The regional centralized dispatch undertaken by ISOs/RTOs is known as Security Constrained Economic Dispatch (SCED)." ISO/RTO Council, "EPA CO_2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals," January 31, 2014.

20. Figure 21 shows the ranking of states according to their reliance of utility-owned (and not IPP-owned) generation.

Figure 20

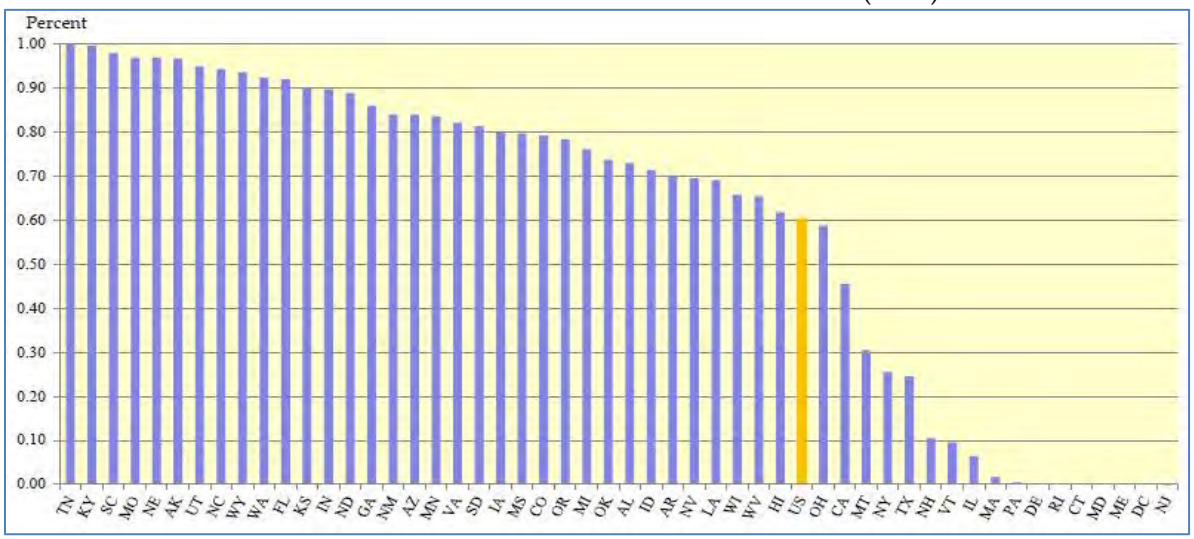
Footprint of RTOs and States' Reliance on Utility versus Non-Utility Power Generation



Source: EIA Generation by Type of Producer and by State, 2012.

Figure 21

States' Reliance on Utility-Owned Generation as a Percent of Total Power Generation in the State (2012)



Source: EIA, EIA Generation by Type of Producer and by State, 2012.

Recent modeling by Bruce Phillips for the CATF examines how two alternative policy designs for an emissions standard would work in a regional dispatch. As shown previously in Table 1, the "CATF 2.0" options that they modeled were: (a) a single mass-based standard applicable to all fossil power plants, and (b) an alternative that has a mass-based budget for emissions from coal-fired power plants and a rate-based standard for emissions from gas-fired power plants (which they have called the "Mass-Based Coal" budget as a short hand name).[113] Phillips' analysis found that both "approaches would reduce emissions through a mix of compliance actions: by reducing the heat rates (and consequently the emission rates) of coal units; displacing high emission rate coal generation with lower emission rate gas generation through an emission credit trading program; retiring coal generating capacity, and reducing electric demand through customer response to higher electric prices. Of these, the emission reductions from fossil dispatch represent the largest single source of reductions, in both cases approximately 70 percent of total compliance…..Heat rate improvements, coal retirements and electric price response comprise the remainder, with approximately 10 percent, 15 percent and 5 percent respectively."[114] The analysis also concluded that these policies would lead to relatively similar changes in generation and capacity mix: "Under the mass-based coal case, 42 GWs of coal capacity retire due to the policy (that is, relative to what would otherwise be expected in 2020), average national coal capacity factors decline from 67 to 58 percent and average national NGCC capacity factors increase from 48 to about 65 percent. Under the mass-based fossil case, 37 GWs of coal capacity retire, average national coal capacity factors decline to 58 percent and average national NGCC capacity factors increase to 63 percent."[115]

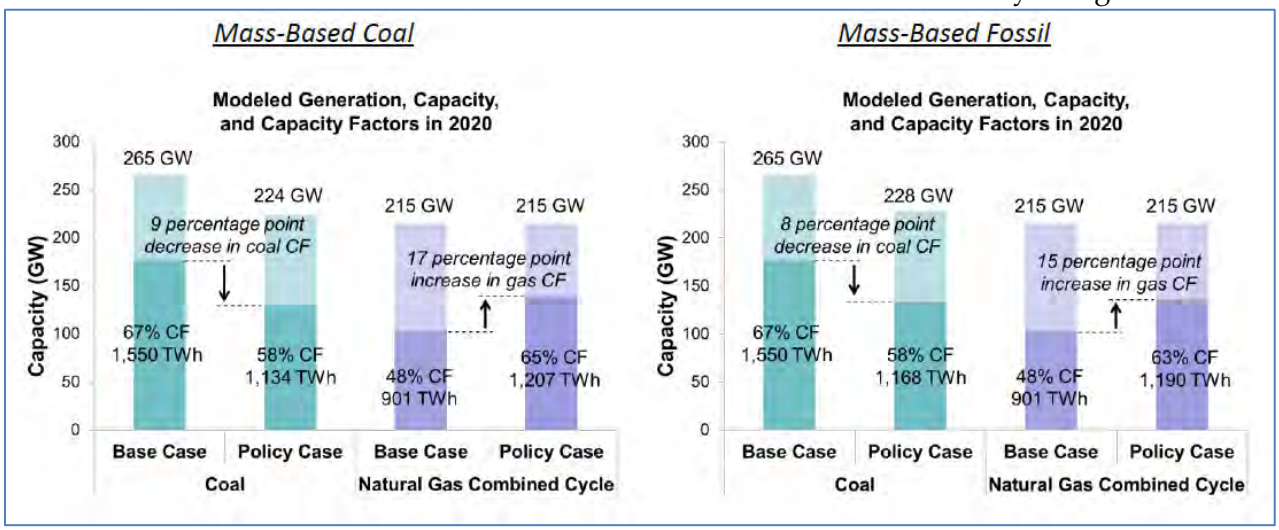
[113] Phillips/CATF 2014, page 17.

[114] Phillips/CATF 2014, page 21.

[115] Phillips/CATF 2014, page 21.

Figure 22

Modeled Changes in Generation Output, Capacity Retirements and Capacity Factors of Coal-Fired and Gas-Fired Power Plants under Two Alternative CATF Policy Designs



Phillips/CATF 2014, page 22.

This analysis suggests that there will be capacity retirements that are manageable, especially in light of the existence of underutilized NGCC capacity in all regions of the country, along with inherent flexibility in the Section 111(d) framework that will allow states to tailor their SIPs to local conditions and reliability requirements. ,

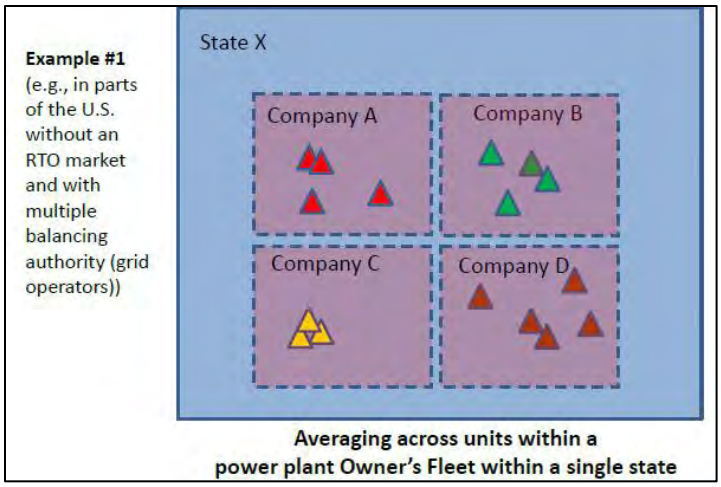
Outside-the-Fence Models Approaches: Examples to ensure reliable and economic compliance in states with different electric industry structures

Because states have different electric industry structures that affect how groups of power plants are dispatched to supply electricity at different times during the year, states will likely seek to take this factor into account as they consider different options for and inside-the-fence and outside-the-fence compliance approaches.

For example, there are two key features of industry structure: (1) presence or absence of an RTO; and (2) the extent to which utilities versus merchant generators (IPPs) dominate the power generation – seem relevant for how a state might consider structuring its SIP to include relatively cost-effective outside-the-fence policy elements. These two features essentially are proxies for the extent to which power plants owned by different entities participate in a common system for generation dispatch within a state (or across a region).

Consider the following examples as ways that a state could develop an economically efficient tradable compliance mechanism and in so doing, support more cost-effective, reliable compliance with GHG reduction targets. All of these examples are based on an assumption that EPA will issue state-specific guidance that reflects either a blended target emissions rate for all fossil-fuel generation (EGUs and NGCCs) or a separate one for each fuel, with a multi-year period over which a state needs to make reasonable progress toward compliance. The examples also assume that the state may use a variety of tools to achieve the targeted emissions reductions, many of which accommodate planning to mitigate electric system reliability concerns.

Example 1: Trading Among Power Plants Owned by Common Owner within a Single State: In this example, the state has a traditional electric industry structure, with several vertically integrated utility companies owning power plants in that state. These utilities do not belong to an RTO. Several of the utilities have more than one generating unit subject to Section 111(d) and these units have different emissions rates (CO_2/MWh). A simple trading approach the state could adopt in its SIP would be to allow emission trading across all of the units owned by a single utility. Each owner could determine the set of actions through which it would maintain reliability and bring its fleet into overall compliance with the target. These approaches could include redispatch of existing fossil plants to find the optimal mix of production, investment in a zero-carbon generating source, and/or other actions to produce a blended lbs of CO_2/MWh rate consistent with the state target.

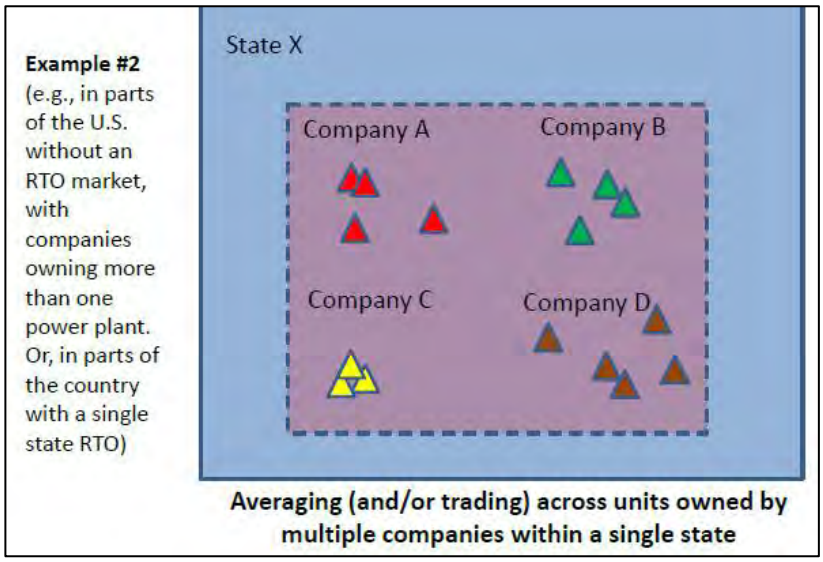


Let's assume further that one of these utilities had recently made investments in one of its coal-fired power plants to enable it to comply with MATS. To retain the economic and reliability value of that investment, the utility would be allowed (through the state's SIP) to operate that plant for more years into the future, as long as these emissions are offset somewhere else in the system. Perhaps this could be accomplished by relatively aggressive investment in energy efficiency to reduce the utility's MWh requirements that would otherwise have been met by its

marginal and high-emitting generating unit(s) and in so doing offset the emissions from plants. Perhaps another utility wanted to retain its ability to operate an otherwise relatively inefficient power plant in order to manage an overall resource adequacy issue. This utility could propose a limit on the operating permit of that power plant, in order to maintain it on the system for reliability reasons during seasonal peak energy demand, while also committing to lower output at that plant.

To allow different sets of actions for different utilities that reflected each one's particular circumstances, the state could structure its SIP to give each utility the ability to manage the cumulative emissions associated with its fleet's power generation over a multi-year time period in order to satisfy economic and reliability requirements efficiently while also complying with the necessary GHG emission reductions.

Example 2: Trading Among Power Plants Owned by Multiple Owners Within a Single State. In this example, another state with a similar industry structure (no RTO, power plants owned by multiple companies) decides that it will propose a SIP that would permit intra-state trading among all of the power plants subject to Section 111(d) plants within the state. The state could use the EPA's state-wide target CO_2/MWh rate(s) for that state, and allow owners of plants with emissions higher than that rate to trade with plants lower than that rate. The state could either use the tradable-rate-based model or a mass-based approach, with a ceiling on total emissions during a time period and with tradable allowances that companies were either given for free or allowed to purchase through an auction.



Different states in this situation might approach this allowance allocation differently. One might chose to give away for free the allowed statewide average target emissions rate (e.g., CO_2/MWh). The plants with higher-than-average emissions would purchase enough CO_2 credits to accomplish the target blended rate. The generator with lower-than-average emissions

could sell off the difference between its actual rate and the target rate allocated to it, without taking any further action. Another generator with economically attractive opportunities to make improvements and/or add low-carbon resources to bring its own fleet average even further below the statewide target would have even more CO_2 credits to sell.

By contrast, another state could decide to allocate higher-than-average emissions credits to one owner of Section 111(d) units with relatively high emissions, and a different allocation rate to another owner, reflecting equity, stranded costs, electricity price impacts and reliability considerations across the different service territories. Another state might decide that each owner of a Section 111(d) generating unit would need to buy all of its needed CO_2 credits (rather than receiving even the average initial allocation for free), and then use the proceeds from the sale of those CO_2 credits to offset consumers' price impacts or to fund energy efficiency program to reduce the overall MWh requirements, achieve CO_2 emissions reductions as a result.

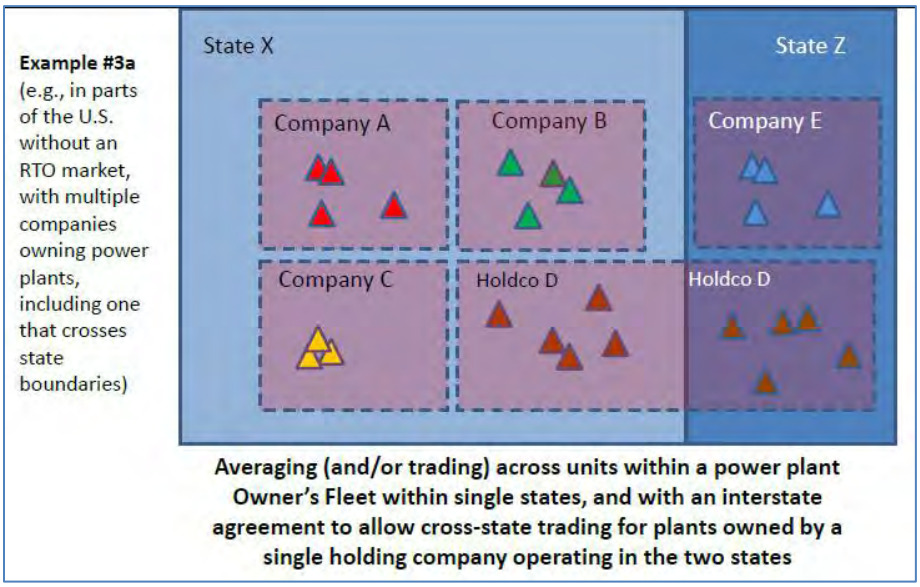
Additionally, the state could choose whether to allocate the target CO_2/MWh rate to only Section 111(d) generating units, to all fossil units, or to all generating sources (including ones with zero carbon electricity production). The former would tend to lead to trading among fossil units only, and the state could accompany this model with other SIP elements (e.g., increased RPS requirements; new nuclear unit upgrade; a new TES or CES) to increase and/or maintain zero-carbon electricity as a displacement of MWh produced at fossil units. The latter would tend to rely on an economically efficient mechanism for lowering CO_2/MWh through creating value for zero-carbon energy options and retaining capacity for reliability and diversity purposes.

A company could manage its own in-state fleet by using its preferred combination of inside-the-fence options, redispatch of its own power plants, procurement of zero-carbon MWh, and purchases/sales of tradable CO_2 credits with other power plant owners in the state. The tradable credit or tradable allowance would end up having a price reflecting economic investments in CO_2 reductions across the state's set of power plants.

Such approaches could accommodate many different operational/reliability issues economically. The utility with potential stranded investment in MATs compliance, for example, could purchase output (and credits) from another power plant owner's lower-emitting but otherwise underutilized generator. The power plant owner that faces a curtailment of natural gas supply during a winter shortage condition could run a unit with higher emissions at that time and offset that unit's CO_2 rate with purchases of a tradable credit from another power plant with lower-than-average emissions. Again, the main point is that states could formulate

their SIPs to allow each power plant owner to manage the cumulative emissions associated with its fleet's power generation over a multi-year time period so that the average CO_2/MWh target is met, along with all operating and resource-adequacy requirements necessary for system reliability.

Example 3a: Trading Among Power Plants in Multiple States That are Owned by a Common Holding Company. In this example, electric generating units located in two states are owned by a common parent company (Holding Company D, in the figure) that operates all of its power plants as a single integrated system for resource adequacy, operational security and economic purposes. From the point of view of system operations, Holding Company D dispatches plants in both states according to security-constrained economic dispatch principles, and shares the economic value of that common system with customers in both states. In this example, there are also other utility companies and IPPs (Companies A, B, C, and D) that own power plants in the relevant state.

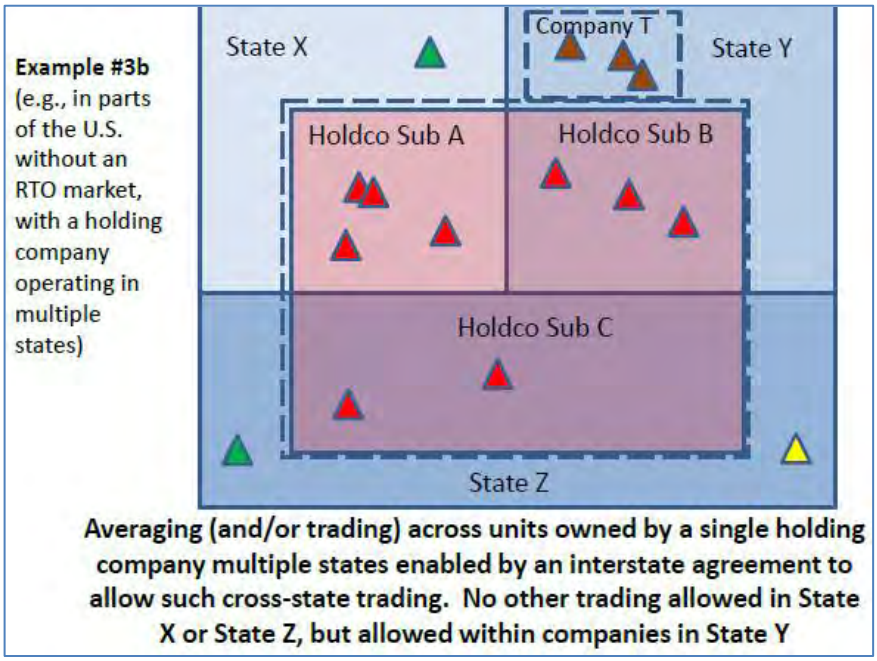


Let's assume that each state has been given a different GHG emissions' rate target in EPA's guidance. Each state decides to include in its SIP a mechanism that allows for trading within company-owned fleets or across companies within a state (as in Examples 1 and 2). But for the holding company, the two states decide that they would like to retain the efficiencies associated with that company's multi-state dispatch. So the two states enter into a formal agreement to allow for interstate trading specifically for Holdco D located in both states, thus enabling it to continue to operate its fleet on a single system basis. (The two states may or may not allow Holdco D to trade with Companies A, B, C, and E.) To the extent that such multi-state dispatch of Holdco's plants means that State X's CO_2/MWh average rate that is higher over the relevant time period than it otherwise would be under single state operation, then the states' agreements

would need to establish a mechanism for tracking and offsetting such emissions through deeper reductions in State Y.

This example suggests a way for states to collaborate voluntarily in the design of their SIPs, to tailor elements to fit the structure of their electric industry and to honor long-standing economic and reliability relationships among various utilities and other industry institutions.

Example 3b: Trading Among Power Plants Owned by Multi-State Holding Companies and With the States Having Different Appetites for Other In-State Trading. This example is a slight variation on the same theme as Example 3A. Here, the three states still get different CO_2/MWh targets from the EPA, in light of the different conditions in those states. The three states sharing the holding company agree formally to allow that company's subsidiary companies in the three states to participate in a common interstate CO_2 credit-trading program. In exchange for allowing that flexibility, the states agree to require the holding company to achieve more GHG emissions reductions in its fleet than it would otherwise absorb if each state gave the holding company each state's statewide average CO_2/ MWh target. For power plants owned by entities unaffiliated with the holding company, one of those states allows other trading within the states, but the others do not.

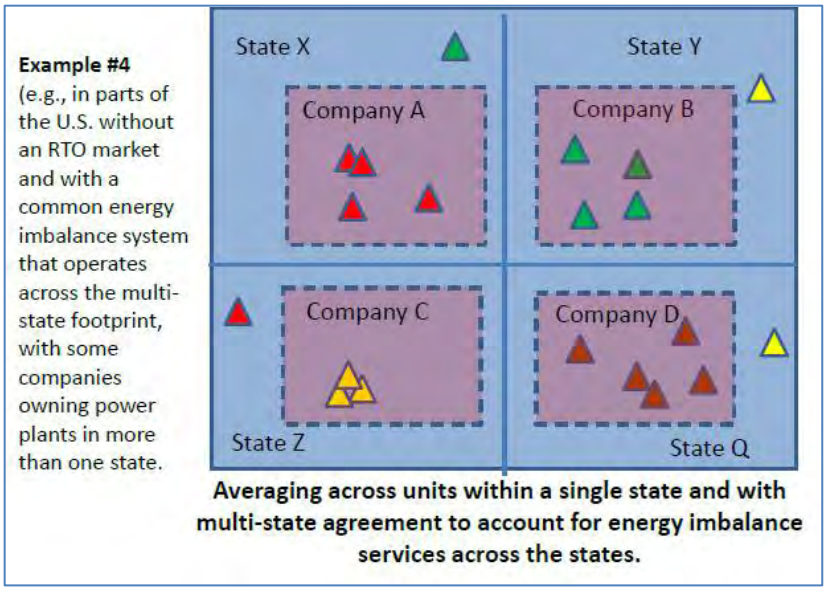


The three-state agreement is included in each of the three states' SIPs, and it details the mechanism through which the states will credit/offset/true-up emissions located in one state against the other states' compliance requirements. The three states could establish a multi-state cap over that holding company's generating resources. The holding company has the ability to meet its target through a combination of dispatching its power plants, incremental purchase of

power generated at low-carbon resources, energy efficiency, demand response or other actions to reduce CO_2/MWh across the three states. The other company in State Y has the same ability to use its fleet to achieve a blended average emissions rate that complies with EPA guidance for the state.

Again this example suggests tailored strategies to reflect economic, reliability and other conditions unique to a set of states.

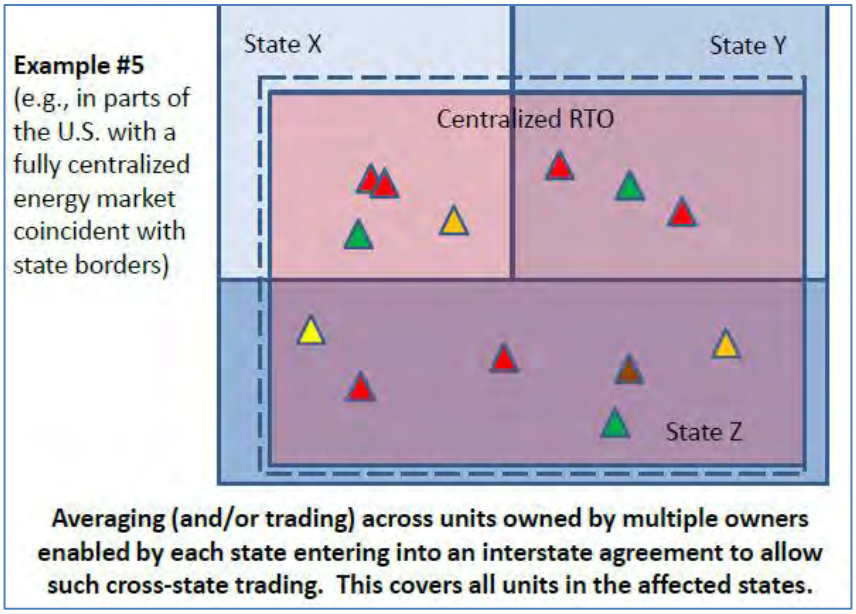
Example 4: No Interstate Trading Except for Emissions Associated with a Multi-State Energy Imbalance Market. In this example, the electric companies in a number of states operate as vertically integrated stand-alone utilities, owning generating assets and serving load in a single state. Some of them (e.g., Company A in State X) also own power plants (or contracts for power) in another state (e.g., in State Z) for producing part of the supply for retail customers in the home state (State X). These various approaches have traditionally provided resource adequacy. Each company is interconnected to other utilities in the region through transmission lines, and each company plans for and schedules the dispatch of its own power plants to meet its customers' requirements (load) with operational reliability. Specifically, each company is the grid operator (balancing authority) in its electric system. Because anticipated demand varies in real time from actual demand, the interconnected utilities have entered into an "energy imbalance market" to allow power companies to voluntarily make their generating assets available to the entire region to allow for efficient dispatch of generating units across multiple systems to make sure that the systems have supply and demand in balance at all times.



The states in this interconnected region enter into an agreement to allow for the CO_2 emissions associated with such energy imbalances (which are important for both reliable and efficient

power supply) to be accommodated within each affected states' SIPs and to credit/offset emissions changes in one state that result from such an interstate energy imbalance market.

Example 5: Multistate RTO. Example 5 depicts a multi-state area, where all of the power plants located in the three states participate in a single RTO. The RTO is responsible for centralized security-constrained economic dispatch of all power plants in the states. The three states seek to retain the economic and reliability benefits of this multi-state RTO, recognizing that CO_2/MWh in one state may be affected by the dispatch protocols of the RTO that affect all power plants in the region.

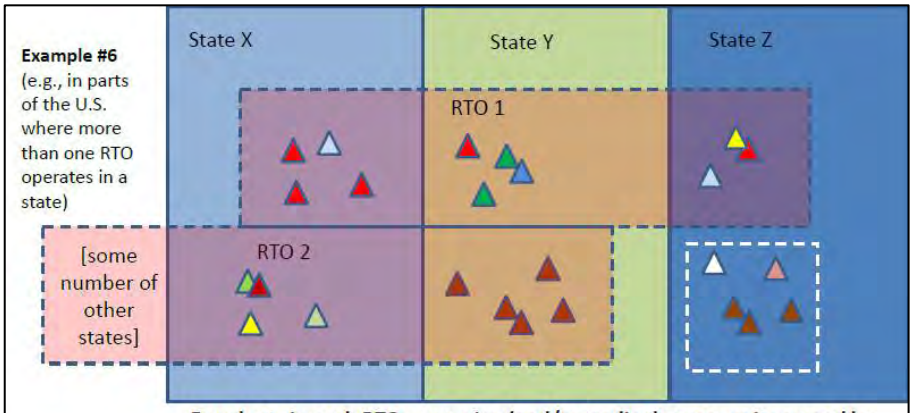


Each of the states includes in its SIP a formal agreement to allow trading across the units in the RTO footprint. The states could work with the RTO to establish the mechanism(s) through which the RTO would introduce CO_2 prices and/or other constraints into the dispatch (e.g., through a shadow price[116] or through actual tradable credits).

In addition to providing this interstate trading arrangement as part of their SIPs, affected states could also include in their SIPs various other policies – energy efficiency, clean energy standards, more aggressive RPS, contracts with zero-carbon electricity supplies, integrated resource planning with a shadow price on carbon, and so forth – that affect the CO_2 emitted from the fossil plants in the RTO. Together, these approaches respect the regional operational reliability practices, market-based dispatch approaches, and state-specific policy preferences and resource-adequacy approaches.

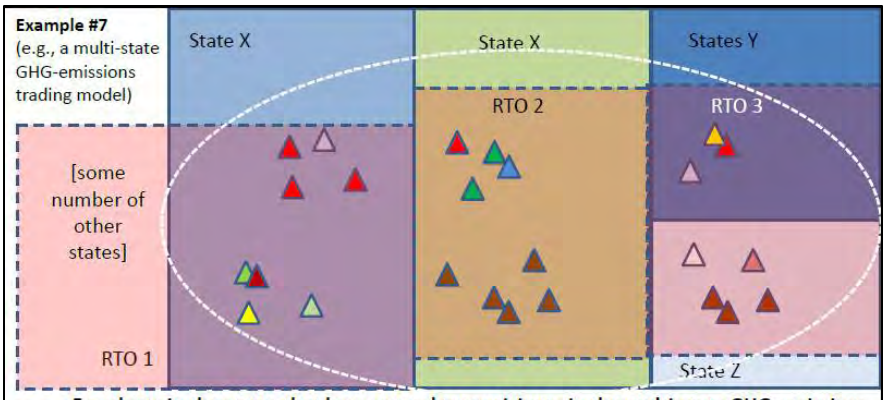
[116] As an example, stakeholders in MISO are exploring the implications of a CO_2 design that would use a limit on total emissions in the RTO footprint, along with a shadow price to use in security-constrained economic dispatch. Judy Chang, Jurgen Weiss, Yingxia Yang, Jon Brekke, and Will Kaul, "A Market-based Regional Approach to Implementing EPA's GHG Emissions Regulation," Brattle Group and Great River Energy, January 2014. Also, MISO, "Refresh of MTEP-10 Carbon Analysis," presentation to PAC Meeting February 19, 2014.

Example 6: States with Multiple Multi-State RTOs: This example is similar to the prior one, except that one of the states in this region has Section 111(d) power plants located in two different RTOs, each covering a portion of the state. In this example, to the extent that each state seeks to allow its power plants to trade within the RTO market, each state would enter into an agreement to participate in a common trading program, potentially administered by each RTO. The state with electric utilities situated in two RTOs could determine the target CO_2/MWh that Section 111(d) units in each part of the state would need to achieve through the inter-state trading program administered by each RTO.



For plants in each RTO, averaging (and/or trading) across units owned by multiple companies within a common multi-state RTO, enabled through interstate agreements with states in that RTO. In state with units outside of an RTO, averaging (or trading) among those other units but not with units in the RTOs.

Example 7: States with Multiple Multi-State RTOs and a Multi-State CO_2 Trading Programs. A final example involves a multi-state region with multiple RTOs and with a multi-state GHG trading program whose boundaries are not coincident with the boundaries of the RTO. The GHG trading program is a mass-based model, using a cap-and-trade system with CO_2 allowances purchased by all fossil generating units (including EGUs and NGCCs). (An example of such an approach is the RGGI program in the Northeast.) In this model, the states have



For plants in the states that have agreed to participate in the multi-state GHG-emissions control program, the units in those states may average (and/or trade) emissions across units owned by multiple companies. The units in the one state (State X) whose companies participate in an RTO not otherwise involved in the multi-state GHG trading program may not trade with the other units in the RTO.

included in their SIPs their agreements with the other states that participate in the multi-state GHG program. State SIPs would delineate the manner in which the Section 111(d) units within their borders may trade emission allowances (or reductions or averaging) within the program, but not with other units in the portions of the RTO (e.g., RTO 1) where the program is not in effect. Reliability practices, like security-constrained dispatch or capacity markets for resource adequacy, would integrate smoothly with the multi-state nature of the RTO and GHG emission-reduction program.

Outside-the-Fence Models Approaches: Collateral policies

In the examples above, each state may also choose to include in its SIP other elements that contribute to the state's compliance strategy for reliably reducing GHG emissions at existing EGUs and NGCCs. The state would need to demonstrate and quantify the effect of such other SIP elements on emissions from Section 111(d) units, with a monitoring and verification protocol with back-up actions in the event that such other SIP elements do not bring forth their anticipated emissions reduction outcomes. For example:

- A state wanting to encourage the eventual shutdown of a particular utility-owned generating unit (e.g., a coal plant with high emissions CO_2 per MWh) learns from the grid operator that the plant is needed for reliability issues pending completion of transmission upgrades (or the completion of a new power plant then under construction). The utility does not want to retire the plant when those other facilities are complete, because the plant would have stranded costs. To encourage the timely retirement of the high-emitting coal plant, the state could include in its SIP a plan to allocate to the utility owner a quantity of CO_2/MWh credits for some number of years beyond the unit's actual retirement, as long as the unit were to retire by a date certain. This could allow that unit's owner offset its stranded costs by selling those emissions to others after the unit retirement occurs.

- One state wanting to gain access to underutilized NGCC capacity in a neighboring state through cost-effective transmission upgrades might enter into an interstate agreement to allocate additional credits to the neighboring state upon completion of the line. The state might propose to shut down a particular Section 111(d) unit upon the completion of the transmission-system upgrade, and free up those credits to cover the emissions in the neighboring state that will go up once the line is energized and the NGCC capacity factors increase.

- A state seeking to avoid the premature retirement of a financially challenged but well-performing existing nuclear unit(s) might propose a SIP element to create financial incentives for the unit to remain in operation through its full operating license period. For example, a state already participating in a multi-state RTO and multi-state GHG program might additionally introduce a clean energy (applicable to LSEs) or a tradable emission standard (applicable to all generating units located physically within the state). Through the CES or the TES, the nuclear unit could generate MWh without emitting any CO_2, sell those zero-carbon MWh credits to other generators in the state, capture enough monetary value for its supply of zero-carbon MWh to remain in service, and in so doing, help the entire system retain greater fuel diversity and reliability while also cost-effectively reducing system-wide CO_2/MWh.

These examples are suggestive of the types of elements that a state may include in its SIP to address local industry conditions, reliability considerations, system diversity, and economic impacts of Section 111(d) compliance. As many states have already begun to do, they can start their SIP planning processes with the expectation that they will be able to tailor their plan to suit their own preferences and policy objectives. This flexibility is inherent within Section 111(d), and affords a strong basis for allowing the states to comply with the CAA's requirements without jeopardizing electric system reliability.

Conclusions

The bottom line: as long as states and the industry start their planning process soon, there is no reasonable basis for anticipating that EPA's guidance, the states' SIPs and the electric industry's compliance with them will create reliability problems for the power system.

The nature of Section 111(d) affords the states with many options for compliance, both in terms of plan elements and timing. States will have significant flexibility in developing their GHG reduction plans, and EPA will allow them to craft their plans in ways that accommodate reliability considerations. This flexibility is a hallmark of the Section 111(d) regulatory framework, and this 'cooperative federalism' framework distinguishes it from some of the other recent air regulations that allow for a more narrow range of compliance strategies (e.g., MATS regulations affecting existing coal-fired power plants).

Moreover, the conditions in the industry are such that compliance paths may be facilitated by low natural gas prices, significant existing under-utilized NGCC capacity, relatively slow

growth in demand for electricity, increased supply expected from low-carbon renewable energy, and retirements of many of the older and least efficient coal-fired power plants before the implementation dates anticipated for Section 111(d).

To a significant degree, if a state has concerns about the reliability implications of compliance with EPA's action to regulate GHG emission from existing fossil power plants, that state has a range of actions it can take today to address and mitigate these concerns. The states need not wait for EPA to propose and finalize its guidance before asking parties to propose plan elements; many states have already begun such discussions and planning. States can request transmission plans from their utilities and grid operators that examine the implications of particular plan elements on generation dispatch, emissions outlooks, and reliability issues. They can examine conditions that could cause output at Section 111(d) units to increase and to put pressure on meeting GHG emissions targets, and explore potential actions to mitigate those risks. State can step up actions to address reliability concerns now, rather than 18 months from now when the EPA finalizes its guidance.

The states are in the driver seat in navigating compliance paths under Section 111(d) that assure reliable electricity supply as well as cost-effective GHG emissions reductions from existing power plants.

APPENDIX 1:

The Clean Air Act Section 111 – Excerpts

Section 111(a)

(a) Definitions. For purposes of this section:

(1) The term "standard of performance" means 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 (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

(2) The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

(3) The term "stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant. Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.

(4) The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

(5) The term "owner or operator" means any person who owns, leases, operates, controls, or supervises a stationary source.

(6) The term "existing source" means any stationary source other than a new source……

Section 111(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 108(a) or 112(b)(1)(A) but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. 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.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 110(c) in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 113 and 114 with respect to an implementation plan. 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.

APPENDIX 2 –

Generating Capacity Subject to 111(d) by State as of the beginning of 2013 (Page 1)

	Steam Turbine - Coal			Steam Turbine - Oil			Steam Turbine - Natural Gas			Combined Cycle - Natural Gas			Combined Cycle - Oil		
State	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)
ALABAMA	10,790	35	49%	453	15	49%	64	9	77%	6,255	42	63%	0	0	0%
ALASKA	118	16	67%	-	-	0%	-	-	0%	279	4	70%	47	1	77%
ARIZONA	6,230	18	75%	-	-	0%	974	9	7%	6,452	43	32%	0	0	0%
ARKANSAS	5,144	7	63%	300	11	71%	1,203	8	8%	3,060	23	38%	0	0	0%
CALIFORNIA	250	8	61%	-	-	0%	12,848	48	8%	12,830	129	51%	0	0	0%
COLORADO	5,377	26	73%	-	-	0%	120	4	1%	1,663	28	39%	0	0	0%
CONNECTICUT	388	1	3%	1,861	7	2%	44	5	23%	2,303	15	23%	0	0	0%
DELAWARE	430	3	31%	-	-	0%	846	6	15%	756	6	53%	0	0	0%
FLORIDA	10,493	29	49%	5,499	23	17%	1,038	14	22%	16,785	104	60%	0	0	0%
GEORGIA	12,583	43	38%	655	20	52%	129	2	9%	4,877	26	55%	0	0	0%
HAWAII	180	1	95%	1,119	21	46%	-	-	0%	-	-	0%	375	12	55%
IDAHA	17	6	61%	74	4	65%	-	-	0%	374	4	39%	0	0	0%
ILLINOIS	15,943	71	56%	-	-	0%	40	7	3%	2,005	14	33%	0	0	0%
INDIANA	18,283	78	58%	158	4	0%	-	-	0%	1,549	12	64%	0	0	0%
IOWA	6,784	49	60%	-	-	0%	65	2	14%	813	7	12%	0	0	0%
KANSAS	5,096	14	63%	-	-	0%	1,714	29	11%	-	-	0%	0	0	0%
KENTUCKY	15,329	54	63%	-	-	0%	-	-	0%	-	-	0%	0	0	0%
LOUISIANA	4,430	14	64%	266	7	62%	8,049	64	22%	5,916	41	54%	0	0	0%
MAINE	-	-	0%	1,222	19	20%	93	2	65%	880	5	33%	0	0	0%
MARYLAND	4,771	16	40%	1,730	4	18%	321	8	6%	157	2	31%	0	0	0%
MASSACHUSETTS	1,439	8	18%	2,138	6	1%	645	16	6%	4,315	26	34%	282	4	4%
MICHIGAN	11,778	83	53%	51	2	86%	2,182	9	4%	3,378	33	45%	0	0	0%
MINNESOTA	4,755	41	55%	15	1	50%	174	17	18%	1,502	11	29%	0	0	0%
MISSISSIPPI	2,566	7	33%	235	8	59%	2,773	23	20%	4,685	29	49%	0	0	0%
MISSOURI	12,435	51	67%	-	-	0%	116	6	1%	1,425	11	19%	0	0	0%
MONTANA	1,763	8	62%	-	-	0%	-	-	0%	41	1	0%	0	0	0%
NEBRASKA	4,160	20	69%	-	-	0%	268	9	2%	296	5	11%	0	0	0%
NEVADA	1,303	7	36%	-	-	0%	470	5	7%	3,377	34	54%	0	0	0%
NEW HAMPSHIRE	554	4	26%	407	4	2%	-	-	0%	882	4	57%	0	0	0%
NEW JERSEY	2,001	7	15%	163	3	2%	629	8	3%	4,132	42	49%	0	0	0%
NEW MEXICO	3,430	7	72%	-	-	0%	779	11	32%	925	8	48%	0	0	0%
NEW YORK	1,736	15	25%	2,795	9	10%	6,927	22	17%	6,425	63	49%	0	0	0%
NORTH CAROLINA	11,084	34	50%	163	7	66%	-	-	0%	2,809	21	46%	0	0	0%
NORTH DAKOTA	4,153	14	78%	-	-	0%	-	-	0%	-	-	0%	0	0	0%
OHIO	19,394	84	49%	45	3	82%	35	2	1%	2,292	20	67%	0	0	0%
OKLAHOMA	5,323	15	63%	58	1	85%	5,085	32	19%	4,394	31	49%	0	0	0%
OREGON	585	1	52%	59	2	41%	32	2	26%	2,100	18	44%	0	0	0%
PENNSYLVANIA	14,901	59	58%	842	5	7%	1,635	4	11%	5,614	42	64%	0	0	0%
RHODE ISLAND	-	-	0%	4	2	19%	9	4	22%	1,293	11	47%	0	0	0%
SOUTH CAROLINA	6,082	22	50%	244	7	44%	107	3	47%	1,682	10	48%	0	0	0%
SOUTH DAKOTA	475	1	68%	-	-	0%	-	-	0%	170	1	1%	0	0	0%
TENNESSEE	7,734	49	52%	186	6	46%	-	-	0%	960	5	48%	0	0	0%
TEXAS	21,335	40	69%	161	6	77%	18,553	88	13%	27,324	207	50%	0	0	0%
UTAH	4,887	15	72%	-	-	0%	240	4	6%	713	5	55%	0	0	0%
VERMONT	-	-	0%	2	3	26%	-	-	0%	-	-	0%	0	0	0%
VIRGINIA	5,890	41	26%	1,899	14	11%	334	4	7%	2,779	20	78%	0	0	0%
WASHINGTON	1,340	2	32%	150	9	55%	5	1	15%	2,225	21	23%	0	0	0%
WEST VIRGINIA	14,378	33	56%	-	-	0%	-	-	0%	-	-	0%	0	0	0%
WISCONSIN	8,618	58	44%	135	8	55%	7	1	16%	1,724	12	44%	0	0	0%
WYOMING	6,431	24	77%	0	1	51%	3	3	65%	-	-	0%	0	0	0%
50 STATES	292,375	1,204		22,636	227		68,489	482		148,160	1,154		705	17	

source: SNL Financial

APPENDIX 2 –

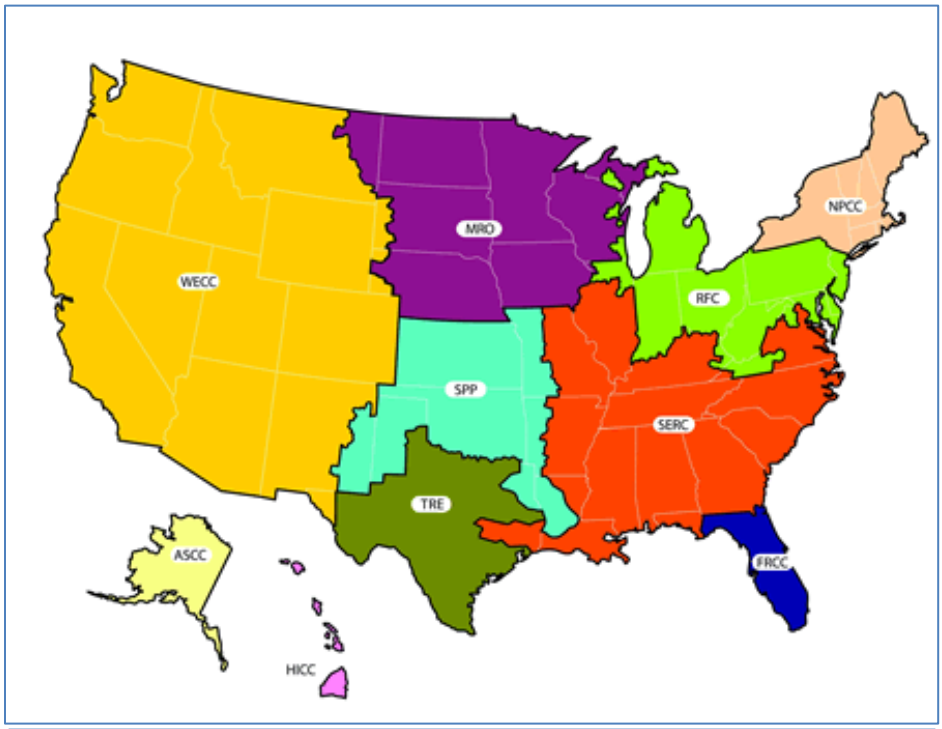
Generating Capacity Subject to 111(d) by State as of the beginning of 2013 (Page 2)

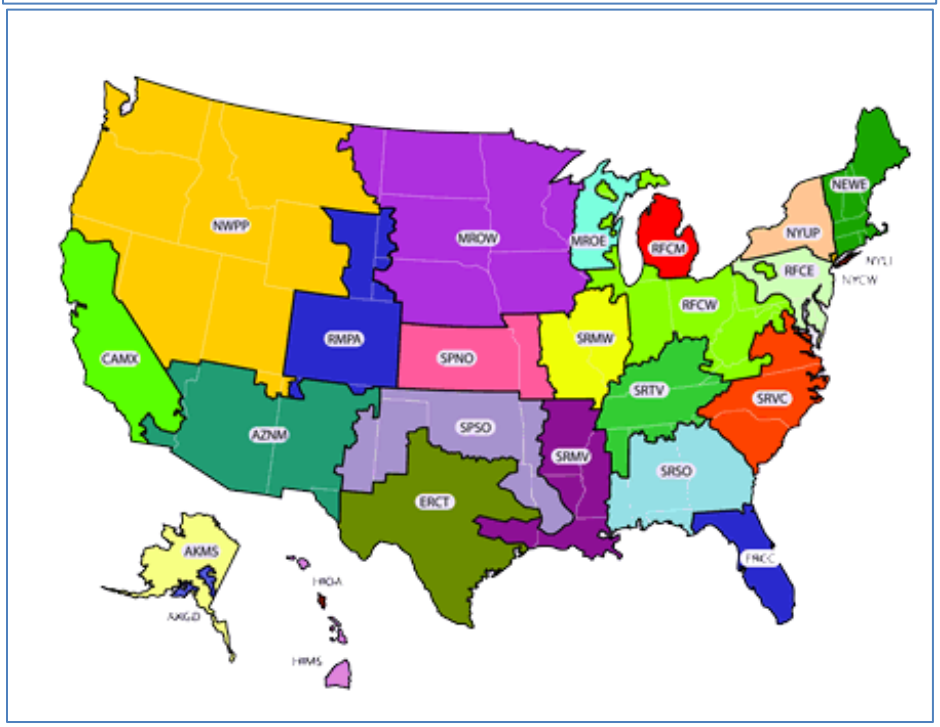
	All Section 111(d) Units		Nuclear			Wind and Solar			Other		Total Grid-Connected	
State	MW Capacity	Number of Units	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	MW Capacity	Number of Units
ALABAMA	17,562	101	5,135	5	91%	0	1	0%	10,361	175	33,058	282
ALASKA	444	21	-	-	0%	33	25	7%	1,766	473	2,243	519
ARIZONA	13,656	70	3,937	3	93%	829	65	16%	9,634	133	28,056	271
ARKANSAS	9,707	49	1,865	2	95%	-	-	0%	4,300	112	15,872	163
CALIFORNIA	25,929	185	2,240	2	90%	6,202	498	19%	33,424	1,431	67,795	2,116
COLORADO	7,161	58	-	-	0%	2,411	61	29%	5,685	228	15,256	347
CONNECTICUT	4,596	28	2,117	2	92%	1	6	0%	2,687	144	9,401	180
DELAWARE	2,032	15	-	-	0%	15	4	20%	1,001	31	3,048	50
FLORIDA	33,815	170	3,140	4	65%	74	11	16%	23,441	401	60,470	586
GEORGIA	18,244	91	4,061	4	95%	3	3	5%	17,498	350	39,806	448
HAWAII	1,674	34	-	-	0%	185	27	20%	813	110	2,672	171
IDAHA	465	14	-	-	0%	973	32	22%	3 725	203	5 162	249
ILLINOIS	17,988	92	11,673	11	94%	3,579	36	25%	14,462	577	47,703	716
INDIANA	19,991	94	-	-	0%	1,543	15	24%	6,300	217	27,834	326
IOWA	7,663	58	622	1	80%	5,050	77	32%	3,134	499	16,469	635
KANSAS	6,810	43	1,205	1	78%	2,516	19	22%	3,504	403	14,034	466
KENTUCKY	15,329	54	-	-	0%	-	-	0%	6,768	111	22,098	165
LOUISIANA	18,660	126	2,157	2	83%	-	-	0%	5,551	134	26,368	262
MAINE	2,195	26	-	-	0%	411	10	23%	2,057	292	4,663	328
MARYLAND	6,979	30	1,734	2	89%	148	14	26%	3,819	156	12,680	202
MASSACHUSETTS	8 820	60	685	1	98%	93	32	11%	5 171	231	14 769	324
MICHIGAN	17,389	127	4,131	4	77%	820	16	15%	9,412	644	31,753	791
MINNESOTA	6,445	70	1,697	3	80%	2,867	145	30%	5,333	433	16,342	651
MISSISSIPPI	10,260	67	1,265	1	66%	-	-	0%	4,532	71	16,056	139
MISSOURI	13,977	68	1,240	1	99%	459	6	31%	7,185	377	22,860	452
MONTANA	1,803	9	-	-	0%	638	10	26%	3,150	95	5,591	114
NEBRASKA	4,725	34	1,271	2	52%	415	11	34%	2,032	253	8,443	300
NEVADA	5,150	46	-	-	0%	411	18	12%	5,486	135	11,046	199
NEW HAMPSHIRE	1,843	12	1,247	1	75%	171	3	14%	1,311	142	4,571	158
NEW JERSEY	6 924	60	4 273	4	88%	285	128	11%	8 889	233	20 371	425
NEW MEXICO	5,134	26	-	-	0%	921	34	31%	1,833	67	7,887	127
NEW YORK	17,883	109	5,286	6	88%	1,598	27	20%	15,171	843	39,937	985
NORTH CAROLINA	14,056	62	5,206	5	86%	153	64	8%	11,321	344	30,736	475
NORTH DAKOTA	4,153	14	-	-	0%	1,805	28	34%	626	40	6,585	82
OHIO	21,765	109	2,176	2	90%	484	13	24%	9,588	332	34,012	456
OKLAHOMA	14,860	79	-	-	0%	2,973	27	31%	5,494	129	23,326	235
OREGON	2,776	23	-	-	0%	3,154	60	22%	8,144	256	14,074	339
PENNSYLVANIA	22,992	110	9,896	9	87%	1,377	43	18%	9,967	375	44,232	537
RHODE ISLAND	1,306	17	-	-	0%	2	1	0%	712	35	2,019	53
SOUTH CAROLINA	8,115	42	6,659	7	88%	0	1	0%	9,158	254	23,931	304
SOUTH DAKOTA	645	2	-	-	0%	767	11	42%	2,825	75	4,237	88
TENNESSEE	8,879	60	3,512	3	82%	44	5	12%	8,077	190	20,512	258
TEXAS	67 373	341	5 020	4	87%	11 700	116	31%	22 492	504	106 585	965
UTAH	5,840	24	-	-	0%	19	1	24%	1,550	143	7,408	168
VERMONT	2	3	628	1	91%	133	11	9%	545	139	1,308	154
VIRGINIA	10,902	79	3,637	4	90%	-	-	0%	11,750	626	26,288	709
WASHINGTON	3,719	33	1,158	1	92%	2,802	24	27%	24,743	379	32,422	437
WEST VIRGINIA	14,378	33	-	-	0%	583	6	25%	1,542	50	16,503	89
WISCONSIN	10,485	79	1,209	2	92%	614	12	28%	6,252	534	18,559	627
WYOMING	6,434	28	-	-	0%	1,383	30	35%	586	58	8,404	116
50 STATES	532,364	3,084	94,944	95		60,642	1,786		354,445	13,992	1,042,395	18,957

source: SNL Financial

APPENDIX 3 –

MAP of NERC REGIONS AND SUBREGIONS





From:	Heather Cantino
To:	Mccarthy, Gina
CC:	McCabe, Janet
Sent:	2/18/2015 10:21:58 AM
Subject:	Ohio groups call on you to count biomass CO2 emissions accurately
Attachments:	EPA Letter on bioenergy from Ohio Environmental Groups Feb 18, 2015.pdf

letter also attached. Please acknowledge receipt. Thank you.

February 18th, 2015

Gina McCarthy

Administrator

Office of the Administrator 1101A

U.S. Environmental Protection Agency

1200 Pennsylvania Ave., N.W.

Washington, DC 20460

Dear Administrator McCarthy:

We are writing to express our concern that under the Clean Power Plan, EPA may inaccurately treat biomass electricity as carbon neutral, that is, as having no net emissions of carbon dioxide, the greenhouse gas most responsible for climate change.

Such a policy threatens forests, because wood is the primary fuel consumed by biomass power plants. Here in Ohio, we have been deeply worried by proposals by power companies to co-fire wood at coal plants or even convert coal plants to biomass. Nine large biomass co-firing or conversion projects have been approved by the Public Utilities Commission in Ohio,[1] projects that would consume millions of tons of wood a year. While these plans have been shelved for the time being, EPA's plan to allow biomass, particularly "sustainably harvested" biomass, to qualify as renewable energy under the Clean Power Plan could change the economic balance of these proposals, making them more feasible. This is not just a theoretical possibility. We have watched with alarm what happened in Virginia, where Dominion Energy has converted the Altavista, Southampton, and Hopewell coal plants to burn wood, and will be co-firing 20% biomass at its new 600 MW Virginia City plant. Reports of pellet industry harvesting of bottomland hardwood forests in the Southeast also highlight the vulnerability of Ohio's treasured and limited forests if EPA makes wood-fired biomass power more viable.

Our groups advocate for the preservation of Ohio's forests, the quality of our air, and renewable energy policies that actually reduce air pollution and greenhouse gas emissions. We are dismayed that EPA would include bioenergy as a means for coal companies to "reduce" their emissions, when this reduction is based on simply not counting the CO_2 coming out of the smokestack. As EPA knows, biomass is not instantaneously carbon neutral. EPA's own modeling shows that burning even forestry residues that would decompose and emit CO_2 anyway has cumulative net emissions that exceed those from coal, creating a carbon debt that takes years to decades to offset. An even longer carbon debt occurs from cutting and burning trees that would otherwise continue to grow and sequester carbon, with massive consequences for forest uptake of carbon dioxide and, most importantly, for forest integrity and ecological function.

Biomass power plants don't just emit greenhouse gases. EPA's own data show that even the best-performing biomass plants emit as much or more particulate matter, carbon monoxide and other pollutants as a similar-sized coal plant. Parts of Ohio have been designated as out of attainment with EPA's 2012 $PM_{2.5}$ standard,[2] with the coal-fired power sector responsible for a great part of the air pollution burden on Ohio's citizens. Promoting biomass energy under the Clean Power Plan makes no more sense for controlling conventional air pollutants than it does for controlling greenhouse gasses.

Our groups want clean energy, and we want to support EPA in its efforts to reduce power sector emissions, but biomass power is not "clean" and it doesn't belong in the Clean Power Plan. If the Plan counts the electricity generated at biomass power plants and coal plants co-firing biomass, then it must count the CO_2, as well. It is essential that EPA recognize the toll that biomass power takes on greenhouse gas emissions, air pollution, and forests.

Thank you for your consideration,

Nancy Pierce, steering committee member

Athens County Fracking Action Network

Heather Cantino, Board Vice Chair

Buckeye Forest Council

Kathie Jones, Co-Founder

Concerned Citizens of Medina County

Leatra Harper, Managing Director

FreshWater Accountability Project

Carol Apacki, Coordinator

Licking County Concerned Citizens for Public Health and Environment

Nathan G. Johnson, Attorney

Ohio Environmental Council

Nancy Walker

Appalachian Ohio Sierra Club

Loraine McCosker, Chair, Forests and Public Lands

Ohio Sierra Club

---

[1] Miami Fort Generating Station Hamilton Cty, OH

W.H. W.H. Zimmer Generating Station, Clermont Cty, OH

Conesville Generating Station, Coshocton Cty, OH

Bay View Co-Generation Plant, Lucas Cty, OH

Walter C. Beckjord Generating Station, Clermont Cty, OH

Bay Shore Generating Station, Lucas Cty, OH

Picway Generating Station, Pickaway Cty, OH

South Point Biomass Generation Plant, Lawrence Cty, OH

Killen Generating Station, Adams Cty, OH

[2] http://epa.maps.arcgis.com/apps/MapJournal/index.html?appid=04f3d530f6d34d4ea6b9471ff37e084e&webmap=fc297672dd074e4ab5b208aebe21fa52

February 18th, 2015

Gina McCarthy
Administrator
Office of the Administrator 1101A
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, DC 20460

Dear Administrator McCarthy:

We are writing to express our concern that under the Clean Power Plan, EPA may inaccurately treat biomass electricity as carbon neutral, that is, as having no net emissions of carbon dioxide, the greenhouse gas most responsible for climate change.

Such a policy threatens forests, because wood is the primary fuel consumed by biomass power plants. Here in Ohio, we have been deeply worried by proposals by power companies to co-fire wood at coal plants or even convert coal plants to biomass. Nine large biomass co-firing or conversion projects have been approved by the Public Utilities Commission in Ohio,[1] projects that would consume millions of tons of wood a year. While these plans have been shelved for the time being, EPA's plan to allow biomass, particularly "sustainably harvested" biomass, to qualify as renewable energy under the Clean Power Plan could change the economic balance of these proposals, making them more feasible. This is not just a theoretical possibility. We have watched with alarm what happened in Virginia, where Dominion Energy has converted the Altavista, Southampton, and Hopewell coal plants to burn wood, and will be co-firing 20% biomass at its new 600 MW Virginia City plant. Reports of pellet industry harvesting of bottomland hardwood forests in the Southeast also highlight the vulnerability of Ohio's treasured and limited forests if EPA makes wood-fired biomass power more viable.

Our groups advocate for the preservation of Ohio's forests, the quality of our air, and renewable energy policies that actually reduce air pollution and greenhouse gas emissions. We are dismayed that EPA would include bioenergy as a means for coal companies to "reduce" their emissions, when this reduction is based on simply not counting the CO_2 coming out of the smokestack. As EPA knows, biomass is not instantaneously carbon neutral. EPA's own modeling shows that burning even forestry residues that would decompose and emit CO_2 anyway has cumulative net emissions that exceed those from coal, creating a carbon debt that takes years to decades to offset. An even longer carbon debt occurs from cutting and burning trees that would otherwise continue

---

[1] Miami Fort Generating Station Hamilton Cty, OH
W.H. W.H. Zimmer Generating Station, Clermont Cty, OH
Conesville Generating Station, Coshocton Cty, OH
Bay View Co-Generation Plant, Lucas Cty, OH
Walter C. Beckjord Generating Station, Clermont Cty, OH
Bay Shore Generating Station, Lucas Cty, OH
Picway Generating Station, Pickaway Cty, OH
South Point Biomass Generation Plant, Lawrence Cty, OH
Killen Generating Station, Adams Cty, OH

to grow and sequester carbon, with massive consequences for forest uptake of carbon dioxide and, most importantly, for forest integrity and ecological function.

Biomass power plants don't just emit greenhouse gases. EPA's own data show that even the best-performing biomass plants emit as much or more particulate matter, carbon monoxide and other pollutants as a similar-sized coal plant. Parts of Ohio have been designated as out of attainment with EPA's 2012 $PM_{2.5}$ standard,[2] with the coal-fired power sector responsible for a great part of the air pollution burden on Ohio's citizens. Promoting biomass energy under the Clean Power Plan makes no more sense for controlling conventional air pollutants than it does for controlling greenhouse gasses.

Our groups want clean energy, and we want to support EPA in its efforts to reduce power sector emissions, but biomass power is not "clean" and it doesn't belong in the Clean Power Plan. If the Plan counts the electricity generated at biomass power plants and coal plants co-firing biomass, then it must count the CO_2, as well. It is essential that EPA recognize the toll that biomass power takes on greenhouse gas emissions, air pollution, and forests.

Thank you for your consideration,

Nancy Pierce, steering committee member
Athens County Fracking Action Network

Heather Cantino, Board Vice Chair
Buckeye Forest Council

Kathie Jones, Co-Founder
Concerned Citizens of Medina County

Leatra Harper, Managing Director
FreshWater Accountability Project

Carol Apacki, Coordinator
Licking County Concerned Citizens for Public Health and Environment

Nathan G. Johnson, Attorney
Ohio Environmental Council

Nancy Walker
Appalachian Ohio Sierra Club

Loraine McCosker, Chair, Forests and Public Lands
Ohio Sierra Club

---

2 http://epa.maps.arcgis.com/apps/MapJournal/index.html?appid=04f3d530f6d34d4ea6b9471ff37e084e&webmap=fc297672dd074e4ab5b208aebe21fa52

From: Dunham, Sarah
To: Sarah Dunham
Sent: 3/25/2015 1:32:53 PM
Subject: FW: For your review: draft CPP preamble sections
Attachments: CPP Section V_032315.docx; CPP Section VI_032315.docx; CPP Sections I through IV_032315.docx; CPP Sections VIII through X_032115.docx; CPP_Section VII_032315.docx

Sent from my Windows Phone

From: Harvey, Reid
Sent: 3/23/2015 6:00 PM
To: Dunham, Sarah; Friedman, Kristina
Subject: FW: For your review: draft CPP preamble sections

I will be reviewing quickly over the next few days.

From: Vasu, Amy
Sent: Monday, March 23, 2015 5:07 PM
To: Tsirigotis, Peter; Culligan, Kevin; Harvey, Reid; Stenhouse, Jeb; Adamantiades, Mikhail; Zenick, Elliott; Hoffman, Howard
Subject: For your review: draft CPP preamble sections
Importance: High

Thank you for your review of the attached draft preamble sections.

We have grouped the draft preamble sections into 5 files, for easier review and to also reflect that the document has not yet been compiled and reviewed:

Ex. 5 - Deliberative

Please send comments to me as you complete review of a section and/or large subsection. I will get them to preamble coordinators and lead authors for revision. We will do our best to address/incorporate your comments prior to sending the revised draft to Janet and Joe on Friday. Getting comments to us before noon on Thursday would be helpful. Whatever does not make it in to the Friday version we will incorporate into the next draft.

Thank you.

Amy

~~~~~~~~~~~~~~~~~~~~~~~~~

Amy B. Vasu
~~~~~~~~~~~~~~~~~~~~~~~~~

U.S. EPA / OAQPS
Sector Policies and Programs Division
email: vasu.amy@epa.gov
phone: 919.541.0107

From: Goffman, Joseph
To: Ex. 6 - Personal Privacy; Administrator; McCabe, Janet
CC: Dunham, Sarah
Sent: 9/16/2014 6:12:56 PM
Subject: Fwd: Request for Accounting Framework Issuance for Public Comment
Attachments: ATT00001.htm; ATT00002.htm; ATT00003.htm; ATT00004.htm; ATT00005.htm; ATT00006.htm; EPA Request for Framework Issuance 091614 FINAL.pdf; image002.jpg; image003.jpg; image004.jpg; image005.jpg; image006.jpg

- Joseph Goffman
Sent from my iPhone

Begin forwarded message:

From: "Harman, Donna" <Donna_Harman@afandpa.org>
Date: September 16, 2014 at 5:40:06 PM EDT
To: "'McCarthy.gina@Epa.gov'" <McCarthy.gina@Epa.gov>
Cc: "'goffman.joseph@epa.gov'" <goffman.joseph@epa.gov>, "'porterfield.terri@epa.gov'" <porterfield.terri@epa.gov>
Subject: Request for Accounting Framework Issuance for Public Comment

Dear Gina,

Please find attached our request for issuance of the Accounting Framework for Biogenic CO2 Emissions for public comment as soon as possible. We appreciate the additional time you provided today for commenting on the 111(d) Proposed Rule, but hope that we can do it in conjunction with our review of the Accounting Framework.

Thank you for your consideration.

Best regards,

Donna

DONNA HARMAN
President and CEO
Donna_Harman@afandpa.org
(202) 463-5151
AMERICAN FOREST & PAPER ASSOCIATION
1101 K Street, N.W., Suite 700
Washington, D.C. 20005

American Forest & Paper Association

AMERICAN WOOD COUNCIL

NAFO
National Alliance of Forest Owners

September 16, 2014

The Honorable Gina McCarthy, Administrator
United States Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Mail code: 28221T
Washington, D.C. 20460
Attn: Docket ID No. EPA-HQ-OAR-2013-0602

Re: **Request for Notice of Data Availability and Extended Comment Period (Docket ID No. EPA-HQ-OAR-2013-0602)**

Dear Administrator McCarthy:

On behalf of the forest products industry, we are writing to request that the United States Environmental Protection Agency (EPA) make available for public comment the revised *Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources* (Accounting Framework) referred to in the proposed rule "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units." 79 Fed. Reg. 34,830 (Jun. 18, 2014) (111(d) Proposed Rule). We appreciate that EPA extended the public comment period for the 111(d) Proposed Rule, but until the Accounting Framework is issued for public comment, we and other interested parties will not have an adequate opportunity to comment on the 111(d) Proposed Rule.

Three years ago, EPA committed to completing an Accounting Framework for biogenic CO_2 emissions by July 2014. While EPA proposed a draft Accounting Framework in September 2011, it has not yet issued a revised Framework for comment that accounts for the substantial and significant input of the public and the Science Advisory Board. The 111(d) Proposed Rule discusses the use of biomass energy as one option the states can use to mitigate greenhouse gas emissions. However, EPA has not disclosed how it intends to treat biogenic carbon emissions from affected entities and refers to the pending revised Accounting Framework. Interested parties who want to comment on biomass-related issues in the 111(d) Proposed Rule are deprived of their right to fair notice and an opportunity to comment so long as EPA fails to issue the revised Accounting Framework that will determine the central issue of biomass carbon neutrality.

We request that the EPA immediately issue a Notice of Data Availability (NODA) that contains the Accounting Framework and provide a reasonable comment period to analyze it and develop comments on both the Framework and its effect on the 111(d) Proposed Rule.

EPA's recent actions support our request. On February 25, 2014, EPA issued a NODA in support of its proposed rule "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." 79 Fed. Reg. 10,750 (Feb. 26, 2014) (111(b) Proposed Rule). The 111(b) Proposed Rule NODA produced technical support documentation, which had not been produced to the docket at the time of proposal on January 8, 2014. In addition to rectifying its error via the NODA, EPA announced a 60-day extension of the public comment deadline for the 111(b) Proposed Rule. Thus, EPA has ample precedent to take the requested action under these circumstances.

In light of the concerns expressed by potentially affected entities, we strongly urge EPA to take immediate action to rectify this matter and release the Accounting Framework critical to meaningful public comment on biomass-related issues.

Sincerely,

Donna Harman
President & CEO
American Forest & Paper Association

Robert Glowinksi
President & CEO
American Wood Council

David P. Tenny
President & CEO
National Alliance of Forest Owners

From: Jason Bordoff
To: Ex. 6 - Personal Privacy: Administrator
Sent: 11/3/2013 9:24:55 AM
Subject: Follow up
Attachments: CRS Biopower LCA report.pdf; Wood Pellet Market and Environmental Impact Analysis 20131104.docx

Please find attached a memo summarizing state of the wood pellet global market and existing GHG analysis, as well as a CRS report on the GHG question. Few highlights:

- Ex. 5 - Deliberative
- Ex. 5 - Deliberative
- Ex. 5 - Deliberative

Happy to discuss further. Hope this is helpful. Please don't hesitate to reach out with any questions. All best wishes, Jason
--
Jason Bordoff
Professor of Professional Practice in International and Public Affairs
Director, Center on Global Energy Policy
Columbia University
Jbordoff@columbia.edu
(212) 851-0193
Visit us at energypolicy.columbia.edu

Congressional Research Service

Is Biopower Carbon Neutral?

Kelsi Bracmort
Specialist in Agricultural Conservation and Natural Resources Policy

July 19, 2013

Congressional Research Service
7-5700
www.crs.gov
R41603

CRS Report for Congress
Prepared for Members and Committees of Congress

ED_000419-0005537

Summary

Congress has expressed interest in biopower—electricity generated from biomass. Biopower, a baseload power source, has the potential to strengthen rural economies, enhance energy security, and improve the environment, proponents say. Biopower could be produced from a large range of biomass feedstocks nationwide (e.g., urban, agricultural, and forestry wastes and residues). One challenge to biopower production is a readily available feedstock supply. At present, biopower requires tax incentives to be competitive with conventional fossil fuels. If Congress considers a renewable electricity standard or other measures (e.g., farm bill energy programs) that include biopower, there may be concerns about the carbon neutrality of biopower. Congressional support for biopower has aimed to promote energy diversity and improve energy security, and has generally assumed that biopower is carbon neutral. An energy production activity is typically classified as carbon neutral if it produces no net increase in greenhouse gas (GHG) emissions on a life-cycle basis. The premise that biopower is carbon neutral has come under scrutiny as its potential to help meet U.S. energy demands and reduce U.S. greenhouse gas emissions is more closely examined.

Whether biopower is carbon neutral depends on many factors, including the definition of carbon neutrality, the feedstock type, the technology used, and the time frame examined. Carbon flux (emission and sequestration) varies at each phase of the biopower pathway, given site- and operation-specific factors. A life-cycle assessment (LCA) is a common technique to calculate the environmental footprint, including the carbon flux, of a particular biopower pathway. However, past legislation has not required a standardized LCA.

Interest in the carbon classification of biopower is in part due to sustainability and air quality concerns. Where the feedstock supply for biopower originates, if it is managed in a sustainable manner, and whether the associated air quality impacts from biopower generation are tolerable are questions that are part of the biopower carbon-neutrality debate. Congress may decide whether the current carbon-neutral designation for biopower is accurate, or whether additional carbon accounting for biopower is warranted and what impact this accounting might have on renewable energy, agricultural, and environmental legislative goals.

Rulings by the U.S. Environmental Protection Agency have raised questions about the carbon neutrality of biopower. For instance, the 2010 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule did not exempt emissions from biomass combustion. Some view EPA's decision as equating biomass emissions with fossil fuel emissions. EPA decided in 2011 to defer for three years GHG permitting requirements for carbon dioxide emissions from bioenergy and other biogenic stationary sources in order to conduct a detailed examination of the science associated with these emissions. EPA's Science Advisory Board conducted an independent review of the agency's biogenic accounting framework and released its findings in September 2012. The board acknowledged the "daunting task" of assessing the greenhouse gas implications of bioenergy, and the "narrow regulatory boundaries" within EPA's purview that limit the consideration of greenhouse gas flux at various points along the bioenergy pathway. The deferral was vacated in July 2013 by a federal court decision.

State perspectives on the tailoring rule are divided. Some states contend that treating biomass combustion the same as fossil fuel combustion will result in excessive permitting requirements and fees that jeopardize renewable energy development. Other states argue that not treating it the same will aggravate climate change over time.

ED_000419-0005538

Contents

Introduction 1
Biomass Carbon Cycle 2
Greenhouse Gas Accounting for Biopower Production 3
Recent Developments Affecting Biopower Assessment 6
  Title V Greenhouse Gas Tailoring Rule 7
  Manomet Biomass Study 10
Is Biopower Carbon Neutral? It Depends 12
Legislative Implications 13

Figures

Figure 1. Bioenergy CO_2 Balance vs. Fossil Fuel CO_2 Balance 4
Figure 2. Biopower and Biofuel Pathways 5
Figure 3. Cumulative GHG Flux for Biomass and Fossil Fuel 12

Tables

Table 1. Years to Achieve Equal Cumulative Flux with Fossil Fuels 12

Contacts

Author Contact Information 14

ED_000419-0005539

Introduction

Biomass energy, or bioenergy, is receiving increased attention as an alternative to fossil fuel energy because of its potential to improve the environment, provide energy security, and promote economic development. Biomass is organic matter—woody biomass, agricultural biomass, animal wastes, aquatic biomass—that can be converted to energy (e.g., heat, electricity, or liquid transportation fuels). A substantial supply of biomass feedstocks may be required to produce bioenergy, depending on current and future renewable energy mandates. A large biomass feedstock requirement could lead to water, land use, sustainability, and economic concerns.[1] Federal support for bioenergy is available via tax incentives, loan guarantees, technical and financial assistance, and mandated use requirements.

Legislative support for bioenergy, particularly for biopower (electricity generated from biomass),[2] has thus far been granted under the premise that it is carbon neutral. As more public and private resources are spent—or as greater spending is debated—on biopower, more attention is being directed to the rationale for designating biopower as carbon neutral. The carbon-neutral designation is typically assigned to an energy production activity that essentially produces no net increase in greenhouse gas (GHG) emissions on a life-cycle basis (or one in which the amount of carbon dioxide emitted during the power production cycle is absorbed).[3] Where biopower stands among the other renewable energy sources with respect to GHG emissions may affect the level of future legislative support granted to it. Is biopower carbon neutral? If it is not, should it receive the same type and amount of federal resources as carbon-neutral or less carbon-intensive energy sources? How might the federal government account for carbon associated with biopower ventures? How Congress addresses biopower's carbon neutrality could shape how Congress treats biopower in general.

Many views exist about whether biopower is carbon neutral. Some contend that biopower is carbon neutral because the carbon released during bioenergy production comes from a carbon-neutral feedstock—biomass. Some argue that biopower is not carbon neutral because the amount of GHG emissions released per unit of energy during simple biopower combustion may be higher for certain biomass fuels than for fossil fuels; or, if the GHG emissions from certain biomass fuels are lower than fossil fuels, they are still not zero. These perspectives are often based on differing assumptions, technologies, and time frames.

The debate concerning biopower's designation as carbon neutral may intensify, given possible congressional and Administration decisions. Congress may consider legislation involving biopower (e.g., a renewable electricity standard, a clean energy standard, or the next farm bill). The U.S. Environmental Protection Agency (EPA) has already promulgated regulations involving biopower (e.g., the 2010 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule) and may consider further regulatory actions. Although EPA deferred for three years GHG permitting requirements for carbon dioxide emissions from biomass-fired and other

[1] For more information, see CRS Report R41440, *Biomass Feedstocks for Biopower: Background and Selected Issues*, by Kelsi Bracmort.

[2] Biopower is a baseload power source offering "firm" power without the need for power storage. Combustion—the burning of biomass in a power plant—is the dominant technology used to produce biopower.

[3] The life cycle of a bioenergy pathway includes all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through distribution, delivery, and use of the finished fuel by the ultimate consumer. The mass values for all greenhouse gases are adjusted to account for their relative global warming potential.

ED_000419-0005540

biogenic sources (later vacated by a federal court decision),[4] Congress may still decide to examine how the widely accepted premise of biopower's carbon neutrality contributes to energy, environmental, and economic development goals.

This report discusses some of the most relevant factors to take into account when considering if biopower is carbon neutral. It does not discuss carbon accounting for other bioenergy pathways.[5]

Biomass Carbon Cycle

The carbon cycle encompasses the many pathways through which carbon is exchanged between the atmosphere and the land and water.[6] Human activities (also called anthropogenic activities) contribute to the carbon cycle by emitting carbon dioxide (CO_2). The human contribution of CO_2 to the carbon cycle is relatively small compared to other contributions, but CO_2 released to the atmosphere from human activities is taken up by soils, vegetation, and the ocean at a rate that is relatively slower than the rate at which human activities are emitting CO_2. If the excess carbon is not stored in land and ocean sinks, the atmospheric concentration of CO_2 increases, potentially impacting the Earth's climate.

One significant anthropogenic source of CO_2 in the carbon cycle is energy production. The net effect of an energy activity on the carbon cycle can be classified in one of three ways. A "carbon-positive" activity releases CO_2 into the atmosphere. A "carbon-negative" activity removes more CO_2 from the atmosphere than it emits. A "carbon-neutral" activity is one where the CO_2 releases and absorption are in balance. There is no commonly accepted definition for a "carbon-neutral" activity in the biopower arena. Indeed, multiple assertions about carbon neutrality have been put forth by those involved with biomass energy, including the following:[7]

- Biomass energy is carbon neutral because biomass is naturally carbon neutral.
- Biomass energy is neutral if the activity removes as much CO_2 as was emitted into the atmosphere.
- Biomass energy is neutral only if the net life-cycle emissions are zero.[8]
- Biomass energy is neutral if it achieves lower net increases in atmospheric GHGs when compared to alternative energy activities.

[4] Environmental Protection Agency, "Deferral for CO_2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs: Final Rule," 76 *Federal Register* 43490, July 20, 2011; Center for Biological Diversity v. Environmental Protection Agency (D.C. Cir. Case #11-1101 July 12, 2013).

[5] Congress addressed carbon accounting for another major bioenergy pathway—liquid transportation biofuels—with a life cycle emission analysis (a requirement within the Renewable Fuel Standard). For more information, see CRS Report R40460, *Calculation of Lifecycle Greenhouse Gas Emissions for the Renewable Fuel Standard (RFS)*, by Brent D. Yacobucci and Kelsi Bracmort.

[6] For more information, see CRS Report RL34059, *The Carbon Cycle: Implications for Climate Change and Congress*, by Peter Folger. Carbon is an elemental building block of molecules that make up all organisms on Earth. Carbon cycling is the process by which living things absorb carbon from the atmosphere, carbonate rocks and ocean deposits, dead organic matter in the soil, or food and return it to the atmosphere or soil by respiration, combustion, or decay.

[7] R. Miner, "Biomass 'Neutrality' in the Context of Forest-based Fuels and Products," USDA Bioelectricty and GHG Workshop, Washington, DC, November 15, 2010. Some of the definitions are not mutually exclusive.

[8] GHGs from bioenergy production can be accounted for using a life-cycle assessment (LCA). The LCA is further discussed in "Greenhouse Gas Accounting for Biopower Production," below.

ED_000419-0005541

There are pros and cons for each assertion. For instance, declaring that biomass energy is carbon neutral because biomass is naturally carbon neutral does not account for GHG emissions released due to management of crops grown for energy production (e.g., fertilizer). There may need to be additional plantings of certain biomass feedstocks to remove the CO_2 emitted from biomass cultivated for energy production.

The carbon cycles for a bioenergy system and a fossil fuel system differ in at least two ways: the carbon source (finite versus renewable) and the atmospheric carbon concentration (potentially stable versus additional; see **Figure 1**). Three main factors contribute to the amount of carbon emitted from biopower generation: feedstock production (cultivation and harvest), feedstock transport, and the biopower technology type. However, as noted by many sources, feedstock production also absorbs carbon during growth.

Greenhouse Gas Accounting for Biopower Production

Whether and how to conduct GHG accounting for biopower is an issue at the forefront of the bioenergy movement. GHG accounting can be used to compare the environmental footprint of a biopower operation with that of conventional fossil fuel (e.g, electricity from coal). The environmental footprint is often calculated using a life-cycle assessment (LCA), an analytic method for identifying, evaluating, and comparing the environmental impacts of emissions and the resource depletion associated with a specific process.[9] An LCA generally uses observed data and assumptions to model what GHGs are being released at each phase of the process. Ideally, an LCA would encompass economic and social factors for a more comprehensive assessment. Alternatively, an LCA can be one element used in assessing a preferred energy approach, along with cost and performance data. In some cases, even if LCA results favor a particular approach, an LCA alone might not be the deciding factor when choosing an energy process; financial objectives, policy goals, and other factors may influence which approach is selected.

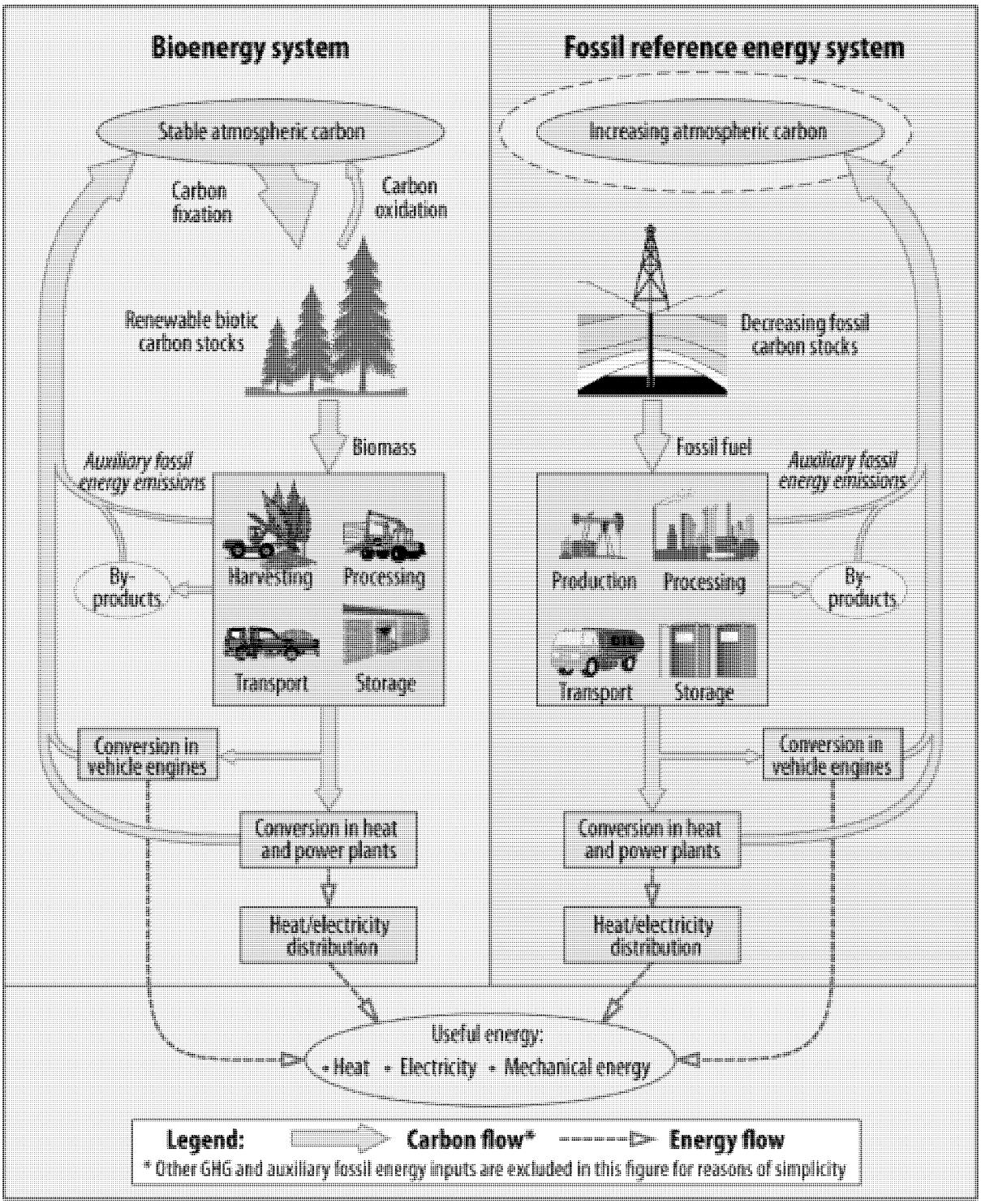
An LCA has four major stages: goal and scope definition, inventory analysis, impact assessment, and interpretation.[10] While an LCA can be performed to meet various goals, the goals most applicable to the biopower arena are to support broad environmental assessments, support public policy, and provide information and direction to decision-makers. The goal and scope definition stage determines the amount of resources and time needed to conduct an LCA. The inventory analysis stage of an LCA quantifies energy and raw material requirements, atmospheric emissions, waterborne emissions, solid wastes, and other releases for the entire life cycle of a product, process, or activity. The impact assessment stage evaluates the potential human health and environmental impacts of the environmental resources and releases identified during the inventory analysis stage. The interpretation stage identifies, quantifies, checks, and evaluates the results of the inventory analysis and impact assessment stages, and communicates the results.

[9] National Renewable Energy Laboratory, *Energy Analysis*, October 2010, http://www.nrel.gov/analysis/tech_bio_analysis.html.

[10] U.S. Environmental Projection Agency, *Life Cycle Assessment: Principles and Practice*, EPA/600/R-06/060, Cincinnati, OH, May 2006, http://www.epa.gov/nrmrl/lcaccess/pdfs/600r06060.pdf.

ED_000419-0005542

Figure 1. Bioenergy CO_2 Balance vs. Fossil Fuel CO_2 Balance



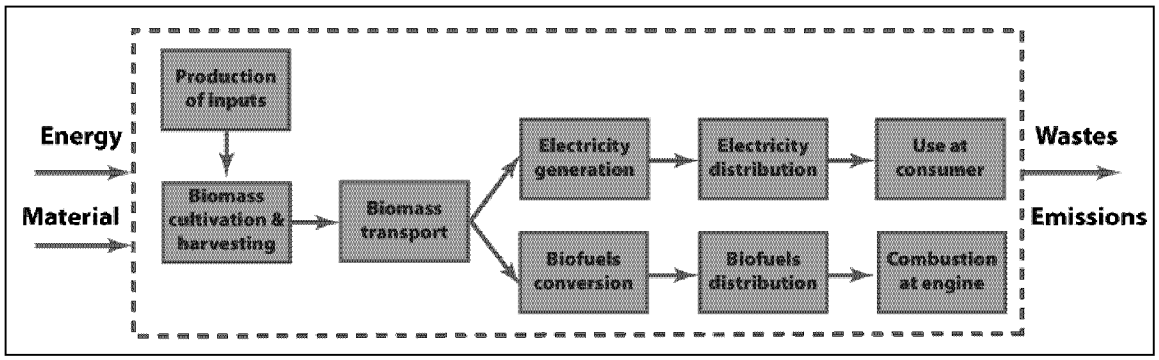
Source: International Energy Agency, IEA Bioenergy Task 38, Greenhouse Gas Balances of Bioenergy and Bioenergy Systems, 2002. Adapted by CRS.

Notes: The magnitude of the carbon flows, as indicated by the width of the arrows, is a significant part of the debate over the carbon neutrality of bioenergy.

ED_000419-0005543

GHG accounting with an LCA can be performed at each phase of the biopower pathway: biomass cultivation and harvest, biomass transport, electricity generation, electricity transmission and distribution, and electricity end use (**Figure 2**). The first three phases of the biopower pathway (cultivation and harvest, transport, and electricity generation) are where the bulk of GHG emissions occur. GHG flux during the first three phases is site- and operation-specific, and depends on many factors, including the biomass type, management strategies, and the biopower generation technology.

Figure 2. Biopower and Biofuel Pathways



Source: Q. Zhang, K.R. Goldstein, and J.R. Mihelcic, "A Review of Life Cycle Assessment Renewable Energy Derived from Forest Resources," in *Renewable Energy from Forest Resources in the United States*, ed. B.D. Solomon, C. A. Luzadis (New York: Routledge, 2009). Adapted by CRS.

Published LCAs for biopower are limited and, as noted above, may not be applicable to specific cases.[11] The LCAs performed are often tailored to one feedstock and one biopower technology type, and LCA results vary depending on assumptions such as the time frame of the assessment. The LCAs presented in this section are based on both a long time frame (e.g., cradle to grave) and a relatively short time frame (e.g., cradle to gate).[12] Different LCA time frames can lead to radically different, even contradictory, results.

Although biopower LCAs are scarce compared to liquid transportation biofuel LCAs, certain trends appear in existing assessments. For instance, the National Renewable Energy Laboratory (NREL) conducted a review and analysis of 57 biopower LCAs. The NREL review shows that biopower reduces greenhouse gas emissions when compared with fossil-based generation of electricity.[13] And based on a separate review of more than 25 LCAs, biopower is in the top tier of bioenergy pathways that avoid the most GHG emissions and replace the largest amounts of fossil energy.[14] Approximately 15 of the LCAs reviewed included electricity as an end product, of which at least 10 had an LCA time frame of cradle to gate.

[11] Most LCAs for bioenergy have focused on GHG emissions from biomass used for liquid transportation fuels and its impact on climate.

[12] A cradle to grave time frame generally includes all phases from feedstock production to energy end use. A cradle to gate time frame generally includes a fraction of the complete biopower pathway which may include feedstock production, feedstock cultivation, feedstock transport, and electricity generation.

[13] The analysis did not consider land use change. NREL, *Biopower Greenhouse Gas Emissions inthe LCA Literature*, October 5, 2011, http://lcacenter.org/lcaxi/final/446.pdf.

[14] Q. Zhang, K. R. Goldstein, and J. R. Mihelcic, "A Review of Life Cycle Assessment Renewable Energy Derived from Forest Resources," in *Renewable Energy from Forest Resources in the United States*, ed. Barry D. Solomon, Calerie A. Luzadis (New York: Routledge, 2009). Information regarding the feedstocks, conversion processes, end (continued...)

ED_000419-0005544

Biopower LCAs are usually limited to two biopower technology types: combustion and gasification. Both technologies have strengths and weaknesses.[15] The technology to co-fire (or combust) biomass with coal is available at commercial scale and is in use today. A cradle-to-grave DOE LCA found that a co-firing power plant, at both the 15% and 5% biomass levels (with a 350 and 354 MW plant capacity, respectively), compared with a power plant with no co-firing, led to a reduction in GHG emissions by roughly 18% and 5%, respectively.[16] Gasification technology is in the development and demonstration phase.[17] A cradle-to-grave DOE LCA for a hypothetical 113 MW biomass plant—performed in part to identify CO_2 emissions from a biopower plant using gasification technology—concluded that more than half of all net CO_2 emissions came from feedstock production, primarily the use of fossil fuels in farming operations.[18] The LCA was performed only on the biomass system and not for an immediate comparison with fossil-fueled power options.

Recent Developments Affecting Biopower Assessment

Certain actions have propelled the biomass carbon-neutrality issue to the center of the bioenergy debate. Most notable are the EPA's Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule, finalized in June 2010, and the June 2010 release of the Manomet Center for Conservation Sciences Biomass Sustainability and Carbon Policy Study.[19] Also, many scientists contributed to the discussion with the submission of two letters to Members of Congress. The first letter provided the authors' reasons for supporting legislation that differentiates GHG emissions from bioenergy based on the source of the biomass.[20] The second letter provided the authors' reasons why equating biogenic carbon emissions (or bioenergy emissions) with fossil fuel emissions in the tailoring rule could hinder development of bioenergy technologies and may not be scientifically valid for certain sources of biomass.[21]

(...continued)

products, system boundaries, allocation methods, and impact metrics for each LCA is available in Table 8.1.

[15] D. Peterson and S. Haase, *Market Assessment of Biomass Gasification and Combustion Technology for Small- and Medium-Scale Applications*, U.S. Dep. of Energy National Renewable Energy Laboratory, NREL/TP-7A2-46190, July 2009, http://www.nrel.gov/docs/fy09osti/46190.pdf.

[16] M. K. Mann and P. L. Spath, "A Life Cycle Assessment of Biomass Cofiring in a Coal-Fired Power Plant," *Clean Technologies and Environmental Policy*, vol. 3, no. 2 (2001).

[17] Some coal gasification plants are under consideration to be constructed over the next few years.

[18] M. K. Mann and P. L. Spath, *Life Cycle Assessment of Biomass Gasification Combined-Cycle System*, Department of Energy National Renewable Energy Laboratory, December 1997, http://www.nrel.gov/docs/legosti/fy98/23076.pdf.

[19] There are other studies that examine carbon classification and feedstock sustainability for biopower. The Manomet Study is profiled in this section because it has received the most media attention thus far.

[20] May 17, 2010, http://www.saveamericasforests.org/Forests%20-%20Incinerators%20-%20Biomass/Documents/Forests-Carbon%20Sequestration/90scientistsletter.pdf.

[21] Society of American Foresters, *Scientist/Academic Letter on Biomass Energy*, July 20, 2010, http://www.safnet.org/documents/biomass_science_letter_SENATE7-20-10.pdf.

ED_000419-0005545

Title V Greenhouse Gas Tailoring Rule

The designation of biomass combustion as carbon neutral has come under scrutiny partly due to the tailoring rule finalized by EPA. The tailoring rule was developed by EPA to limit the number of facilities that would be required to obtain permits for greenhouse gas emissions under the Clean Air Act's Prevention of Significant Deterioration (PSD) and Title V permit programs.[22] By statute, the PSD program requires any new or modified facility emitting more than 100 tons or 250 tons of pollutants subject to regulation to obtain a permit prior to construction or operation. Title V sets a statutory 100-ton threshold for operating permits and applies to existing as well as new facilities. These thresholds limit the applicability of the permit requirements to the largest emitters of most pollutants that have traditionally been covered by the Clean Air Act; but when applied to carbon dioxide emissions, they would not serve the same limiting function. EPA estimates that a 100-ton threshold for GHGs would ultimately require more than 6 million sources to obtain Title V permits, with administrative costs for the state and local permitting authorities in the billions of dollars annually. Faced with these "absurd results" of following the letter of the law, EPA developed the tailoring rule to focus first on the largest emitters of GHGs. The rule sets a 75,000 ton per year of carbon dioxide equivalent (CO_2e)[23] threshold initially, allowing the agency to decide over a six-year period what to do about smaller sources.[24]

The tailoring rule does not exempt emissions from biomass combustion.[25] The rule grants exemptions based not on source category (e.g., fossil fuels, biomass) but on carbon tonnage emitted from a facility. One reason EPA did not exempt the biomass industry from the tailoring rule requirements is lack of information demonstrating the costs and administrative burdens the biopower industry would face if subject to the permitting requirements.[26] EPA issued a call for information in July 2010 to request comment on possible accounting approaches for biogenic emissions under the tailoring rule.[27] EPA received over 7,000 comments in response (approximately 600 were detailed responses). The two central themes for the comments reviewed by EPA included the request for certainty when it comes to biomass energy, and the recognition that all biomass is not the same.[28]

---

[22] Environmental Protection Agency, "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," 75 *Federal Register* 31514, June 3, 2010.

[23] Carbon dioxide-equivalent (CO_2 eq. or CO_2e) is the principal unit of measurement across the greenhouse gases. Different gases are converted into CO_2e by multiplying a quantity of the gas by its Global Warming Potential (GWP). GWP is an estimate of the relative greenhouse effectiveness over time relative to CO_2 which has a GWP value of 1.

[24] For more information on the history of the tailoring rule, see CRS Report R41103, *Federal Agency Actions Following the Supreme Court's Climate Change Decision in Massachusetts v. EPA: A Chronology*, by Robert Meltz.

[25] Environmental Protection Agency, "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," 75 *Federal Register* 31590-31591, June 3, 2010. For more information on the final rule, see CRS Report R41212, *EPA Regulation of Greenhouse Gases: Congressional Responses and Options*, by James E. McCarthy.

[26] U.S. EPA, "Prevention of Significant Deterioration," 75 *Fed. Reg.* 31590, June 3, 2010.

[27] U.S. EPA, *Call for Information on Greenhouse Gas Emissions Associated with Bioenergy and Other Biogenic Sources*, July 9, 2010, http://www.epa.gov/climatechange/emissions/biogenic_emissions.html.

[28] D. Kruger, EPA, "Panelist, Carbon Neutrality," oral presentation at Ag Energy Symposium, Washington, DC, November 4, 2010. EPA's response to the comments received is provided in U.S. Environmental Protection Agency, *Deferral for CO_2 Emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration (PSD) and Title V Programs Summary of Public Comments and Responses*, Washington, DC, June 28, 2011, http://www.epa.gov/NSR/documents/RTC_6-30_final_comb.pdf.

ED_000419-0005546

In July 2011, EPA announced that it would defer for a period of three years GHG permitting requirements for CO_2 emissions from biomass-fired and other biogenic sources.[29] Some were concerned that the deferment would lead to delays in biomass energy investments, due to uncertainty about how EPA would address these types of facilities in three years. However, data is not available to determine if the ruling inhibited investment. EPA proposed using the three-year time period to conduct a detailed examination of the science associated with biogenic CO_2 emissions from stationary sources to determine how to treat emissions from biomass-fired and biogenic sources.

EPA charged its Science Advisory Board (SAB) with reviewing and commenting on (1) EPA's characterization of the science and technical issues relevant to accounting for biogenic CO_2 emissions from stationary sources; (2) EPA's framework, overall approach, and methodological choices for accounting for these emissions; and (3) options for improving upon the framework for accounting for biogenic CO_2 emissions, among other issues.[30] The SAB conducted the independent review of the agency's biogenic accounting framework and released its findings in September 2012.[31] The SAB acknowledged the "daunting task" of assessing the greenhouse gas implications of bioenergy, and the "narrow regulatory boundaries" within EPA's purview that limit the consideration of greenhouse gas flux at various points along the bioenergy pathway. The SAB identified multiple factors (e.g., time scale, spatial scale, leakage) that require further assessment by EPA and provided recommendations to revise the biogenic accounting framework. The SAB "found that quantification of most components of the framework has uncertainties, technical difficulties, data deficiencies and implementation challenges." The SAB recommended an alternative biogenic accounting factor based on feedstock category, region, land management, and prior land use. Additionally, a dissenting opinion from one of the SAB members was included in the report that would abandon the proposed framework process.

A July 12, 2013, federal court decision vacated the deferral rule because the rule "cannot be justified under any of the administrative law doctrines [*de minimis*, one-step-at-a-time, administrative necessity, and absurd results] relied on by EPA".[32] Going forward, EPA could appeal the decision, perhaps requesting that the deferral be allowed to remain in effect pending appeal; provide new justification for the deferral rule; or expedite issuance of a rule that permanently addresses CO_2 emissions from bioenergy and other biogenic sources. The court's opinion on the deferral rule "leaves for another day the question whether the agency has authority under the Clean Air Act to permanently exempt biogenic carbon dioxide sources from the PSD permitting program."[33]

EPA also noted in the PSD and Title V Permitting Guidance for Greenhouse Gases issued in 2010 that certain types of biomass could be considered a best available control technology (BACT)—a pollution control standard mandated by the Clean Air Act—after taking into account

[29] Environmental Protection Agency, "Deferral for CO_2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs: Final Rule," 76 *Federal Register* 43490, July 20, 2011. Biogenic includes facilities that emit CO_2 from sources originating via biological processes, such as landfills.

[30] The agency's charge for the SAB, review documents including the accounting framework, and meeting materials are available at http://yosemite.epa.gov/sab/sabproduct.nsf/0/2f9b572c712ac52e8525783100704886!OpenDocument&TableRow=2.2#2.

[31] U.S. Environmental Protection Agency, *SAB Review of EPA's Accounting Framework for Biogenic CO2 Emissions from Stationary Sources*, EPA-SAB-12-011, September 28, 2012.

[32] Center for Biological Diversity v. Environmental Protection Agency (D.C. Cir. Case #11-1101 July 12, 2013).

[33] Ibid.

ED_000419-0005547

environmental, energy, and economic considerations and state and federal policies that promote biomass for energy-independence and environmental reasons. EPA provided guidance in early 2011 on how to consider the unique GHG attributes of biomass as fuel in the BACT selection process.[34] PSD permits require that facilities apply the BACT, but BACT is determined by individual states with EPA guidance on a case-by-case basis.[35]

State perspectives on the inclusion of emissions from biomass combustion in the tailoring rule are divided.[36] Some states contend that the inclusion of biomass combustion will lead to excessive permitting requirements and fees that jeopardize renewable energy development. Other states argue that not including biomass combustion will contribute to GHG emissions over time.

Advocates of not exempting biomass combustion from the tailoring rule assert that not all biomass is carbon neutral.[37] They point out that some types of biomass, particularly biomass coming from waste streams, settle closer to the carbon-neutral and carbon-negative side of the scale. However, they assert that cutting down trees from a forest to burn in a power plant without regard to replenishing the tree stand is carbon positive. Moreover, these advocates argue, fossil fuels are still used to farm, harvest, and transport the biomass for biopower purposes, potentially negating carbon neutrality over the life cycle.

Advocates of a complete biomass combustion exemption from the tailoring rule contend that biopower plant emissions add no new carbon to the atmosphere because biopower plants would use only residuals, byproducts, and thinnings, or waste materials that would decay.[38] Furthermore, they argue that CO_2 released during biomass combustion is carbon neutral because it is re-absorbed by growing biomass. Thus, they say, measuring the emissions released during biomass combustion does not capture the entire biomass emission portfolio.

These competing interests may continue to be concerned with the designation of biomass combustion as carbon neutral because of congressional discussions and proposals to expand the biomass definition in energy legislation. Expanding the biomass definition could increase the amount of land eligible for biomass removal.[39] The biomass definition in the Energy Independence and Security Act of 2007 (EISA, P.L. 110-140) for the Renewable Fuel Standard (RFS) excludes biomass removal from federal lands, and crops from forested lands are excluded as a biofuel feedstock.[40] However, the Food, Conservation, and Energy Act of 2008 (2008 farm bill, P.L. 110-246) includes biomass from federal lands as a biofuel feedstock. The RFS addresses the carbon balance issue of liquid transportation biofuels by requiring advanced biofuels to have

---

[34] U.S. Environmental Protection Agency, *Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production*, Washington, DC, March 2011, http://www.epa.gov/NSR/ghgdocs/bioenergyguidance.pdf.

[35] Environmental Protection Agency, *PSD and Title V Permitting Guidance For Greenhouse Gases*, November 2010, http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf.

[36] Energy Washington, *States Split on Whether Biomass Should Be Exempt from GHG Permits*, September 22, 2010.

[37] N. Greene, *Scientists to Congress & Obama: Count the Carbon in Biomass*, Natural Resources Defense Council, May 24, 2010, http://switchboard.nrdc.org/blogs/ngreene/scientists_to_congress_obama_c.html.

[38] Personal communication with B. Cleaves, CEO, Biomass Power Association, October 1, 2010.

[39] For more information, see CRS Report R40529, *Biomass: Comparison of Definitions in Legislation Through the 112th Congress*, by Kelsi Bracmort.

[40] The Renewable Fuel Standard (RFS) is a provision established by the Energy Policy Act of 2005 requiring gasoline to contain a minimum amount of fuel produced from renewable biomass. For more information on the RFS, see CRS Report R40155, *Renewable Fuel Standard (RFS): Overview and Issues*, by Randy Schnepf and Brent D. Yacobucci.

ED_000419-0005548

lower life cycle emissions relative to petroleum products. EPA was responsible for determining how the LCA would be carried out. The debate about how EPA should address the LCA, especially the land use component, was controversial.[41] While the RFS focuses on liquid transportation fuels, legislation was introduced in the 111th Congress to create a renewable electricity standard (RES).[42] If Congress debates an RES that includes biomass energy, many of the same biomass and thus carbon-neutrality concerns may emerge.

Manomet Biomass Study

The Biomass Sustainability and Carbon Policy Study by the Manomet Center for Conservation Sciences examined the use of forest biomass to generate energy for Massachusetts.[43] It studied the GHG impact of substituting one biomass feedstock type—forest biomass—for fossil fuels in the Massachusetts energy sector. More specifically, the study addressed three concerns: atmospheric GHG implications of forest biomass, forest biomass supply to support bioenergy development, and potential ecological impacts (including sustainability) associated with forest biomass harvests. Some of the study's conclusions for Massachusetts biomass include the following:[44]

- For conventional technologies, more GHGs are emitted per unit of energy produced from forest biomass than from fossil fuels.
- As a result of the excess emissions, referred to in the study as biomass "carbon debt," using forest biomass for energy initially can lead to increases in atmospheric GHG levels. However, the carbon debt is reduced as the harvested forest grows back, and at some point biomass energy yields benefits, or biomass "carbon dividends," in the form of lower GHG levels than fossil fuels.
- The time needed to pay off the carbon debt and accrue carbon dividends (or GHG benefits) can vary by decades. This timing is a function of the characteristics of the bioenergy combustion technology, the fossil fuel technology it replaces, and the biophysical and forest management characteristics of the forests from which the biomass is harvested.
- GHG benefits can be realized relatively quickly when only waste wood—for example, logging debris that would otherwise have been left in the forest—is burned for energy. But when using biomass from harvests of live trees that would otherwise have continued to grow, GHG benefits may only be realized after many decades. Due to their efficiency, small-scale thermal and combined heat and power technologies generally yield GHG benefits sooner than utility-scale biomass electricity plants. However, where biomass replaces natural gas, the time required to achieve GHG benefits can be very long—upwards of 100 years in some cases.

[41] For more information, see CRS Report R40460, *Calculation of Lifecycle Greenhouse Gas Emissions for the Renewable Fuel Standard (RFS)*, by Brent D. Yacobucci and Kelsi Bracmort.

[42] For more information on the renewable electricity standard debate, see CRS Report R40565, *Biomass Resources: The Southeastern United States and the Renewable Electricity Standard Debate*, by Richard J. Campbell.

[43] The Manomet Center for Conservation Sciences is a non-profit research organization that works to integrate society's social, economic, and environmental values to create sustainable systems for present and future generations.

[44] Personal communication with T. Walker, November 30, 2010.

ED_000419-0005549

- Sustainability issues are associated with forest biomass supply at the stand level (e.g., maintenance of soil productivity and biodiversity) and the landscape level (e.g., aesthetics, recreation, tourism, and long-term health of the wood-products sector).

The study's findings received considerable press attention, but a smaller spotlight was placed on the study's assumptions. Critics could argue that at least one prominent assumption renders the study irrelevant to current and future nationwide forest energy operations: the biomass feedstock type. The analysis was limited to one type of biomass—actively managed natural forests. The study found that woody biomass generated solely from logging debris (tops and branches) will contribute minimally to commercial-scale biomass facilities in Massachusetts, which "implies that the only way to meet demand would be to increase annual forest harvest." Critics might counter that throughout the United States, a range of biomass feedstocks are available for energy generation, many of which will have different greenhouse gas emission implications than actively managed natural forests.[45] The study stated "Our results for biomass from natural forests likely understate the benefits of biomass energy development relative to facilities that would rely primarily on these other wood feedstocks [tree care and landscaping sources, biomass from land clearing, and construction and demolition materials]." In some cases, if biomass feedstock types other than natural forest are used, such as woody matter that will decay, the GHG impact may be alleviated by removing material that would eventually decompose and release more potent greenhouse gases (e.g., methane). There are differing opinions on whether a single feedstock type will be the dominant feedstock for biopower, and which feedstock type (e.g., trees from natural forest, logging debris, dedicated energy crops) this could be. Assessment of national GHG implications of the various feedstock options is an area for further study.

Another study assumption that may not apply to the nationwide debate is the time required to pay off the carbon debt. GHG emission levels vary depending on the biopower pathway stage.[46] The Manomet Biomass Study compared GHG emissions per unit of energy produced by each technology for biomass, coal, oil, and natural gas. The comparisons include both direct combustion emissions as well as indirect emissions related to feedstock production, processing, and transportation. The study estimated that at the fuel combustion stage of utility-scale electricity generation, biomass emits significantly more GHGs relative to coal.[47] However, over time, biomass combustion for electricity reaches an equal cumulative GHG flux with that of fossil fuel technology (**Table 1**). Cumulative GHG emissions from biomass for electricity then level off at a rate significantly less than that of fossil fuels (**Figure 3**). Thus biomass combustion for electricity may not be the most effective method to immediately reduce GHG emissions in the short term, but may be a viable technique for GHG emission reduction over a long period. Lastly, other aspects of the study outside the scope of this report (e.g., conversion technology, biomass feedstock source, fossil fuel to be displaced) may require further examination if the findings are to be applied more broadly.

[45] For more information on the different kinds of biomass available for power generation, see CRS Report R41440, *Biomass Feedstocks for Biopower: Background and Selected Issues*, by Kelsi Bracmort.

[46] The various biopower pathway stages are explained in the "Greenhouse Gas Accounting for Biopower Production" section of this report.

[47] T. Walker, P. Cardellichio, and A. Colnes, et al., *Biomass Sustainability and Carbon Policy Study*, Manomet Center for Conservation Sciences, NCI-2010-03, June 2010, p. 103, http://www.manomet.org/sites/manomet.org/files/Manomet_Biomass_Report_Full_LoRez.pdf.

ED_000419-0005550

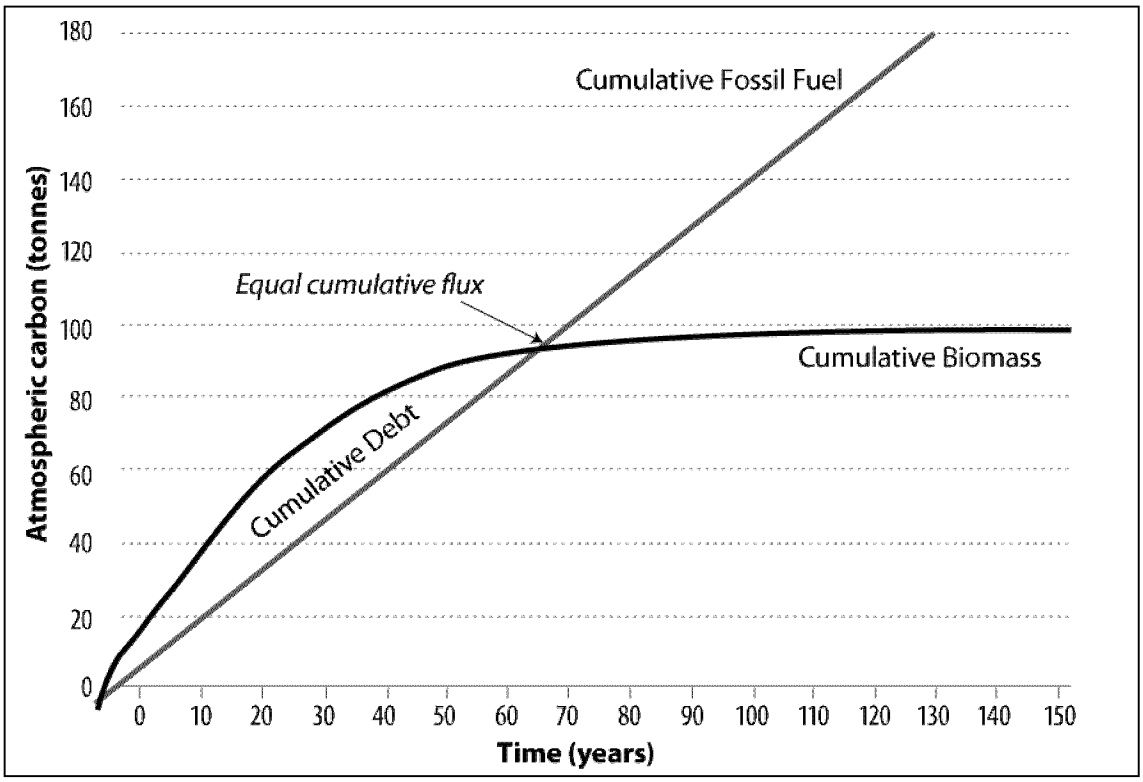
Table 1. Years to Achieve Equal Cumulative Flux with Fossil Fuels

Harvest Scenario	Fossil Fuel Technology			
	Oil (#6), Thermal	Coal, Electric	Gas, Thermal	Gas, Electric
Mixed Wood	15-30	45-75	60-90	>90
Logging Residues Only	<5	10	10	30

Source: T. Walker, "USDA Bioelectricity and GHG Workshop," Oral Presentation – "Manomet & Biomass: Moving Beyond the Soundbite," Washington, DC, November 15, 2010.

a. Cumulative flux is a tally of the emission and sequestration that occurs during the electricity pathway.

Figure 3. Cumulative GHG Flux for Biomass and Fossil Fuel



Source: T. Walker, "USDA Bioelectricity and GHG Workshop," oral presentation – "Manomet & Biomass: Moving Beyond the Soundbite," Washington, DC, November 15, 2010. Adapted by CRS.

Is Biopower Carbon Neutral? It Depends

Carbon neutrality for biopower is most accurately calculated based on the carbon flux (GHG emission or sequestration) of several parameters over a specified time period. These parameters include at least the following: (1) the feedstock type; (2) the management and procurement of the energy source (in the case of biomass, how the feedstock is managed and harvested); (3) the feedstock transportation method; (4) the energy generation technology; and (5) the timeframe to replenish the feedstock. Carbon flux attributed to the management and procurement of biomass feedstock deviates according to the type or mixture of feedstocks used. For instance, agricultural

ED_000419-0005551

biomass entails a different nutrient management plan than woody biomass. GHG emissions may be higher for agricultural biomass due to fertilizer treatments (e.g., nitrous oxide emissions from biofuel-dedicated crops).[48] Carbon flux will also vary given how the biomass feedstock is harvested. For example, removal of woody biomass (e.g., thinnings) in large quantities may reduce carbon, and some methane, emissions on a CO_2 equivalent basis that would have been released if the woody biomass had been left in the forest to decompose. Biomass feedstock transport emits differing amounts of GHGs depending on how far the feedstock must be transported and if fossil fuels are used.[49] The carbon flux of the biopower generation technology will depend on the type of technology and if the emissions are captured and sequestered.[50] Last, the time frame (e.g., 40 years, 100 years) assigned for biomass feedstock replenishment will determine CO_2 sequestration rates to balance out the GHGs emitted during biomass combustion, particularly for woody biomass, as growth periods (rotation ages for the trees) are often measured in decades.[51]

It could be argued that only an LCA for each biopower operation can truly determine whether biopower generation is carbon neutral. Such an LCA would measure carbon flux for each phase of the biopower pathway and incorporate biomass feedstock replenishment. A standard approach to perform a biopower LCA could ensure uniformity in GHG accounting across the biopower sector. However, multiple LCAs can be expensive and time-consuming to complete.

Biopower's carbon neutrality is a contentious aspect of the bioenergy debate. One reason the topic is so controversial is the concern about unsustainable harvests of biomass feedstocks. Some contend that if biopower proceeds with no carbon balance restrictions, large amounts of woody biomass, for example, will be removed for energy production. Another reason for controversy is concern about the air quality of areas surrounding biopower plants. These two concerns—sustainability and air quality—can be, and in some cases already are, addressed through other avenues (e.g., sustainability requirements, air quality regulations) at the federal and state level.

Legislative Implications

Biopower thus far has been included in legislation to provide energy independence and security, and under the premise that it is carbon neutral. Recent developments may prompt Congress to further analyze this premise. Carbon neutrality depends in part on the feedstock type, the technology, and the time frame for feedstock replenishment. Biopower can be created using multiple biomass feedstocks and technologies. Each feedstock and technology has its own environmental footprint. The time frame to analyze carbon neutrality is relevant because it incorporates feedstock replenishment, and thus CO_2 removal rates, and considers technology developments.

[48] When biomass used for biopower production is agricultural waste, some GHG emissions may be attributed to crop cultivation whereby the crop is used for other feed, fiber and fuel purposes.

[49] Some make the case that fuels (e.g., ethanol) other than fossil fuels (e.g., diesel or gasoline) may be used to transport the feedstock.

[50] There are no commercial carbon capture and sequestration(CCS) projects in operation at the moment. Therefore, CCS is not likely to impact carbon flux at the biopower generation stage in the near-term.

[51] For more information on carbon sequestration in trees, see CRS Report R40562, *U.S. Tree Planting for Carbon Sequestration*, by Ross W. Gorte.

ED_000419-0005552

To the extent carbon neutrality continues to be a legislative concern, Congress faces a determination of whether the current carbon neutral assumption for biopower is adequate, or if additional carbon accounting for biopower is warranted and what impact this accounting might have on renewable energy, agricultural, and environmental legislative goals, especially if decisions concerning biopower made by the executive branch contradict legislative goals set by Congress (e.g., RES). A scientific assessment of whether a biopower plant is carbon positive, carbon negative, or carbon neutral may require an analysis, such as an LCA. There are time and economic constraints in conducting an LCA for each biopower operation.

Congress could decide to use existing legislative authorities to address carbon accounting for biopower. Federal environmental regulatory controls exist for the three chief environmental concerns associated with a biopower plant—air quality, land use, and water discharges. GHG emissions may be accounted for with federal regulations regarding air quality. In addition, a biopower plant also has to meet state regulatory standards, which in some cases may be stricter than the federal regulatory controls.

A full carbon accounting for biopower may result in slowing the achievement of multiple renewable energy, agricultural and environmental goals. Alternatively, the carbon neutrality debate for biopower may lead to requests for carbon accounting of some or all energy ventures—renewable and conventional. Lastly, an ill-defined carbon accounting assessment for biopower may limit public and private investment, feedstock production, and more. Scientists, investors, biomass producers, and others may hesitate to expend time and money on expanding biopower efforts if they are not provided certainty about the future contribution of biopower to U.S. energy and environmental goals.

If Congress chooses to address energy security and GHG emission increases, some have argued that these goals could be met through the creation of a national RES or a clean electricity standard (CES). The mandate of a potential national RES or CES may require substantial quantities of baseload power which some see as achieved by using biopower. If biopower is a part of an RES or CES, and if Congress continues its ongoing debate about some farm bill energy programs, the carbon neutrality designation of biopower may need to be reconsidered in response to environmental and sustainability concerns.

Author Contact Information

Kelsi Bracmort
Specialist in Agricultural Conservation and Natural Resources Policy
kbracmort@crs.loc.gov, 7-7283

ED_000419-0005553

From:	Adamantiades, Mikhail
To:	Dunham, Sarah
CC:	Krieger, Jackie; Harvey, Reid; Haeuber, Richard; Friedman, Kristina; Mulholland, Denise
Sent:	12/22/2014 3:39:28 PM
Subject:	RE: 111d comments
Attachments:	Clean Energy Group Comments_GHG 111d_Final Dec 1.docx; ECOS 111d Comment Letter FINAL 12_1_14.pdf; Exelon_EPA-HQ-OAR-2013-0602-23155-A1.pdf; NARUC Letter to McCarthy on 111d guidelines1.pdf; NRDC Comments_air_14120101a.pdf; RGGI 111d Supplemental Comments_FINAL.pdf; RGGI_EPA-HQ-OAR-2013-0602-22395-A2.pdf; UARG Section 111(d) Comments.pdf; Xcel_EPA-HQ-OAR-2013-0602-22748-A1.pdf

Here they are, I have included a holiday bonus item – UARG.

Misha

From: Haeuber, Richard
Sent: Monday, December 22, 2014 3:14 PM
To: Dunham, Sarah; Friedman, Kristina; Mulholland, Denise; Adamantiades, Mikhail
Cc: Krieger, Jackie; Harvey, Reid
Subject: RE: 111d comments

Sarah – Misha is here, so I've asked him to work on this for us. I'm not sure how the comments are organized, so he'll reach out to folks in other places (e.g., Denise in CPPD), it that's necessary.

Richard Haeuber, Ph.D.
Chief, Assessment and Communications Branch
Clean Air Markets Division, Office of Atmospheric Programs
USEPA
202-343-9250

From: Dunham, Sarah
Sent: Monday, December 22, 2014 3:04 PM
To: Haeuber, Richard; Friedman, Kristina; Mulholland, Denise
Cc: Krieger, Jackie
Subject: 111d comments

I'm not sure who is in, but if anyone is in who can easily get me an electronic copy of the following 111d comments, I'd appreciate it:

- ECOS
- RGGI
- NARUC
- NRDC
- Exelon
- Xcel
- Clean Energy Group

The
Clean
Energy
Group

Michael Bradley
Director
The Clean Energy Group
47 Junction Square Drive
Concord, MA 01742
978-369-5533
978-369-7712

December 1, 2014

Docket ID No. EPA-HQ-OAR-2013-0602
Environmental Protection Agency
EPA Docket Center (EPA/DC), Mailcode 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
(submitted via regulations.gov)

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

To Whom it May Concern:

The Clean Energy Group appreciates the opportunity to comment on EPA's proposal for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.[1]

Draft and Confidential

In his remarks on climate change on June 25, 2013, President Obama said that he was willing to work with anyone on a "bipartisan, market-based solution to climate change" but in the absence of Congressional action, he was directing EPA to move forward with rules for power plants under the Clean Air Act (CAA). In this context, the members of the Clean Energy Group continue to support EPA's authority to regulate greenhouse gases (GHGs) under the CAA. We are committed to working constructively with EPA and other stakeholders on policies that encourage the reduction of GHG emissions from the electric generating sector.

We support the proposed rule's overall objective of achieving meaningful emission reductions from existing power plants and encouraging investment in a clean energy future, and these technical comments are offered for the purpose of constructively supporting that objective.

We agree with EPA that meaningful emission reductions can be achieved from the electric sector while maintaining electric system reliability. While the national emission reductions that are estimated to result from the proposed rule are achievable, these comments include recommended changes to the building blocks, underlying assumptions, and key aspects of the proposed rule to ensure that the final state targets can be reasonably achieved by states given the flexibilities states have under section 111(d). Thus, these recommended changes are essential to ensure the final rule is based on sound technical assumptions, which in turn will result in greater regulatory

[1] Entergy Corporation, a Clean Energy Group member, is supportive of the important dialogue that the Clean Energy Group provides for its member companies and with EPA and other regulators. However, Entergy holds positions different from those stated herein on many of the issues discussed in this letter and, therefore, does not join in filing these Clean Energy Group comments.

certainty for investment decisions.

As EPA notes in the proposed rule, the electric grid is interconnected and changing one element of the system will affect the remaining components. It is important for EPA to consider the interaction among the four Building Blocks to ensure the final rule can be implemented in a cost-effective way while maintaining electric system reliability. This is particularly important in light of some of the potential changes to the proposal on which EPA asks for comment in the notice of data availability (NODA) published on October 30, 2014.

In separate letters to EPA, member companies may offer comments on the legal framework of the rule and on additional issues raised in the proposed rule. This letter assumes EPA plans to finalize a rule that is largely consistent with the proposed building block structure and offers comments on the assumptions underlying individual building blocks, the methodology EPA uses to calculate the state goals, and flexibilities available to states for development, implementation, and enforcement of state plans.

We look forward to working with EPA, Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), and the states as they take advantage of the flexibilities available under section 111(d) to ensure a reliable electric system while achieving significant carbon reductions.

I. Building Block 1: Heat Rate Improvements

In Building Block 1, EPA proposes that owners and operators of existing coal-fired steam electric generating units (EGUs) can reduce the carbon intensity of generation through heat rate improvements. EPA identifies two types of heat rate improvements: those achieved through use of best practices and those achieved through equipment upgrades. Based on a statistical analysis and a review of the technical literature, EPA proposes that it is reasonable to estimate that a six percent heat rate improvement is available across the existing fleet of coal-fired steam EGUs.

Draft and Confidential

Members of the Clean Energy Group view Building Block 1 as a foundational building block, and it will be important for the language in the final rule to incorporate the feedback plant owners and operators, including individual members of the Clean Energy Group, as well as independent experts provide on the technical feasibility of a six percent heat rate improvement across the coal fleet. In general, we are concerned that the proposed six percent improvement based on heat rate improvements may not recognize existing financial incentives to continually improve efficiency and reduce fuel costs, which could limit the ability of a unit to implement an additional six percent improvement. However, we acknowledge that not all companies have implemented heat rate improvements and for some, there is a tension between making efficiency improvements and a reluctance to trigger new source review. While EPA acknowledges this tension, it is a long-standing deterrent for many efficiency investments, and we urge EPA to evaluate regulatory approaches that encourage these improvements.

In addition to the specific concerns individual members may submit on the technical basis for the six percent heat rate improvement, we are also concerned about the equal application of the heat rate improvement factor to all states without recognition of investments firms may have recently made to improve the heat rate of existing coal-fired fleets. In a number of states where member companies operate, investments have been made to improve the heat rate of some units. EPA could provide a mechanism to recognize recent investments that have resulted in improved power plant efficiency. To that end, we would support a standardized process for states to

demonstrate that owners or operators of specific, in-state units have made recent investments that resulted in clear efficiency improvements within a timeframe defined by EPA. If states were to make such a public demonstration, EPA would adjust the assumed availability of heat rate improvements in that state.

Within its statistical analysis of the potential for heat rate improvement through the deployment of best practices, EPA highlights that hourly ambient temperature and capacity factor together explain 26 percent of the change in heat rate for the study population.[2] However, EPA also notes that there is considerable variability within the sample set and that at some EGUs, typically load-following EGUs, capacity factor explains more than 50 percent of the change in heat rate.[3] Adding the 10 percent associated with temperature to the 50 percent associated with capacity factor suggests that among load-following units capacity factor and temperature explain more than 60 percent of the change in heat rate. As a result, if a state were to make a showing that the majority of in-state coal units operate as load-following units, EPA could consider that that the state will have less opportunity to make heat rate improvements across the fleet. EPA should also consider that the increased dispatch of NGCC resulting from this rule will affect the way coal units operate. This outcome will increase the number of load-following units, and there may be fewer opportunities to improve fleet heat rate.

In the proposed rule and again in the October 30th NODA, EPA asks for comment on co-firing natural gas in a coal boiler. As EPA notes in the NODA, a number of power companies, including members of the Clean Energy Group, currently co-fire natural gas in coal boilers or have made announcements to invest in co-firing capabilities at coal-fired power plants. Co-firing lowers the GHG profile of units and also reduce emissions of nitrogen dioxide (NOx), sulfur dioxide (SO_2), and mercury, providing additional flexibility as companies look to address other CAA requirements. We encourage EPA to consider the information it receives during the comment period, including additional details on existing co-firing projects, before finalizing the rule. As noted throughout the proposed rule, EPA's consideration of a specific component of BSER or inclusion of a technology as part of a building block does not require a state to implement that measure. Thus, assuming a level of co-firing does not require any state to impose such a requirement. Some member companies encourage EPA to evaluate whether it is reasonable to assume that it is cost-effective for at least some coal-fired EGUs to co-fire with natural gas.

Draft for Comments

Finally, we support EPA's proposal that BSER should include heat rate improvements only at coal-fired steam EGUs, not at other EGU types. We agree with EPA's finding that "the total additional potential reduction [associated with requiring heat rate improvements at oil/gas steam EGUs and combustion turbines] is small compared to the potential coal-steam CO_2 reduction."[4] Further, we agree with EPA's conclusion for NGCC EGUs that "[r]egularly scheduled maintenance practices are the most effective heat rate improvement methods that can be applied on NGCCs" and that they are "likely already being applied across most of the NGCC fleet."[5]

---

[2] Technical Support Document: GHG Abatement Measures *available at:* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

[3] Id.

[4] Technical Support Document: GHG Abatement Measures at Appendix at A-6.

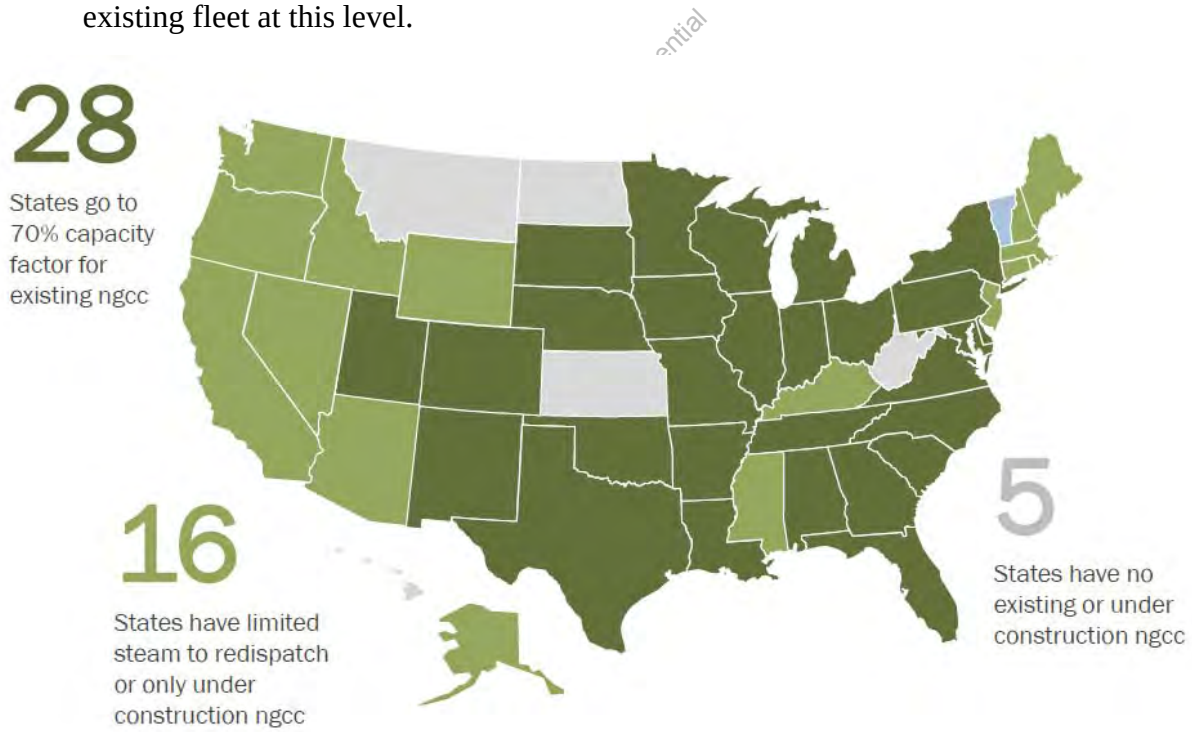
[5] Technical Support Document: GHG Abatement Measures at Appendix at A-5.

II. Building Block 2: Increased Utilization of Existing NGCC

Building Block 2 is based on the redispatch of affected EGUs—specifically, the increased utilization of existing and under construction natural gas combined cycle (NGCC) units to displace higher emitting fossil steam units (coal, oil, and natural gas). EPA based the proposed state goals on state-specific NGCC fleets achieving up to a 70 percent average annual capacity factor by 2020 (Option 1).[6] EPA also asks for comment on an alternative approach, based on a 65 percent average capacity factor (Option 2). EPA assumes that by displacing higher-carbon intensity EGUs with lower-carbon intensity EGUs, overall CO_2 emissions are reduced.

Figure 1 groups the states in terms of the impact of Building Block 2 on NGCC utilization using the 2012 data EPA used to develop the proposed state emission goals (updates to EPA's underlying data on existing or under construction NGCC units may alter these results):

- Five states have no existing or under construction NGCC capacity, as a result, Building Block 2 has no effect on their proposed standards.[7]
- Sixteen states have limited steam capacity to displace or only under construction NGCC; therefore, the building block is only partially implemented.[8] The average 2012 NGCC capacity factors in such states range from 30 to 65 percent.
- Twenty-eight states are assumed to be capable of increasing their existing NGCC utilization to a 70 percent average capacity factor. However, EPA's modeling of the proposed rule shows that the majority of states are not anticipated to operate their existing fleet at this level.



[6] However, few states approach this level of dispatch in EPA's modeling of compliance with the proposed rule.

[7] Hawaii, Montana, Nebraska, North Dakota, and West Virginia.

[8] Alaska, Arizona, California, Connecticut, Idaho, Kentucky, Rhode Island, Maine, Massachusetts, Mississippi, New Hampshire, New Jersey, Nevada, Oregon, Washington, and Wyoming.

Figure 1. Impact of Proposed Building Block 2 on the NGCC Utilization Assumptions by State

In general, the Clean Energy Group agrees with EPA that significant CO_2 reductions are available by re-dispatching the electric generating fleet. To some extent, the system has already demonstrated the viability of this approach. In 2012, NGCC facilities in the U.S. increased their annual capacity factors to an average of 51.1 percent (from 43.6 percent in 2011) and coal-fired EGUs reduced their annual capacity factors to an average of 56.7 percent (from 63.7 percent in 2011), according to the Energy Information Administration's (EIA's) *Electric Power Monthly*. As a result, electric sector CO_2 emissions were at their lowest level since 1996. However, this shift in utilization was not consistent across all states, and there are operational considerations that the Clean Energy Group believes should be reflected in the standard setting calculations, as discussed in more detail below.

The Clean Energy Group believes that most NGCC facilities have the technical capability to operate at an average annual capacity factor of 65 or 70 percent. In fact, several plants owned by member companies have operated above these levels for extended periods of time. For example, as noted by EPA in its analysis supporting the rule,[9] the following power plants owned or operated by Clean Energy Group members had annual capacity factors in excess of 70 percent in 2012:

- Calpine's Pine Bluff Energy Center, a 184-MW NGCC power plant in Pine Bluff, AR;
- Calpine's Deer Park Energy Center, a 1,103-MW NGCC power plant in Deer Park, TX;
- Calpine's York Energy Center, a 519-MW NGCC power plant in York County, PA;
- New York Power Authority's Richard M. Flynn Power Plant, a 164-MW NGCC power plant in Holtsville, NY; and
- Tenaska's Central Alabama Generating Station, a 885-MW NGCC power plant in Autauga County, AL.

Draft and Confidential

Whether the system as a whole can operate with most states' NGCC fleets averaging this utilization level by the early part of the compliance period (as implied by the goal computation) is less clear. While many states would be able to rapidly increase the utilization of existing NGCC facilities, others may require additional time because of infrastructure constraints, characteristics of existing in-state generation facilities, or because of their load centers' locations in the electric or gas transmission system. Procuring adequate natural gas supplies to sustain a high level of utilization year round could mean, in the case of some states, building new pipelines or increasing the capacity of existing ones.[10] For others, getting the electricity to consumers currently served by steam units without expanding transmission may be a challenge.

[9] Supporting & Related Material: 2012 NGCC Plant Capacity Factor, *available at:* www regulations.gov, Docket #EPA-HQ-OAR-2013-0602-0250.

[10] For example, in New Jersey, the BL England facility continues to operate on coal and oil despite a 2006 consent decree to repower the facility. Unit 2 was originally scheduled to shutdown in 2015 and the owner planned to complete construction of a new NGCC unit in 2016. However, Units 2 (coal-fired EGU) and 3 (oil-fired EGU) remain in operation because a natural gas pipeline must be built to deliver natural gas to the facility, and the conservation commission for the area through which the pipeline was to be built, rejected the project in January 2014. The plant owners subsequently submitted a generation deactivation request to PJM for Units 2 and 3; however, the owners withdrew the request after PJM identified reliability concerns. PJM determined that closure would require significant transmission upgrades that may take several years to complete. The New Jersey Department of Environmental Protection (NJDEP) extended the retirement requirement for Unit 2 to mid-2017. The amended consent order allows for an extension beyond 2017 if the New Jersey Board of Public Utilities (NJBPU) or

[11]

Based on these types of uncertainties, we recommend that EPA establish a more strategic approach to Building Block 2. While we agree with EPA's conclusion that, over time, existing fleets have the technical capability of reaching a 70 percent capacity factor and we agree with EPA's finding that states could comply with the emission guidelines without increasing NGCC utilization to 70 percent, we would support changes to the rate at which Building Block 2 is deployed as part of the goal-setting process. As much as the shift EPA has proposed as a part of Building Block 2 is about increasing NGCC utilization, it is also about decreasing boiler steam generation and replacing the services that boiler steam capacity currently provides to the grid.

Specifically, we recommend the following suite of adjustments to EPA's Building Block 2 calculation. Note that we support these three changes as a package because each addresses a distinct area of concern; we would not support adopting one or two and not the other(s).[12] We think it is important that EPA maintain the interim targets to ensure that states achieve emission reductions across the compliance period and not delay emission reduction programs to the latter half of the decade. However, we also think it is important to establish more of a "glide path" from where states are today to the final goals in 2030. Each of these changes is described in more detail below:

- First, we recommend that, in developing the proposed state targets, EPA assume a ramping to a 70 percent NGCC fleet capacity factor in order to provide states with additional flexibility to make sure the infrastructure necessary to support this level of utilization is in place or to increase the use of other compliance strategies.
- Second, we recommend that 2012 generation from affected oil/gas steam units be excluded from the goal computation since oil/gas steam units serve a different segment of the dispatch curve and are often used as a backup to coal and natural gas baseload generating facilities, as opposed to a replacement for those facilities.
- Third, we recommend that EPA retain 10% to 12% of coal steam MWhs in the state goal computation.

Draft and Confidential

In terms of the ramp rate, Clean Energy Group members are concerned that EPA's proposed methodology for calculating the NGCC contribution to the interim goals would reduce the flexibility EPA intended to provide.[13] The final proposed goal is calculated based on the following formula:

PJM determine that additional time is necessary to avoid reliability issues. To date, the potential closure/repowering of this facility has been ongoing for eight years and is expected to continue.

[11] For example, in 2007, PJM approved the Susquehanna-Roseland Electric Reliability Project (Project) for inclusion in its Regional Transmission Expansion Plan (RTEP) as a necessary project to address reliability issues in the constrained northern New Jersey area. The Project required approvals for the following: Board of Public Utilities, Freshwater Wetlands Permits/Flood Hazard Area Permits, National Park Service (NPS), Picatinny Arsenal, and required land use agreements. The original in-service date was scheduled for 2012; however, commencement of construction was delayed by three years due to an Environmental Impact Study. In total, the Project will have taken eight years from PJM approval to complete.

[12]

[13] Technical Support Document: GHG Abatement Measures at 3-16 (For example, EPA states, that: "[t]his rule provides for flexible implementation that will permit efficient scheduling of infrastructure upgrades as needed.").

For each year during the interim period, 2020 through 2029, EPA repeats the above procedure to calculate annual rates. The final goal in 2030 is the annual rate calculated for the year 2029, whereas the interim goal is the simple average of all the annual rates.

In using the above formula to determine the final goal and interim year annual rates, EPA assumes increasing renewable energy and energy efficiency levels between 2020 and 2029 to reflect the gradual movement of states toward regional benchmarks. Because of the way the goal computation formula is structured, ramping up renewable energy and energy efficiency levels progressively lowers the annual rates starting in 2020 and reaching the final goal in 2029.

By contrast, the two other building blocks, coal plant efficiency improvement and increased utilization of NGCC capacity (highlighted in bold in the formula above—*BB1 and BB2 Reductions*) have no impact on annual rates between 2020 and 2029. Their impact on annual rates is muted during the interim period because the goal computation formula raises efficiency levels of coal plants and utilization of NGCC facilities to their final target levels in 2020. By doing so, EPA implicitly assumes that all emission rate reductions associated with Building Blocks 1 and 2 under the proposed rule happen before 2020, the start of the interim period.

Draft and Confidential

Because Building Blocks 1 and 2 account for over 40 percent of the total proposed reduction under the rule—more in the case of states with low levels of renewable energy and energy efficiency, front loading the emission rate trajectory causes the rates used to calculate the interim goals to be sharply lower in 2020 than the 2012 baseline, with little change thereafter between 2020 and 2029. For example, the proposed annual rate trajectories for Arizona and Minnesota suggest that over 80 percent of the rate reductions would be reflected in the calculated 2020 emission rate. On average, across all states, two-thirds of all proposed reductions are reflected in the calculated 2020 emission rate, with the remainder spread over the period 2020-2029.

We recommend that EPA assign to each state a specific annual increase that is calculated based on the difference between 70 percent and the state's actual average annual NGCC capacity factor in 2012. (In 2012, natural gas prices were relatively low, so NGCC utilization rates were relatively high.) EPA could take a range of approaches to introducing NGCC to the goal setting equation. To be consistent with the proposed approaches to renewable energy and energy efficiency, EPA could start increasing NGCC from 2012 levels in 2017 to the 70 percent target in 2029. Alternatively, EPA could consider reaching the 70 percent level in 2025. We would expect that EPA would arrive at a ramping rate that considers the potential permitting and system constraints described above.

The other two changes that we recommend to Building Block 2 are similar in terms of justification and implementation. Oil/gas steam units serve a different segment of the dispatch curve and are often used as a backup to coal and natural gas baseload generating facilities. In 2012, NGCC capacity factors increased significantly and coal steam utilization rates declined. However, as shown in Figure 2, the average utilization of natural gas and oil steam units was virtually unchanged between 2011 and 2012, demonstrating that utilization rates of oil/gas steam units do not correlate with NGCC capacity factors.

According to EPA's eGrid database, we determined that fossil steam units with capacity factors of 40 percent or less accounted for 12.3 percent of total fossil steam MWhs in 2012. Based on this analysis, we recommend that EPA preserve at least 10 percent to 12 percent of coal steam generation in calculating the state goals. These lower capacity factor units tend to be used for peak demand periods and to maintain grid stability. As a result, we do not think they should be included in the redispatch analysis.

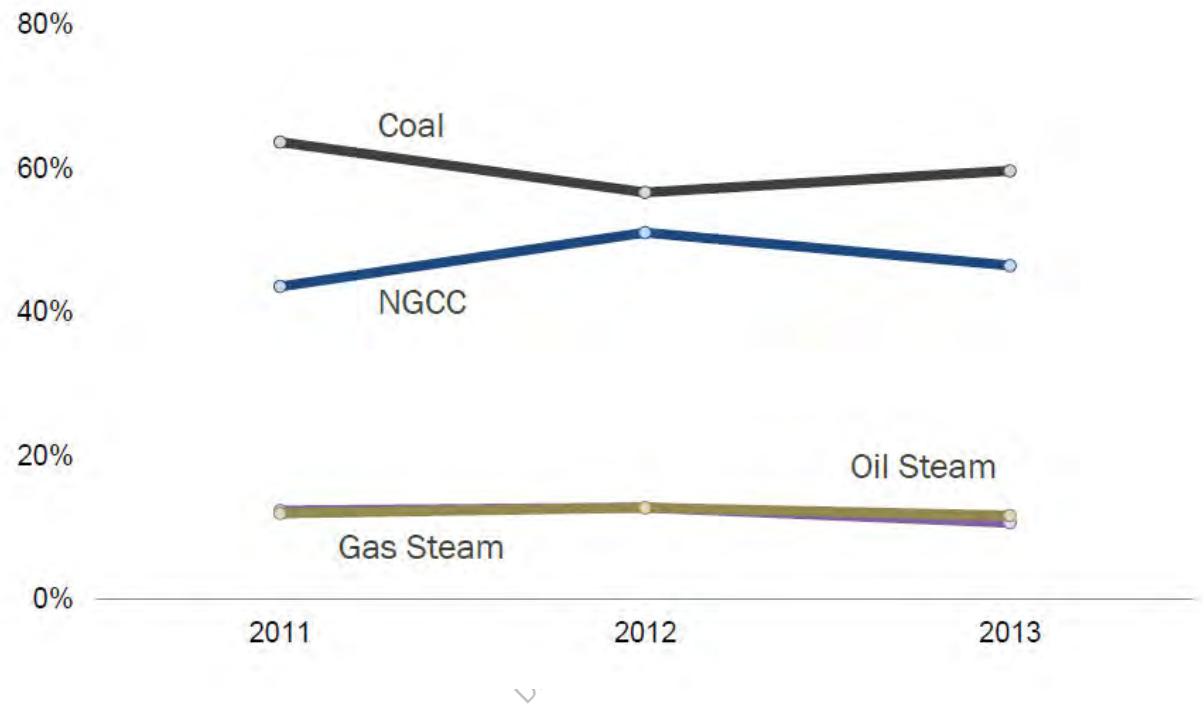


Figure 2. Average Capacity Factors for EGUs by Fuel Type; 2011-2013 (Source: EIA Electric Power Monthly Table 6.7.A.)

To implement these changes, EPA could treat affected 2012 oil/gas steam MWhs and a minimum share of affected 2012 coal steam MWhs (we recommend 10 percent to 12 percent) like it does "Other Generation" in the redispatch analysis, meaning not subject to NGCC redispatch. The sources responsible for this generation would continue to be affected sources subject to the standard. By excluding this generation from the NGCC redispatch, EPA would avoid situations where the redispatch would assume elimination of 100 percent of boiler steam MWhs in the state goal computation. Under EPA's proposed approach (Option 1), there are 12 states where all coal and oil/gas boiler steam generation is assumed eliminated from the goal computation.[14] The proposed change would preserve an element of fuel diversity that we believe is important to capture in the goal computation.

III. Building Block 3: Zero Emitting Generation

In Building Block 3, EPA evaluates the potential for states to deploy or maintain zero emitting generation. Zero emitting generation includes renewable energy and nuclear energy.

Renewable Energy

[14] These states include: Alaska, Arizona, California, Connecticut, Maine, Massachusetts, Mississippi, Nevada, New Hampshire, New Jersey, Oregon, and Washington.

The Clean Energy Group prefers EPA's alternative approach to quantification of potential renewable energy generation over the proposed policy-based approach. EPA's proposed policy-based approach, which groups states into regions and averages the effective 2020 generation-based Renewable Portfolio Standards (RPSs) for states in each region to arrive at individual state goals, results in arbitrary state renewable targets based on political considerations rather than technical availability. For example, only one state in the Southeast has a qualifying RPS (North Carolina) and that single state policy results in EPA assuming all eight states in the EPA-defined Southeast region can meet the same target. It is unclear why one state's policy implies that other states can meet the same level of renewable deployment. Conversely, a lack of an RPS does not indicate a state could not deploy renewable generation.

We also disagree with EPA's conclusion that existing state policies "support the feasibility and costs" associated with the scenarios developed by EPA. Rather, it is our view that the existing state policies reflect policy decisions made in the states with the RPSs based on the myriad objectives of the state (which may not be the same as EPA's objective here; *e.g*. carbon reduction) and the projected cost and availability of renewable energy at the time the state targets were passed. In some states, costs are moderated with alternative compliance payment provisions that limit the need for renewable generation if costs exceed expectations. Many state RPS targets were also predicated on the existence of a national market for renewable energy credits to limit costs and increase availability of qualifying resources, which include many resources not considered for compliance under the proposed rule, such as large hydropower. And, while EPA refers to that market, it does not use the market to justify the target renewable energy levels.

Graham Confidential

Thus, the Clean Energy Group prefers the alternative approach to quantification of renewable energy generation that EPA describes in the preamble to the proposed rule and in a separate technical support document.[15] By relying on a state-by-state assessment of the technical and market potential for renewable energy, the alternative approach provides a perspective that aligns with the state-by-state goal setting process that EPA is undertaking. If EPA were to finalize the alternative approach, we would encourage EPA to look at options for updating the underlying technical assessment of renewable energy and to include state-specific data for all states. The renewable energy sector is a rapidly advancing sector, and the National Renewable Energy Laboratory assessment on which EPA relies for the alternative approach, while rigorous, does not reflect the advances that have been made since its publication. We would further recommend that any update to the renewable energy assessment be accompanied by a review of the economic assumptions EPA used in the IPM model runs conducted in support of the alternative approach.

If EPA were to finalize the proposed RPS-based approach to the renewable energy component of Building Block 3, it should review its methodology to ensure the measures used to develop the state targets are consistent with the measures allowed for compliance. For example, in some states existing hydropower resources, which EPA proposes to exclude from its assessment of 2012 renewable generation and from use in compliance plans, are eligible for compliance with renewable standards. If EPA retains its treatment of existing hydropower, EPA should adjust the RPS levels to exclude the associated generation from hydropower. Additionally, in North

[15] Technical Support Document: Alternative RE Approach, *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-alternative-re-approach.pdf.

Carolina (the basis for the Southeast region target), utilities can demonstrate compliance using energy efficiency measures.[16] Consistent identification of what is and is not a qualifying resource will be important and may be a difficult task if EPA retains an RPS-based approach for setting Building Block 3 targets.

Additionally, EPA should also review its conclusions for the South Central region under an RPS-based approach. It is our understanding that, when calculating the regional averages, EPA did not include capacity-based RPS targets. However, in the South Central region, EPA based the regional renewable energy goal on the Kansas RPS, which is capacity-based. Without the Kansas renewable goal, there are no states with qualifying RPS programs in the South Central region. Instead of a 20 percent regional goal, the target for the South Central region should be either zero percent (if EPA were to follow its existing methodology) or 10 percent (if EPA were to follow its methodology for Hawaii and Alaska).

Separate from EPA's methodology for determining state goals, we agree with EPA's assertion that "existing markets for renewable energy certificates, which facilitate investment in renewable energy, are already well-established."[17] Clean Energy Group members participate in renewable energy markets and have confidence in existing protocols and contractual mechanisms. EPA should issue guidance that clarifies that compliance credit under 111(d) follows the purchaser of the environmental attributes of a renewable (or zero-carbon) energy credit unless otherwise specified in contract or state law. To the extent states use these existing tools, EPA's guidance should describe how states can avoid double counting emission reductions.

Draft and Confidential

We urge EPA to support the development of credit markets for 111(d) compliance. Such markets should function similar to existing REC markets, which verify and track credits to avoid double counting, and states may elect to utilize the existing REC market as a component of their compliance plans to the extent that RECs have equivalent attributes. We recommend that EPA issue guidance for state plans that clarifies the use of compliance markets as a part of state plans. For example, we expect that some states may be interested in submitting partial joint plans that reference the use of a national 111(d) energy credit for compliance without entering into memoranda of understandings with each state that might be a generator or purchaser of renewable energy credits, and EPA should ensure it does not create a barrier for this compliance option. If requested by states, EPA may also want to consider developing a national tracking system for 111(d) compliance credits to facilitate this multi-state dynamic.

Finally, the Clean Energy Group sees the option for states to coordinate compliance as a means to mitigate the different treatment that results by using a state-by-state assessment of the technical and market potential for renewable energy to establish the state goals and by using RECs to demonstrate compliance. We discuss the benefits of multi-state compliance mechanisms further below.

Nuclear

Nuclear power produces about 20 percent of U.S. electricity without emitting CO_2. According to EIA, it made up more than 60 percent of zero-carbon electricity sources in 2013. Without

[16] North Carolina: Incentives/Policies for Renewables & Efficiency, Database of State Incentives for Renewable & Efficiency (DSIRE), *available at*: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC09R.

[17] 79 Fed. Reg. at 34883

nuclear, carbon emissions will be higher, as will the cost of carbon allowances under any meaningful carbon control program. Simply put, nuclear power is a critical zero-carbon resource that Clean Energy Group members believe must be part of the portfolio of electric sector resources if the United States is going to meet the climate targets set out by President Obama. Without nuclear power plants operating in 31 states, carbon emissions from the U.S. electric sector would be approximately 25 percent higher.

Independent analyses of the climate change issue show that nuclear energy must be part of the portfolio of resources that helps drive carbon reductions. For example, the Intergovernmental Panel on Climate Change's report on climate change mitigation released in April 2014 found that nuclear is one of the central options to reducing the costs of mitigating climate change.[18] Further, in November 2013, four leading climate scientist published an open letter stressing the daunting challenge presented by climate change and the need for nuclear power to play a role.[19]

Moreover, nuclear facilities are critical to the reliability of the electric grid because they operate continuously and are available under a wide range of weather conditions. To cite one example: the deep freeze brought on by the polar vortex in January 2014 resulted in more than 35,000 megawatts of outages, and during this time nuclear units accounted for only three percent of forced outages despite making up 12 percent of total capacity that operated at 90 percent capacity through the polar vortex event.

EPA has correctly acknowledged that despite generating large amounts of clean energy and playing a vital role in grid reliability, nuclear facilities across the country are at risk of premature retirement. EPA recognized this threat in the Proposed Rule, stating that "a host of factors – increasing fixed operation and maintenance costs, relatively low wholesale electricity prices, and additional capital investment associated with ensuring plant security and emergency preparedness – have altered the outlook for the U.S. nuclear fleet in recent years."[20] A key reason is the absence of a carbon policy that would value the carbon-free electricity that nuclear plants produce, thereby avoiding emissions from fossil-fired plants. Member companies will submit individual comments that address their perspectives on how best to preserve the existing nuclear fleet.

Draft - not confidential

IV. [21]Building Block 4: Energy Efficiency

Building Block 4 is based on a state-by-state forecast of increased demand-side energy efficiency. We do not offer comment on EPA's proposed savings target or calculation methodology; however, we do offer comment on EPA's approach to evaluation, measurement, and verification (EM&V).

In the preamble of the rule, EPA indicates that it plans to develop guidance for the EM&V of

---

[18] Intergovernmental Panel on Climate Change, Working Group III – Mitigation of Climate Change, Technical Summary, *available at:* http://www.ipcc.ch/report/ar5/wg3/.

[19] Revkin, Andrew C., "Nuclear Power 'To Those Influencing Environmental Policy But Opposed to Nuclear Power'", Open letter by Dr. Ken Calderia, Dr. Kerry Emanuel, Dr. James Hansen, Dr. Tom Wigley, as published on *The New York Times* Dot Earth Blog, November 3, 2013, *available at: http://dotearth.blogs.nytimes.com/2013/11/03/to-those-influencing-environmental-policy-but-opposed-to-nuclear-power/?_r=1*.

[20] 79 Fed. Reg. at 34,871.

[21]

renewable energy and demand-side energy efficiency programs incorporated in state plans. In developing this guidance, we strongly encourage EPA to focus on the development of high-level guidelines, rather than specifying a detailed and prescriptive set of analytical methods and protocols. Rather, EPA's guidelines should reference existing EM&V programs that provide robust measurement and verification to guide states that do not yet have programs. Some of the leading programs that EPA could reference in the guidance include programs in Massachusetts, Rhode Island, New York, New Jersey, Pennsylvania, Illinois, and California. We recommend high-level guidelines for several reasons. First, it would be extremely challenging to develop detailed guidelines in the time available to the Agency. Existing state EM&V programs have been developed and refined over many years, based on extensive stakeholder engagement and feedback. Second, high-level guidance would allow states to continue relying on established EM&V programs, avoiding the burden that would result from creating a new set of program requirements. State EM&V programs would be reviewed as part of the state plan approval process to confirm that they are consistent with EPA's guidance.

One issue that we think should be clarified in the guidelines is the metric used for compliance determinations. Specifically, we recommend that the guidelines require the use of "gross" verified savings (or evaluated gross savings) to standardize the metric used for claimed energy savings across all states. This avoids the added complexity that comes from measuring net energy savings. Further, utility companies, regardless of whether they report net or gross savings for state program compliance, would all have the data compiled on gross energy savings.

Draft and Confidential

Also, we strongly recommend that EPA not limit the types of demand-side energy efficiency programs or policies that states can incorporate in their plans, given the savings goals inherent in the goal computation formula. We also recommend that EPA not penalize net importers of electricity by discounting their energy efficiency programs. The EM&V protocols adopted for 111(d) compliance should include the full range of energy efficiency programs and measures being employed by states; for example, new and innovative behavioral programs and whole building programs are initiatives that will be important for states to achieve their energy savings goals. EPA's EM&V guidelines should allow the use of traditional incentive programs, behavioral methods, and credit for codes and standards. For example, utility companies will conduct training clinics to improve compliance with buildings codes and standards. Rhode Island, for example, provides credit for these types of programs. Savings can also be estimated when a state or local community goes beyond the existing code and standards.

As EPA develops its guidance, we would also encourage the Agency to consider incorporating a so-called "weight-of-evidence" (WOE) pathway, like EPA has done for criteria air pollutants. EPA's "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix H: Weight of Evidence Pathway" provides guidance to states on a WOE approach for EE and RE policies. A similar approach could be applied in the 111(d) context where energy saving benefits may be difficult to quantify.

Finally, the guidelines for EM&V should be issued as soon as possible, allowing states to evaluate the extent of change needed to current EM&V practices and to evaluate the extent to which energy efficiency programs might contribute toward compliance.

V. Early Action

There are two main categories of early action where we offer comments: early action credit for

activities before the 2012 baseline and early action credit for activities before the 2020 start date of the compliance period.

Early Action and 2012 Baseline

In the period leading up to EPA's 2012 baseline year, companies have undertaken a variety of initiatives that directly or indirectly reduce the carbon intensity of the electric generating system. As discussed in Section I to recognize investments, we recommend that EPA apply an alternative percent heat rate improvement to states that can demonstrate significant, recent investments in coal fleet efficiency. EPA should also consider encouraging recognition of recent uprates at nuclear power plants.

Encouraging Reductions Programs Prior to 2020

In addition to the emission reductions this program will drive starting in 2020, we urge EPA and states to encourage entities to make investments in reductions prior to 2020. Early investments to reduce CO_2 will help ensure states are on a trajectory to meet the required reductions and will have an important environmental benefit.

EPA is proposing that, with the exception of existing renewables, a state may apply emission reductions that existing state programs and measures achieve during a plan performance period (*i.e.*, from January 1, 2020 through December 31, 2029) as a result of actions taken after the date of the proposed rule (*i.e.*, after June 18, 2014). EPA notes that this option would ensure that actions taken after June 18, 2014 and prior to 2020 as a result of requirements in a state plan would be recognized as contributing toward meeting a state's required emission performance level for affected EGUs. We agree with the use of the date June 18, 2014 after which EPA will recognize actions that reduce emissions for compliance purposes.

Draft and Confidential

EPA is proposing that this limitation would *not* apply to existing renewable energy requirements, programs, and measures because EPA factored existing renewable energy generation prior to the date of proposal of the emission guidelines into the state-specific CO_2 reduction goals as part of Building Block 3. Therefore, under the proposed emission guidelines, renewable energy generated during a plan performance period from all existing renewable energy requirements, programs and measures could be used for compliance. We support this distinction for existing renewable energy requirements to ensure that *all* existing renewable projects can generate electricity that can be used for compliance when the program starts in 2020.

However, as proposed, EPA's Clean Power Plan would *not* allow any CO_2 emission reductions occurring between now and the end of 2019 to be counted toward compliance with the state emission performance standards, given the instantaneous nature of a rate-based compliance method. EPA is requesting comment on whether emission reductions that existing state requirements, programs, and measures achieved prior to January 1, 2020 should be applied toward meeting the required level of emission performance in a state plan. EPA notes that this approach would effectively allow higher emissions during the interim period, 2020 to 2029, than would occur under the proposed approach (*i.e.*, requiring less emission performance improvement during that period). However, these higher emissions in 2020 to 2029 could be offset by pre-2020 emission reductions.

The Clean Energy Group has long supported the recognition and encouragement of early emission reductions. To the extent that states and developers of emission reduction projects are able to both adopt and implement measures earlier than 2020, EPA should encourage states to provide an incentive for earlier emission reductions. Recognition of incremental emission reductions prior to 2020 would allow a state to begin demonstrating emission performance earlier and develop a more gradual emission reduction trajectory. In order to ease the transition to a lower carbon energy system and promote the adoption of low- and zero-carbon technology, EPA should indicate that it will approve the recognition of incremental GHG reductions that occur prior to 2020 provided that the reductions result from new measures that become part of a state's compliance plan as approved by EPA. Measures such as new legislation, new regulations, executive orders, or municipal government or public utility commission approvals of integrated resource plan (IRP) elements undertaken between 2014 and 2020 would be eligible for early action credit. For example, in the context of a rate-based trading system, new programs or policies requiring incremental zero-carbon energy builds or early retirement or re-dispatch of affected fossil units (beyond existing state policies) could be eligible to credit that generation and apply those credits toward its rate-based compliance determination after 2020. Qualifying measures would be subject to EM&V protocols. This approach will help to mitigate the perverse incentive of delaying the implementation of reduction opportunities, including heat rate improvements, emission reductions at the stack, energy efficiency measures, and the development of new renewable projects until 2020, which could otherwise exist under EPA's proposed approach.

Draft and Confidential

While crediting early action could provide some relief to the concerns we expressed about the ramp rate of NGCC, we do not see early action and changes to Building Block 2 as necessarily interchangeable.

VI. Multi-State Coordination and Plans

There is a long tradition of multi-state compliance approaches that have successfully reduced air emissions under the Act, including the Ozone Transport Region trading program for NOx, the NOx Budget Trading Program under the NOx SIP Call, the Clean Air Interstate Rule (CAIR) for SO_2 and NOx, the Regional Haze Program for SO_2 and NOx, and the Acid Rain Program SO_2 and NOx (which was created by legislation). Each of these programs were designed to facilitate interstate compliance through mass-based trading programs and were successful in cost-effectively reducing emissions.

CO_2, an air pollutant with global impacts, is particularly well-suited for regulation under a broad regional or multi-state compliance system—whether it be a region of contiguous or non-contiguous states. Appropriately, EPA recognizes in the proposed rule that states, affected EGUs, and ratepayers may benefit from states collaborating on state compliance plans or strategies given the interconnectedness of the power sector and interstate flows of electricity. States are part of various EGU dispatch systems and may either import or export electricity (or, in some cases, both). Compliance plans that recognize such multi-state dynamics may have important advantages that states should consider. Multi-state compliance plans or agreements may mitigate some of the inter-state dynamics and market inefficiencies that could result if states take different regulatory approaches under section 111(d). A patchwork of different state plans could lead to perverse incentives and market distortions as a result of electricity markets and existing credit markets that cross state borders, but states coordinating compliance plans or components of plans can help

minimize the resulting economic distortions.

Further, electric generators that operate in multiple states may be able to reduce compliance costs within their own operations by taking advantage of the lowest-cost reduction opportunities across their generating fleet. Additionally, a multi-state compliance program provides greater flexibility to the electric system as it responds to compliance decisions under section 111(d). If the program encompasses a broader geographic region, electric system operators will benefit as they manage the flow of electricity across state lines and match supply to demand. A multi-state compliance program would also reduce the market distortions that may result from a patchwork of individual state programs.

Thus, we support EPA encouraging the consideration of multi-state compliance options and providing additional time (June 30, 2018) to submit a multi-state compliance plans. We urge EPA to provide this additional time for states submitting a joint plan or for states submitting individual plans that coordinate compliance opportunities, by for example, agreeing to accept certain compliance credits from specified states. Given the potential benefits of multi-state plans, EPA should ensure that it encourages all levels of coordination among states. However, we support the start of the program for all states by 2020 provided the final rule addresses our concerns as outlined above regarding the glide path. To encourage the consideration of the benefits of multi-state compliance, we urge EPA to clarify how states might alter compliance plans as the program is implemented over time.

We also agree with EPA, that RGGI is a multi-state program that EPA should consider as an appropriate compliance option for those participating states.

Draft and Confidential

VII. Enforcement

EPA is proposing that states can either submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level, or to submit plans that rely in part on measures imposed on entities other than affected EGUs. Given that affected EGUs may not directly control several of the measures that EPA considered in establishing BSER and that states can consider as compliance opportunities, we urge EPA to ensure that affected EGUs are not necessarily the only entities responsible for achieving the final emission performance levels.

It is important for EPA to urge states to consider which entities would be responsible for the measures states include in compliance plans as some entities may be responsible for implementing energy efficiency measures but also dependent on decisions beyond their control to achieve the projected reductions. For example, an energy efficiency program could be dependent on customers' choices. EPA should also ensure that states consider the multiple parties that may be necessary for successful implementation of certain programs and ensure that entities are only responsible for the components in their control. For example, success of many renewable and energy efficiency programs often depends on a state's ability to fund the program. In such cases, the state should have the enforceable obligation to provide the funding rather than having the implementing entity fully responsible for a program's success. We would further recommend that the requirements to meet renewable or energy efficiency obligations should be enforced consistent with current practice.

States should have the authority to determine whether they want to design a plan consistent with EPA's-described "portfolio approach" or the "state commitment approach". Provided states are ensuring implementation and enforcement of the appropriate emission reductions, state plans can

be designed consistent with the requirements of 111(d). The choice of the federally enforceable entity should be a state's decision. If a state chooses to include a measure as an express component of its 111(d) compliance plan, that program can become federally enforceable. However, as an alternative, a state can commit to achieve a portion of the required emission performance level on behalf of affected EGU, and the state can be responsible for demonstrating those reductions without the associated state programs becoming federally enforceable. This alternative is consistent with the procedures under section 110 to which section 111 references.

In either approach, it will be important to ensure the plan includes corrective measures that take effect automatically if a state is unable to demonstrate the required emission reductions. This self-correcting component ensures that affected EGUs are not responsible for emission reductions if a state fails to implement measures that are designed to reduce generation demand and are outside of the control of an EGU.

It is also important that the final rule make clear that if a milestone is missed during the interim period, the state would have the opportunity to identify any delay to EPA, explain the cause, and describe the steps the state will undertake to accelerate subsequent implementation to achieve the planned improvement in emission performance before EPA would take any enforcement measures. However, if a state failed to demonstrate that it met the interim goal at the end of the compliance period, it would be subject to enforcement.

VIII. Compliance Approaches

Draft and Confidential

In the preamble to the proposed rule, EPA describes a range of potential compliance approaches for states to consider as they develop compliance plans. Those approaches fall within two basic frameworks: a rate-based approach to compliance and a mass-based approach. The Clean Energy Group supports EPA's efforts to have a mass-based equivalent option available to states. We believe that mass-based targets provide a clear objective for states as they evaluate the implications of the rule. Mass-based regulatory approaches have been shown to be highly effective in addressing conventional air pollutants emissions, including the NOx SIP Call program and Acid Rain trading program, and we think should be encouraged.

Supplementing the June proposed rule, EPA issued a technical document in November that provides two possible options for translating rate-based goals to a mass-based equivalents, including tables of two of these approaches. We support EPA's effort to provide a more straightforward translation method based on the rate-based targets and historic data. Requiring multiple model runs to derive a mass-based goal adds significant complexity to the state planning process, and we believe would discourage the adoption mass-based targets. Finally, we support EPA offering mass-based equivalents that allow for the inclusion of both new and existing sources.[22] Like the RGGI program, we believe a more rational and cost-effective market response will result if both new and existing sources are subject to the same regulatory program and market signals.

In terms of the specific calculation methodology that EPA has proposed, we appreciate that EPA's proposed methodology is straightforward to implement and linked to the rate-based goals. With this approach, the mass-based equivalents can be directly recalculated based on a set of

[22] As part of any expanded documentation on compliance options, we also recommend that EPA facilitate states' understanding of the potential electric market implications of treating existing and new sources differently in order to facilitate states evaluation of such a decision.

revised rate-based goals. We think this is an attractive feature of EPA's proposed approach. However, we think that EPA's proposed approach in the TSD produces relatively stringent mass-based equivalents. In some cases, the mass-based equivalents imply a 50 to 60 percent reduction from 2012 levels. One possible option for addressing these extreme cases would be to adjust for variability. In general, EPA's choice of a 2012 baseline does not appear to have a significant impact on the calculation of the rate-based targets. For example, average coal-plant emission rates may not vary significantly from year-to-year. However, on a mass basis, the choice of a baseline year can have a significant influence on the resulting goal. We recommend that EPA provide a "variability adjustment" in calculating the mass-based equivalents, whether it applies to existing sources or both new and existing sources.

Regardless of the form of the goal, EPA makes it clear in the proposed rule that states would have discretion in terms of the regulatory approach used to achieve the rate- or mass-based goal. While EPA discusses the use of market-based allowance and emission rate trading systems, it does not include significant discussion of a carbon fee-based compliance approach. The Clean Energy Group supports EPA making clear in the final rule that fee-based approaches could be implemented by states if they choose. Such programs would promote economic dispatch reflecting the fee EPA determined was appropriate through bids in competitive markets or, in vertically-integrated states, through a carbon fee added to the state's existing least cost dispatch regime. There are a range of benefits to a carbon-fee approach, including a greater degree of certainty as to the cost of compliance. An appropriately constructed and administered carbon fee program could be a simple and efficient way for states to comply with the Clean Power Plan provided that it is structured to demonstrate that the emission performance goal will be achieved and could be structured as a voluntary safe harbor for a period of years in the interim years of the program.

Draft and Confidential

IX. Additional Comments

Below, we offer additional comments on the October 30th NODA and offer other suggestions for EPA to consider as it develops the final rule.

<u>October 30th NODA</u>

EPA recognizes in the NODA that stakeholders have raised concerns about the significant disparities in the state goals between those states with little to no NGCC generating capacity and those with significant amounts of NGCC capacity. We encourage EPA to pursue modifications in the final rule to ensure it does not place a heavier reduction burden on early movers, but rather more equitably apportions the emissions reduction responsibility among states.

Additionally, EPA notes in the NODA that some stakeholders have suggested that EPA should revise the goal-setting equation to reflect a consistent approach to accounting for incremental generation from existing NGCC, incremental renewable generation, and energy efficiency savings. Specifically, some stakeholders have suggested that state goals should reflect the potential for renewable and energy efficiency to displace existing fossil steam generation. In its discussion of the alternative goal-setting methodology, EPA includes two options for revising the formula: (1) assume that renewable and energy efficiency directly replace all historic fossil generation on a pro rata basis; or (2) assume that renewable and energy efficiency first replace fossil steam generation below 2012 levels and then replace gas turbine generation if any incremental renewable and energy efficiency remain.

Our concern with the second approach is that the electric system does not function by selectively replacing one type of fuel over another as renewable MWhs are added to the grid or demand-side energy efficiency measures are implemented. Renewable generation and energy efficiency may displace fossil MWhs or other zero-carbon sources. Therefore, we would oppose altering the building block formula to first replace fossil steam generation below 2012 levels and then replace gas turbine generation if any incremental renewable and energy efficiency remain.

Regardless of the formula used in the final rule, it is essential that EPA ensure that each state target is achievable, and ensures a states, companies, and grid operators can maintain a reliable electric system and the necessary voltage support. For example, if EPA were to pursue the alternative goal-setting methodology discussed in the NODA, it may want to consider limits to the amount of renewable generation and energy efficiency relative to the amounts in the proposed rule to account for the increased stringency. Under the proposed or alternative goal-setting methodology, we encourage EPA to consider reliability impacts given the interactions among the building blocks.[23]

Independent Technical Justification for Each Building Block

As a general matter, the Clean Energy Group encourages EPA to focus on making the technical justifications associated with each building block independent. We are concerned that justifications based on flexibility provided by the incorporation of other building blocks undermine the severability of the components of the rule. Each building block should be justified on the technical achievability, availability, and cost of the measures within that building block, not on flexibility provided by other building blocks to ensure each withstands judicial scrutiny

Draft and Confidential

Source Categories for Power Plants

EPA asks for comment on existing categories (*e.g.*, subparts) of affected EGUs under 111(d). Consistent with the Clean Energy Group comments on EPA's proposed standard for new EGUs under 111(b), we support the use of flexible compliance measures under 111(d). If EPA concludes that combining the two existing source categories (fossil steam EGUs [Da] and combustion turbines [GG/KKKK]) into a single subpart (TTTT) for purposes of regulating existing sources under 111(d) would facilitate such flexibility, we would support such a regulatory structure. We appreciate EPA taking the time to solicit comments on the regulatory structures that facilitate trading.

Program Reset

Based on the experience of member companies that participate in RGGI, we recommend that EPA consider an explicit mechanism for periodic review and "reset" of the program to adjust for unanticipated events and opportunities. For example, in its program review carried out in 2012 and 2013, RGGI made several adjustments to its program, including a significant reduction in emissions levels. Similarly, EPA should recognize and allow the currently established reset process used by RGGI as a means of possible mid-course corrections for the existing source

[23] MJB&A Clean Power Plan Evaluation Tool, *available at*: http://www.mjbradley.com/about-us/case-studies/clean-power-plan-evaluation-tool.

performance standards to ensure mass-based targets remain comparable to the rate-based alternative.

If you have any questions, please do not hesitate to contact me, Carrie Jenks at cjenks@mjbradley.com.

Sincerely,

Michael Bradley
Director
The Clean Energy Group

Draft and Confidential

E C O S

THE ENVIRONMENTAL COUNCIL OF THE STATES

50 F Street, N.W.
Suite 350
Washington, D.C. 20001

Tel: (202) 266-4920
Fax: (202) 266-4937
Email: ecos@ecos.org
Web: www.ecos.org

Robert Martineau
Commissioner, Tennessee Department of Environment and Conservation
PRESIDENT

Martha Rudolph
Director, Environmental Programs, Colorado Department of Public Health and Environment
VICE PRESIDENT

Henry Darwin
Director, Arizona Department of Environmental Quality
SECRETARY-TREASURER

Dick Pedersen
Director, Oregon Department of Environmental Quality
PAST PRESIDENT

Alexandra Dapolito Dunn
Executive Director & General Counsel

December 1, 2014

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Via email to: A-and-R-Docket@epa.gov

Re: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule: Docket ID No. EPA-HQ-OAR-2013-0602

Dear Administrator McCarthy:

On behalf of the Environmental Council of the States (ECOS), I submit this letter to the U.S. Environmental Protection Agency (EPA or Agency) on the proposed national rulemaking *"Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule" Under the Clean Air Act* (79 Fed. Reg. 34830, June 18, 2014). This letter provides comments to EPA on this proposed rule (hereinafter, "proposed rule", "proposal", "§ 111(d)", or "guidelines").

States, territories, and tribes (hereinafter, "states") are co-regulators with EPA as we jointly seek to deliver the nation's environmental protection system. States have many laws that address and influence air pollution, and implementing the Clean Air Act (CAA) is a fundamental responsibility of states.

The following comments from ECOS make broad suggestions that should be addressed by EPA in any final rule. Importantly:

- these comments do not supersede or alter the comments or opinions of any individual state; and
- states' positions vary significantly on many aspects of this proposal.

As such, these comments do not take a position on stringency, legality, or need for the proposed rule. Instead, given the above limitations, these comments offer shared state perspectives which are relevant to EPA's further consideration and finalization of the proposed rule, or to any other related next steps in this field of activity. Over the years, ECOS has adopted Resolutions in response to various federal climate policy proposals under consideration at the time. Today's comments raise principles and priorities consistent with prior policy statements.[1] ECOS does not have a Resolution on the CAA § 111(d) proposal.

[1] *See, e.g.,* ECOS Resolution 07-2, Revised March 2013, *Reducing Greenhouse Gas Emissions*; ECOS Resolution 12-1, Approved March 2012, *Challenges of Achieving Significant Greenhouse Gas (GHG) Emissions Reductions*; and ECOS Resolution 09-3, Revised March 2012, *Preserving States' Rights to Regulate Greenhouse Gas Emissions*.

Engage with States

States have long supported early, meaningful, and substantial state involvement in the development and implementation of environmental statutes and related rules.[2] EPA must engage states as co-regulators prior to and during the rulemaking process, and ECOS recognizes EPA's extensive efforts to do so for this proposed rule. The Agency's time and effort spent on calls, meetings, and outreach to states, individually and through ECOS and other associations, regarding the proposed rule has been almost unprecedented. Many states and other stakeholders commend EPA for this significant outreach on the proposal, and suggest that this type of engagement represents a model for future engagement on Agency matters of national significance and import such as this one.

The Agency's efforts have addressed many state inquiries about the proposal, but questions remain. Significant engagement and outreach will remain as important as EPA prepares to finalize the proposal and as states then formulate, submit, and implement the resulting plans. EPA must maintain regular forums and contact with states prior to finalization, and then during implementation, of the rule.

Provide Adequate Resources

The CAA § 111(d) planning process will place a significant administrative burden on state agencies and on EPA. CAA § 111(d) work should not come at the expense of state agencies' core programs. EPA and the states must work efficiently together. As the CAA provides, EPA must exercise flexibility in reviewing and approving state § 111(d) plans. ECOS also requests that EPA seek to secure additional federal funding for the states to cover the customary portion of costs associated with any new rule, and consider the availability of funding support in planning for new obligations.

We understand that the Administration is seeking Congressional reallocation of funds from state air quality planning budgets for FY2015. It is important for EPA to provide states with *additional* assistance, not reallocated funding, wherever possible, to help states meet the deadlines and obligations proposed under § 111(d). In recognition of the significant and wide range of activities necessary to implement new requirements and regulatory obligations, ECOS requests EPA include in its support of any final rule estimates of both state administrative costs and state direct implementation costs.[3]

As an example, we understand that environmental justice concerns have been raised concerning the proposal and that some will advocate requiring states to take such concerns into consideration in drafting and administering § 111(d) plans, such as adding criteria for considering impacts on underprivileged communities to generation distribution decisions. For any such requirement included in the proposal, EPA should provide needed assistance and resources to states for their fulfillment.

Acknowledge State Differences

While some states predict they will achieve necessary reductions with modest efforts and anticipate net economic benefits, others are very concerned about their ability to meet the proposed (especially interim) targets and about grid reliability and the cost of the rule. Uncertainty about the effects of the proposal exists among states largely due to state-specific regional, geographic, economic, and power generation and regulation differences and due to the wide range of options proposed by EPA. Cost, timing, and energy generation impacts will likely differ from state to state depending on legislative and

[2] *See* ECOS Resolution 11-1, Renewed April 2014.
[3] *See* ECOS Resolution 14-3, Approved September 2014.

administrative factors and differences in each state's energy portfolio and connections, or lack thereof, to the larger grid. EPA must:

- consider variations in states' ability to implement the various proposed options;
- account for variations in state implementation costs as appropriate; and
- structure any final guidelines to "provide the maximum flexibility possible that is still consistent with underlying statutory objectives".[4]

EPA sought comment on the use of a baseline approach, which will present advantages and disadvantages that will vary among states. If EPA establishes state baselines, they must be representative of actual performance related to the goals of the rule and must not, for example, work against states or entities that took early action contributing to that goal. EPA also must consider significant year-to-year variations that have occurred, and will continue to occur. Many states have observed, for instance, anomalies in hydropower and plant outages had an undue influence on their baseline in the proposal. EPA should work with those specific states, and others with concerns, to make needed adjustments in any final rule to show how such an approach works over time.

Maximize State Flexibility

EPA must develop CAA § 111(d) guidelines that foster both regional coordination and the option for states to submit individual plans. The Agency also must provide states multiple options for capturing the benefits of state energy efficiency and renewable energy programs. EPA must provide a workable mechanism for states to adopt either a rate-based or mass-based approach to achieving state goals, as well as to modify their plans – such as to continue achieving reductions cost-effectively by incorporating new technologies that become available. The rule and EPA's manner of implementation and approval must recognize that regional plans could appropriately take many different forms. EPA must allow states flexibility to allocate credit for zero-carbon resources and to reach agreements allocating carbon liabilities.

EPA also should support the dialogue and standardization needed to promote state flexibility. For example, EPA should work with states to ensure states receive proper credit for energy efficiency programs. The guidelines must account for the need for both accountability and flexibility in developing Estimation, Measurement and Verification (EM&V) protocols that work across states and will meet federal standards.

Acknowledge State Institutional Realities

EPA must acknowledge and accommodate legal, administrative, and technical realities states face implementing such an expansive rule. Several states may need additional legislative authorization before finalizing and implementing § 111(d) plans. The timing of legislative sessions dictates when they can seek such authority and may affect a state's pace for developing, proposing, and finalizing § 111(d) plans. In terms of practicality and the speed at which markets and infrastructure can be changed, many states will need latitude for establishing their path to the 2030 targets. State utility commission docket timelines also must be considered.

Timely Plan Review

EPA must also ensure that it dedicates sufficient resources to review state § 111(d) plans and to continue approving other state air quality plans. EPA and the states recently agreed on an approach to reduce the

[4] *See* ECOS Resolution 12-2, Approved March 2012.

backlog of State Implementation Plan approvals; ECOS recommends EPA apply these principles to the process for approving § 111(d) plans.

Issue Clear Rule and Concurrent Guidance Developed with States

Any final rule should be clear and comprehensive enough that the need for implementation guidance is minimized. If such guidance is needed, EPA should develop any guidance with state involvement and publish it concurrently with any final rule, especially given the very short timelines proposed for states to submit plans and begin implementation.

To maintain a level playing field while achieving meaningful reductions, the rule should be written to encourage accountability. Monitoring, verification, and backstop provisions should be reasonable and clear, developed in consultation with states. EPA should work with states to ensure that contingency measures are available, recognizing the importance of states maintaining control over their programs and advancing a system of flexible and iterative implementation.

Practicable Enforcement and Oversight

To maintain and build upon the time tested cooperative federalism upon which the Clean Air Act is founded, EPA must preserve the states' role as primary implementers of the § 111(d) performance standards, as envisioned by the Act. EPA must balance its need for enforceability with the states' need for flexibility as they deliver emission reductions under § 111(d). EPA must also provide options, such as the state commitment option approach described in the proposal's preamble, under which states with solid records of performance and established approaches can implement or expand energy efficiency and renewable energy programs for § 111(d) compliance.

Given the significant resources that have been, and will continue to be, needed to respond to this proposal and any final rule, there is significant risk to states should this rule be overturned in whole or in part by the courts. While the Agency cannot ensure against this, the rule's legal foundation must be as clear and compelling as possible to prevent possible years of uncertainty.

Conclusion

Again, this letter, though submitted on behalf of states, in no way overrides individual comments and concerns made through the rulemaking process by states - our members and your co-regulators. We appreciate the opportunity to offer these comments. If you have any questions, please contact Alexandra Dunn, ECOS Executive Director and General Counsel, adunn@ecos.org or 202-266-4929.

Sincerely,

Robert J. Martineau, Jr.
ECOS President
Commissioner, Tennessee Department of Environment and Conservation

cc:
Janet McCabe, Acting Assistant Administrator, EPA Office of Air and Radiation
Mark W. Rupp, Deputy Associate Administrator for Intergovernmental Relations, EPA Office of Congressional and Intergovernmental Relations
ECOS Officers & Executive Committee
Director Tracy Stone-Manning, Montana Department of Environmental Quality, ECOS Air Committee Chair *(through 11/21/14)*
Commissioner Bryan Shaw, Texas Commission on Environmental Quality, ECOS Air Committee Vice Chair

N A R U C

National Association of Regulatory Utility Commissioners

November 19, 2014

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: ***Regulation of Carbon from Existing Power Plants; EPA Clean Carbon Plan*; HQ- OAR-2013-0602**

Dear Administrator McCarthy:

Recognizing that "*compliance with ... environmental regulations regulating greenhouse gas emissions will affect ratepayers differently depending upon each State's existing generation, energy resources, electricity market and State commission decisions*,"[1] both you personally, as well as Environmental Protection Agency (EPA) staff, engaged in extensive outreach[2] to National Association of Regulatory Utility Commissioners (NARUC) and its members.

NARUC genuinely appreciates that outreach about the agency's now published proposal to regulate carbon emissions from existing power plants under Section 111(d) of the Clean Air Act. We also appreciate the opportunity and the additional time the EPA has provided for all stakeholders to provide additional feedback on these proposed rules.

NARUC's members include the public utility commissions serving all States and territories responsible for ensuring the availability of reliable and affordable electric service. Our members regulate the retail rates and services of electric, gas, water, and telephone utilities. They are obligated to assure such utility services as may be required by the public convenience and necessity are established and maintained, and to assure that such services are provided at just, reasonable, and non-discriminatory rates, terms, and conditions.

---

1 ***Resolution on Increased Flexibility with Regard to the EPA's Regulation of Greenhouse Gas Emissions from Existing Power Plants*** (NARUC, November 20, 2013), attached as Appendix A and available online at: *http://www.naruc.org/Resolutions/Resolution%20on%20Increased%20Flexibility%20with%20Regard%20to%20the%20EPAs%20Regulation%20of%20Greenhouse%20Gas%20Emissions%20from%20Existing%20Power%20Plants.pdf.*

2 ***EPA 111-d Outreach Activities, Page 1*** (May 29, 2014) online at: http://blog.epa.gov/epaconnect/wp-content/uploads/2014/10/List-of-EPA-111-d-events-May-29-2014.pdf. (Accessed 10/10/2014)

NARUC is *sui generis* and recognized by Congress in several statutes,[3] consistently by Article III Courts[4] as well as a host of federal agencies, including the EPA,[5] as the proper entity to represent the collective interests of State utility commissions.

In part, as a result of the EPA's early outreach, on November 20, 2013, prior to the June 2014 release of the agency's draft guidelines, NARUC passed a ***Resolution on Increased Flexibility with Regard to the EPA's Regulation of Greenhouse Gas Emissions from Existing Power Plants.*** The resolution is attached as Appendix A to this letter.

The resolution highlights the diversity among States in the options and authorities they have available to address any EPA rule or guideline, noting, *inter alia*, specifically that:

> *Many States have: 1) implemented mandatory and/or voluntary renewable portfolio/energy standards, 2) implemented energy efficiency and/or peak load reduction programs, 3) experienced significant retirements of coal based generating plants and/or 4) mandated emission reductions programs; all of which have already contributed to a reduction in GHG emissions; and*
>
> *It may be in the best interest of ratepayers to maintain the operation of certain existing coal-based electricity generating plants that meet environmental performance requirements for priority pollutants for a period of time; and*

---

[3] See 47 U.S.C. § 410(c) (1971) (Congress designated NARUC to nominate members of Federal-State Joint Board to consider issues of common concern); See also 47 U.S.C. § 254 (1996); See also *NARUC, et al. v. ICC*, 41 F.3d 721 (D.C. Cir 1994) (where this Court explains "Carriers, to get the cards, applied to…(NARUC), an interstate umbrella organization that, as envisioned by Congress, played a role in drafting the regulations that the ICC issued to create the "bingo card" system.)

[4] See, e.g., *United States v. Southern Motor Carrier Rate Conference, Inc.*, 467 F. Supp. 471 (N.D. Ga. 1979), aff'd 672 F.2d 469 (5th Cir. 1982), aff'd en banc on reh'g, 702 F.2d 532 (5th Cir. 1983), rev'd on other grounds, 471 U.S. 48 (1985) (where the U.S. Supreme Court notes: "The District Court permitted . . . (NARUC) . . . to intervene as a defendant. Throughout this litigation, the NARUC has represented the interests of the Public Service Commission's of those States in which the defendant rate bureaus operate." 471 U.S. 52, n. 10. See also, *Indianapolis Power and Light Co. v. ICC*, 587 F.2d 1098 (7th Cir. 1982); *Washington Utilities and Transportation Commission v. FCC*, 513 F.2d 1142 (9th Cir. 1976); Compare, *NARUC v. Federal Energy Regulatory Commission*, 475 F.3d 1277 (D.C. Cir. 2007); *NARUC v. DOE*, 851 F.2d 1424, 1425 (D.C. Cir. 1988); *NARUC v. Federal Communications Commission*, 737 F.2d 1095 (D.C. Cir. 1984), cert. denied, 469 U.S. 1227 (1985).

[5] See, e.g., *EPA Administrator Lisa P. Jackson, Remarks to NARUC* (02/17/2010), available online at: http://yosemite.epa.gov/opa/admpress.nsf/12a744ff56dbff858525759000 4750b6/e373453ce486f853852576cd005adcc7!opendocument ("Building strong, working partnerships with the states is one of my top priorities."), *EPA and NARUC Announce Energy Efficiency and Renewable Energy Projects with Six States* (02/16/225) at: http://yosemite.epa.gov/opa/admpress.nsf/b1ab9f485b098972852562e7004dc686/d1a603bc8fe4de9285256faa00745c34!OpenDocument; *Consolidated Water Rates: Issues and Practices in Single-Tariff Pricing (Sept 1999) – A joint Publication of the U.S. Environmental Protection Agency and the National Association of Regulatory Utility Commissioners*, at: http://www.epa.gov/ogwdw000/utilities/stptitle.pdf. Compare, Atomic Safety and Licensing Board *Memorandum and Order* (Granting Intervention to Petitioners and Denying Withdrawal Motion), LBP-10-11, *In the Matter of U.S. Department of Energy (High Level Waste Repository)* Docket No. 63-001-HLW; ASLBP No. 09-892-HLW-CABO4, mimeo at 31 (June 29, 2010) ("We agree with NARUC that, because state utility commissioners are responsible for protecting ratepayers' interests and overseeing the operations of regulated electric utilities, these economic harms constitute its members' injury-in-fact.")

States rely on EPA to issue a procedure under Section 111(d) that reflects the best system or systems of emission reductions that has been adequately demonstrated at affected facilities; and

State utility regulators have jurisdiction over decisions regarding integrated resource planning and/or resource adequacy, processes which ultimately determine the mixes of fuels and resources in State generation portfolios, which differ from State to State; and

States have different mixes of fuels and resources in their existing generation portfolios; and

States have achieved different levels of GHG reductions to date, and have diverse economies and face different economic conditions, including States with energy intensive manufacturing industries that provide goods for the entire nation.

Citing these differences, the November 2013 resolution[6] urges the EPA, in developing any emissions guidelines for regulating carbon emissions from existing power plants, to assure any guidelines:

[R]ecognize the primacy of States [and] rely on both State utility and environmental regulators to lead the creation of emission performance systems that reflect the policies, energy needs, resource mix, economic conditions of each State and region; and

[Are] flexible enough to allow States individually or regionally to take into account, when establishing standards of performance, the different makeup of existing power generation in each State and region; and

[A]void GHG emissions reductions that are not feasible; and

[P]rovide sufficiently flexible compliance pathways or mechanisms that recognize State and regional variations to achieve the most cost-effective emissions reductions in each State; and

[R]ecognize and credit States' emissions reduction achievements to date, recognize any and all existing State emission reduction programs, and . . . not intrude on the States' jurisdiction over decisions regarding integrated resource planning and/or resource adequacy or otherwise mandate specific modifications to the mix of fuels and resources in existing and future State generation portfolios.

---

[6] This resolution follows two earlier resolutions that stress the need for EPA to build in any rules the flexibility required to minimize costs to consumers and to maintain reliability. See, e.g., *Resolution on Increased Flexibility for the Implementation of EPA Rulemakings* (NARUC July 20, 2011), available online at: http://www.naruc.org/Resolutions/Resolution%20on%20Increased%20Flexibility%20for%20the%20Implementation%20of%20EPA%20Rulemakings.pdf; *Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations* (NARUC February 16, 2011), available online at: http://www.naruc.org/Resolutions/Resolution%20on%20the%20Role%20of%20State%20Regulatory%20Policies%20in%20Development%20of%20Fed%20Enviro%20Regs.pdf

Subsequently, on November 19, 2014, NARUC passed two more resolutions that specifically target the EPA's proposed June 2014 guidelines.

The first, captioned: ***Resolution Recognizing the Importance of Nuclear Power in Meeting Greenhouse Gas Goals,*** urges the EPA, "to the extent it regulates carbon from existing power plants under Section 111(d) of the Clean Air Act" to adopt final GHG guidelines that:

> *[W]ill encourage States to preserve, life-extend, and expand existing nuclear generation;*
>
> *[R]emove(s) the generic approximately 6 percent at-risk nuclear and nuclear under construction from the calculation of State-specific emissions targets; and*
>
> *[Allows States to] include in compliance plans and thus receive emissions credit related to all output of new nuclear capacity (including uprates of existing plants) that begins operating after the issuance date of the proposed rule.*

The full text of that resolution is attached to this letter as Appendix B.

The second resolution passed by NARUC at that November 2014 meeting, titled ***Resolution Regarding the Water-Energy Nexus***, points out that the treatment and delivery of water and wastewater services requires about four percent of all U.S. energy consumption each year and that policy makers at all levels are examining opportunities to achieve greater efficiencies in water and energy usage. The resolution, after detailing some of these options, urges the EPA in this proceeding to:

> *[Provide States with] maximum flexibility to [i] support energy efficiency measures stemming from the water-energy nexus and [ii] incorporate those efforts, and their positive impacts on the environment, into any compliance plan that might emerge.*

The full text of that resolution is attached to this letter as Appendix C.

NARUC urges EPA to incorporate these principles in any final guidelines adopted in this proceeding. If you have any questions regarding the resolution or NARUC's positions, please do not hesitate to contact me at (202) 898-2207, (jramsay@naruc.org), or NARUC's Assistant General Counsel, Holly Rachel Smith at (202) 898-1350, (hsmith@naruc.org). Thanks again for the opportunity to provide input. We look forward to working with EPA on these and other issues.

Respectfully Submitted,

/s/ James Bradford Ramsay
General Counsel
National Association of Regulatory Utility Commissioners

cc: *Acting Assistant Administrator Janet McCabe, Office of Air and Radiation (OAR)*
Joseph Goffman, Associate Assistant Administrator & Senior Counsel, OAR

Attachments

Appendix A

Resolution on Increased Flexibility with Regard to the EPA's Regulation of Greenhouse Gas Emissions from Existing Power Plants

WHEREAS, A reliable, affordable energy supply is vital to the nation's future economic growth, security, and quality of life; *and*

WHEREAS, Compliance with expected environmental regulations regulating greenhouse gas (GHG) emissions will affect ratepayers differently depending upon each State's existing generation, energy resources, electricity market and State commission decisions; *and*

WHEREAS, States have jurisdiction over the reliability and affordability of electricity provided to retail customers; *and*

WHEREAS, Incorporating flexibility in the implementation of EPA regulations to allow for unique State or regional strategies can lessen generation cost increases because of improved planning, greater use of energy efficiency and demand-side resources, and orderly decision-making; *and*

WHEREAS, NARUC at this time takes no position regarding the merits of EPA rulemakings for the purpose of regulating GHG from new or existing power plants; *and*

WHEREAS, In 2009, President Obama made a pledge that by 2020, America would reduce its greenhouse gas emissions in the range of 17 percent below 2005 levels; *and*

WHEREAS, The Regional Greenhouse Gas Initiative implemented by nine States is recognized as reducing emissions and provides a net consumer and economic benefit**;** *and*

WHEREAS, Ten States have successfully implemented market-based emissions trading systems applicable to the electrical power sectors for the purpose of reducing emissions; *and*

WHEREAS, Many States have: 1) implemented mandatory and/or voluntary renewable portfolio/energy standards, 2) implemented energy efficiency and/or peak load reduction programs, 3) experienced significant retirements of coal based generating plants and/or 4) mandated emission reductions programs; all of which have already contributed to a reduction in GHG emissions; *and*

WHEREAS, It may be in the best interest of ratepayers to maintain the operation of certain existing coal-based electricity generating plants that meet environmental performance requirements for priority pollutants for a period of time; *and*

WHEREAS, On June 25, 2013, the President issued a memorandum to the U.S. EPA Administrator directing the EPA to:

- Issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;
- Issue final standards, regulations, or guidelines as appropriate for modified, reconstructed and existing power plants by no later than June 1, 2015;

- Include in the guidelines addressing existing power plants a requirement that States submit to the U.S. EPA the implementation plans required under Section 111(d) of the Clean Air Act and its implementing regulations by no later than June 30, 2016; *and*

WHEREAS, The President instructed the EPA, in its efforts to address GHG emissions from modified, reconstructed and existing power plants to engage directly with States, and expressly recognized that States "will play a central role in establishing and implementing standards for existing power plants;" *and*

WHEREAS, The President instructed the EPA to work with State agencies to "promote the reliable and affordable provision of electric power through the continued development and deployment of cleaner technologies and by increasing energy efficiency, including through stronger appliance efficiency standards and other measures;" *and*

WHEREAS, Section 111(d)(1)(A) requires the EPA to establish a procedure under which each State shall submit to the Administrator a plan which establishes standards of performance for existing sources; *and*

WHEREAS, Section 111(d)(1)(B) requires: (1) the plan submitted by the State to provide for the implementation and enforcement of such standards of performance and (2) the Administrator to permit a State, in applying such standards of performance, "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies;" *and*

WHEREAS, The States rely on EPA to issue a procedure under Section 111(d) that reflects the best system or systems of emission reductions that has been adequately demonstrated at affected facilities; *and*

WHEREAS, State utility regulators have jurisdiction over decisions regarding integrated resource planning and/or resource adequacy, processes which ultimately determine the mixes of fuels and resources in State generation portfolios, which differ from State to State; *and*

WHEREAS, States have different mixes of fuels and resources in their existing generation portfolios; *and*

WHEREAS, States have achieved different levels of GHG reductions to date, and have diverse economies and face different economic conditions, including States with energy intensive manufacturing industries that provide goods for the entire nation; *now, therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners, convened at its 125th Annual Meeting in Orlando, Florida, urges the EPA, in developing any emissions guidelines for regulating carbon emissions from existing power plants, to recognize the primacy of States to rely on both State utility and environmental regulators to lead the creation of emission performance systems that reflect the policies, energy needs, resource mix, economic conditions of each State and region; *and be it further*

RESOLVED, That the guidelines should be flexible enough to allow States individually or regionally to take into account, when establishing standards of performance, the different makeup of existing power generation in each State and region; *and be it further*

RESOLVED, That the States need EPA under the relevant statutory factors, to issue guidelines that avoid GHG emissions reductions that are not feasible; *and be it further*

RESOLVED, That the guidelines should provide sufficiently flexible compliance pathways or mechanisms that recognize State and regional variations to achieve the most cost-effective emissions reductions in each State; *and be it further*

RESOLVED, That the guidelines recognize and credit States' emissions reduction achievements to date, recognize any and all existing State emission reduction programs, and shall not intrude on the States' jurisdiction over decisions regarding integrated resource planning and/or resource adequacy or otherwise mandate specific modifications to the mix of fuels and resources in existing and future State generation portfolios.

Sponsored by the Committee on Electricity
Recommended by the NARUC Board of Directors November 19, 2013
Adopted by the NARUC Committee of the Whole November 20, 2013.

Appendix B

Resolution Recognizing the Importance of Nuclear Power in Meeting Greenhouse Gas Goals

WHEREAS, Reliable, clean and affordable electricity is vital to local, State, and national economic growth, jobs, and the overall interests of citizens; *and*

WHEREAS, As demonstrated during the Polar Vortex of 2014, maintaining reliability and fuel diversity; while ensuring compliance with proposed carbon reduction rules, are common challenges for our States and we jointly recognize the need to maintain the existing, baseload nuclear generation fleet; *and*

WHEREAS, Nuclear power plants provide approximately 20% of the nation's total electricity generation, and can provide carbon-free electricity for decades into the future; *and*

WHEREAS, On June 2, 2014, the United States Environmental Protection Agency (EPA) issued proposed regulations for reducing greenhouse gas (GHG) emissions from existing power plants, known as the Clean Power Plan, in which EPA identified the avoidance of the retirement of existing nuclear capacity as one of the "best system of emission reduction" (BSER) methods;[7] *and*

WHEREAS, EPA states in its proposed regulations that policies "that…discourage premature retirement of nuclear capacity could be useful elements of GHG reduction strategies and are consistent with current industry behavior;"[8] *and*

WHEREAS, Nuclear energy has played a substantial role in the achievement of existing GHG State or regional emission reduction goals to date, and continued operation of nuclear power plants is vital to States' ability to economically meet new federal regulations, and provides an essential tool to manage risks associated with potential GHG emissions reduction requirements; *and*

WHEREAS, In the absence of a public safety or environmental concern, the premature shutdown of these valuable assets may cause economic, social, reliability and environmental harm to families and businesses; *and*

WHEREAS, The United States Department of Energy, grid operators, and Federal Energy Regulatory Commission (FERC) commissioners have cautioned that the premature shutdown of nuclear power plants could jeopardize both the nation's electric reliability and the ability to timely address climate change; *and*

WHEREAS, The EPA's proposed GHG regulations for existing power plants would lower a State's allowed GHG emissions rate by counting approximately 6 percent of its nuclear capacity as being "at risk" and including this zero-carbon energy in the goal-setting formula, leading to lower (more stringent) emission rate targets for States that have nuclear power plants; *and*

---

[7] ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 60, [EPA-HQ-OAR-2013-0602; RIN 2060-AR33, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, June 2, 2014, at p. 114.

[8] *Id.*, at p. 151-152

WHEREAS, The EPA's proposed rule treats new nuclear power plants under construction as though they are already operating, and uses their output in the rate-setting formula, which drives down the States' emission rate goals, *and*

WHEREAS, State commission actions to approve the uprating of existing nuclear power plants or the siting of new nuclear power plants have and will play a substantial role in GHG emissions reduction goals; *now, therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners, convened at its 126th Annual Meeting in San Francisco, California, urges the EPA, to the extent it regulates carbon from existing power plants under Section 111(d) of the Clean Air Act, to adopt final GHG rules and regulations that: 1) will encourage States to preserve, life-extend, and expand existing nuclear generation; and 2) remove the generic approximately 6 percent at-risk nuclear and nuclear under construction from the calculation of State-specific emissions targets; *and be it further*

RESOLVED, That, to the extent the EPA regulates carbon from existing power plants under Section 111(d) of the Clean Air Act, that States may include in compliance plans and thus receive emissions credit related to all output of new nuclear capacity (including uprates of existing plants) that begins operating after the issuance date of the proposed rule.

Sponsored by the Committee on Electricity
Recommended by the NARUC Board of Directors November 18, 2014
Adopted by the NARUC Committee of the Whole November 19, 2014

Appendix C

Resolution Regarding the Water-Energy Nexus

WHEREAS, The water-energy nexus describes a close relationship between two critically important sectors of the economy; *and*

WHEREAS, Today's energy extraction and electricity production processes require a tremendous amount of water; *and*

WHEREAS, The treatment and delivery of water and wastewater services requires a significant amount of energy, representing about four percent of all U.S. energy consumption each year, a share that could rise significantly as a result of the antiquated and inefficient nature of U.S. water and wastewater infrastructure, as evaluated by the American Society of Civil Engineers in its 2013 Report Card on U.S. Infrastructure; *and*

WHEREAS, Numerous research and government organizations, including the U.S. Department of Energy, have highlighted a range of opportunities for companies, including regulated utilities in both sectors to work together and with regulatory counterparts at the State and federal levels to provide efficiencies in water and energy usage in their respective industries; *and*

WHEREAS, Many newer thermoelectric power plants use significantly less water as a result of cooling processes that reuse water and other alternative methods; *and*

WHEREAS, Many energy production States are innovating and adopting new environmental quality standards that are aimed at promoting efficient water usage; *and*

WHEREAS, State regulatory commissions are encouraging that water used in the energy production process be recycled rather than disposed of; *and*

WHEREAS, Efforts by water utilities to enhance efficiency by replacing outdated water pumps, integrating "smart" information and communication technologies to identify leaks in real time and streamline other processes, and using a greater share of alternative energy to fuel operations, among other initiatives, have already yielded measurable reductions in the amount of energy used to deliver water and wastewater services; *and*

WHEREAS, The EPA is currently considering rules to reduce emissions of carbon dioxide from existing stationary sources throughout the country; *and*

WHEREAS, A provision of the EPA's proposed rules would provide States with considerable latitude to design programs to meet federally-mandated targets for cutting Statewide emissions; *and*

WHEREAS, States possess many of the tools needed to implement policies, programs, and incentives, to fully employ the water-energy nexus for the purposes of enhancing energy efficiency efforts that could also yield more reliable service, stable rates for consumers, and lower carbon emissions for States and the country as a whole; *and*

WHEREAS, A growing number of State regulatory commissions, environmental agencies, and legislatures are actively exploring opportunities for harnessing the water-energy nexus for these purposes; *and*

WHEREAS, As an example of its support of State commissions to appropriately regulate issues related to the water-energy nexus, in July 2009, the NARUC Board of Directors passed a resolution "Supporting State Regulation of Hydraulic Fracturing;" *now, therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners, convened at its 126th Annual Meeting in San Francisco, California, urges States, working with the appropriate federal authorities, to proactively explore the water-energy nexus and pursue regulatory reforms that might be needed to unlock further progress toward enhanced water and energy efficiency, recognizing and reiterating that States are well suited to effectively regulate their natural resources; *and be it further*

RESOLVED, That, as the EPA moves forward with its proposed rules for reducing carbon emissions from existing stationary sources, NARUC recommends that States be provided maximum flexibility to support energy efficiency measures stemming from the water-energy nexus and to incorporate those efforts, and their positive impacts on the environment, into any compliance plan that might emerge.

Sponsored by the Committees on Energy Resources and the Environment, Gas, and Water
Recommended by the NARUC Board of Directors November 18, 2014
Adopted by the NARUC Committee of the Whole November 19, 2014

Kathleen Barrón
Senior Vice President
Federal Regulatory Affairs
and Wholesale Market
Policy

101 Constitution Avenue, N.W.
Suite 400 East
Washington, DC 20001
(202)347-7500
(202)347-7501 Fax
kathleen.barron@exeloncorp.com

December 1, 2014

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

Re: Comments of Exelon Corporation on U.S. Environmental Protection Agency's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014)

Dear Administrator McCarthy:

Exelon Corporation submits the attached comments on the U.S. Environmental Protection Agency's Proposed Carbon Pollution Emission Guidelines For Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014) (Proposal). We appreciate the tremendous effort you and your staff have put into this important rulemaking and associated public outreach.

In the six months since EPA issued this Proposal, some of our colleagues in the industry have argued that the regulation of carbon pollution is illegal, that EPA is moving too quickly, and that Americans must confront a choice between protecting the environment for our children, on the one hand, and affordable and reliable electricity, on the other. While there is no doubt that these arguments will be reasserted in many of the comments that you will receive today, the industry data developed over the last six months demonstrates that their doomsday predictions are simply not correct.[1] Indeed, this new data released by the nation's grid operators has shown that the industry can immediately begin to control carbon pollution while maintaining electric reliability *and at a cost in line with the typical increases that utilities themselves have charged customers over the past year*.

[1] In addition, as reflected both in the attached comments and those submitted with other Clean Energy Group companies, Exelon believes the proposed rule is well within EPA's statutory authority and is in fact legally and scientifically required. We disagree strongly with claims asserted by other industry groups that EPA has exceeded its authority by looking to the full electric system for reductions, or by proposing the rule at all.

ED_000419-0005569

According to the EIA, between 2013 and 2014, customer rates have fluctuated between a decrease of 2.5 percent and an increase of 11.8 percent across the different regions of the U.S., with a national average increase of 3.2 percent, as shown in the following table.[2]

Region	Change in Residential Electricity Prices *(First Half 2013 to First Half 2014)*
New England	+11.8%
Mid-Atlantic	+6.7%
Mountain	+4.5%
South Atlantic	+4.0%
East North Central	+3.7%
U.S. Average	**+3.2%**
East South Central	+3.1%
West South Central	+2.4%
West North Central	+1.8%
Pacific Contiguous	-2.5%
Source: EIA	

Based upon the analyses performed by grid operators PJM and ERCOT, carbon pollution control can be achieved with a modest two to five percent retail rate increase in these regions – roughly a nickel to a quarter per day for the average family – by charging emitting plants the cost of pollution and smartly dispatching the nation's power plants in a way that dispatches cleaner plants before dirtier ones (Smart System Dispatch).

As a result, Exelon urges EPA to take a critical leap forward and implement a consumer protection price ceiling as part of a safe harbor to guarantee compliance for all states that participate in a Smart System Dispatch program by 2020. Using the grid operator data, we estimate that EPA can develop a price-based compliance program that would result in a retail rate increase of no more than five percent on a regional basis. States and regions that implement Smart System Dispatch programs sooner should be rewarded with early action credits in the form of a lower price ceiling, *e.g.*, early action by 2018 could be encouraged by implementing a price ceiling that will result in an average retail rate increase of not more than four percent. While Exelon agrees with EPA that the price of compliance has been overstated by many commenters, we respectfully urge you to take the issue off the table by creating strong consumer and state protections as set forth in detail in our comments.

Given the deep and public disagreements over the legality and feasibility of carbon pollution regulation, EPA should take note that a diverse group of stakeholders has recommended that EPA consider compliance methods such as Smart System Dispatch, including EEI and other major industry trade organizations, other individual companies, major environmental organizations, think tanks, and major academic institutions. This point of agreement across the stakeholder spectrum is an important opportunity for EPA to bridge the divisions regarding this rule and ensure on-time, affordable implementation

[2] This figure includes companies that did not file rate cases and had no rate increases. For companies that filed rate cases, the average rate increase was higher than 5 percent.

of carbon pollution reductions. Moreover, we believe Smart System Dispatch is a logical outgrowth of EPA's proposal, as explained fully in our comments. It could also be considered through a Notice of Data Availability without jeopardizing the June 2015 target date for the final rule if EPA preferred to seek additional public comment on this specific option

Our comments also highlight several additional ways that we believe EPA should revise the Proposal to ensure that the final rule achieves the desired emission reductions. Broadly, these comments address (1) implementation of the interim compliance goals, as touched on above, (2) treatment of nuclear generation, (3) goal-setting, (4) treatment of new NGCC, and (5) the benefits of a mass-based approach. In all areas, after explaining the concern and how implementation of the rule as proposed (or as interpreted by stakeholders) would run contrary to EPA's emissions reductions goals, we provide easily adoptable solutions, such as Smart System Dispatch, that work within the context of the Proposal and EPA's Clean Air Act authority, as well as the physical, technical, and economic limits of the electricity grid. We intend for these comments to be constructive and to assist EPA in finalizing a meaningful, timely rule that promotes emission reductions and electric reliability while protecting electric customers from unacceptable bill impacts.

Please do not hesitate to contact me if you would like additional information or clarifications related to our comments. We look forward to continue to work with EPA to support regulations to further improve air quality and modernize the nations' power generation infrastructure.

Respectfully Submitted,

/s/ Kathleen Barrón

COMMENTS OF EXELON CORPORATION ON

U.S. ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS

Docket ID No. EPA-HQ-OAR-2013-0602
79 Fed. Reg. 34,830 (June 18, 2014)

December 1, 2014

TABLE OF CONTENTS

GLOSSARY 3

EXECUTIVE SUMMARY 5

COMMENTS 18

I. THE INTERIM GOALS ARE ACHIEVABLE, BUT EPA SHOULD PROVIDE A SAFE HARBOR FOR STATES THAT HARNESS EXISTING LEAST-COST ELECTRIC DISPATCH MECHANISMS TO CONTAIN COSTS AND MINIMIZE IMPACTS ON RETAIL ELECTRICITY CONSUMERS. 18

A. EPA's Proposed Interim Goals Are Reasonable. 21

1. EPA's Approach Reflects the Operation of the Electric System. 21

2. EPA's Proposed Interim Goals Are Achievable and Should Not Be Relaxed. 22

B. Smart System Dispatch Would Minimize Compliance Costs and Minimize Consumer Impacts While Reducing CO_2 Emissions Commensurate with EPA's Interim Goals 25

1. Smart System Dispatch Would Work in Harmony With Existing Grid Management Tools. 25

2. Smart System Dispatch Would Contain Compliance Costs, Achieving the Interim Goals at a Reasonable Carbon Fee 28

3. Smart System Dispatch Would Minimize Consumer Impacts if States Direct Carbon Fees to Retail Electric Bill Relief 33

4. EPA Should Deem States Adopting Smart System Dispatch to Have Complied With Their Interim Goals 34

C. A Safe Harbor for Smart System Dispatch Would Contain Costs, Minimize Consumer Impacts, Preserve Reliability and Address the Other Principal Concerns Raised in Opposition to the Interim Goals 37

II. EPA MUST REVISE THE TREATMENT OF EXISTING NUCLEAR GENERATION. 40

A. Nuclear Facilities Are the Largest and Most Reliable Source of Carbon-Free Electricity. 41

B. Nuclear Facilities Are at Risk of Premature Retirement. 43

C. Preventing the Early Retirement of Existing Nuclear Generation Is Essential to Reducing Carbon Emissions From the Power Sector. 48

D. The Proposed Rule Fails Adequately to Value Nuclear Power. 55

1. EPA's Arbitrary Treatment of Nuclear Generation. 55

2. EPA's Inadequate Proxy for At-Risk Nuclear Facilities. 58

E. Solutions. 61

1. EPA Should Use a System-Wide Emissions Rate to Set Emissions Rate Targets. 62

2. An Alternative: Accounting for Nuclear Generation That Is Lost. 69

ED_000419-0005573

3. At a Minimum, EPA Should Use a State-Specific Determination of "At-Risk" Nuclear Capacity. 70

4. EPA Should Expressly Recognize the Ability to Demonstrate Compliance Through Portfolio Standards That Credit Nuclear and Hydropower. 71

III. EPA SHOULD MODIFY THE GOAL-SETTING FORMULA IN SEVERAL KEY RESPECTS. 72

A. EPA Should Treat Incremental Renewable Energy and Energy Efficiency as Displacing Existing Fossil Fuel Generation, Not as Additional Generation. 73

B. EPA Should Look Beyond State Borders When Calculating Reductions Achievable from Dispatch to NGCC Units in Building Block 2 and From Zero-Carbon Electricity Generation in Building Block 3. 75

C. In Setting State Goals, EPA Should Incorporate Co-Firing With Natural Gas and Other Types of Fuel Switching in Building Block 1. 80

IV. EPA SHOULD CLARIFY the TREATMENT OF NEW GAS GENERATION. 85

A. Accounting for New NGCCs in Mass-Based States. 87

B. Accounting for New NGCCs in Rate-Based States. 89

V. PROPOSED ACCOUNTING RULES FOR INTERSTATE INTERACTIONS. 93

A. Background. 93

B. EPA Should Provide States With Equal Trading Opportunities Regardless of How They Choose to Comply. 95

C. RECs Should Be Valued in Accordance With Their Emissions Reductions. 96

D. The Problem of Double-Counting and a Proposed Set of Accounting Rules. 100

VI. EPA SHOULD ADOPT MASS-BASED TARGETS. 104

CONCLUSION. 110

APPENDIX. A-1

FIGURES

Figure 1. U.S. Sources of Low-Emission Electricity, 2012. 6
Figure 2. U.S. Carbon-Free Electricity Sources, 2013. 41
Figure 3. U.S. Emission-Free Generation, 2013. 42
Figure 4. Nuclear Retirement Candidates in Competitive Markets. 47
Figure 5. Costs of Reducing or Avoiding Carbon Dioxide Emissions. 54
Figure 6. Location of Shale Gas Deposits in the Continental U.S. 83

ED_000419-0005574

GLOSSARY

Agency .....Environmental Protection Agency

BSER.....Best System of Emission Reduction

CCS .....Carbon Capture and Sequestration (or Storage)

CO_2.....Carbon Dioxide

CO_2e.....Carbon Dioxide-equivalent

CSAPR.....Cross-State Air Pollution Rule

DSIRE.....Database of State Incentives for Renewables & Efficiency

EGUs.....Electric Generating Units

EIA .....Energy Information Administration

EPA .....Environmental Protection Agency

ERCOT .....Electric Reliability Council of Texas

FERC.....Federal Energy Regulatory Commission

GATS .....Generation Attribute Tracking System

GWh.....Gigawatt-hour

IPM .....Integrated Planning Model

ISO .....Independent System Operator

M-RETS.....Midwest Renewable Energy Tracking System

MATS .....Mercury and Air Toxics Standards

MISO.....Midcontinent Independent System Operator

MWh .....Megawatt-hour

NARUC.....National Association of Regulatory Utility Commissioners

NERC.....North American Electric Reliability Corporation

ED_000419-0005575

NGCC .....Natural Gas Combined-Cycle (also known as CCGT)

NODA .....Notice of Data Availability

NPRM .....Notice of Proposed Rulemaking

NRC .....Nuclear Regulatory Commission

PJM .....PJM Interconnection

PSD .....Prevention of Significant Deterioration

REC.....Renewable Energy/Electricity Certificate

RGGI.....Regional Greenhouse Gas Initiative

RPS .....Renewable Portfolio Standard

RTO.....Regional Transmission Organization

SIP.....State Implementation Plan

TSD .....Technical Support Document

ED_000419-0005576

EXECUTIVE SUMMARY

Exelon Corporation ("Exelon") hereby submits comments concerning the Environmental Protection Agency's ("EPA") proposed rule entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,"[1] as well as the supplemental proposal and notices related to the Proposed Rule published in October and November 2014.[2]

Headquartered in Chicago, Exelon does business in 48 states, the District of Columbia, and Canada. The company is one of the largest competitive U.S. power generators, with approximately 35,000 megawatts of owned capacity, comprising one of the nation's cleanest and lowest-cost power generation fleets. Exelon also owns three utilities, which deliver electricity and natural gas to more than 7.8 million utility customers in central Maryland (BGE), northern Illinois (ComEd), and southeastern Pennsylvania (PECO). Constellation's family of retail businesses serves more than 2.5 million residential, public sector, and business customers, including more than two-thirds of the Fortune 100.

Exelon strongly supports EPA's goal of reducing carbon emissions from the existing power sector. As EPA notes in the Proposed Rule, the current level of carbon emissions is environmentally unsustainable, and action must be taken now in order to prevent significant, irreversible environmental damage and major economic loss.[3] To that end, Exelon has made substantial investments in shifting to a lower-carbon portfolio. Exelon is one of the least carbon-

[1] 79 Fed. Reg. 34,830 (June 18, 2014) ("Proposed Rule" or "NPRM").

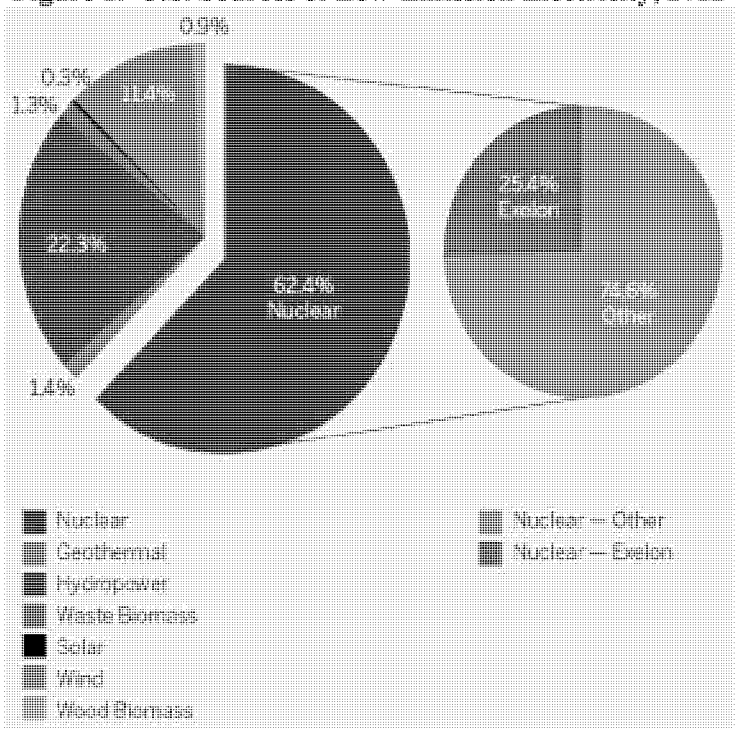
[2] Carbon Pollution Emission Guidelines for Existing Stationary Sources: EGUs in Indian Country and U.S. Territories; Multi-Jurisdictional Partnerships, 79 Fed. Reg. 65,481 (Nov. 4, 2014); Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units Notice of Data Availability, 79 Fed. Reg. 64,543 (Oct. 30, 2014) ("Goal-Setting NODA"); Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 67,406 (Nov. 13, 2014) ("Mass Translation Notice").

[3] NPRM, 79 Fed. Reg. at 34,841-44.

ED_000419-0005577

intensive generators in the United States. Exelon owns and/or operates 24 of the nation's 100 nuclear reactors in five states and is the nation's largest owner and operator of nuclear generation. As shown in Figure 1, Exelon's nuclear plants provide more than one-quarter of the U.S.'s nuclear generation, avoiding approximately 150 million metric tons of carbon-dioxide equivalent ("CO_2e").[4]

Figure 1. U.S. Sources of Low-Emission Electricity, 2012



In addition, Exelon has made significant investments in renewable generation. It owns and operates 2,000 MW of hydroelectric generation, 250 MW of solar, and 1,300 MW of wind, making Exelon the nation's tenth-largest wind generator.[5] Exelon also operates about 5,000 MW of low-emitting natural gas generation in New England and Texas. In total, Exelon's

[4] Nuclear Energy Institute ("NEI"), "Nuclear Energy: America's Low-Carbon Electricity Leader," (May 2014). *Available at* http://www.nei.org/CorporateSite/media/filefolder/Backgrounders/Fact-Sheets/Nuclear-Energy-Americas-Low-Carbon-Electricity-Leader-May-2014.pdf?ext=.pdf. NEI data, Exelon graphic.

[5] Solar generation total includes projects under construction.

ED_000419-0005578

current fleet net generating capacity is 55 percent nuclear, 28 percent natural gas, and more than ten percent hydro, wind, solar, and other clean generation, with the remainder coal and oil-fired generation.[6] As one of the nation's leading clean energy generators with a nationwide presence, Exelon is uniquely situated to evaluate EPA's Clean Power Plan, to comment on its impact on the wholesale energy markets in which Exelon participates, and to offer suggestions to strengthen and improve the final rule. In our comments below, Exelon submits the following points for EPA's consideration:

1. In order to mitigate the cost borne by consumers, EPA should adopt a safe harbor that places a consumer protection price ceiling on overall compliance costs during the interim compliance period (2020-2029). Under the "Smart System Dispatch" program described below, EPA would determine a carbon fee sufficient to achieve the interim goals, and states adopting such a fee would be deemed to comply with the interim goals – locking in a maximum compliance cost while still reducing carbon pollution consistent with the interim goals. Contrary to the dire predictions of opponents of the rule, new data released by the nation's grid operators show that the industry can immediately begin to control carbon pollution while maintaining electric reliability, and do so at a cost in line with the typical increases that utilities themselves have charged customers over the past year. Recent modeling by regional transmission organizations ("RTOs") and other stakeholders shows that EPA's interim goals could be achieved at a modest cost, and that states could eliminate at least 80 percent of the rule's impact on retail electric rates if they use the fees collected for consumer relief.

[6] Exelon's remaining coal-fired assets are currently under an agreement of sale.

ED_000419-0005579

By participating in Smart System Dispatch, states could limit average consumer costs due to the rule to a total increase of two to five percent for the decade-long interim period. By way of comparison, average retail electric rates rose 35 percent between 2003 and 2013 and an average of 3.2 percent between 2013 and 2014. In other words, this option would allow states to *guarantee* interim compliance for an average consumer cost increase far smaller than typical retail rate increases.

These low consumer impacts are possible because EPA could effectively cap interim compliance costs at a very modest figure. Recent modeling by PJM Interconnection, LLC ("PJM"), the largest grid operator in the country,[7] suggests that EPA's interim goals can be achieved in the PJM states for a carbon fee as low as $15 or $20 per ton.[8] The Electric Reliability Council of Texas ("ERCOT") found that similar costs, between $20 and $25 per ton, would suffice to achieve even the more stringent final goal within ERCOT.[9] If compliance costs are contained at these levels and redirected to consumer rate relief, average consumer costs will likewise be contained. Thus, contrary to claims that a U.S. program to combat climate change will cripple the economy and compromise electric reliability, the data from PJM and ERCOT demonstrate that compliance can be achieved at costs below the average utility retail rate increases that are driven by inflation and rate case filings.

---

[7] PJM serves more than 61 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

[8] PJM Interconnection, Inc., "EPA's Clean Power Plan Proposal, Review of PJM Analyses Preliminary Results" (Nov. 17, 2014) at 33 ("PJM Modeling"), *available at* http://www.pjm.com/~/media/committees-groups/committees/mc/20141117-webinar/20141117-item-03-carbon-rule-analysis-presentation.ashx.

[9] ERCOT Analysis of the Impacts of the Clean Power Plan (Nov. 17, 2014) at 1 ("ERCOT Modeling"), *available at* http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf.

ED_000419-0005580

Smart System Dispatch relies on the reliability-driven least-cost dispatch mechanisms of regional and local grid management systems, and so preserves the viability of the existing generation fleet as necessary to preserve reliability. That is why Smart System Dispatch and variations of it are being endorsed by electric industry organizations, environmental groups and other stakeholders. As EPA has noted many times, environmental protection and reliable, affordable electricity are not mutually exclusive. The dramatic reductions in carbon pollution that EPA seeks can be achieved at a small cost to consumers, but only if EPA clears a path for states to contain compliance costs. Of course, the safe harbor program would be optional, and would not limit the latitude EPA gives states in the Proposed Rule to develop unique implementation plans. For example, EPA could approve lower fees in states that implement Smart System Dispatch before 2020, leading to equivalent carbon pollution reductions through 2029.

Exelon strongly supports EPA's fundamental premise that the "best system of emission reduction" is one that leverages the integrated electric generation, transmission, and distribution system.[10] As we detail below, grid operators often control dispatch on a regional basis, as the electricity system is interconnected and electrons flow freely across state borders. The order of dispatch is primarily based on units' relative variable costs and these variable costs do not currently reflect relative carbon pollution. Unless incorporated through the costs of pollution control or other costs, units' environmental attributes are not considered in dispatch decisions. To affect the order of dispatch, it is necessary to change the variable costs of coal units relative to natural gas and other lower-carbon units.

[10] 42 U.S.C. § 7411(a)(1); NPRM, 79 Fed. Reg. at 34,878-81.

ED_000419-0005581

Smart System Dispatch would apply a predetermined cost of CO_2 to each unit based upon its individual characteristics (*e.g.*, carbon intensity) to establish a unit-specific variable cost that would be included in the unit's market bid. A similar approach can be deployed in states without organized markets. Through modeling similar to that performed by PJM, ERCOT, and other RTOs, EPA would determine the carbon fee necessary to achieve the carbon pollution reductions reflected in its emission rate goals. Generators in participating states would then account for that cost in determining the price at which they are willing to offer to sell electricity. As a result, lower-carbon units would become more likely to offer lower prices than coal units, and accordingly would be dispatched more frequently relative to the coal units.

A voluntary "safe harbor" – under which a state choosing to participate in such a program would be deemed compliant with interim targets – would provide states with a strong incentive to adopt what is effectively a coordinated regional emissions reduction strategy. States would enjoy planning certainty for the interim period and could begin the longer-term planning process to achieve their 2030 goals, free from immediate compliance uncertainty. Moreover, by participating in such a program, states would provide long-term market signals that would catalyze capital investment in cleaner resources – including in technologies that have yet to be commercialized.

As EPA has recognized, a regional approach toward compliance (like Smart System Dispatch) can achieve emissions reductions more cost-effectively and produce significantly greater net benefits than a state-by-state approach.[11] This approach would also mesh well with the existing control mechanisms in place in the nine states of the Regional Greenhouse Gas Initiative ("RGGI") and California, and provide support for those programs by reducing

[11] NPRM, 79 Fed. Reg. at 34,840.

ED_000419-0005582

"leakage," the shift of generation to states without carbon regulation. Most importantly, because Smart System Dispatch relies on existing market mechanisms designed to ensure electric reliability (*e.g.*, reliability-driven least-cost dispatch), it would obviate any reliability concerns. As a leading participant in the nation's wholesale electricity markets – as a generator, marketer, and purchaser – Exelon agrees with EPA that "mechanisms are in place in both regulated and [restructured] electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected [electric generating units ("EGUs")]."[12] EPA can have confidence in the resiliency of the wholesale electricity markets in the face of changes in supply resulting from the Clean Power Plan, and the Agency should resist calls to weaken or delay interim goals.

Accordingly, Exelon urges EPA to establish in the final rule a safe harbor for states that adopt Smart System Dispatch, and deem participating states to have complied with their interim goals as long as they remain in the program.

2. EPA's treatment of nuclear power is seriously flawed and should be revised in order to ensure that the existing nuclear fleet remains available to provide carbon-free generation. Although Exelon broadly supports EPA's objectives and the Proposed Rule's focus on the integrated electrical system as providing the best system for emission reduction ("BSER"), the Proposed Rule is flawed in ways that jeopardize EPA's emission-reduction objectives and Clean Air Act mandates. One of the most important of these flaws concerns the Proposed Rule's treatment of the existing nuclear fleet, as numerous other stakeholders have indicated.

[12] EPA, Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602-0419 ("EPA Legal Memorandum"), at 88.

ED_000419-0005583

As EPA correctly recognizes, preserving the existing nuclear fleet is an essential precondition to reducing carbon emissions. Nuclear facilities currently provide almost 65 percent of the nation's carbon-free electricity. A single nuclear plant represents a substantial infrastructure investment and generates enough electricity to power hundreds of thousands of homes. Nuclear plants operate reliably even during adverse weather conditions, regardless of the availability of wind or sun and in all weather extremes.

Until recently, nuclear plants were assumed to continue operating until license expiration or beyond. That expectation is no longer sound. Many nuclear plants that are producing large quantities of emissions-free electricity and operating at above 90 percent capacity factors are in danger of early closure. Among the causes has been the lack of a coherent carbon policy. The federal government and many states have reacted to the absence of carbon legislation by implementing subsidies and mandates that benefit specific types of generation, but not nuclear, the largest and most reliable carbon-free energy source. These policies have had the unintended effect of undermining the economics of nuclear energy production. In 2013 alone, approximately four GW of nuclear generation retirements were announced. Wall Street analysts and industry experts predict a continuing wave of nuclear retirements, as well as decisions to forgo plans to improve the output of existing nuclear plants (known as "uprates").[13] Exelon itself is evaluating the closure of four plants and previously announced the upcoming retirement of a fifth; and it has cancelled nuclear uprate projects that would have increased the output at existing nuclear facilities, providing even more carbon-free generation.

[13] *See, e.g.*, Credit Suisse, "Nuclear… The Middle Age Dilemma" (Feb. 2013); UBS, "US Electric Utilities and IPPs" (Jan. 2013).

ED_000419-0005584

Further, the early retirement of nuclear units will make the achievement of meaningful carbon reductions difficult or impossible. Replacing even a single nuclear plant with other carbon-free generation resources would, given current technology, be extremely challenging; more likely, if a nuclear plant retires prematurely, the bulk of its capacity will be replaced by new natural gas combined-cycle ("NGCC) plants without carbon capture, resulting in a significant net increase in carbon emissions. Thus, preserving existing nuclear plants would be crucial even if EPA's goal were merely to prevent *increased* carbon emissions – let alone to achieve the *reduced* carbon emissions required by the statute and scientific realities.

The Proposed Rule falls far short of what is needed. It perpetuates a policy of supporting renewable generation while largely ignoring the contribution of existing nuclear plants in avoiding carbon emissions. For example, in determining each state's initial emissions rate and its emissions goals, EPA has proposed to include *all* megawatt-hours of electricity presently generated by wind and solar generating facilities. Doing so provides states with a strong incentive to preserve all such renewable resources. Illogically, however, EPA proposes to include only *six percent* of the generation from a state's existing nuclear fleet. That approach leaves a state largely indifferent to the early retirement of existing nuclear capacity.

To the extent that EPA finalizes a rule that sets rate goals instead of mass goals, EPA should set initial rates and calculate interim and final goals using a system-wide rate that accurately reflects a state's entire existing portfolio of generation resources, instead of ignoring nearly all of the existing nuclear fleet and all hydropower generation. Failing that, EPA should revisit the justification for considering only six percent of generation from a state's existing nuclear fleet, as the six-percent approach is also flawed on its own terms. The Proposed Rule reasons that, on average nationwide, six percent of the nation's nuclear facilities are at risk of

ED_000419-0005585

premature retirement. In reality, the percentage of nuclear capacity at risk of premature retirement varies dramatically from region to region. In some areas – such as Illinois – that percentage approaches half of existing nuclear capacity. EPA's final rule should encourage states to take all necessary steps to protect existing nuclear plants from retiring early, or many states simply will not achieve emission reductions – even if those states can demonstrate on-paper compliance with EPA's rate goals.

3. EPA should modify its goal-setting in several respects. As suggested in the Goal-Setting Notice of Data Availability ("NODA"), EPA should develop states' emission goals in a manner consistent with the Agency's determination of the BSER.[14] That requires several additional changes to the way in which EPA has established states' goals. First, EPA should value incremental renewable energy generation and energy efficiency in Building Blocks 3 and 4 in terms of the CO_2 emissions they avoid by displacing existing fossil fuel generation. Currently, EPA values them only as additional megawatt-hours ("MWh") of generation, and fails to account for or require displacement of existing fossil fuel-fired generation, an approach inconsistent with the BSER rationale.

Second, when determining reductions available to states from Building Block 2, EPA should consider a state's potential for reducing emissions by redispatching not only to existing NGCCs located within the state, but also to NGCCs located in other states that are electrically interconnected with the state. Because redispatch can and will be performed on a regional basis, even states with little or no under-utilized NGCC capacity may still be able to realize substantial emissions reductions through redispatch. Reductions in carbon emissions achievable through regional redispatch can be allocated among states in the region based upon a rational criterion

[14] Goal-Setting NODA; 79 Fed. Reg. at 64,546-47, 64,549-52, 64,552-53.

ED_000419-0005586

such as historic generation, cost, or accepted modeling protocols, as EPA has done in the Cross-State Air Pollution Rule ("CSAPR") and other rules governing the electricity sector.

Moreover, when determining reductions available to states from Building Block 3, EPA should ensure that a state's goals are matched to the means available to comply with those goals. Thus, for example, if EPA continues to allow states to demonstrate compliance through renewable energy credit ("REC") programs that allow the purchase of RECs from any other state, then EPA should modify emissions targets for Building Block 3 to reflect that possibility of compliance. Currently, the emissions targets are premised on renewable generation presumed to be available within state borders. But states that themselves may lack the conditions for robust renewable generation may nonetheless be able to carry out substantial emissions reductions in Building Block 3 by buying RECs produced by renewable facilities in other states. Moreover, Building Block 3 should also account for states' ability to buy clean energy credits produced by nuclear and hydropower facilities with regard to both goal-setting and compliance calculations.

Third, EPA should account for reductions achievable from increased co-firing of natural gas as part of Building Block 1. Co-firing is an "inside the fence" change that will reduce emissions from existing coal-fired EGUs.

4. EPA should clarify treatment of new NGCCs to prevent gamesmanship that would undermine EPA's emissions reduction goals. As EPA recognizes, states may seek to achieve EPA's emission rate goals by encouraging the development of new NGCCs, which would be expected to displace generation from higher-emitting existing EGUs. EPA has requested comment on how to account for emissions from new NGCCs. Proper accounting for those emissions is critical in order to prevent gamesmanship that would undermine EPA's emission-reduction goals. If a state adopts a program that establishes an emissions mass limit (a

ED_000419-0005587

"mass-based" program), EPA should expressly indicate that a state will be required to account for the emissions of new NGCCs that displace existing EGUs in demonstrating compliance with emissions targets. Otherwise, such a state might argue that it can demonstrate compliance with its mass target simply by replacing its existing EGUs with new NGCCs, without actually meaningfully reducing carbon emissions at all.

A state that adopts a program limiting the rate at which carbon is emitted to generate a megawatt-hour of electricity (a "rate-based" program; as proposed (lb/MWh)) should be permitted to take new NGCCs into account for purposes of demonstrating compliance *only to the extent* that the new NGCCs are proven to displace higher-emitting existing EGUs. This approach is consistent with EPA's description of how new NGCCs would be treated in the Goal-Setting NODA.[15] Otherwise, a state whose emissions rate exceeds that of a new NGCC could attempt to comply simply by introducing new NGCCs to its generation portfolio, without otherwise reducing carbon pollution from existing EGUs. The new NGCCs would bring down the state's calculated emissions rate, even while actually *increasing* total emissions.

5. EPA must adopt accounting rules for interstate trading of RECs and emission allowances that prevent the double-counting of emissions reductions. The Proposed Rule is correct to envision that trading of RECs and carbon emission allowances will play a significant role in allowing states to achieve their emission reduction goals in a cost-effective manner. Without proper guidance from EPA, however, this sort of trading has pitfalls that could hinder achievement of those goals. For instance, without proper accounting rules, trading could result in double-counting of the emission-reduction benefits resulting from zero-carbon generation. It also could result in states taking credit for such generation beyond its

[15] *See* Goal-Setting NODA, 79 Fed. Reg. at 64,546, 64,550.

ED_000419-0005588

actual effect on emissions. In addition, failure to provide states with equal trading opportunities regardless of their chosen compliance method (rate or mass) could leave states with artificial incentives to elect rate-based systems, even though regional mass-based approaches can reduce emissions most efficiently. These and other problems can be readily addressed by appropriate Agency guidance. Accordingly, we propose a set of accounting rules concerning both REC and allowance trades that are consistent with the approach taken by California and upon which EPA could rely in order to prevent double-counting.

6. EPA should adopt mass-based emissions targets rather than rate-based targets. Many of the problems with the Proposed Rule just discussed – inadequate incentives to preserve nuclear generation, the need for rules to govern the treatment of new gas plants in rate-based states, the potential for double-counting due to the trading of RECs among rate-based states and between rate-based and mass-based states – could be avoided if EPA were to require states to meet emissions targets expressed in terms of the total mass of CO_2 emitted rather than in terms of a rate. Such mass-based targets allow emissions reductions to be achieved most efficiently and with the least regulatory complexity. Further, the statute allows EPA to mandate a mass-based approach as the BSER. Accordingly, the final rule should utilize EPA's mass-based emissions targets as the emission reduction goals upon which state plans will be evaluated, rather than the proposed rate-based targets. At a minimum, EPA should employ a mass-based check when evaluating the adequacy of a state plan or compliance with a rate-based standard.

ED_000419-0005589

COMMENTS

I. THE INTERIM GOALS ARE ACHIEVABLE, BUT EPA SHOULD PROVIDE A SAFE HARBOR FOR STATES THAT HARNESS EXISTING LEAST-COST ELECTRIC DISPATCH MECHANISMS TO CONTAIN COSTS AND MINIMIZE IMPACTS ON RETAIL ELECTRICITY CONSUMERS.

EPA has proposed state-by-state emission goals that must be achieved, on average, over the interim compliance period from 2020 to 2029. These interim goals can be achieved for a reasonable cost, while ensuring continued electric reliability, preserving the value of existing generation assets and minimizing impacts on electricity consumers. As an additional option for compliance, EPA should explicitly allow states to comply with the interim goals by choosing to participate in a program – which we call "Smart System Dispatch" – that harnesses existing reliability-driven least-cost dispatch to shift generation to cleaner sources while ensuring reliability and protects consumers by placing a ceiling on compliance costs. Under Smart System Dispatch, EPA would determine a uniform per-ton fee on CO_2 emissions from power plants that would result in emissions reductions commensurate with EPA's interim goals. Carbon-emitting generators in a state that opts into this program would include that carbon value as a cost of operating, and the state would be deemed to comply with its interim goals as long as it participates in Smart System Dispatch, regardless of its actual emissions and emissions rate. Of course, states would remain free to adopt other implementation mechanisms that would achieve their targets; however, a full compliance demonstration and interim compliance checks would be required.

As noted, carbon-emitting power plants in states participating in Smart System Dispatch would account for the carbon fee when determining the amount for which they were willing to

ED_000419-0005590

sell their electricity.[16] As a result, lower-emitting units would be relatively less expensive than higher-emitting units, all other factors being equal. This price differential would in turn cause lower-emitting units to operate more frequently, and higher-emitting units to operate less. However, higher-emitting units would not be precluded from operating when they are economic, which would keep many of those plants available when needed to maintain reliability. In addition, under the Smart System Dispatch program, the carbon fees could be directed to the load-serving entities that deliver electricity to retail customers, avoiding significant retail bill increases during the interim compliance period.[17]

Recent modeling conducted by PJM indicates that a carbon fee sufficient to achieve the aggregate interim goals of the PJM states – $15 to $20 per ton – would increase retail electric bills by less than five percent if the fees were used for consumer relief. Acting on a request by its member states, PJM modeled fifteen scenarios, some of which included extremely conservative assumptions (*e.g.*, very high natural gas prices), for the years 2020, 2025, and 2029, bracketing the interim compliance period. For each scenario, "[t]he approach results in satisfying the emission target with the least cost mix of resources to meet PJM load requirements."[18] PJM's "load requirements" include a substantial "reserve margin," that is, additional generation over and above PJM's projections for peak electricity demand in order to ensure electric reliability. While the carbon fee necessary to achieve EPA's interim goals varies

[16] Just as EPA expresses the cost-effectiveness of other emissions reduction methods, the carbon fee would be expressed as an amount per ton of CO_2 emitted, but would be assessed on each megawatt-hour of electricity sold, based on the carbon intensity of the generation source. For example, if the carbon fee were set at $20 per ton, a coal plant with an emissions rate of 2,000 lb/MWh would add $20/MWh to the price at which it offers to sell its electricity (or, in a regulated market, the implicit price).

[17] There are any number of ways to allocate the revenue; the key is to properly implement the carbon price, thus reordering dispatch through existing price-based mechanisms.

[18] PJM Modeling at 33.

ED_000419-0005591

in each scenario, PJM's modeling shows that the interim goals can be achieved, without threatening reliability, through a carbon fee comparable to the cost of other measures that EPA determined to be cost-effective, and well within the bounds of EPA's estimated social cost of carbon.[19] EPA could use similar modeling techniques to determine a uniform carbon fee sufficient to achieve emissions reductions commensurate with the Proposed Rule's interim goals.

Moreover modeling by PJM and other stakeholders shows that consumers would be protected from significant bill increases, as long as states applied carbon fees to retail rate relief. Retail consumers would experience a total increase of just one to five percent between 2020 and 2029, far less than typical rate increases. Smart System Dispatch would not only meet EPA's interim emission goals; it would also answer the objections of those who urge EPA to postpone the reductions required by the Proposed Rule. The program would function as a regional, market-based compliance plan without the complex interstate negotiations necessary to produce a multistate compliance plan. Regional market-based programs offer lower total costs, fewer forced retirements, undisturbed grid management ensuring reliability, and, if carbon fees are redistributed to load-serving entities, minimized impact on retail electric bills. Moreover, Smart System Dispatch would enhance the effectiveness of existing carbon reduction programs in California and the RGGI states by reducing leakage. Thus, the interim goals proposed by EPA do not need to be relaxed or delayed, particularly if EPA offers states a safe harbor through participation in Smart System Dispatch.

---

[19] *See* NPRM, 79 Fed. Reg. 34,856-58; EPA, "Fact Sheet: Social Cost of Carbon" (Nov. 2013), *available at* http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf.

ED_000419-0005592

A. EPA's Proposed Interim Goals Are Reasonable.

1. EPA's Approach Reflects the Operation of the Electric System.

Exelon supports EPA's basic premise that the integrated electric generation, transmission, and distribution system itself plays an important role in determining the BSER.[20] Electricity itself is a fungible commodity, and the lower 48 states are served by three interconnected electric grids through which electricity flows without regard to political boundaries. Whether a particular generation unit operates at any given time depends upon whether the unit will be paid the price it requires to operate; if other plants in the same interconnected grid are willing to supply that electricity for a lower price, those will be dispatched instead. As EPA has correctly explained, "[t]he fact that generation at one EGU can be substituted for generation at another allows operators to utilize their least-cost assets first, and hold their higher-cost assets in reserve, thereby assuring that the system achieves the objectives of providing reliable and least-cost electricity service."[21] To the extent that environmental regulations raise the cost of generation at higher-emitting facilities, they tend to shift generation away from those facilities toward lower-emitting sources. Thus, as EPA has recognized in CSAPR and other rules affecting the electricity sector, the most cost-effective approach to emissions reductions leverages the integrated nature of the electricity market to shift production from higher-emitting sources to lower-emitting sources.[22]

Accordingly, it is appropriate for EPA to base standards of performance for affected sources on reductions that could be achieved from so-called "outside the fence" actions – that is,

---

[20] 42 U.S.C. § 7411(a)(1); See also, *e.g.*, 79 Fed. Reg. 34,836.

[21] EPA Legal Memorandum at 44.

[22] This effectively reverses current market distortions, where cleaner sources are often underbid by dirtier resources that are not required to internalize the cost of their emissions.

ED_000419-0005593

those that exploit the interconnected nature of the electric system as a whole – while, of course, giving states the flexibility to achieve those standards of performance through the policies of their choice. Moreover, because of the limited potential for reductions from "inside the fence" actions, including modifications to existing fossil fuel-fired generation units or their fuels, EPA must look "outside the fence" to the electric system as a whole in order to achieve the meaningful reductions in carbon emissions from affected units that the Clean Air Act requires.[23] The BSER should not be handicapped by artificially restricting CO_2 reduction potential to inside-the-fence actions. While the displacement of CO_2 emissions by outside-the-fence options must be subject to verification, redispatch to lower-carbon resources, renewable energy and improved end-use energy efficiency undeniably have the potential to reduce CO_2 emissions by reducing fossil generation.

2. EPA's Proposed Interim Goals Are Achievable and Should Not Be Relaxed.

The proposed interim goals are derived using the same "building blocks" EPA used to determine the proposed final goals. However, the interim goals reflect the reality that some emission reduction techniques must be deployed over a longer period of time than others. Therefore, the interim goals are based primarily on emission reductions from Building Block 1 (heat rate improvements at coal plants) and Building Block 2 (redispatch of generation from coal plants to under-utilized NGCC plants), as well as preservation of some existing nuclear

[23] As numerous commenters noted during development of the Mercury and Air Toxics Standards ("MATS"), CSAPR, and other recent rulemakings, there is not a distinct line between "inside" and "outside" the fence actions in the electric sector. All individual unit actions necessarily increase or decrease demand on other units, and all actions part of the BSER ultimately reduce emissions by affected sources. *See* NPRM, 79 Fed. Reg. at 34,889 n.237. In fact, "inside the fence" reductions based on heat-rate improvements could paradoxically increase carbon emissions by making high-emitting generators relatively more efficient compared to lower-emitting alternatives, resulting in their more frequent dispatch.

ED_000419-0005594

generation, that EPA has determined can be accomplished between the rule's finalization in 2015 and the beginning of interim compliance in 2020. Additional reductions from new renewable energy facilities and energy efficiency projects will be phased in over the course of the interim period, and the interim goals reflect the average of the achievable emissions rates for each of the interim years. Thus, EPA proposed a ten-year averaging period for compliance with the interim goals to provide sufficient time for states to implement all of the reductions necessary to meet these goals. The phase-in of Building Blocks 3 and 4 and the ten-year averaging period, not to mention the five years between finalization and the beginning of the compliance period, combine to provide the electric industry with a gradual "glide path" to the final goals.

Nonetheless, the interim goals have been criticized as requiring too much, too soon. In the Goal-Setting NODA, EPA discussed several categories of comments the Agency has received, including many aimed at weakening and delaying the interim goals, or eliminating them entirely. Some commenters insist that additional natural gas and electric transmission capacity will be required before some NGCCs are able to achieve the higher capacity factors projected by EPA.[24] Some commenters unabashedly exaggerate the suddenness with which emissions must be reduced to meet the interim goals, while others express concerns about the potential that state implementation measures will force coal-fired plants to retire.[25]

To evaluate and address these concerns, EPA solicited comment on two alternative approaches to the interim goals which would delay some of the emission reductions attributed to Building Block 2 beyond 2020. One approach would relax the interim goals by deferring some Building Block 2 reductions if states demonstrate that the infrastructure improvements necessary

[24] Goal-Setting NODA, 79 Fed. Reg. at 64,546, 64,548.

[25] *Id.* at 64,544, 64,546, 64,548-49.

ED_000419-0005595

to achieve those goals cannot be constructed by 2020.[26] A second approach would be to delay some Building Block 2 reductions indefinitely based on a concept of "book life," meaning that coal-fired plants might be allowed to continue to operate without emission reductions until their financial value is fully amortized.[27] EPA should reject these approaches, which will lock in avoidable CO_2 emissions.

As a starting point, it is clear that significant reductions in CO_2 emissions can be achieved by 2020 and sustained thereafter by maximizing the redispatch of coal-fired generation to existing NGCCs. The recent PJM modeling proves as much and, as we discuss below, other modeling efforts have produced comparable results. While concerns about electric or natural gas transmission capacity may be real in specific instances, these issues are not widespread and should not be used as an excuse to weaken or delay all interim reductions. More importantly, these instances are already factored into the existing grid-management system on which Smart System Dispatch relies. For example, if a NGCC plant becomes unavailable due to a natural gas curtailment, a different plant will be dispatched to take up its load, even if that plant is a higher-cost, higher-emissions coal plant. By relying on existing mechanisms of reliability-driven least-cost dispatch, Smart System Dispatch would render moot the potential concerns raised by the North American Electric Reliability Corporation ("NERC") with regard to resource adequacy and essential reliability services. NERC's preliminary qualitative analysis assumed that the Building Blocks were implemented literally, without regard to reliability-driven least-cost

[26] *See id.* at 64,548.

[27] *See id.* at 64,548-49.

ED_000419-0005596

dispatch across states, which necessarily would increase costs and reduce reliability margins beyond what would actually be expected to occur.[28]

B. Smart System Dispatch Would Minimize Compliance Costs and Minimize Consumer Impacts While Reducing CO_2 Emissions Commensurate with EPA's Interim Goals.

1. Smart System Dispatch Would Work in Harmony With Existing Grid Management Tools.

Affecting the order of dispatch so that lower-carbon sources are more likely to operate before higher-carbon sources is a critical component of the BSER, as set forth in the Proposed Rule. Currently, for example, many coal plants have lower variable costs than natural gas plants; as a result, coal plants tend to be dispatched first. EPA suggests at least two alternatives by which a state could affect the order of dispatch. States could either "impose limits on the hours of operation (or emissions) of individual [EGUs] over a given time period," or "change the relative costs of generation for more carbon-intensive and less carbon-intensive generating units by imposing a cost on carbon emissions."[29] Smart System Dispatch is an example of the latter approach, and is thus a logical outgrowth of the Proposed Rule.

States that choose the former approach will be required to impose operating permit constraints on individual plants, limiting hours of operation or setting emission caps in order to achieve their goals. Such measures work against, not with, the system of reliability-driven least-cost dispatch at the heart of the grid-management system. Limits on operating hours or total emissions at a given power plant would reduce, or at least effectively cap, CO_2 emissions from

---

[28] *See* North American Electric Reliability Corporation, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review" (Nov. 2014), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf (hereinafter "NERC Initial Reliability Review").

[29] NPRM, 79 Fed. Reg. at 34,882.

ED_000419-0005597

that source, but would complicate dispatch decisions and could render the plant unavailable when it is needed most. Instead, EPA should encourage states to leverage the nation's existing system of reliability-driven least-cost electricity dispatch by adopting Smart System Dispatch. In general, grid operators would find such a system much easier to navigate – and less potentially disruptive to the existing electricity markets – than the thicket of idiosyncratic state compliance schemes that could arise in response to states' implementation of the final rule.

Any rule seeking to achieve cost-effective emissions reductions from the electricity sector must be designed to function in harmony with both restructured and traditionally regulated markets for electricity in which a plant's cost of operation is the most critical factor in determining whether and when that plant runs. As EPA recognizes, "[t]he nation's EGUs are interconnected by transmission grids extending over large regions. EGU owners and grid operators … use the flexibility provided by these interconnections to prioritize among available EGUs when deciding which units should be called upon … to increase or decrease generation in order to meet electricity demand at any point in time."[30] Because electricity demand varies, grid operators must "constantly respond[] to changes in demand and 're-dispatch[]' to meet demand in the most reliable and cost-effective manner possible."[31]

The order of dispatch is determined by a bidding process. Each owner of an EGU submits a "bid" to the grid operator indicating the price at which it is willing to run its unit. Typically, the bid will be directly linked to the unit's marginal operating cost, which includes

[30] *Id.* at 34,862.

[31] *Id.*

ED_000419-0005598

fuel, pollution controls, and the cost of pollution allowances or fees. The grid operator then typically dispatches units in ascending cost order until demand is met.[32]

In the U.S., prior pollution control programs (for example, the Title IV program (Acid Rain Program), the NO_x SIP Call, and Clean Air Interstate Rule) have achieved significant cost-effective reductions by imposing a cost on pollution. The same principle applies here. Efficient NGCC plants emit carbon dioxide at a rate that is roughly 40 percent that of coal plants, and even single-cycle gas turbines and natural gas-fired steam plants have lower emissions rates than coal-fired plants. Yet these gas plants tend to have higher operating costs, and thus bid higher and run less frequently than higher-emitting coal plants. Smart System Dispatch would use a carbon fee to bridge this gap, achieving the "redispatch" envisioned by EPA in Building Block 2. The fee would be "factored directly into [the] EGUs' variable costs, like the variable costs of operating pollution control devices," and would "thereby [be] accounted for in least-cost economic dispatch decisions by grid operators."[33]

Smart System Dispatch would help to implement EPA's other building blocks as well. A carbon fee would incentivize the heat rate improvements envisioned by Building Block 1, because coal plants with lower CO_2 emissions will be rewarded with lower carbon fees per megawatt-hour. A fee would also aid the development of energy efficiency and renewable

[32] The price that a unit receives, however, is not necessarily equal to its bid. Wholesale electricity markets operate on the principle of the "single market clearing price." All generators are paid a price based on the bid of the last unit needed to meet demand. This pricing scheme creates a powerful incentive to reduce operating costs, as units with lower operating costs can submit lower bids and be dispatched more frequently, and can earn larger profit margins (the difference between their costs of operation and the ultimate clearing price) when they are dispatched.

[33] NPRM, 79 Fed. Reg. at 34,862. Data concerning each generator's facility-specific emissions in generating electricity are already available. For example, PJM, the nation's largest RTO, and MISO, the nation's second largest RTO, currently participate in the "Generation Attribute Tracking System" ("GATS") and the Midwest Renewable Energy Tracking System ("M-RETS"), which are capable of identifying the emission characteristics (including the facility-specific CO_2 emissions rate) of each megawatt-hour delivered to the grid. See http://www.pjm-eis.com/ and http://www.mrets.org/.

ED_000419-0005599

generation and prevent the premature retirement of nuclear and hydropower plants, as envisioned by Building Blocks 3 and 4. Moreover, if implemented regionally, Smart System Dispatch could address the concerns of some stakeholders that Building Block 2 "has little or no effect on certain states with large amounts of coal-fired generation and limited excess NGCC capacity,"[34] or on states with "little existing natural gas infrastructure" that otherwise "do not have the same opportunities to shift generation to lower-emitting NGCC units."[35] Lastly, a meaningful, longer-term carbon price would incentivize the commercialization of novel technologies to drive further emission reductions in the sector.

The Proposed Rule recognizes the benefits of leveraging the existing regional bulk power system administered by grid operators to achieve emissions reductions. Such "regional approaches," the Proposed Rule notes, "may reduce costs and strengthen the reliability of the electricity grid."[36] As EPA acknowledges, emissions reductions can be achieved more efficiently, and with greater net benefits, if they are pursued through a coordinated regional approach rather than a state-by-state approach.[37]

2. Smart System Dispatch Would Contain Compliance Costs, Achieving the Interim Goals at a Reasonable Carbon Fee.

As noted above, PJM has released preliminary results from a modeling effort requested by PJM states.[38] PJM considered fifteen scenarios representing a range of assumptions in the context of regional rate-based as well as regional and state-by-state mass-based compliance

---

[34] Goal-Setting NODA, 79 Fed. Reg. at 64,551.

[35] *Id.* at 64,550.

[36] NPRM, 79 Fed. Reg. at 34,899.

[37] *Id.* at 34,840.

[38] Organization of PJM States, Inc., Letter from L. Ann McCabe to Terry Boston, PJM (Sept. 2, 2014) *available at* http://www.pjm.com/~/media/committees-groups/committees/mc/20141117-webinar/20141117-item-03-carbon-rule-analysis-opsi-request.ashx.

ED_000419-0005600

programs for 2020, 2025 and 2029.[39] PJM extracted several values, including implied carbon price, total production costs, and likelihood of retirements. Qualitatively, PJM found that regional mass-based systems had lower production costs, lower carbon prices, and fewer units at risk of retirement than rate-based systems.[40] PJM found implied carbon prices of $20 or less to be sufficient for compliance with interim goals in all but a handful of the most conservative scenarios, as averaged over the three modeled years.[41] PJM continues to refine its modeling and may produce additional results.

A number of other modeling efforts suggest similar carbon fees would achieve the proposed interim goals. ERCOT found that EPA's interim and final goals would be achieved by a carbon fee of no more than $25 per ton.[42] Similar carbon fees have also been proposed by environmental groups and other utilities.[43] While EPA must ultimately determine the uniform

---

[39] PJM Modeling at 22-23. PJM has not yet completed analysis of state-by-state rate-based systems given their complexity.

[40] *Id.* at 43, 44, 58.

[41] *Id.* at 26.

[42] ERCOT Modeling at 1.

[43] The Clean Air Task Force published an analysis by the Northbridge Group prior to publication of the Proposed Rule suggesting that a carbon price of $20 per ton of CO_2 emissions (if a price is put on emissions from coal-fired plants only) or $34 per ton of CO_2 emissions (if a price is put on emissions from all fossil fuel-fired plants) would achieve substantial reductions in CO_2 emissions, largely from re-dispatch to lower-emitting existing gas-fired plants. *See* Clean Air Task Force, "Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants," at 6 (Feb. 2014), *available at* http://www.catf.us/resources/publications/files/Power_Switch.pdf; Bruce Phillips, The NorthBridge Group, "Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," at 2-3 (Feb. 27, 2014) ("Northbridge CATF Report"), *available at* http://www.catf.us/resources/publications/files/NorthBridge_111d_Options.pdf. *See also* A. Chang, J. Weiss, Y. Yang, "A Market-based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector" (April 2014) (proposing a carbon fee-based approach with a carbon fee ranging from $5 to $25 per ton during the interim period), *available at* http://www.brattle.com/system/publications/pdfs/000/005/003/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector_Chang_Weiss_Yang_Apr_2014.pdf.

ED_000419-0005601

carbon fee adequate to qualify for the safe harbor, there is much evidence that a fee of about $20 per ton would be sufficient.[44] Such a fee would be comparable to the cost of measures that EPA has determined to be cost-effective, and far less than the estimated social cost of carbon.[45] A uniform carbon fee of about $20 per ton would also protect ongoing CO_2 emissions reductions from existing mass-based programs in California and the nine RGGI states. These states have adopted allowance auction systems with minimum or "reserve" allowance prices that function as a minimum carbon fee. California's program increases the reserve price each year; the reserve price will exceed $20 per ton by 2024.[46] RGGI's reserve prices are lower, but RGGI allowance prices are expected to be approximately $10 per ton by 2020 even without the Proposed Rule, with prices increasing as the number of allowances is reduced.[47] These existing CO_2 reduction

---

[44] One Bloomberg study concluded that a carbon price of $10 per ton applied uniformly across the country would be sufficient to bring power-sector GHG emissions below the 23 percent below 2005 levels by 2020 estimated as a result of the Proposed Rule, and that a price of $25 per ton would bring emissions 25 percent below 2005 levels by 2030. William Nelson and Colleen Regan, Bloomberg New Energy Finance, "EPA Clean Power Plan – tons of details, mass confusion," at 11 (June 9, 2014), *available at* http://www.midwesterngovernors.org/IEE/2014/ConferenceCalls/June/Presentations/Bloomberg.pdf.

[45] EPA would, of course, perform their own modeling in order to determine the necessary fee that would be sufficient to achieve the interim goals. However, EPA should revise the model to include more realistic assumptions regarding natural gas prices. When developing the Proposed Rule, EPA assumed that gas prices will rise to $6/MMBtu in 2020. That is a gross overestimate and should be revised. Natural gas futures for 2020 are currently trading at less than $4.50/MMBtu. Futures market prices reflect the actual price at which market participants will buy and sell gas in any given year, and therefore EPA should use these actual market prices in modeling rather than a projection.

[46] California increases its reserve price by five percent plus the rate of inflation annually. Cal. Code Regs. Title 17 § 95911(c)(3)(A). The price stood at $11.34 in 2014. California Cap-and-Trade Program and Québec Cap-and-Trade System, 2014 Annual Auction Reserve Price Notice Issued on September 19, 2014, *available at* http://www.arb.ca.gov/cc/capandtrade/auction/2014_annual_reserve_price_notice_joint_auction_update.pdf. Assuming a one percent inflation rate, the reserve price will be $16.08 per ton in 2020 and will exceed $20 per ton by 2024.

[47] *See* RGGI States' Comments on Proposed Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602-22395 (Nov. 5, 2014) at 3-4 (hereinafter, "RGGI States' Comments"). The RGGI states distribute allowances by auction with a reserve price. If the modeled emissions cap is too high, the reserve price acts like the fee

ED_000419-0005602

programs, combined with the modeling exercises performed in response to EPA's Proposed Rule, amply demonstrate that the interim goals can be achieved through Smart System Dispatch.

Because California and the RGGI states impose a price on carbon emissions (in the form of an allowance cost rather than a carbon fee), and the states around them do not, these programs are vulnerable to leakage. Leakage describes the shift of electric generation – and the emissions from that generation – to states outside these programs when the cost of generation within the program states rises to account for the carbon price. For example, Maryland is a RGGI state in PJM. The cost of fossil generation is higher in Maryland to account for the cost of allowances, which makes fossil generation in other non-RGGI PJM states relatively less expensive. Generation shifts to fossil power plants in the non-RGGI states, which therefore run more and emit more CO_2. Thus, while the carbon price does produce a dispatch switch, it is not always the switch intended. Rather than switching dispatch from higher-emitting to lower-emitting sources within RGGI, the price drives some generation out of RGGI without any net reduction in emissions, and potentially increasing total emissions.

Smart System Dispatch will reduce leakage from existing state carbon programs by increasing the number of states that put a price on carbon emissions. Even if the carbon fee determined by EPA is lower than allowance prices in California and RGGI, there will be far less leakage than there is now, with no carbon price in any other state.[48] Moreover, once EPA's final rule takes effect and *all* states must control CO_2 emissions, the leakage phenomenon could have

---

proposed here. In fact, this occurred in the early years of the program. The RGGI states initially underestimated potential emissions reductions, so that the cap became non-constraining. The reserve price, not the cap, drove emissions reductions attributable to RGGI. *See* RGGI 2012 Program Review, *available at* http://www.rggi.org/design/program-review.

[48] The converse is also true: even if the carbon fee determined by EPA is higher than allowance prices in these programs, the leakage from Smart System Dispatch states would be smaller than now exists in California and RGGI.

ED_000419-0005603

a positive effect. Fossil generation units in states that do not participate in Smart System Dispatch or otherwise impose a price on CO_2 emissions will tend to run more, making it more challenging for the state to meet its emission goals. In such a case, the safe harbor that Exelon proposes will be even more attractive to states that would otherwise receive the generation demand "leaked" from states adopting Smart System Dispatch.

Ultimately, all fossil generators will incur some compliance cost that will be reflected in their cost of generation, and the problem of leakage will diminish or disappear entirely. While there may be differences in costs between states, if the rule is appropriately structured, these differences will be small and variable, and more related to the state-by-state disparities in the emission rates imposed by rule than to Smart System Dispatch or any other carbon price system. The efficacy of Smart System Dispatch will not be undermined by leakage during the interim compliance period, as long as EPA ensures that the implementation plans of non-participating states will result in compliance with those states' interim emissions rate goals.

Finally, the efficacy of Smart System Dispatch is not limited to regional wholesale markets served by ISOs and RTOs. Vertically-integrated utilities similarly determine least-cost dispatch among their generation sources. A single utility dispatching multiple generation sources to serve the load of its retail customers could employ Smart System Dispatch simply by reflecting a carbon fee in the dispatch cost of each source, taking that fee into account in its dispatch decision exactly as an RTO would. In this circumstance, the generator and the load-serving entity are the same; the carbon fee would be internal to the utility, and there would be no need to redistribute the fee through a third party.

ED_000419-0005604

3. *Smart System Dispatch Would Minimize Consumer Impacts if States Direct Carbon Fees to Retail Electric Bill Relief.*

A carbon fee unavoidably affects wholesale electricity prices that are paid by the load-serving entities that deliver electricity to retail customers. However, under Smart System Dispatch, the carbon fees collected from generators could be redistributed to the load-serving entities and used to mitigate bill impacts. Many RGGI states employ a similar mechanism in which they apply revenues from the auction to consumer rate relief and other strategic energy purposes.[49] In its modeling, PJM calculated implied carbon prices, but did not release any information on the impact of those carbon prices on retail rates, with or without redistribution of carbon fees for retail electric bill relief. Interpolating from the materials released by PJM, we believe that this redistribution could eliminate at least 80 percent of the retail price impact of the carbon fee, limiting retail electricity rate increases to one to two percent.[50] Another study on behalf of the Clean Air Task Force found that with a carbon fee of $34 per ton – much higher than the carbon prices implied in nearly every PJM scenario – retail electric bill increases would be less than five percent if carbon fees were applied to retail bill relief programs.[51]

To put such an increase in perspective, it should be considered in both absolute and relative terms. Smart System Dispatch involves a single carbon price prevailing for the ten-year interim compliance period. The incremental retail cost increase would be between two and five

---

[49] Modeling conducted by the RGGI states has demonstrated that this approach has driven economic growth, yielding increases in both jobs and gross state domestic products. Thus, modeling predicted that the lower 91 million ton cap ultimately selected by the RGGI states will drive more economic growth than a higher cap would have. REMI Economic Impact Analysis Assumptions and Results (June 3, 2013), *available at* http://www.rggi.org/docs/ProgramReview/REMI%2091%20Cap%20Bank%20MR_2013_06_03.pdf.

[50] PJM has not yet made available detailed spreadsheets containing its data. These will likely be released after the comment deadline, and may provide additional insight into retail impacts.

[51] Northbridge CATF Report at 28 (finding retail bill increases of 4.1 percent at carbon price of $34 per metric ton).

ED_000419-0005605

percent total for the entire ten-year interim period. Compared to typical electric rate increases, the increase due to Smart System Dispatch would be negligible.[52] The average retail rate increase in the United States in the decade between 2003 and 2013 was 35 percent.[53] This trend continued with an average residential rate increase of 3.2 percent between 2013 and 2014 alone.[54]

Ideally, the redistribution would occur at the level of RTOs and ISOs that administer regional markets in which wholesale electricity is sold by generators (at a price that would include the carbon fee) and purchased by load-serving entities. Carbon fees could be withheld from generator payments and redistributed to load-serving entities in proportion to load. This redistribution, which must be authorized by the states participating in Smart System Dispatch, could be accomplished either pursuant to a tariff approved by the Federal Energy Regulatory Commission ("FERC") or through an unregulated RTO affiliate.[55]

4. EPA Should Deem States Adopting Smart System Dispatch to Have Complied With Their Interim Goals.

Regional, market-based incentives to control pollution are the most economically efficient means to achieve interim goals, but there are still some uncertainties. Dispatch decisions can be influenced by unanticipated generation or transmission outages, unusual

---

[52] Based on rate case data from the past year, the average rate increase granted to utilities in rate cases was about 5 percent of revenues, even higher than the 3.2 percent national average for all utilities.

[53] Energy Information Administration, Electricity Data Browser Pre-Generated Report 5.6 Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State (comparing All Sector rates from 2003 and 2013), *available at* http://www.eia.gov/electricity/data/browser/.

[54] Energy Information Administration, "Today in Energy: Residential electricity prices are rising" (Sept. 2, 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=17791. Based on rate case data from the past year, the average rate increase granted to utilities in rate cases was about 5 percent of revenues, even higher than the 3.2 percent national average for all utilities.

[55] Each RTO uses an independent (though sometimes affiliated) firm to collect and track data, process transactions and perform other functions outside the responsibilities of the RTO itself. For example, in PJM these functions are served by PJM Environmental Information Systems.

ED_000419-0005606

weather events, and changing fuel prices, all of which can shift CO_2 emissions unexpectedly between states in a market-based dispatch system. These uncertainties could lead states to pursue rate-based compliance schemes relying on facility-specific operational limits or emission caps, which could appear to be a more predictable means to meet their goals despite their cumbersome inefficiency and the potential risks to electric reliability. However, the overall carbon reductions related to such rate-based systems are much less certain than with mass-based and/or price-based approaches. Therefore, EPA should encourage states to adopt a more efficient regional market-based approach, by providing a safe harbor from the interim goals for states that participate in Smart System Dispatch. Once EPA identifies the minimum carbon fee sufficient to achieve cost-effective emissions reductions, states adopting Smart System Dispatch should be deemed to comply with their interim goals, regardless of their actual emissions or emissions rate during the interim period.

While EPA's Proposed Rule is certainly broad enough to accommodate a carbon fee as a means of compliance, it is critical that EPA's final rule provide *explicitly* that states that participate in Smart System Dispatch will be deemed to comply with their interim goals for as long as they impose the fee. Giving states the option to choose this safe harbor would overcome any reasonable argument that the interim goals are not achievable. It would result in significant CO_2 reductions beginning in 2020, and relieve states of the risk that short-term actions might produce unexpected adverse consequences for reliability or compliance. Moreover, states opting for the safe harbor would then be free to focus on developing a long-term plan to achieve final emission goals by 2030.

As EPA recognizes, a regional approach would be more efficient than a state-by-state approach, and would lead to greater net benefits. As the Proposed Rule notes, "[s]pecifically in

ED_000419-0005607

the area of pollution control, state governments and the federal government have repeatedly taken advantage of the integrated nature of the electricity system when designing programs to allow the industry to meet the pollution control objectives in a least-cost manner. Examples include several cap-and-trade programs to reduce national or regional emissions of SO_2 and NO_x."[56] These programs, the Proposed Rule correctly explains, were "designed to take advantage of the fact that in an integrated electricity system, some EGUs can reduce emissions at lower costs than others, and that by allowing the industry to determine through market mechanisms which EGUs to control and which to leave uncontrolled, and which EGUs to potentially operate more and which to potentially operate less, overall compliance costs can be reduced."[57]

Indeed, a regional carbon price, potentially coupled with other measures to encourage longer-term investment in the other building blocks, would likely represent the most cost-effective way reliably to achieve the interim as well as the final goals. By requiring a constant, uniform carbon adder, a state would be taking steps to preserve its existing cost-effective nuclear and renewable capacity and to create incentives to invest in new NGCCs and natural gas infrastructure, as well as new zero-emissions generation capacity, energy efficiency, and other measures to reduce CO_2 emissions. Of course, the carbon price would need to be sufficient to produce emission reductions commensurate with EPA's interim goals. As noted above, ample evidence suggests that a price of about $20 per ton would be adequate to achieve the interim goals.

---

[56] NPRM, 79 Fed. Reg. at 34,880.

[57] *Id.*

ED_000419-0005608

While the core notion of Smart System Dispatch is straightforward, the program could accommodate a number of variations that could make it more attractive. For example, some states might be able to achieve the interim goals at a carbon fee significantly lower than the uniform carbon fee determined by EPA. Such states would have a disincentive to participate in Smart System Dispatch, and would likely submit individual implementation plans. In order to promote regional approaches, EPA could consider extending the safe harbor at a lower carbon fee to states that demonstrate that EPA's uniform carbon fee would reduce emissions more than 10 percent (or some other margin) below the state's emission goals. Similarly, EPA could also extend safe harbor protection to states that impose a lower carbon fee before 2020 if those states can demonstrate that the lower fee will produce equivalent emission reductions over a longer period than EPA's higher fee during the interim compliance period. Exelon encourages EPA not only to adopt a Smart System Dispatch safe harbor in the final rule, but to exercise its discretion to extend safe harbor treatment to other thoroughly documented proposals that meet the spirit of Smart System Dispatch.

C. A Safe Harbor for Smart System Dispatch Would Contain Costs, Minimize Consumer Impacts, Preserve Reliability and Address the Other Principal Concerns Raised in Opposition to the Interim Goals.

Smart System Dispatch would have a variety of benefits in addition to achieving emissions reductions in the most cost-effective manner. First, Smart System Dispatch will provide cost-containment certainty for states, placing a ceiling on compliance costs and protecting consumers from large, rapid rate increases due to the Clean Power Plan. Moreover, states could enjoy the advantages of coordinated regional action without negotiating comprehensive interstate compliance agreements – a complex process that might take years to complete. Instead, they could rely on existing resources and existing market structures to reduce

ED_000419-0005609

emissions during the interim compliance period, with a minimum of disruption to the existing grid management system.

Second, states would enjoy the certainty of knowing that, so long as they continued to participate in the program, they would be deemed compliant with their interim goals, without needing to build a new emissions reduction program from the ground up before 2020. As EPA's Goal-Setting NODA recognizes, stakeholders have expressed concern that the Proposed Rule demands certain states to make what they characterize as too many reductions in carbon emissions too soon, and have suggested that a less demanding route to compliance is needed.[58] Some commenters suggest that EPA should require no reductions at all until 2030.[59] Instead, Smart System Dispatch would provide a glide path that will capture the reductions available at a reasonable cost during the interim period. Having met their interim compliance goals by virtue of participating in the program, states could begin focusing now on devising the additional strategies and programs necessary to meet final compliance goals. States would still retain the flexibility to withdraw from Smart System Dispatch, or not to participate at all, if they prefer to demonstrate interim compliance through other means.

Third, Smart System Dispatch would obviate any concern that compliance with interim goals – for example, through placing run-time limitations on the operations of higher-emitting plants – would adversely affect electric reliability. Grid operators' planning and dispatch

---

[58] Goal-Setting NODA, 79 Fed. Reg. at 64,548.

[59] *See, e.g.*, NRG Energy, "Glide Paths instead of Cliffs: Greater Emissions Reductions at Lower Cost," Docket ID No. EPA-HQ-OAR-2013-0602-17281 at 9 ("EPA should simply set 2030 emission goals and allow each state to determine the appropriate emission reduction trajectory to reach those goals. . . ."); Coalition for Innovative Climate Solutions, "Preliminary Comments by the Coalition for Innovative Climate Solutions on EPA's Proposed Interim Goals," Docket ID No. EPA-HQ-OAR-2013-0602-11216 at 1 ("CICS urges EPA to eliminate the proposed interim goals and, instead, allow states to determine a graduated compliance path to reach their final goals in 2030.").

ED_000419-0005610

decisions already take into account the availability of gas and electric transmission infrastructure, issues raised by EPA and NERC.[60] More importantly, Smart System Dispatch speaks in the *lingua franca* of grid management: price. The carbon fee is just another cost included in operators' bids that grid operators are well-equipped to address through dispatch and reliability planning. Under Smart System Dispatch, grid operators would continue to manage the Bulk Power System in the same way and with the same tools that have proven so effective.

Smart System Dispatch would ensure that when higher-emitting plants are needed for electric reliability, the market will keep them online. Owners of existing coal-fired generation in participating states would have planning certainty for the length of the interim period, and could choose whether additional plant investments, such as improvements to the heat rate, are economic. However, if the higher-emitting plants are not needed for electric reliability, they will operate less frequently.

Fourth, Smart System Dispatch would create the market signals necessary to spur investment in new clean generation resources and to retain existing clean resources. To the extent that the cost of carbon emissions is appropriately reflected in market signals, this approach would help to mitigate the economic pressures faced by existing nuclear and hydroelectric plants, and thereby help to prevent the early retirement of those plants. It would also make investment in nuclear uprates, additional renewable generation, and energy efficiency more profitable. Thus, although Smart System Dispatch is primarily aimed at affecting the order of dispatch, the program would drive long-term investment in all forms of lower-carbon generation as well as carbon capture and sequestration ("CCS").

---

[60] NODA, 79 Fed. Reg. at 64,546; NERC Initial Reliability Review at 10.

ED_000419-0005611

Finally, as emphasized above, Smart System Dispatch could largely offset any bill increases that retail customers might otherwise experience. The carbon fees collected could be redistributed to the load-serving entities that purchase electricity on the wholesale market. The redistributed fees could then be used for retail bill relief, to support investment in energy efficiency or clean demand response programs, or for some other mechanism to reduce total costs for consumers.

In sum, the emissions reductions achieved by Smart System Dispatch would establish a stable base on which states could layer other emission reduction measures they must adopt to achieve the final emission goals effective in 2030. States would have a clear path to comply with the interim goals without risking the potential harm to the electric system that might result from dozens of hastily conceived state limitations intended to force in-state emission reductions. And these reductions will remain stable even as states implement additional emission reduction measures to achieve compliance with the final goals.

II. EPA MUST REVISE THE TREATMENT OF EXISTING NUCLEAR GENERATION.

EPA was correct to include consideration of nuclear generation in the Proposed Rule. As EPA Administrator McCarthy explained to the Senate Environment and Public Works Committee, "[n]uclear energy is a zero-emitting carbon energy generating technology and for that reason we have actually gone to great lengths in this proposal to make sure states are aware of that and that nuclear energy is factored into the standard-setting process."[61] Nevertheless, for the reasons discussed below, the targets for existing nuclear generation in the Proposed Rule do

[61] Hearing before the Senate Environment and Public Works Committee, July 23, 2014, *available at* http://www.c-span.org/video/?320607-1/hearing-epa-power-plant-standards.

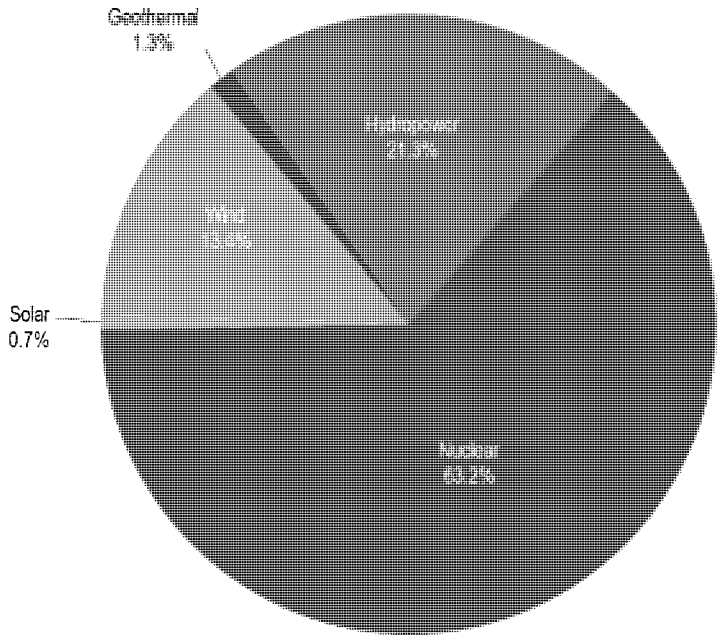
ED_000419-0005612

not go far enough and must be revised to ensure that states have the incentive to take the necessary steps to preserve the nation's existing nuclear fleet from early retirement. Retaining the existing nuclear fleet is vital to meeting carbon reduction goals.

A. Nuclear Facilities Are the Largest and Most Reliable Source of Carbon-Free Electricity.

Electricity generation accounts for nearly 40 percent of U.S. carbon emissions. However, existing nuclear power plants, which produce 19 percent of the nation's electricity, emit no carbon dioxide and are among the cleanest sources of electricity available. In 2013, nuclear power plants provided more than 63 percent of our carbon-free electricity (see Figure 2).

Figure 2. U.S. Carbon-Free Electricity Sources, 2013

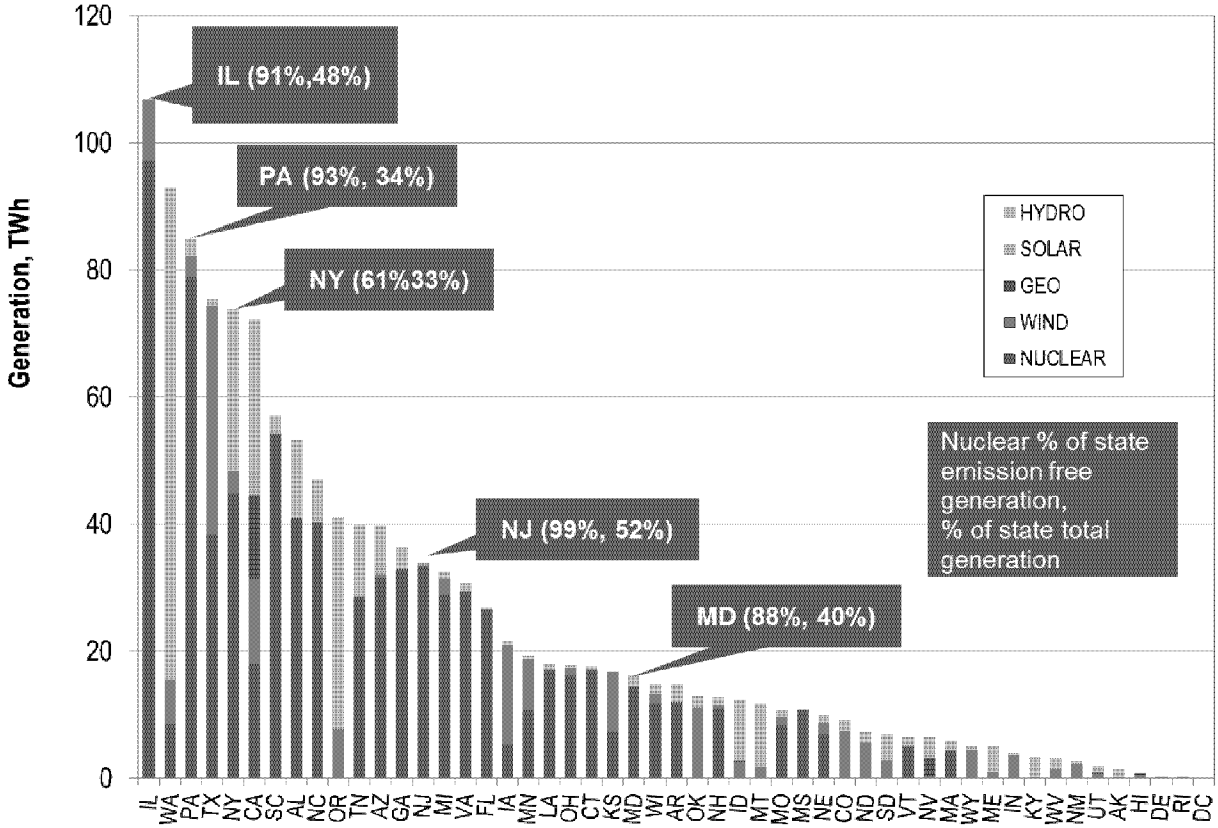


Source: EIA Electric Power Monthly

Reliance on nuclear generation varies significantly from state to state, but in a number of states, more than 90 percent of the emission-free generation is nuclear (see Figure 3).

ED_000419-0005613

Figure 3. U.S. Emission-Free Generation, 2013



Source: EIA[62]

Nuclear facilities are critical to the reliability of the electric grid because they operate continuously and entirely independent of weather conditions. To cite one example: the deep freeze brought on by the polar vortex in January 2014 resulted in more than 35,000 megawatts of outages. In the eastern part of the U.S. and Texas, natural gas plants accounted for 55 percent of these outages. Nuclear units accounted for only three percent of forced outages – despite making up 12 percent of total capacity – and were least affected by the weather conditions, operating at

[62] A table showing the data underlying this chart is included in an Appendix to these comments.

90 percent capacity through the polar vortex event.[63] In contrast to natural gas plants, which receive their fuel supply through a gas pipeline system that may be constrained under certain circumstances, nuclear facilities have their fuel on-site.[64] In contrast to wind or solar power, nuclear facilities continue to generate electricity at all times of day and in all weather conditions. The ability to rely on nuclear power in all circumstances will become increasingly important as the nation's electricity system becomes less reliant on coal, and more reliant on gas pipelines and on renewable technologies that are weather-dependent.

B. Nuclear Facilities Are at Risk of Premature Retirement.

Despite generating large amounts of clean energy and playing a vital role in grid reliability, nuclear facilities across the country are at risk for premature retirement – a prospect that Terry Boston, President and Chief Executive Officer of PJM, described as "unthinkable."[65] Approximately half of the nation's existing nuclear units are merchant generators in states with competitive electricity markets, in which wholesale prices are set by generators' bids. Nuclear plants have largely fixed costs and cannot vary their output in response to market signals. Nor can they even affect the market price for generation – because nuclear facilities must run all of the time, they must accept the lowest market-clearing price offered by other generators. Unless wholesale electricity prices (and capacity prices in RTOs that have capacity markets) are high enough to allow the nuclear plants to cover their costs, they will retire.

---

[63] North American Electric Reliability Corp., "Polar Vortex Review" (Sept. 2014) at 13, 32, *available at* http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[64] Natural gas availability can also constrain the operation of coal plants, which often require natural gas as a startup fuel.

[65] Martin LaMonica, "For Some Utility Execs, EPA Carbon Rules Are Only One Worry in a Changing Business," The Energy Collective (June 9, 2014), *available at* http://theenergycollective.com/martin-lamonica/395541/some-utility-execs-epa-carbon-rules-are-only-one-worry-changing-business.

ED_000419-0005615

Against this background, nuclear units' market-based revenues have recently been insufficient for a number of reasons, threatening the economic viability of a significant fraction of the nation's nuclear fleet. EPA recognized this threat in the Proposed Rule, stating that "a host of factors – increasing fixed operation and maintenance costs, relatively low wholesale electricity prices, and additional capital investment associated with ensuring plant security and emergency preparedness – have altered the outlook for the U.S. nuclear fleet in recent years."[66] Specifically, as EPA noted, lower natural gas prices have reduced wholesale electricity prices and thereby made it more difficult for nuclear plant owners to recover their fixed costs or to make new capital investments, such as those needed to meet new safety requirements adopted after the 2011 accident at Fukushima Daiichi Nuclear Plant in Japan.

The economic pressure on nuclear units has been exacerbated by subsidized wind power, which has placed further downward pressure on wholesale electricity prices. Subsidies allow wind generators to remain profitable even when they *pay* to put their electricity onto the grid; these units can therefore bid a negative price into the electricity markets yet still make money. On breezy nights, the market-clearing price of electricity has become negative in locations where there is insufficient transmission to relieve the local area of excess electricity production.[67] Nuclear plants in those areas cannot cycle down their output during such times, and therefore have no choice but to run and incur substantial losses during those hours. Thus, subsidies to encourage wind end up displacing nuclear generation, to no carbon benefit. In other words,

---

[66] NPRM, 79 Fed. Reg. at 34,871.

[67] Frank Huntowski, Aaron Patterson, and Michael Schnitzer, "Negative Electricity Prices and the Production Tax Credit: Why wind producers can pay us to take their power – and why that is a bad thing," The NorthBridge Group (September 10, 2012), *available at* http://www.nbgroup.com/publications/Negative_Electricity_Prices_and_the_Production_Tax_Credit.pdf.

ED_000419-0005616

policies intended to support renewable resources that are carbon-free have had unintended and deleterious consequences for nuclear power, by far the largest carbon-free resource.

In part because of these factors, the U.S. has recently lost two viable nuclear plants: the Kewaunee power station in Wisconsin, and the Vermont Yankee nuclear unit in Vermont, which is set to close at the end of 2014. When Dominion announced in October 2012 that it would be closing the Kewaunee plant, it stated that the decision was "based purely on economics."[68] Likewise, Entergy's August 2013 announcement regarding the closure of Vermont Yankee cited "sustained low power prices, high cost structure and wholesale electricity market design flaws" that result in "artificially low energy and capacity prices" that "do not provide adequate compensation to merchant nuclear plants for the fuel diversity benefits they provide."[69]

Currently, Exelon is evaluating the continued economic viability of four nuclear stations – Byron, Quad Cities, and Clinton in Illinois; and Ginna in New York. Byron and Quad Cities are located in the PJM region, but were not selected in the last PJM capacity auction. Clinton is located in the Midcontinent ISO ("MISO"), which has no forward capacity market. With respect to Ginna, Exelon has certified to the New York Public Service Commission that it expects that revenues from the sale of energy and capacity in the New York ISO will not be sufficient to cover the costs of continued operation. If any of these stations were to retire, it would be for purely economic reasons. The current operating licenses for these plants do not expire until 2024

[68] Dominion News, "Dominion to Close, Decommission Kewaunee Power Station," Oct. 22, 2012, *available at* http://dom.mediaroom.com/2012-10-22-Dominion-To-Close-Decommission-Kewaunee-Power-Station.

[69] Entergy news release, "Entergy to Close, Decommission Vermont Yankee," August 27, 2013, *available at* http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.

ED_000419-0005617

for Byron at the earliest, and as late as 2032 for Quad Cities. Collectively, these plants generate 48,295 gigawatt-hours ("GWh") and avoid 30.7 million metric tons of CO_2 emissions annually.[70]

Previously, Exelon announced the retirement of Oyster Creek in New Jersey, effective in 2019. Exelon made that decision for economic reasons as well – the plant's operating license does not expire until 2029, but wholesale electricity prices did not support the construction of new cooling towers that the State of New Jersey required for Clean Water Act compliance. As a result, New Jersey will lose 5,102 GWh of carbon-free generation – eight percent of the state's total annual electricity generation.

Although the Proposed Rule recognizes the economic pressures faced by the existing nuclear fleet, the proxy used by EPA to estimate the quantity of nuclear generation that is at risk of premature retirement is a significant underestimate.[71] Relying on national projections from the Energy Information Administration ("EIA"), EPA estimated that six percent of the nation's nuclear capacity is at risk of premature retirement.[72] Exelon, however, has used industry analyst data and its own modeling to examine the economics of the nation's 27 nuclear plants operating in competitive markets.[73] As indicated in the chart below, Exelon has determined that no fewer than 13 of the 27 nuclear plants in competitive markets are expected to have revenue shortfalls in 2015 (see Figure 4).[74] All of these plants are thus at risk of retirement. If revenues continue to

---

[70] Avoided emissions are calculated based on a region-specific emissions factor developed from EIA Outlook 2013: 1,509 lb/MWh for the three Illinois plants, and 472 lb/MWh for Ginna.

[71] Among other problems discussed in the text above, the risk of early retirement fluctuates with factors such as the price of natural gas, which has come down since the forecast relied upon by EPA.

[72] NPRM, 79 Fed. Reg. at 34,871.

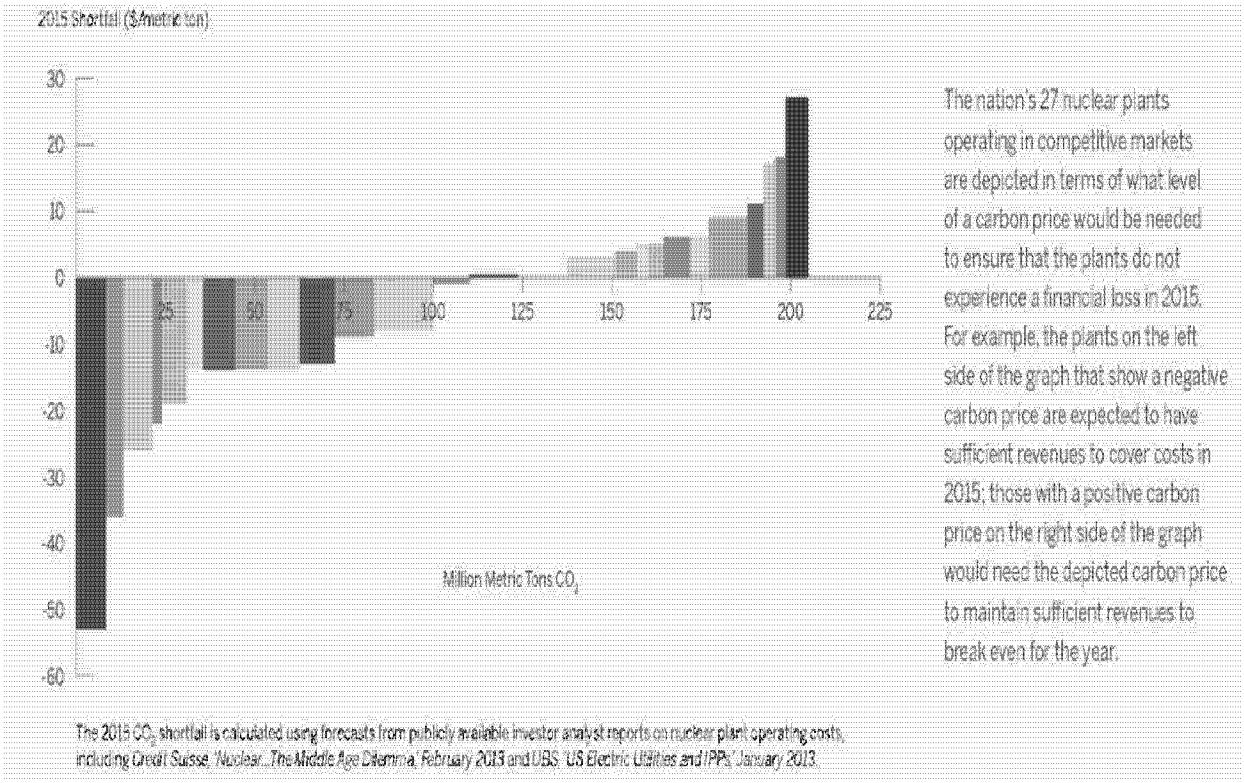
[73] Exelon and EPA both use versions of ICF's Integrated Planning Model ("IPM") to predict industry response to price changes.

[74] Exelon Corporation, "2013 Corporate Sustainability Report," at 21, *available at* http://www.exeloncorp.com/environment/strategy/Pages/overview.aspx.

ED_000419-0005618

fall due to low gas prices or an expansion of subsidized wind generation, an even greater number of nuclear plants may be endangered.

Figure 4. Nuclear Retirement Candidates in Competitive Markets



Moreover, the Proposed Rule has a potential, paradoxically, to *increase* the financial pressure on existing nuclear plants. Currently, NGCCs have higher variable costs than coal units, nuclear units, or renewables. Electricity prices, therefore, tend to reflect the marginal costs faced by NGCCs, whose bids in competitive markets set the price paid to all generators. The Proposed Rule envisions that states will achieve EPA's emissions goals partly by shifting dispatch from existing coal plants to NGCCs. A rate-based state that does not adopt Smart System Dispatch could seek to encourage this sort of redispatch by artificially increasing the marginal cost of higher-emitting generators (like coal plants) while reducing the marginal cost of lower-emitting generators (like NGCCs). For instance, the rate-based state might adopt an

ED_000419-0005619

emissions credit or rate-trading program that taxes higher-emitting fossil fuel plants and subsidizes lower-emitting fossil fuel plants. As a result of such a subsidy, an NGCC would be able to sell electricity for less than its true marginal cost, similar to subsidized wind today. Such a subsidy could have the effect of lowering the market price of electricity for all generators – further undercutting the economic viability of existing nuclear plants in the near term and muting the market signals to invest in clean generation.[75] In the long run, however, the premature retirement of nuclear plants will result in *increased* electricity prices, as nuclear plants are replaced with higher-cost generation, such as NGCCs.

C. Preventing the Early Retirement of Existing Nuclear Generation Is Essential to Reducing Carbon Emissions From the Power Sector.

Exelon strongly supports EPA's inclusion of nuclear power as part of the BSER set forth in the Proposed Rule. As EPA correctly recognized, "[n]uclear generating capacity facilitates CO_2 emission reductions at fossil fuel-fired EGUs by providing carbon-free generation that can replace generation at those EGUs."[76] Exelon further strongly supports EPA's recognition that one "way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that might otherwise be retired."[77]

Indeed, maintaining the existing nuclear fleet is in fact an essential precondition to reducing carbon emissions from the power generation sector. As EPA notes, "[n]uclear generating capacity facilitates CO_2 emission reductions at fossil-fired EGUs by providing

[75] This perverse result could be avoided with Smart System Dispatch, a mass-based cap-and-trade program, or if EPA modifies the state-specific target rates so that no state has a target rate higher than that of the existing NGCC fleet. Based on Exelon's examination of its own NGCC fleet, that rate is approximately 900 lbs/MWh rather than the 1,100 lbs/MWh that EPA has proposed for the new source standards under section 111(b).

[76] NPRM, 79 Fed. Reg. at 34,870.

[77] *Id.*

ED_000419-0005620

carbon-free generation that can replace generation at those EGUs."[78] FERC Commissioners, state public service and environmental commissioners, scientists, and others have all called upon environmental and energy policymakers to develop solutions to preserve nuclear energy's unique role among the nation's clean energy resources. Former FERC Commissioner John Norris similarly observed that "[w]e need to maintain our nuclear fleet, as it is a valuable base load and carbon free resource."[79]

Likewise, in November 2013, four of the world's most respected climate and energy scientists – Dr. Ken Caldeira of Carnegie Mellon, Dr. Kerry Emanuel of MIT, Dr. James Hansen of Columbia University, and Dr. Tom Wigley of the National Center of Atmospheric Research – acknowledged the critical importance of nuclear energy to addressing climate change. The scientists released a letter calling on world leaders to support nuclear energy, concluding that "in the real world there is no credible path to climate stabilization that does not include a substantial role for nuclear power."[80] The Center for Climate and Energy Solutions released a study identifying the challenges facing nuclear units and noting that retirements of nuclear units will have serious climate change implications.[81] Similarly, the National Association of Regulatory Utility Commissioners ("NARUC") passed a resolution recognizing that "[n]uclear energy has played a substantial role in the achievement of existing [greenhouse gas] State or regional

---

[78] NPRM, 79 Fed. Reg. at 34,870.

[79] Statement of former FERC Commissioner John R. Norris, "Preserving our Country's Nuclear Fleet," May 15, 2014. Available at http://www.ferc.gov/media/statements-speeches/norris/2014/05-15-14-norris.asp.

[80] *Available at* http://dotearth.blogs.nytimes.com/2013/11/03/to-those-influencing-environmental-policy-but-opposed-to-nuclear-power/.

[81] Doug Vine & Timothy Juliani, Center for Climate and Energy Solutions, *Climate Solutions: The Role of Nuclear Power* (Apr. 2014), *available at* http://www.c2es.org/docUploads/nuclear-energy-brief-04-14-final.pdf.

ED_000419-0005621

emissions reduction goals to date, and continued operation of nuclear power plants is vital to States' ability to economically meet new federal regulation, and provides an essential tool to manage risks associated with potential [greenhouse gas] emissions reduction requirements."[82] NARUC urged EPA to adopt rules encouraging states to "preserve, life-extend, and expand existing nuclear generation."[83]

The premature retirement of a nuclear facility leaves an enormous hole to be filled: each nuclear facility dependably generates so much electricity that, with current technology, it simply cannot feasibly be replaced by alternative zero-emissions generation resources with much lower capacity factors, such as wind or solar. For example, to produce the same 1,000 megawatts of electricity generated by a single nuclear unit, a solar farm operating at a 26 percent capacity factor would need to be spread across 30 square miles, more than the size of Manhattan.[84] A wind farm operating at 30 percent capacity would need to be spread across 300 to 400 square miles.[85] Indeed, although California is the nation's leader in renewable generation production, the closure of the San Onofre nuclear plant in early 2012 resulted in the loss of more zero-emissions electricity than the combined production of all wind, solar, and biomass in the state.[86]

---

[82] *Id.*

[83] NARUC, Resolutions Passed by the Committee of the Whole, Resolution EL-1, Nov. 19, 2014, *available at* http://www.naruc.org/Resolutions/14%201119%20NARUC%20Board%20Substantive%20Resolutions%20Packet.pdf.

[84] National Renewable Energy Laboratory, "Land-Use Requirements for Solar Power Plants in the United States" (June 2013) at v, *available at* http://www.nrel.gov/docs/fy13osti/56290.pdf.

[85] National Renewable Energy Laboratory, "Land-Use Requirements for Modern Wind Power Plants in the United States" (Aug. 2009) at 10, *available at* http://www.nrel.gov/docs/fy09osti/45834.pdf. As these figures are based on 2009 data, current technology may require somewhat less land.

[86] Energy Almanac, "California Electrical Energy Generation," *available at* http://energyalmanac.ca.gov/electricity/electricity_generation.html.

ED_000419-0005622

Thus, the loss of a just a single nuclear plant can have a devastating impact on a state's ability to reduce CO_2 emissions.

Moreover, even if it were feasible to replace a nuclear plant with an equal number of megawatts of wind or solar power, there would still be an adverse impact on the grid's reliability unless carbon-emitting plants (NGCCs or simple-cycle combustion turbines ("CTs")) are added to "firm up" the renewable generation sources, that is, to back them up to ensure electricity can be generated at night and in all weather conditions.[87] According to EIA data, so far in 2014, nuclear facilities have had a capacity factor of approximately 90 percent; by comparison, wind facilities have a capacity factor of approximately 30 percent, and utility-scale photovoltaic solar generation had a capacity factor of 33 percent.[88] Thus, wind and solar power cannot come close to replicating nuclear power's ability to generate electricity 24 hours per day, independent of weather conditions.

Because of a nuclear facility's large size and unparalleled reliability, a retiring nuclear plant is most likely to be replaced by natural gas-fired plants. New NGCCs have the lowest entry costs to provide baseload power. But NGCCs obviously emit carbon, so replacement of nuclear plants with NGCCs increases carbon emissions. For example, California's annual CO_2 emissions increased by 35 percent after the San Onofre nuclear reactors were shut down in early 2012.[89] Similarly, when the Kewaunee nuclear plant in Wisconsin closed in 2013, the fossil fuel

---

[87] EPA has proposed that the vast majority of CTs would not be subject to carbon emissions regulations.

[88] *See* EIA, "Electric Power Monthly," data for Aug. 2014 (released Oct. 24, 2014), tbl. 6.7.B (reporting capacity factors for utility scale generators not primarily using fossil fuels), *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_b (hereinafter, "EIA Electric Power Monthly").

[89] The California Air Resources Board reported that CO_2 emissions in the state increased from 2011 to 2012, "primarily due to emission increases from California electricity generation using natural gas a fuel," which in turn were caused in part by the shutdown of the San Onofre nuclear station in early 2012. World

ED_000419-0005623

generation that took its place emitted an additional 3.6 million metric tons of carbon dioxide annually.[90]

The dramatic increase in greenhouse gas emissions that occurred in Japan following the closure of reactors in response to the 2011 Fukushima Daiichi accident further demonstrates the critical importance of nuclear reactors to reduction of greenhouse gas emissions. In Japan, the CO_2 intensity of the power sector in 2012 was 39 percent higher as compared to when the country's reactors were operating. CO_2 emissions from electricity generation increased 29 percent to 486 million metric tons of CO_2 in 2012 from 377 million metric tons in 2010.[91]

As these examples demonstrate, every premature nuclear retirement moves the nation in the wrong direction when it comes to CO_2 emissions. As the Proposed Rule recognizes, retaining even the small portion of existing nuclear capacity that EPA deems at risk of premature retirement "could support avoiding 200 to 300 million metric tons of CO_2 over an initial compliance phase-in period of ten years."[92] Preventing premature nuclear retirements is essential to prevent CO_2 emissions increases, let alone to achieve emissions reductions.

Preventing the early retirement of nuclear facilities does not just avoid carbon dioxide emissions: as EPA has recognized, it is one of the most cost-effective ways to do so. EPA determined in the Proposed Rule that, "based on available information regarding the cost and

---

Nuclear News, "Greenhouse gas emissions from power plants in California increased by 35 percent in 2012, partly due to the early closure of the San Onofre nuclear power plant" (Nov. 5, 2013), *available at* http://www.world-nuclear-news.org/EE-California-emissions-rise-on-San-Onofre-shut-down-0511135.html.

[90] This calculation is based on Kewaunee's 4,519.9 GWh of output in 2012, replaced with MISO generation with an emissions factor of 1,756 pounds of CO_2 emitted per MWh.

[91] World Nuclear Association, "Nuclear Power in Japan" (updated Nov. 11, 2014), *available at* http://www.world-nuclear.org/info/Country-Profiles/Countries-G-N/Japan/.

[92] NPRM, 79 Fed. Reg. at 34,871.

ED_000419-0005624

performance of the nuclear fleet, preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO_2 reductions from affected EGUs at a reasonable cost."[93] Specifically, EPA estimates that the cost of keeping "at risk" nuclear plants operating is approximately $12 to $17 per metric ton of CO_2 avoided – which is more cost-effective than virtually any other carbon abatement strategy.[94] For example, as indicated in the chart below (Figure 5), EPA estimates that preventing the early retirement of "at risk" nuclear plants is more cost-effective than:

- Adding renewable capacity ($10 to $40 per metric ton of CO_2 abated).[95]
- Increasing natural gas combined cycle power plant utilization rates to 70 percent state by state ($33 per metric ton of CO_2 abated).[96]
- Implementing demand-side management programs ($16 to $24 per metric ton of CO_2 abated).[97]

---

[93] *Id.*

[94] *Id.* Exelon's own analysis of the economic pressures faced by nuclear plants in competitive electricity markets, shown in Figure 4, indicates that the bulk of at-risk nuclear plants face a revenue shortfall in the range of $12 to $17 per metric ton of CO_2 avoided. However, a small number of at-risk plants face a slightly greater revenue shortfall, in the range of $20 to $27 per metric ton of CO_2 avoided. As discussed in the text above, however, preserving even those plants still is just as cost-effective as the other programs EPA has considered in formulating the building blocks.

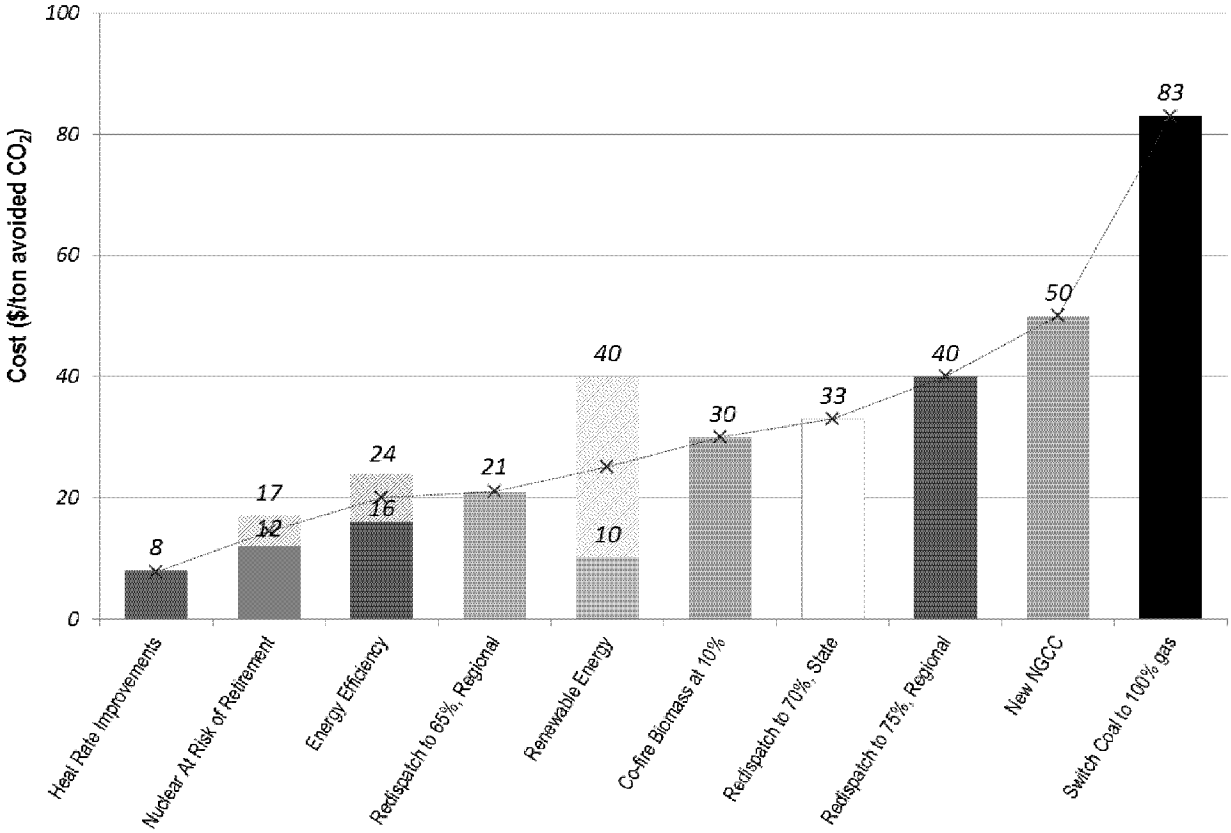
[95] NPRM, 79 Fed. Reg. at 34,858.

[96] *Id.* at 34,865.

[97] *Id.* at 34,875.

ED_000419-0005625

Figure 5. Costs of Reducing or Avoiding Carbon Dioxide Emissions from Electric Power Generation



Source: EPA

According to EPA's estimates, only improving the heat rate of coal plants would be more cost-effective than preventing the premature retirement of nuclear facilities.[98] While these heat-rate improvements are important, they alone cannot achieve the total carbon emission reductions necessary. Indeed, if implemented alone, heat-rate improvements could result in *increased* carbon dioxide emissions due to a "rebound" effect resulting from lower marginal costs for coal-fired plants that would result in those plants being dispatched more frequently.[99] Moreover, as

[98] *Id.* at 34,856.

[99] Heat-rate improvements will reduce the marginal cost for coal-fired plants. Because bids into electricity markets are based on marginal costs, this could change the order in which generation resources are dispatched, with heat-improved coal generation displacing lower-emitting generation sources. Thus, although a single coal-fired plant's emissions rate would be reduced, system-wide emissions would increase because the coal-fired plant would be dispatched more frequently than before.

ED_000419-0005626

discussed above, the premature retirement of the existing nuclear fleet would also dramatically increase the cost of EPA's proposal in the long run.

D. The Proposed Rule Fails Adequately to Value Nuclear Power.

EPA has requested comment on the proposed approach to accounting for emissions reductions through the preservation of existing nuclear generation.[100] Although EPA recognizes the importance of preserving existing nuclear plants to achieving further emissions reductions, the rule as proposed would not accomplish this goal. Rather, the Proposed Rule adopts rate goals based on a formula that arbitrarily discounts nuclear generation relative to other carbon-free generation, and thereby provides states with an insufficient incentive to preserve nuclear generation.

1. EPA's Arbitrary Treatment of Nuclear Generation.

In the Proposed Rule, EPA calculates a state's initial emissions rate and target emissions rates based upon a formula that accounts for all of the state's existing renewable generation other than hydropower but only six percent of its existing nuclear fleet. EPA excludes existing hydropower entirely; it is not counted in a state's initial emissions rate or accounted for in its target emissions rates, even if the state has significant hydropower resources that may be facing premature retirement.[101]

EPA's methodology provides a state with a strong incentive to preserve all of its existing wind, solar, and geothermal generation, because a state's ability to meet its target will be affected by whether all of those renewable megawatts remain operational. For instance, closure of any

---

[100] NPRM, 79 Fed Reg. at 34,871.

[101] As noted by the RGGI states in their comments, this omission is particularly arbitrary because hydroelectric power is included in many state Renewable Portfolio Standards ("RPS") used to establish state goals. *See* RGGI States' Comments at 24-25.

ED_000419-0005627

wind power facility will require the state to find an equivalent amount of zero-carbon generation just to keep its calculated emissions rate the same. But EPA's goals provide a very weak incentive to preserve the existing nuclear fleet. Even if *all* of a state's existing nuclear capacity were to retire, the state would be able to retain the same calculated emissions rate by finding new zero-carbon generation totaling just six percent of the retired nuclear generation. The loss of the remaining 94 percent will be immaterial to the state; the state could still comply, even if it replaced the remaining 94 percent with generation from new NGCCs, thereby significantly increasing its total emissions. For example, if a nuclear plant generates 10 million MWh annually, the Proposed Rule would require a state to replace that nuclear plant with only 0.6 million MWh of wind. The remaining 9.4 million MWh of lost nuclear capacity could be replaced by new NGCCs – thus massively increasing carbon emissions – without undermining the state's ability to comply. The Proposed Rule's approach is even worse for hydropower: even if a state loses all of its hydropower capacity, there will be no effect on its calculated emissions rate. The state can, without consequence, replace retired hydropower with new fossil-fired generation.[102] In short, EPA creates insufficient incentives for states to prevent the premature retirement of carbon-free generation (and may drive states to keep 111(b) units out of 111(d) calculations).

There is no reason why only six percent of a state's nuclear capacity should be counted in the state's initial and target emissions rates, as though the remainder of the state's nuclear capacity does not exist. Likewise, there is no reason to omit hydropower. A critical objective of the Proposed Rule is to reduce CO_2 emissions from the electric power sector – and EPA has determined that the best system for doing so is, among other things, to rely upon the

[102] Assuming 111(b) units are not included.

ED_000419-0005628

interconnected electric system, and increase, generation from low- and zero-emitting facilities.[103] To do so, it is essential to preserve the progress already made in reducing carbon dioxide emissions and to prevent the emissions *increases* that would result from the replacement of existing zero-emissions facilities with new fossil fuel plants. All of a state's existing nuclear and hydropower capacity is available as zero-carbon resources and should be counted accordingly.[104]

New and existing fossil fuel plants should not get more credit for CO_2 reductions than zero-carbon generation. For example, consider following this treatment to its logical conclusion in a true rate-trading system. Suppose an illustrative state's emissions rate target were 1,286 lb/MWh. An NGCC with a CO_2 emissions rate of 900 lb/MWh would be credited with 386 lb/MWh. Nuclear power emits no CO_2 per MWh, which should mean it would receive a credit

---

[103] In relying on the building blocks as the best system for emission reduction, EPA is not seeking to require those building blocks or direct states to invest any particular type of generation technology. Instead, EPA is identifying the building blocks as proven methods for displacing emissions from affected units. EPA has no emissions-related interest in encouraging one type of zero-emissions generation more than another type; accordingly, the rule should be neutral among zero-emission generation sources and treat all zero-emissions megawatts the same, as all displace carbon emissions. Indeed, the approach taken by the Proposed Rule has anomalous consequences. For example, in determining initial and targeted emissions rates for California – an "early mover" state with respect to emissions abatement – EPA would include all of the electricity generated from California's Shiloh Wind Power Plant, which came online in 1989; six percent of the electricity generated from the Diablo Canyon Nuclear Power Plant, which came online in 1985-1986; and none of the electricity generated from the Stenner Canyon Hydropower Plant, which came online in 1985. Yet all three plants are approximately the same age, and all three plants provide carbon-free generation, displacing fossil generation and related emissions. All three plants equally serve EPA's emission reduction goals.

[104] In setting states' interim and final emission goals, EPA should also include nuclear uprates as an available Building Block 3 action. Uprates increase the generation capacity of an existing nuclear unit. *See* Nuclear Regulatory Comm'n, "Backgrounder on Power Uprates for Nuclear Plants," *available at* http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html. NRC has approved uprates consisting of 7 GW of capacity to the nation's nuclear fleet. *Id.* The Proposed Rule expressly includes in states' final goals the completion of under construction nuclear units, *see* NPRM, 79 Fed. Reg. at 34,870, and it should do the same with nuclear uprates currently under construction. Currently, there are 291 MW of uprates under construction, "Backgrounder on Power Uprates," *supra*. Further, in calculating states' goals, EPA should also count new uprates, which, like new renewable capacity, increase a state's carbon-free generating capacity. Currently, there are 536 MW of nuclear uprates that have been proposed but are on hold. *Id.* Targets that appropriately valued the zero-carbon attributes of nuclear power could potentially incentivize plant owners to invest in further nuclear uprates.

ED_000419-0005629

equal to the target, or 1,286 lb/MWh. However, because only six percent of nuclear generation counts in the proposed formula, it is credited with only 77 lb/MWh. Nuclear would have to generate five times the MWh to receive the same CO_2 credit as one MWh of natural gas. If the credits have financial value, this creates a subsidy to natural gas at the expense of zero-emitting nuclear generation.

2. EPA's Inadequate Proxy for At-Risk Nuclear Facilities.

EPA explains that the goals in the Proposed Rule account for only six percent of existing nuclear generation because (according to EPA) six percent of nuclear capacity nationwide is "at risk" for premature retirement. That justification cannot support the decision to effectively discount nuclear generation by 94 percent.

If states are to achieve meaningful emission reductions, it is important that *all* existing nuclear generation remain in operation – yet the proposed treatment of nuclear generation inadequately promotes this goal.

The Proposed Rule's rationale for counting only six percent of nuclear generation – namely, that only six percent of nuclear capacity is "at risk" – is neither logical nor defensible on its own terms. First, whatever amount of capacity is "at risk" nationwide, the reality is that "at risk" nuclear facilities are concentrated in a small number of states. Specifically, at-risk nuclear plants are concentrated in states with competitive markets, generally located in the Midwest and Great Lakes regions.[105] In those areas, the fraction of the fleet that is at risk of early retirement is much greater than six percent. In other regions, where nuclear plants are owned by regulated utilities, a smaller fraction, and possibly none, of the fleet is at risk.

---

[105] In fact, the analysis referenced by EPA shows that all at-risk generation is located in the Midwest/Great Lakes region, and not evenly distributed nationwide. EIA, Annual Energy Outlook 2014, Tables 76, 80, 83, *available at* http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

ED_000419-0005630

Second, even within the regions where at-risk nuclear plants are concentrated, conditions vary significantly from state to state or even within the state. Illinois, for example, generates more nuclear energy than any other state – 47 percent of the state's electricity generation is provided by nuclear facilities. However, many nuclear plants in Illinois are facing significant economic pressure, not only because shale gas has driven down the prices of both natural gas and electricity, but also because wholesale electricity prices are suppressed by an increasing amount of subsidized wind generation in transmission-constrained areas. These economic pressures are particularly severe for nuclear plants located on the western side of Illinois, where wind power imports have overloaded the local transmission system and significantly depressed power prices. Prices in the northwest corner of the state are now 25 to 30 percent less than at the Northern Illinois hub. As a result of these dynamics, some of Exelon's plants in Illinois are losing money, as discussed above. If a path to financial sustainability cannot be found, these units may be shut down to avoid long-term losses. For example, in the last capacity auction held by PJM, price signals pointed toward the premature retirement of the Byron and Quad Cities stations in Illinois. These units were unable to sell their capacity in the auction, as market prices were lower than these plants required to remain financially viable. Likewise, market revenues have been too low to sustain the Clinton station, which is located in the MISO region. Each of these stations produces far more than six percent of Illinois's nuclear generation, and collectively, they generate a combined output of 43,300 GWh each year, which is approximately 45 percent of Illinois's nuclear generation and 21 percent of the state's total electricity generation. These numbers demonstrate that EPA's use of a nationwide average fails to account for the many facilities that, in reality, are at imminent risk of shutting down.

ED_000419-0005631

Third, a scenario in which only six percent of a state's nuclear generation is retired is implausible, if not impossible. The owner of a nuclear unit cannot retire only six percent of the unit; its only choices are to retire the unit completely or keep the unit operating. A number of states, meanwhile, have only one nuclear unit – which means that any retirement will necessarily be a retirement of 100 percent of the state's nuclear fleet. And even in states that contain multiple nuclear units, virtually any single nuclear unit will generate more than six percent of nuclear generation. The Ginna unit in New York is instructive. It is a small unit – only 583 MW – but still amounts to 11 percent of New York's nuclear generation. Thus, if any nuclear unit is prematurely retired, it is nearly certain to represent more than six percent of a state's nuclear capacity – indeed, likely far more. Yet that six percent is the most for which the Proposed Rule's goals account.

Fourth, it is illogical to use a snapshot-in-time figure of nuclear capacity at risk as the basis for a rule that will govern the power sector for decades. Market conditions are dynamic: just six years ago, before cheap natural gas and subsidized renewables began to drive nuclear wholesale prices down, nuclear plants did not face the economic challenges that they face today. Thus, a plant that is not at risk today may be at risk tomorrow. Indeed, by potentially spurring further subsidization of renewable and natural gas generation, the Clean Power Plan itself may well increase the economic vulnerability of nuclear plants. EPA's own analysis demonstrates that the proposed guidelines have the potential, paradoxically, to increase the financial pressure on existing nuclear plants. This will occur if states in competitive markets choose to comply with EPA's emissions rate target by subsidizing natural gas or renewable generation in a manner that allows such generation to sell electricity for less than its true marginal cost, which would

ED_000419-0005632

have the effect of artificially lowering the market price of electricity for all generators and further undercutting the economic viability of existing nuclear plants.[106]

Finally, even if 94 percent of nuclear capacity truly is safe from early retirement, and will remain so throughout the foreseeable future, that still is not a reason to give states credit for only six percent. Even if nuclear capacity were not at risk, counting it in a state's initial and target emissions rate or in a state's compliance calculation could do no harm: although the state would be responsible for preserving the nuclear capacity, it would by definition be preserved without further action from the state. Treating nuclear generation as safe when it is actually vulnerable, on the other hand, would insufficiently incentivize a state to preserve it – and, as described above, could result in the premature retirement of a critical carbon-free resource, resulting in the expansion of a state's carbon footprint.

E. Solutions.

While there are flaws in the Proposed Rule that are important to address, many solutions are available. One solution to the problems set forth above is for states to adopt Smart System Dispatch for the interim compliance period; another solution is for states to adopt a mass-based system of emissions reduction that includes both new and existing sources of electricity generation, in which parties trade emissions allowances. For over a decade Exelon has supported such a system, which has already been successfully applied to limit CO_2 emissions from electricity generation in the nine RGGI states and California. A mass-based trading system would not constrain states' choices of low- and zero-carbon resources, and it would ensure actual

[106] *See* Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602-0391, at 3-43 (estimating electric bill *decreases* in some regions of up to 8.7 percent in 2030).

ED_000419-0005633

emission reductions. Such a system necessarily would provide states with a strong incentive to preserve the existing nuclear fleet, because the premature retirement of a nuclear plant and its replacement – even in part – by natural gas-fired facilities would result in substantially increased carbon emissions, higher allowance prices, and higher electricity prices. The desirability and legal permissibility of a purely mass-based regulatory approach (*i.e.*, not merely as a compliance mechanism for a rate-based rule) is described in Part VI of these comments.

To the extent that EPA continues to provide states with the option of adopting a rate-based system for emissions reduction, the rate formula should fully and accurately reflect all of a state's existing carbon-free generation to ensure that states value the carbon-free generation of the entire existing fleet.

1. EPA Should Use a System-Wide Emissions Rate to Set Emissions Rate Targets.

Within the framework of EPA's current proposal, the most straightforward solution is for the Agency to calculate state emissions targets by counting in the denominator of the rate not only all of a state's existing fossil fuel generation and existing renewable generation, but also all of its existing nuclear and hydropower generation.

Use of such a "system-wide" emissions rate is consistent with EPA's approach to defining the "best system of emission reduction," as required by statute. Under EPA's rationale, because the statute uses the term "system of emissions reduction," it is appropriate to consider emissions reduction opportunities from *all* parts of the electricity supply and delivery system. EPA also recognizes that "electricity production ... takes place interchangeably between and among multiple generation facilities and different types of generation."[107] For that reason, EPA

[107] NPRM, 79 Fed. Reg. at 34,835.

ED_000419-0005634

has included non-emitting resources in calculating initial emissions rates and rate targets. Accordingly, the regulatory approach taken by EPA in the Proposed Rule more logically supports consideration of a state's *total* electrical generation when calculating its target emissions rates.

Adopting a true system-wide rate would create an effective incentive for states to keep all existing carbon-free generation online. If a nuclear facility were to retire prematurely, the state's calculated emissions rate would increase by an amount reflecting the full amount of carbon-free generation that has been lost. Because each nuclear facility is so large, a state could not easily replace the lost nuclear generation with other carbon-free resources in the short term, to compensate for the increase in the calculated emissions rate. Therefore, a state would have reason to prevent the premature retirement of any of its nuclear generation.[108]

Using a system-wide rate to set goals would require states eventually to replace existing nuclear units with an equal amount of new zero-emissions generation (or energy efficiency) once those units have reached the end of their useful lives in the coming decades.[109] While it may be challenging for states to do so today, inclusion would give states and industry incentives to speed development of new carbon-free generation technologies.

Adopting a technology-forcing standard is entirely consistent with the Clean Air Act and its legislative history. In proposing the CO_2 new source performance standards for new EGUs, EPA referred to the extensive legislative history and case law supporting the proposition that the

[108] Or to do so in a logical manner, with replacement carbon-free generation in place.

[109] All generation, of course, eventually reaches the end of its useful life and must be replaced. The Nuclear Regulatory Commission ("NRC") license process provides a clear potential endpoint for nuclear plants, but no mechanical equipment lasts forever.

ED_000419-0005635

technology-based standards under section 111 were intended to be technology-forcing.[110] That intent applies equally to standards for existing sources. Both section 111(b) and section 111(d) direct EPA to adopt a "standard of performance," a term defined in section 111(a) to reflect the application of the "best system of emission reduction." As the D.C. Circuit has held, section 111(a)'s "mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation."[111]

Moreover, the electricity industry can meet the challenge, in coming decades, of replacing nuclear units that have reached the end of their useful lives with other zero-emitting generation. Technologies that either already exist, or that are currently under development and are likely to be commercialized in the coming decades, include:

- New nuclear facilities. Nuclear units are a demonstrated, proven technology for generating zero-carbon electricity. Certainly, it is technically feasible to replace units that have reached the end of their remaining useful life with new units. As EPA notes, five nuclear EGUs at three plants presently are under construction: Vogtle in Georgia, Watts Bar in Tennessee, and Summer in South Carolina. More are under consideration, such as additional units at Turkey Point in Florida.

- Innovations that will extend the life of existing nuclear facilities. The nuclear industry continually develops and implements such innovations, and the Nuclear Regulatory Commission will soon receive applications to extend licenses for a fourth twenty-year term.[112]

---

[110] 79 Fed. Reg. 1430, 1465 (Jan. 8, 2014).

[111] *Sierra Club v. Costle,* 657 F.2d 298, 346 (D.C. Cir. 1981).

[112] *See, e.g.*, NEI, "U.S. Nuclear Energy Industry Innovations That Focus on Aging Management or Long-Term Plant Reliability," *available at* http://www.nei.org/Knowledge-Center/Industry-Innovation/U-S-Nuclear-Energy-Industry-Innovations-That-Focus; Matthew L. Wald, "Power Plants Seek to Extend Life of Nuclear Reactors for Decades," New York Times (Oct. 19, 2014), *available at* http://www.nytimes.com/2014/10/20/business/power-plants-seek-to-extend-life-of-nuclear-reactors.html

ED_000419-0005636

- Next-generation nuclear technology. The nuclear industry is currently developing modular small and medium size nuclear reactors that could significantly reduce construction times and costs.[113] Although current economic conditions make the development of such reactors in competitive electricity markets challenging, these innovations could be applied within regulated markets, and when the technology is proven, applied more broadly. The International Atomic Energy Agency has also identified developments in fast reactors and gas-cooled reactors.[114]

- Carbon capture and reuse from existing coal-fired plants. EPA has already found that CCS is technically feasible (though not yet cost-effective) for many existing coal-fired plants, and a variety of such systems are under development.[115] Some involve the capture and purification of CO_2 emissions to compress the CO_2 to a super-critical liquid that can then be reused in industrial processes or injected into geologic formations for long term, permanent sequestration and removal from the atmosphere. In 2009, Pennsylvania examined establishing a network of geologic sequestration sites in the Commonwealth and found it feasible.[116] However, in the absence of market incentives for carbon emissions reduction from existing fossil fuel-fired plants, the efforts to develop a sequestration site network were abandoned. Other processes under development include capture by genetically enhanced algae to produce new fuels, thus recycling carbon dioxide rather than releasing new carbon from long-term carbon sinks.[117]

- CCS from NGCCs. CO_2 capture from NGCCs for reuse or sequestration will be feasible within the next decade, so that retiring nuclear plants could be replaced by new NGCCs that produce electricity without emissions. On October 15, 2014, Exelon Generation announced that it had joined a joint venture that would validate that technology at a site in Texas, using supercritical CO_2 as a working fluid to drive a combustion turbine and

---

[113] *See* Int'l Atomic Energy Agency, "Small and Medium Sized Reactors (SMRs) Development, Assessment and Deployment," *available at* http://www.iaea.org/NuclearPower/SMR/index.html; Int'l Atomic Energy Agency, "Advances in Small Modular Reactor Technology Developments" (Sept. 2014), *available at* http://www.iaea.org/NuclearPower/Downloadable/SMR/files/IAEA_SMR_Booklet_2014.pdf.

[114] Int'l Atomic Energy Agency, "Support for Innovative Fast Reactor Technology Development and Deployment," *available at* http://www.iaea.org/NuclearPower/FR/index.html.

[115] *See* NPRM, 79 Fed. Reg. 34,876 (noting that partial CCS has been "demonstrated at a pilot-scale at Southern Company's Plant Barry, it is being installed for large-scale demonstration at NRG's W.A. Parish facility, and it is expected soon to be applied at a commercial scale as a retrofit at SaskPower's Boundary Dam plant in Canada.").

[116] *See generally* Thomas A. Gray *et al.*, *Assessment of Risk, Legal Issues, and Insurance for Geologic Carbon Sequestration in Pennsylvania* (Nov. 2009), report prepared for the Pennsylvania Department of Conservation and Natural Resources and submitted to Pennsylvania General Assembly pursuant to Act 129 of 2008.

[117] University of Kentucky, Algae CO_2 Capture Part 1: How it Works (Oct. 3, 2013), *available at* www.real.uky.edu/algae_part1_howitworks.

ED_000419-0005637

ultimately to produce pipeline-quality CO_2 that can be sequestered or used in industrial processes. The developer is working toward commissioning the plant in 2016.[118]

- Improved solar generation. Photovoltaic solar is becoming dramatically less costly. There have also been new developments in utility-scale thermal projects that can deliver solar-generated electricity with increasing reliability. For example, the 400 MW Solana plant in Arizona, which came online in October 2014, uses molten sodium to store heat generated during the day to produce steam during late afternoon peak hours or when the sun is no longer shining to achieve a 40 percent capacity factor.[119] The price for Solana's power falls within the range EPA has determined is cost-effective. Moreover, new technologies such as solar shingles and solar films are allowing increasing use of distributed solar generation in or at the building sites where the electricity is consumed.

- Improved storage technologies. Battery, fuel cell, and other storage technologies are improving rapidly.[120] Although these technologies do not generate electricity, they will allow greater and more efficient use of intermittent technologies such as wind and solar. Fuel cell technologies will also permit more efficient production of electricity from natural gas during periods of time that renewable generation is unavailable.

- Smart Grids and improved techniques for distributed generation. These innovations in electricity distribution allow demand to be matched more closely with supply of electricity, allowing intermittent renewable resources to be integrated efficiently, electric vehicles to provide grid balancing services, demand response to reduce electricity consumption at peak times in the most efficient manner, and transmission losses to be reduced through distributed generation.[121]

These emerging technologies hold great promise in reducing the carbon intensity of our electricity system. Their advancement would be strongly encouraged by a Clean Power Plan that requires states to build on the emissions reductions they have already achieved, and that prohibits

---

[118] Exelon Corp., "Exelon, CB&I and 8 Rivers Proceed with Clean Energy Demonstration Plant" (Oct. 15, 2014), *available at* *http*://www.exeloncorp.com/Newsroom/pr_20141015_power_cleanenergydemoplant.aspx.

[119] *See* Abengoa, "Solana," *available at* http://www.abengoasolar.com/export/sites/abengoasolar/resources/pdf/Solana_factsheet_09092013.pdf.

[120] Ars Technica, "Who needs sunlight? In Arizona, solar power never sleeps" (Feb. 18, 2014), *available at* http://arstechnica.com/science/2014/02/making-solar-power-even-after-the-sun-goes-down/.

[121] Dep't of Energy, "Smart Grid: An Introduction," *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_SG_Book_Single_Pages%281%29.pdf; Matthew L. Wald, "In Two-Way Charging, Electric Cars Begin to Earn Money From the Grid," New York Times (Apr. 25, 2013), *available at* http://www.nytimes.com/2013/04/26/business/energy-environment/electric-vehicles-begin-to-earn-money-from-the-grid.html.

ED_000419-0005638

states from backsliding and increasing CO_2 emissions from historical levels.[122] Indeed, historically, environmental regulation has been a strong driver of innovation in the power sector.[123] Moreover, environmental regulations have consistently cost substantially less to implement than EPA or industry originally estimated.[124] Thus, the prospect that existing nuclear

---

[122] Allowing CO_2 emissions to increase would violate fundamental principles of anti-backsliding expressed throughout the Clean Air Act and repeatedly endorsed by Congress in various Clean Air Act amendments and by the courts. The purpose of the Clean Air Act is "to protect and enhance the quality of the Nation's air resources" and its primary goal is "to encourage or otherwise promote reasonable . . . governmental actions . . . for pollution prevention." 42 U.S.C. § 7401(b)(1), (c). Allowing increased emissions is not consistent with enhancing air quality or promoting prevention of pollution.

The District Court for the District of Columbia relied on this statutory language to enter an order, affirmed by the Court of Appeals for the District of Columbia Circuit and an equally divided Supreme Court, requiring disapproval of all state implementation plans that failed to protect areas that were cleaner than NAAQS. *Sierra Club et al. v. Ruckelshaus*, 344 F. Supp. 253 (D.D.C. 1972), *aff'd per curiam*, No. 72-1528, 4 E.R.C. 1815 (D.C. Cir. Nov. 1, 1972), *aff'd*, 412 U.S. 541 (1973). In response to this decision, EPA created the Prevention of Significant Deterioration program ("PSD"). 38 Fed. Reg. 18,986 (July 16, 1973) (proposing PSD program); 39 Fed. Reg. 42,509 (Dec. 5, 1974) (final rule). Both the result of this lawsuit and these rules were preserved in subsequent legislation (*see* Pub. L. No. 95-95, § 406, as amended by Pub. L. 95-190, § 14(b)(6)(a) (preserving lawsuits), (b) (preserving "regulations" and "determinations"), 91 Stat. 140), and the PSD Program was codified by Congress in the 1977 Amendments to the Clean Air Act (Pub. L. No. 95-95, § 127, 91 Stat. 685, 731 (1977) (PSD); *id.* § 128, 91 Stat. 685, 742 (visibility)), and was strengthened by subsequent amendments in 1990 so that it now appears throughout the Act. *See* 42 U.S.C. §§ 7470-7492 (PSD and visibility protection), 7410(a)(2)(C), (a)(D)(i)(II). The same principles should govern here.

Section 111 itself incorporates the concept that states may not move backwards with regard to emissions performance. It mandates periodic review and strengthening of all section 111 standards (both new and existing), and directs the Administrator when revising standards to take account of whether "emission limitations and percent reductions beyond the standards promulgated … are achieved in practice." *Id.* § 7411(b)(1)(B). Section 112 similarly requires that those technology-based standards be strengthened periodically and prevents backsliding on emissions reductions already achieved in practice. The statute requires review and reestablishment of the maximum available control technology-based standards every eight years, *id.* § 7412(d)(6), and provides that "[n]o emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation…." 42 U.S.C. § 7412(d)(7).

[123] *See* NESCAUM, *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers* (Sept. 2000), *available at* http://www.nescaum.org.

[124] *See, e.g.,* Robert V. Percival, *Regulatory Evolution and the Future of Environmental Policy*, 1997 U. Chi. Legal F. 159, 176-184 (1997).

ED_000419-0005639

units will eventually retire should not be a justification for failing to consider the full effect of that generation in setting state goals.[125]

Finally, including nuclear (or hydropower) units in setting emissions rate targets need not negatively affect a state if a nuclear (or hydropower) facility were forced to retire unexpectedly for reasons beyond reasonable control – for example, due to an unexpected equipment failure (or, for hydropower, a prolonged drought). In that circumstance, EPA's regulations implementing section 111(d) provide a mechanism for a state to amend its plan to provide a different pathway for achieving compliance. Indeed, the general regulations explicitly allow for the possibility that a state plan or revision may, under certain circumstances, provide for a longer compliance period or establish less stringent emission standards, at least for a time.[126] Specifically, a state may provide for longer compliance schedules or the application of less stringent emissions standards if the state demonstrates with respect to a facility or class of facilities that costs of control are unreasonable because of "plant age, location, or basic process design," installing necessary control equipment is impossible, or "factors specific to the facility (or class of facilities) … make application of a less stringent standard or final compliance time significantly more reasonable."[127] Such plan submissions would require increments of progress to achieve compliance.[128] Moreover, section 111(d)'s authorization for states to consider "the remaining useful life of the existing source"[129] in establishing standards of performance can also be

[125] Indeed, existing generation of all types will all eventually retire or need substantial investments to continue operation.

[126] *See* 40 C.F.R. § 60.28(a).

[127] *Id.* § 60.24(f).

[128] *See id.* § 60.24(e)(1).

[129] 42 U.S.C. § 7411(d)(1).

ED_000419-0005640

interpreted to authorize a revision of system-based standards where the life of an existing zero emissions source is cut short.

2. An Alternative: Accounting for Nuclear Generation That Is Lost.

An alternative clarification in the final rule could potentially achieve the same incentives as a system-wide rate to maintain existing nuclear facilities, although it would be somewhat more complex. Without changing EPA's proposed target rate calculation methodologies, EPA could still ensure that states have the appropriate incentive to preserve all existing nuclear capacity by adjusting the state's calculated emissions rate, when assessing a state's compliance, to reflect the full impact of any premature nuclear retirement. Thus, EPA could indicate that, in determining whether a state is meeting its goals, EPA will subtract from the rate denominator the full amount of any lost nuclear generation, effectively requiring full replacement with equivalently carbon-free generation. Like a system-wide emissions rate, this approach would give each state an incentive to preserve all of its existing nuclear plants that may be at risk of early retirement. However, because state plans may differ, and because EPA has expressed an intention to measure compliance with respect to each state's plan, it would be more straightforward to include all megawatt-hours of existing power plant generation in determining a state's target emissions rates, as proposed above.[130]

Regardless of methodology, EPA should require that a state plan include requirements that no nuclear generation assets will be prematurely retired – or, alternatively, that any prematurely retired nuclear generation will be replaced by an equal or greater amount of other

[130] If EPA does adopt this option despite its complexity, the Final Rule will also need to address interstate purchases carbon-free energy credits. *See* Part V below, for further discussion of accounting rules to prevent double counting resulting from the interstate trading of credits.

ED_000419-0005641

zero-emissions generation. A plan that failed to satisfy this principle should be deemed non-compliant.

3. At a Minimum, EPA Should Use a State-Specific Determination of "At-Risk" Nuclear Capacity.

As discussed above, EPA should not limit the inclusion of nuclear generation in the calculation of a state's emissions rate goals to those facilities deemed "at risk." However, to the extent that EPA does retain that general framework, it must replace the use of a six-percent nationwide average – which does not accurately reflect conditions in any particular state – with a state-specific determination of the nuclear capacity at risk of early retirement.[131]

This solution, while an improvement to the rule as proposed, does not treat all carbon-free generation the same and is far from preferable. It will not provide states with sufficient incentives to value the carbon-free generation of all existing nuclear facilities, nor will it provide them with sufficient incentives to preserve every cost-effective megawatt of existing nuclear power. Moreover, this solution poses administrative challenges that a system-wide emissions rate would avoid. In particular, EPA would be forced to determine which nuclear facilities are "at risk." EPA would also need to revise that determination from time to time, adjusting state goals with each addition to the list of endangered nuclear plants. The difficulty inherent in such judgments will only be compounded by changing market conditions over the timeframe envisioned in the rule.

[131] Use of a nationwide average is inconsistent with how EPA defines the "best system of emission reduction" elsewhere in the Proposed Rule; rather than a nationwide average, EPA relies on state- and region-specific data. As discussed in Part I, it is also inconsistent with how the electricity system actually functions, which is on a regional basis.

ED_000419-0005642

4. *EPA Should Expressly Recognize the Ability to Demonstrate Compliance Through Portfolio Standards That Credit Nuclear and Hydropower.*

One way that states could choose to help ensure the continued vitality of existing nuclear and hydropower plants is to include such generation in their portfolio standard programs through what might be called a "clean energy credit." Doing so would place a value on the environmental attributes of nuclear and hydropower generation, just as Renewable Portfolio Standard ("RPS") programs place a value on the environmental attributes of wind or solar. Today, few if any state RPS programs encompass all forms of zero-carbon electricity and some may even credit carbon-emitting generation such as clean coal and waste coal.[132] That is unsurprising, given that RPS programs ordinarily seek to achieve state policy goals other than, or in addition to, CO_2 emissions reductions. Most state RPS programs do not encompass nuclear power, and although many include some types of hydropower, they generally exclude the existing large-scale hydropower that provides the largest source of reliable renewable generation.[133]

However, if states are given the proper incentives to preserve existing nuclear capacity and hydropower – for instance, if EPA uses a system-wide rate to calculate emissions targets – then states may expand their portfolio standard programs to include nuclear and existing large-scale hydro by mandating procurement of clean energy credits. Such credits, like RECs under existing programs, could also be traded, thereby allowing a state to comply by helping to preserve an existing nuclear or hydropower facility located in another state. EPA should make

---

[132] *See, e.g.*, OAC § 4901:1-40-04(B)(3) (in Ohio, clean coal is an "advanced energy resource"); 73 P.S. § 1648.2 (in Pennsylvania, the definition of "alternative energy sources" includes "waste coal").

[133] *See generally* Database of State Incentives for Renewables & Efficiency ("DSIRE"), DSIRE Quantitative RPS Data Project (Apr. 15, 2011), *available at* http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf.

ED_000419-0005643

clear in the final rule that such clean energy credit programs will be recognized as a valid method for states to comply and that clean energy credits reflecting nuclear generation will be valued fully, rather than at the six percent factor suggested by EPA's proposed goal-setting methodology.

The reasons for including nuclear and large-scale hydropower in clean energy credit programs are similar to the reasons for fully counting nuclear generation in EPA's goal-setting formula. Procuring one MWh of electricity from a nuclear generator is at least equivalent to procuring one MWh of electricity from a wind generator. Moreover, clean energy credit programs would avoid the negative consequences for emissions reduction that can result from RPS programs that favor some zero-emissions generation technologies and not others. As discussed above, existing RPS programs that favor wind power but exclude nuclear power exacerbate the economic pressures faced by nuclear generators. Tradable nuclear and hydropower credits would help ensure, particularly in rate-based states, that nuclear and hydropower facilities are appropriately valued for the zero-carbon attribute of the electricity they generate.

III. EPA SHOULD MODIFY THE GOAL-SETTING FORMULA IN SEVERAL KEY RESPECTS.

In addition to modifying the treatment of nuclear generation in the goal-setting formula, EPA should make several other adjustments that better reflect the emissions reductions achievable from the "best system of emission reduction" and that align with the interconnected nature of the electric system. Specifically, EPA should (1) value incremental renewable energy and energy efficiency in Building Blocks 3 and 4 in terms of the CO_2 emissions they avoid from existing fossil fuel generation, rather than as simply additional MWh of generation; (2) look

ED_000419-0005644

beyond state borders when calculating the reductions achievable from dispatch to under-utilized NGCC units in Building Block 2 and from zero-carbon electricity that can replace or reduce existing fossil generation in Building Block 3; and (3) account for reductions achievable from increased co-firing of natural gas in Building Block 1. These adjustments will better ensure that emission goals reflect the extent of emissions reductions achievable in light of the integrated nature of the electric system and the opportunities for replacement of generation from higher-emitting sources with generation from lower-emitting sources.

A. EPA Should Treat Incremental Renewable Energy and Energy Efficiency as Displacing Existing Fossil Fuel Generation, Not as Additional Generation.

In setting state goals, the Proposed Rule treated incremental renewable energy (in Building Block 3) and energy efficiency (in Building Block 4) as additional megawatt-hours that would be added to the denominator of the rate formula. In other words, the Proposed Rule would count new renewable generation and energy efficiency as though they will result in more total generation, but with the same overall total carbon emissions. The Goal-Setting NODA invites comment on an alternative and more logical way to account for incremental renewable energy and energy efficiency: as replacing existing fossil fuel-fired generation, and thus reducing CO_2 emissions from the numerator.[134] EPA should adopt this alternative approach.

Valuing incremental renewable energy and energy efficiency as avoided emissions, rather than as additional generation, better aligns both with EPA's rationale for the "best system of emission reduction" and with how the interconnected electricity system works. As EPA recognized, increased renewable electricity "provides electricity that can be substituted for

[134] Goal-Setting NODA, 79 Fed. Reg. at 64,552-53.

ED_000419-0005645

generation from more carbon-intensive EGUs"[135] and ideally reduces CO_2 emissions because it "replaces predominantly fossil fuel-fired generation."[136] Similarly, additional energy efficiency programs are intended to reduce generation from existing fossil fuel generation, and therefore should reduce overall CO_2 emissions.[137] In most cases, when states add renewable generation and energy efficiency, the electric system dispatches less fossil generation and thus reduces the mass of emissions. Thus, in setting state emissions rate goals, EPA should value these measures as emissions avoided, rather than simply treat them as additional generation without a corresponding adjustment to emissions in the numerator.[138] This approach also is more consistent with EPA's approach to Building Block 2, in which existing NGCCs are assumed to replace existing fossil generation that is more carbon-intensive, and the numerator of the goal-setting formula is adjusted correspondingly.[139] In both cases, a reduction in emissions rate occurs because higher-emitting sources are dispatched less frequently, not solely because lower-emitting generation is added.

Moreover, EPA should be promoting zero-carbon electricity sources and demand side reductions not as ends in themselves, but as means to achieve emissions reductions. EPA should value these components of Building Blocks 3 and 4 in the way that is most consistent with that ultimate goal.

---

[135] NPRM, 79 Fed. Reg. at 34,858.

[136] *Id.* at 34,866.

[137] *Id.* at 34,858, 34,871.

[138] EPA's Goal-Setting NODA expressly mentions two options: assume the incremental renewable energy and energy efficiency replace fossil generation on a pro rata basis, or replace higher-emitting fossil generation first. Goal-Setting NODA, 79 Fed. Reg. at 64,552-53. Either option better approximates the system response to additional renewable energy generation or reduced demand for fossil fuel-fired generation than EPA's proposal to add MWh to the denominator without a corresponding adjustment to CO_2 emissions in the numerator.

[139] Goal-Setting NODA, 79 Fed. Reg. at 64,552; NPRM, 79 Fed. Reg. at 34,896.

ED_000419-0005646

B. EPA Should Look Beyond State Borders When Calculating Reductions Achievable from Dispatch to NGCC Units in Building Block 2 and From Zero-Carbon Electricity Generation in Building Block 3.

EPA's Goal-Setting NODA also addresses, among other things, the following two issues related to the calculation of emissions goals: first, whether states that have little or no under-utilized NGCC capacity could nonetheless shift some minimum amount of generation to NGCC plants, even if such plants are located in other states; and second, whether EPA should calculate a state's potential for reducing emissions through renewable electricity by calculating regional potential reductions, and then allocating those reductions to states within each region.[140] While these issues relate to different building blocks in EPA's calculations, they are nonetheless related. Both issues stem from the more general question of whether state goals should reflect emissions reductions that can be supported only by measures within a state's borders (*e.g.*, redispatch, zero-carbon electricity production, and energy efficiency), or instead whether state goals should – consistent with the interconnected, interstate nature of the electricity system – reflect emissions reductions supported by measures that can be taken regionally.

The Proposed Rule limits emissions goals to measures that can be undertaken within a state's borders. Limiting future emissions reductions to those within a state border does not fully reflect a state's potential to economically reduce emissions. For example, under the Proposed Rule, for states with little or no under-utilized NGCC capacity, the emissions goals reflect little or no emissions reductions achievable through Building Block 2 (redispatch), even though those states may well be able to achieve emissions reductions by relying upon redispatch from affected

[140] Goal-Setting NODA, 79 Fed. Reg. at 64,546-47, 64,549-52. More generally, EPA sought comment on whether to establish a minimum value of generation shift for Building Block 2 to reflect switching to existing NGCC units, *or* to reflect dispatch to new NGCC units or co-firing natural gas in existing coal-fired boilers. *Id.* at 64,550. As explained in Part I.C of these comments, EPA should consider the opportunities for emissions reductions from co-firing natural gas in existing fossil units as part of Building Block 1.

ED_000419-0005647

EGUs to NGCCs located in other states. Likewise, for Building Block 3, the Proposed Rule sets emissions goals based upon a state's 2012 renewable generation, scaled up over time using regionally-calculated growth factors. That is so even though a state may be able to achieve emissions reductions by relying upon renewable generation constructed in other states. In fact, the growth factors are based upon RPS programs that expressly allow reliance on renewable generation constructed in other states.[141]

The state-bound approach taken in the Proposed Rule artificially and unrealistically limits the reductions that can be achieved by Building Blocks 2 and 3. For example, Pennsylvania's emission goals reflect redispatch from its coal plants to the 10 GW of NGCC capacity located within the Commonwealth, but they ignore the reality that Pennsylvania is interconnected with New Jersey. EPA projects that after implementation of the Proposed Rule, New Jersey's NGCC fleet will have a capacity factor of only 44 percent, far below the 70 percent used as the ceiling for Building Block 2.[142] New Jersey's NGCC fleet – which is dispatched by the same grid operator as Pennsylvania's coal fleet – could absorb approximately 13 million MWh from coal units in neighboring states. If Pennsylvania coal generation were shifted to New Jersey NGCCs until those units reached 70 percent capacity, the net emissions from the two states would be reduced by nearly eight million short tons of CO_2 per year.[143]

---

[141] When EPA calculated the Building Block 3 reductions for each state, it capped the renewable generation target for each state based on a regional growth factor. *See* Technical Support Document: GHG Abatement Measures, Docket ID No. EPA-HQ-OAR-2013-0602-0437 at 4-19, 4-22 to 4-25, Tables 4.6 and 4.7. However, in some states this formula yields emission goals based on renewable energy output *lower* than the state's current output. Specifically, the proposed renewable generation targets for Iowa, Maine, Minnesota, and South Dakota are lower than the renewable generation in those states in 2012.

[142] Goal Computation Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602-0460, at Appendix 1 ("Goal Computation TSD").

[143] EPA's analysis suggests New Jersey NGCCs could produce approximately an additional 13 million MWh at 70 percent capacity. Avoided emissions are based on the difference between Pennsylvania's

ED_000419-0005648

In the Goal-Setting NODA, EPA proposes alternative methods of calculating emissions rate goals that more closely conform to the integrated, interstate nature of the electricity system. The final rule should account for emissions reductions that can be achieved through measures taken beyond a state's borders. For example, as just discussed, coal-fired generation located in one state can often be displaced by under-utilized NGCCs located in another state. Setting state goals to reflect the potential for redispatch to NGCCs located in other states not only would be reasonable, but failing to account for such potential could significantly underestimate the degree of emissions reductions achievable through the BSER, which, as EPA has explained, takes into account the interstate nature of the electric industry.[144] Likewise, EPA should set state goals to account for a state's ability to reduce emissions through reliance on zero-carbon generation located in another state. Doing so would be consistent with EPA's apparent intention that states be able to demonstrate Building Block 3 reductions through the purchase of credits from other states.

More generally, as discussed in Section I above, in the electricity system, the location of the resource that displaces or avoids emissions reduction is not determined by state boundaries, but instead is dictated by market forces, chiefly cost. Emissions goals reflecting the reductions achievable in that "best system of emission reduction" should, therefore, reflect the full amount of reductions that can occur in an interconnected region. In determining the boundaries of the relevant region, it would be natural for EPA to adopt the boundaries of existing ISOs and RTOs, as those grid operators control dispatch within their territory. In areas of the country not

---

current coal emissions rate (2,108 lbs/MWh) and New Jersey's current NGCC emissions rate (889 lbs/MWh), if this incremental capacity were dispatched. Goal Computation TSD at Appendix 1.

[144] *See* NPRM, 79 Fed. Reg. at 34,880-81.

ED_000419-0005649

governed by an ISO or RTO, power flows are managed within "control areas" that similarly can span state lines.

In determining the emission reductions that can occur within a region due to redispatch from coal to gas, and then apportioning those reductions to states within that region, EPA could rely upon a version of the Integrated Planning Model ("IPM") that it has already developed and used in similar contexts.[145] IPM models areas within ISOs and RTOs as sub-markets. The model would allow EPA to project where emissions reductions occur in the interconnected electricity system, and EPA could easily formulate state goals based upon that modeling. This approach would be very similar to the way in which EPA calculated total allowable emissions from each state in the CSAPR based on the state's ability to achieve highly cost-effective emissions reductions, and approximated an allocation based on cost.[146] EPA could also use a simpler allocation system, in which the total emissions reductions in a region is apportioned to the constituent states based on historical generation (*e.g.*, MWh produced in 2012), electricity load (*e.g.*, MWh consumed in 2012) or historic emissions (*e.g.*, CO_2 tons emitted in 2012).[147]

---

[145] *See, e.g.*, *West Virginia v. EPA*, 362 F.3d 861, 869-71 (D.C. Cir. 2004) (upholding EPA's use of IPM in developing nitrogen oxide emissions limitations).

[146] *See EPA v. EME Homer City Generation L.P.*, 134 S. Ct. 1584, 1596-97 (2014) (describing and affirming EPA's "complex modeling" of cross-state air pollution resulting in emissions budgets for each state).

[147] At the very least, EPA should adopt a minimum percentage for dispatch switching for states with little to no existing NGCC capacity, based upon the ability to repower existing coal-fired units with NGCC units. As EPA notes, this mechanism would increase the emissions reductions required in states with limited existing NGCC capacity and significant coal-fired capacity. *See* Goal-Setting NODA, 79 Fed. Reg. at 64,550. Even if one of these states did not participate in regional markets, that state still could meet minimum re-dispatch requirements by repowering or replacing some of its coal units. As discussed in Part I.C of these comments, many of these coal states are located over or near shale gas formations, so that switching dispatch to converted or new NGCC units would be cost effective and feasible in those states.

ED_000419-0005650

Reductions based on renewable generation also should be determined by looking beyond state borders.[148] Indeed, although the Proposed Rule formulates state goals based upon renewable generation located within the state, it appears to contemplate allowing states to demonstrate compliance through RECs purchased from other states. A state's emissions goals should be consistent with the means available for compliance.[149] Thus, if EPA continues to allow states to demonstrate compliance using RECs generated in other states, then EPA should set state emissions reduction goals consistently. Those goals should reflect states' ability to comply by purchasing RECs from other states, and they should include an allocation of potential renewable generation across states capable of supporting it through the purchase of RECs.

At a minimum, EPA should set state emission reduction goals for renewable generation based on the reductions that can be achieved within a region, using the same regions proposed here for Building Block 2 – *i.e.*, regions that reflect the boundaries of existing ISOs and RTOs or "control areas." As noted, this approach reflects the reductions achievable through the "best system of emission reduction" taking into account the interstate nature of the electric system. Moreover, a regional approach encourages regional compliance, reducing the risk of "double counting" renewable energy credits by ensuring that renewable generation is only counted once.[150]

---

[148] Alaska and Hawaii excepted.

[149] The RGGI States have made a similar comment. *See* RGGI States' Comments at 14, 24.

[150] *See* Part V.D of these comments for a full explanation of trading rules to avoid the problem of double counting.

ED_000419-0005651

C. In Setting State Goals, EPA Should Incorporate Co-Firing With Natural Gas and Other Types of Fuel Switching in Building Block 1.

In the Goal-Setting NODA, EPA also requests comments on whether it should consider re-dispatch from steam generation to existing NGCC units, re-dispatch to new NGCC units, or co-firing natural gas in existing coal-fired boilers in calculating the emissions reduction goals for Building Block 2. Companies may also convert coal-fired steam boilers to natural gas, as EPA notes in the NODA.[151] EPA suggests that this could be accomplished by establishing a minimum percentage for dispatch switching from coal-fired generation for Building Block 2, which would increase the emissions reductions required in states with existing coal-fired units but little or no excess existing NGCC capacity.[152] As part of the proposal, EPA requests comment on the issue of whether co-firing with natural gas and other forms of fuel switching (*e.g.*, to higher ranked coal or biomass), as well as conversion, should be considered as part of the BSER, generally, including in Building Block 1.[153]

Exelon agrees that co-firing with natural gas and converting coal units to natural gas units are feasible mechanisms to reduce CO_2 emissions that are frequently being implemented today even without a price on carbon emissions. Therefore, EPA should consider these mechanisms for emissions reduction in the BSER and increase the stringency of state emissions reduction goals accordingly. However, co-firing with natural gas is best applied as an element of Building

[151] *See* Goal-Setting NODA, 79 Fed. Reg. at 64,549-51.

[152] *Id.* at 64,550.

[153] *See* NPRM, 79 Fed. Reg. at 34,857, 34,875-76, 34,897.

ED_000419-0005652

Block 1 to increase the percentage reduction of emissions from coal-fired power plants attributable to measures that can be implemented at those plants.[154]

As EPA notes, industry is currently rapidly converting or replacing the existing coal-fired fleet to utilize natural gas or to allow co-firing of existing boilers with natural gas. As of January 2013, well before the proposal of the Clean Power Plan, plants representing 5,384 MW of coal-fired capacity located in five NERC regions were involved in conversion projects.[155] Since that time, additional conversion plans have been announced.[156] Likewise, a number of existing coal-fired power plants have made changes or announced plans to accommodate co-firing so that they can run on natural gas, coal, or both.[157]

Repowering and co-firing projects are occurring today without regard to a specific federal requirement to reduce CO_2 emissions from existing sources. Dramatically lower natural gas prices and increased development of shale gas resources arising from directional drilling

---

[154] As noted above at footnote 147, conversion to natural gas also could provide a basis for EPA to establish a minimum percentage for dispatch switching for each state in Building Block 2 of the state goals, if EPA chooses not to take a regional approach in that Building Block.

[155] Neil Powell, SNL Financial, "5,384 MW of U.S. capacity involved in gas combined-cycle conversion projects" (Jan. 16, 2013).

[156] *See, e.g.*, Alliant Energy Press Release, "Alliant Energy transitioning M.L. Kapp Generating Station to natural gas" (Jan. 3, 2014), *available at* http://www.alliantenergy.com/AboutAlliantEnergy/Newsroom/NewsReleases/023317; Zia Ullah Khan, SNL Financial, "UPDATE: OG&E $1.1B compliance plan features scrubber installation, coal-to-gas conversion" (Aug. 7, 2014) (discussing OG&E's application to convert two coal-fired units at Muskogee plant to natural gas); Eric Wolff, SNL Financial, "Ameren Missouri to add renewables, cut coal power in 20-year plan" (Oct. 1, 2014) (discussing Ameren Missouri plan to switch two Meramec Energy Center units from coal to gas).

[157] *See, e.g.*, Platts Megawatt Daily, "Coal plants ramp down to keep more gas online" (Dec. 16, 2013) (two 460 MW units at Curtis H. Stanton Energy Center near Orlando, Florida, co-fire coal and gas); Platts Megawatt Daily, "EPA rules, cheap gas underlie novel fuel switch" (Feb. 11, 2014) (Kentucky Power intends to co-fire gas at its 278 MW unit at the Big Sandy Plant).

ED_000419-0005653

capability have made these projects more feasible.[158] Co-firing also reduces maintenance requirements and increases operational flexibility by allowing the coal-fired plants to increase and decrease their output more readily to respond to changes in load demand.[159] Many companies initiating these projects have indicated that they are using natural gas conversion or co-firing as low-cost mechanisms to reduce emissions of conventional and hazardous air pollutants to comply with the requirements of MATS, CSAPR, the regional haze program, and other state and federal environmental requirements. Indeed, some of these projects have allowed companies to continue to rely on coal-fired facilities that would otherwise have retired. Therefore, EPA has a reasonable basis to include increased natural gas use through co-firing and conversion as cost-effective mechanisms in determining BSER.

The widespread availability of shale gas, as shown in Figure 6, means that co-firing and conversion is available, or could be available, at coal-fired units located across the continental U.S.[160]

---

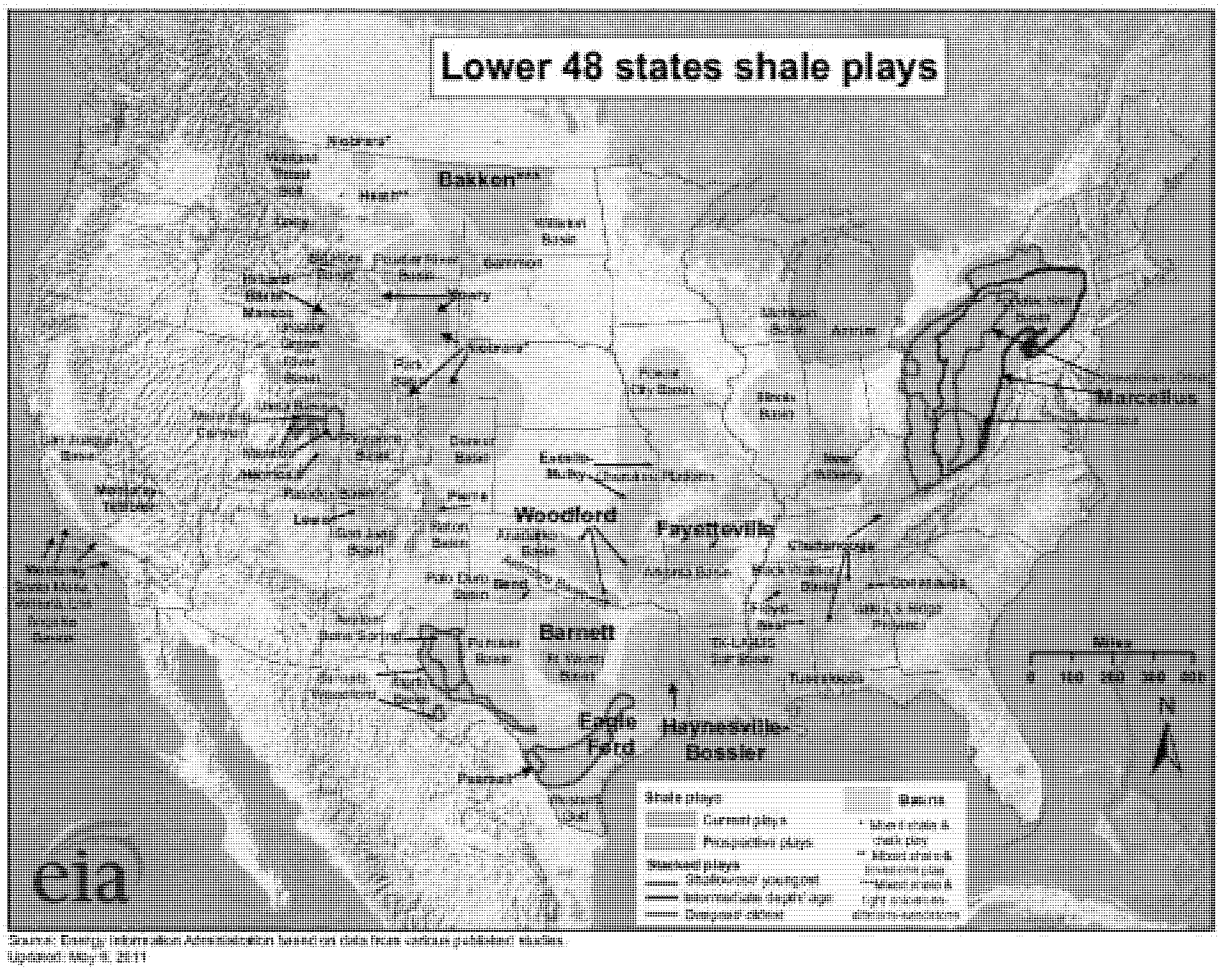
[158] Directional drilling is the technological development that allowed exploitation of shale gas deposits through the use of hydraulic fracturing or "fracking."

[159] *See* Platts Megawatt Daily, "Coal plants ramp down to keep more gas online" (Dec. 16, 2013).

[160] EIA, "Lower 48 states shale plays", May 9, 2011. *Available at* http://www.eia.gov/oil_gas/rpd/shale_gas.pdf.

ED_000419-0005654

Figure 6. Location of Shale Gas Deposits in the Continental U.S.



Source: EIA

The availability of nearby existing pipelines should not be considered a limitation on use of these mechanisms to reduce CO_2 emissions. Many new pipelines have recently been built, are under construction, or have been announced, including FERC-regulated interstate pipelines, intrastate public utility commission-regulated pipelines, and unregulated pipelines characterized as "gathering lines." In addition, FERC certificates pipelines relatively quickly – based on data other commenters have amassed, we understand pipelines generally proceed from application to in-service in under 16 months.

Further, temporary changes in natural gas demand such as that created by last winter's polar vortex should not exclude co-firing as a basis for setting multi-decade average emission reduction goals. Because units equipped to co-fire natural gas and coal can readily switch fuels, adjusting goals to call for a minimum percentage of co-firing would not impair reliability during limited extreme weather events like the polar vortex. Indeed, the additional flexibility provided by dual-fuel units can enhance reliability.

Although EPA has suggested that co-firing could be considered as a part of the goal-setting for Building Block 2, the better approach is to consider natural gas co-firing, like other available forms of fuel switching, as part of Building Block 1.[161] Fuel switching and materials separation are well-established mechanisms that must be considered under other Clean Air Act provisions in establishing technology-based, unit level emissions limitations.[162] Like heat rate improvements, fuel switching occurs "inside the fence" through modification of the existing individual unit. Co-firing involves modifying existing steam boilers solely to accommodate a less carbon-intensive fuel rather than switching the type of unit altogether. By contrast, Building Block 2 relies upon the system response of changing dispatch from one type of facility (coal steam) to another type (NGCC).

---

[161] Although fuel switching to allow co-firing of natural gas provides the most significant opportunity for reducing emissions at the unit level, fuel switching to higher-ranked coals, coal drying, and co-firing with biomass from sustainably harvested "low use wood" provide additional opportunities for emissions reduction that EPA should consider in establishing the emissions reduction goals for Building Block 1. Penn State researchers determined that, in Pennsylvania alone, sustainably sourced "low use wood" could supply five million tons of dry biomass per year with a BTU value 60 percent that of coal to produce energy that would not add CO_2 to the atmosphere. *See* Pennsylvania Hardwoods Development Council, "Report of the Blue Ribbon Task Force On The Low-Use Wood Resource" (Sept. 2008) at iii, 13, 17, *available at* http://www.agriculture.state.pa.us/portal/server.pt/gateway/PTARGS_6_2_75292_10297_0_43/AgWebsite/Files/Publications/low_use_wood_energy_report_08.pdf.

[162] *See, e.g.* 42 U.S.C. § 7412(d)(2)(A) (specifying consideration of mechanisms to reduce pollutants "through process changes, substitution of materials or other modifications" in setting technology-based emissions limitations for hazardous air pollutants.)

ED_000419-0005656

Moreover, because efficiency improvements and co-firing can occur on the same unit, employing both measures will produce greater emissions reductions than applying either measure alone. While emission reductions from these two methods will overlap to some degree, considering both techniques will still lead to more reductions at the unit than six percent on average, and thus will result in more stringent state goals. While EPA will need to assess the degree of additional emissions reduction that can be achieved through co-firing, there are many coal-fired plants located over shale plays, and these units could use natural gas for 20 percent to 100 percent of their operation in less than two years, based on the pipeline construction timeframe discussed above and more thoroughly in other organizations' comments. This revision to Building Block 1 would also help address the disparity in emissions reduction goals between states with little existing NGCC capacity but significant coal-fired capacity, since it would have a proportionately larger impact on the emissions goals for the states with limited excess NGCC capacity.

Accordingly, EPA should consider co-firing and other fuel switching strategies as one of the mechanisms that it might employ in determining what emissions reductions can be achieved under Building Block 1, and it should calculate revised goals reflecting these strategies.

IV. EPA SHOULD CLARIFY THE TREATMENT OF NEW GAS GENERATION.

The Proposed Rule recognizes that, in addition to the Building Blocks outlined in the proposal, states may seek to comply with their emissions targets through the use of new NGCC units that would displace higher-emitting existing EGUs.[163] The Agency has requested comment on how emissions changes resulting from the use of new NGCC units, particularly as part of a

[163] *See* NPRM, 79 Fed. Reg. at 34,923; *see also* Goal-Setting NODA, 79 Fed. Reg. at 64,550.

ED_000419-0005657

rate-based plan, should be calculated.[164] While the displacement of high-emitting existing EGUs by new, comparatively low-emitting NGCCs is certainly a potential means for states to comply with required emission performance levels, the final rule should clarify when and how both mass-based and rate-based states should account for emissions from these new NGCCs.

Specifically, EPA should make clear in the final rule that states must account for emissions from new NGCCs to the extent that the new NGCCs are displacing generation by existing EGUs. This is important in both mass- and rate-based systems. Mass-based states may have to do so in order to avoid overstating their mass reductions. If a mass-based state could comply simply by switching generation from existing EGUs to new NGCCs without counting the resulting emissions from the new NGCCs on which it has relied, the mass-based state would not actually achieve in the real world the full amount of emissions reductions claimed. EPA should likewise make clear that, in demonstrating compliance, rate-based states may take new NGCCs into account only to the extent that they displace higher-emitting EGUs. If states were free to include all new NGCCs in their rate for purposes of compliance, regardless of whether those NGCCs displace existing generation, higher-rate states could comply simply by building new NGCC units to average down their overall emissions rate. Once again, states should not be able to establish on-paper compliance with the required emission performance levels while in reality *increasing* their carbon emissions, contrary to the statutory requirement for the "best system of emission *reduction*."[165] Although that principle is implicit in the Proposed Rule, EPA should make it clear in the final rule in order to preserve the Agency's authority to reject state plans that may meet an emissions rate goal while actually increasing overall emissions.

---

[164] NPRM, 79 Fed. Reg. at 34,924.

[165] 42 U.S.C. § 7411(a)(1). (emphasis added) Allowing emissions increases would be inconsistent with the purpose and text of the Clean Air Act. *See supra* footnote 122.

ED_000419-0005658

A. Accounting for New NGCCs in Mass-Based States.

Existing mass-based emissions programs, such as RGGI and in California, apply a single emissions cap covering both newly constructed power plants and existing EGUs. EPA applied a similar structure to new and existing EGUs when it sought to regulate mercury emissions from EGUs under the Clean Air Mercury Rule.[166] These inclusions are for good reason: a state could otherwise circumvent emissions caps by replacing existing EGUs with new generating facilities not subject to the emissions limitation. Here, that process would be hastened by the fact that an effective exemption for new facilities would essentially subsidize those facilities at the expense of existing plants. EPA has recognized that "under a mass based program, if new NGCCs were not included, their costs would be less than the cost of an existing NGCC unit."[167] This could have the perverse effect of incentivizing the replacement of existing NGCCs with similarly-emitting new NGCCs.

EPA should make clear in the Final Rule that, to the extent that a mass-based state reduces generation at existing EGUs by shifting that demand to new NGCCs, the state must account for the additional emissions resulting from the new NGCCs by adjusting its mass-based target downward by the amount of those new NGCC emissions, or by requiring that new NGCC plants and their emissions be covered by a single mass-based limit. This approach would appropriately prevent a state from receiving compliance credit for emissions that have merely been shifted from existing EGUs to new ones. Unfortunately, the Proposed Rule does not clearly prevent a state from doing just that. For example, the preamble states that "[u]nder a mass-based plan where an emission limit on affected EGUs would assure achievement of the required level

[166] Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 Fed. Reg. 28,606, 28,661 (May 18, 2005) (40 C.F.R. § 60.4104).

[167] NPRM, 79 Fed. Reg. at 34,924.

ED_000419-0005659

of emission performance in the state plan, any emission reductions at affected EGUs resulting from substitution of new NGCC generation for higher-emitting generation by existing affected EGUs would automatically be reflected in mass emission reductions from affected EGUs."[168] That statement misses a vital part of the picture. Focusing solely on the "mass emission reductions from affected EGUs," ignores the emissions that will be created by the new NGCCs, which should bear on a determination whether the state has achieved the required level of emission performance.[169]

One potential exception in this regard is the implementation of Smart System Dispatch. It is preferable to have the price that EPA determines apply to both existing and new EGUs based on their relative carbon emissions. However, once the carbon price is set, an alternative is to apply that price to existing EGUs only. While this alternative approach would not be as economically efficient as a non-discriminatory application of the carbon price, it would not have the significant detrimental emissions impacts discussed above. With a pre-determined uniform price, the new NGCCs will not artificially reduce the carbon price necessary to achieve the target reductions at existing EGUs. New NGCCs would still shift emissions from existing EGUs to new EGUs, but as long as the carbon price is maintained, the overall reductions due to coal to gas redispatch should be maintained.

In the Goal-Setting NODA, EPA has requested comment on whether it should designate a minimum level of redispatch that can occur in each state because states with little existing NGCC capacity could still build new NGCC capacity to reduce the use of coal-fired facilities.[170]

---

[168] *Id.* at 34,923.

[169] *Id.*

[170] Goal-Setting NODA, 79 Fed. Reg. at 64,546.

ED_000419-0005660

Under such a mechanism, the new units would necessarily need to be treated as affected units, and their emissions should be included in calculating compliance with EPA's goals. Exelon supports this approach and EPA should clarify that this approach applies in all states.

B. Accounting for New NGCCs in Rate-Based States.

The Proposed Rule also seeks comment on how to account for the emissions of new NGCCs in rate-based states. EPA must make unmistakably clear in the final rule that rate-based states may take new NGCCs into account in demonstrating compliance with emissions performance levels *only* to the extent that they can establish that the new NGCCs have actually displaced generation by higher-emitting affected EGUs, and must also account for the actual emissions from those new units when measuring compliance. In the absence of such a requirement, a rate-based state with a target rate that is higher than the typical emissions rate for new NGCCs could try to achieve compliance simply by building new NGCCs, either to generate electricity for export or to reduce electricity imports or to replace uncounted generations, such as nuclear and hydropower. Those new NGCCs would reduce the state's adjusted emissions rate by averaging the rate down, allowing the state to move toward compliance even while paradoxically *increasing* total emissions.

Neither the statute – which requires a state to apply standards of performance reflecting the "best system of emission *reduction*"[171] – nor the Proposed Rule appears to countenance that kind of gamesmanship. EPA appears to intend to allow rate-based states to count new NGCCs in determining rate for purposes of compliance only to the extent that the new NGCCs actually displace existing, higher-emitting sources. Thus, the Proposed Rule describes the construction of

[171] 42 U.S.C. § 7411(a)(1) (emphasis added).

ED_000419-0005661

new NGCCs as a means to "reduce utilization and emissions *from affected existing EGUs*,"[172] not as a means to achieve a lower rate without reducing such utilization and emissions. And the proposed definition of "emission standard" includes "any requirement applicable to an 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*."[173]

Nevertheless, the final rule should clearly foreclose a state's ability to comply by building new NGCCs solely to average down the state's emissions rate, without actually displacing any emissions from affected EGUs. One way for the rule to do so is by using the state's change in net electricity exports as a measure of how much of its new generation merely supplements old generation, rather than displacing it or serving increased in-state load. A state whose new natural gas generation simply displaces old generation or serves increased load will have no change in net exports. A state that adds new natural gas generation without a corresponding reduction in output from existing plants or increase in load served, on the other hand, will produce more electricity and thus increase its net exports (or, equivalently, decrease its net imports).

To remove any incentive for a state to add new gas generation solely to lower its rate without actually displacing generation by higher-emitting EGUs, EPA can incorporate into its compliance calculation any increase in the state's net electricity exports. Specifically, EPA can subtract any increase in net exports (or decrease in net imports) from the denominator of the state's rate calculation, while also subtracting the associated emissions from the numerator. For instance, a state generating 150 MWh (exactly the amount necessary to serve its load) and emitting 125 tons of CO_2 would have a calculated rate of 1,667 lbs/MWh. If the state adds 50

[172] NPRM, 79 Fed. Reg. at 34,923 (emphasis added); *see also* Goal-Setting NODA, 79 Fed. Reg. at 64,549-51.

[173] NPRM, 79 Fed. Reg. at 34,955-56 (proposed 40 C.F.R. § 60.5820) (emphasis added).

ED_000419-0005662

MWh of NGCC generation without any increase in load, its carbon emissions might increase to 150 tons, corresponding to a total of 200 MWh of generation – for a calculated rate of 1,500 lbs/MWh, if all of this new generation were included in the denominator and all of its emissions were included in the numerator. But if EPA were to adjust the compliance equation to reflect increased exports in the manner proposed above, the rate calculation would remain 1,667 lbs/MWh, rather than decreasing. And if the in-state load served in this example increased from 150 MWh to 200 MWh, so that the new generation merely kept pace with load growth, then no such adjustment would be required – *i.e.*, the new calculated rate would be 1,500 lbs/MWh. This "net export" adjustment would effectively prevent a state from building new NGCCs solely to average down its rate, without actually relying on those new NGCCs to displace the state's higher-emitting existing EGUs.

Indeed, elsewhere in the Proposed Rule, EPA recognizes that states should not be permitted to circumvent standards of performance established by section 111(d) simply by shifting their generation from affected EGUs to generation units falling under EPA's new source performance standards under section 111(b). EPA has proposed that modified or reconstructed sources (which are subject to regulation under section 111(b)) should also continue to be regulated under section 111(d), lest sources "seek to avoid their obligations under a CAA section 111(d) plan by undertaking modifications."[174] Specifically, EPA has expressed "concern[] that owners or operators of units might have incentives to modify [existing EGUs] purely because of

[174] *Id.* at 34,904. In this regard, the intent of the Proposed Rule as expressed in the preamble appears to be inconsistent with the language of the Proposed § 60.6800. *Cf. id.* at 39,954.

ED_000419-0005663

potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d)."[175]

The more likely scenario of new NGCCs replacing existing EGUs requires EPA to institute a mechanism that ensures states cannot claim credit for shifting emissions from existing to new EGUs, thereby undermining the emission reductions goals of section 111(d). The statute plainly authorizes EPA to adopt a mechanism like accounting for a change in net electricity exports to prevent states from relying on new NGCCs to average down their emissions rates. Section 111(d)(1) requires state plans to establish "standards of performance for any existing source," and section 111(a) defines a "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."[176] As EPA's Legal Memorandum explains, "even if the phrase 'standards of performance for any existing source' is interpreted to mean that the standards of performance must apply directly to, and only to, the affected sources, that application of the standards of performance does not limit the scope of the type of 'system of emission reduction' that may serve as the basis for the standards for emissions."[177] To the extent that a state's proposed "system of emission reduction" is to displace existing EGUs with new NGCCs, the state should be required to demonstrate that that *system* – which includes the new NGCCs and their resulting emissions – satisfies the standards of performance established by the BSER.[178] Indeed, EPA has proposed regulations that formulate emissions standards applicable

---

[175] *Id.* at 34,904. Exelon thinks this incentive is much more likely with regard to new NGCCs than reconstructions.

[176] 42 U.S.C. § 7411(d), (a).

[177] EPA Legal Memorandum at 52-53.

[178] *Cf.* EPA Legal Memorandum at 14 (explaining that EPA's "best system of emission reductions" can take account of entities that are not existing sources, such as renewable generation and demand response,

ED_000419-0005664

to "affected entit[ies]," and has proposed to define an "affected entity" to include "[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]

V. PROPOSED ACCOUNTING RULES FOR INTERSTATE INTERACTIONS.

EPA's proposal envisions that states may seek to satisfy their Clean Power Plan obligations through allowance trading programs or through RPS programs that rest on trading of RECs. Without appropriate accounting and attribution rules from EPA, however, some states may take credit for traded allowances and credits in a manner that does not accurately reflect their contribution to emissions reduction and that undermines the actual purpose of the rule. The accounting and attribution rules to govern interstate trading proposed below can address concerns associated with trading as a means of compliance, including the need to prevent double-counting of emissions reductions.

A. Background.

EPA envisions that states' efforts to satisfy their Clean Power Plan obligations could encompass programs relying upon two different kinds of extant tradable currencies: CO_2 allowances and RECs.[180] CO_2 allowances are issued by states that use mass-based emissions caps as the means of ensuring that those caps are satisfied. In all nine states that currently

---

that offset emissions from existing EGUs, because, due to "the integrated nature of the electricity grid and the fungibility of electricity and electricity services, they displace or avoid the need for generation from those sources and thereby reduce the emissions from those sources.").

[179] NPRM, 79 Fed. Reg. at 34,953, 34,956 (proposed § 60.5780 and § 60.5820) (emphasis added).

[180] CO_2 allowance markets are distinct from REC markets; the two currencies are not traded with each other. In most RPS programs, trading is restricted to states that are in some way interconnected with the state in which the REC may be surrendered for compliance. In contrast, allowance trading may be much broader geographically – in fact, California and Quebec are working to link their trading programs.

ED_000419-0005665

participate in RGGI, facilities may use a common bank of CO_2 allowances for compliance. Those allowances are regularly traded across state lines to allow for emissions reductions to take place where they are most cost-effective. In other words, a facility located in one state can comply by purchasing allowances issued by another state. Because the overall number of allowances is capped, this arrangement ensures that the states participating in RGGI collectively achieve their emission goals – all of which are mass-based – and achieve cost-effective emissions reductions.

EPA also envisions, however, that states might satisfy their Clean Power Plan obligations by obtaining and trading credits, such as RECs, that reflect a certain number of MWh of zero-carbon generation. Importantly, these credits, unlike CO_2 allowances, were not intended to facilitate CO_2 emissions reductions. Rather, they result from state RPS programs, which require retail electric suppliers and local distribution companies to ensure that a certain percentage of the electricity consumed by retail customers is generated by renewable sources. Each REC represents one MWh. Many RPS programs allow a distribution company to comply by purchasing RECs from a generator located in a different state. Once a REC is used to satisfy an RPS obligation, it is "retired" and can no longer be sold or traded.

Unlike carbon allowance programs, RECs (and compliance with RPS programs) do not directly correspond to or ensure emissions reductions.[181] RPS compliance may facilitate emissions reductions to the extent that clean generation replaces more carbon-intensive generation. But to the extent that clean generation merely augments existing carbon-intensive

[181] Many REC programs include resources that are not renewable and that may be carbon-emitting. *See, e.g.*, *supra* footnote 132 (referencing the Ohio and Pennsylvania programs). EPA has excluded tiers or programs that include fossil CO_2 emitting sources from goal-setting and needs to take care that RECs or alternative energy credits generated by fossil resources that emit CO_2 cannot be used for section 111(d) compliance.

ED_000419-0005666

generation or displaces other zero-carbon generation, no emissions reduction will result. Indeed, California and the RGGI states – all of which have RPS programs – treat those programs as *complementary* to their carbon emission programs. They do not use RPS compliance as a direct measure of, or proxy for, emission reductions.

B. EPA Should Provide States With Equal Trading Opportunities Regardless of How They Choose to Comply.

Today, states with opportunities for REC trading significantly outnumber those with opportunities for trading CO_2 allowances. Only ten states currently have mass-based CO_2 allowance trading programs, but 38 states, including all ten states with mass-based CO_2 programs, have RPS programs that provide for REC trading. Thus, trading opportunities are more widely available for RECs than for CO_2 allowances.

The disparity in existing trading programs could unfavorably alter a state's incentives to choose between mass- and rate-based compliance goals. In choosing between those goals, states may consider that choice's impact on the extent to which they can use trading programs to comply with their obligations. If trading opportunities are more widely available for states choosing rate-based systems, the resulting incentive to choose such systems may undermine the flexibility that EPA wants states to have.

To avoid this problem, EPA should ensure that mass- and rate-based states have equal access to trading opportunities. Specifically, EPA has proposed allowing rate-based states to take credit for the out-of-state emission reductions evidenced by tradable RECs – in other words, to benefit from relatively widespread REC markets by treating REC purchases as the equivalent of CO_2 reductions. If EPA allows rate-based states to do this, it should do the same for mass-based ones, and allow those mass-based states to take credit for out-of-state emissions reductions evidenced by tradable RECs. By the same token, EPA should allow rate-based states to take

ED_000419-0005667

credit for the emission reductions evidenced by out-of-state carbon allowances. If EPA fails to take these steps, a state's choice of a mass-based goal could disadvantage it when it comes to compliance strategies. The result would be a significant incentive for states to elect rate-based goals – even though rate-based programs will be more difficult to administer and enforce.[182]

C. RECs Should Be Valued in Accordance With Their Emissions Reductions.

EPA's proposal envisions that states will rely on RPS programs as a means of achieving their emissions targets. Broadly, EPA suggests that states may build RPS programs into their state plans, with the underlying clean generation incorporated into their compliance demonstrations. Critically, however, the zero-carbon generation underlying a REC may vary in the extent to which it results in actual aggregate emissions reductions. EPA cannot simply rely on RECs as a surrogate for those reductions. In the Goal-Setting NODA, EPA discusses comments on the Proposed Rule's use of RECs in setting emissions rate goals and in demonstrating compliance.[183] These commenters urge EPA not to account for RECs as megawatt-hours added to the denominator of the emissions rate, but also to deduct from the numerator of the emissions rate the amount of CO_2 avoided by that renewable MWh. Consistent with this approach, Exelon proposes that all RECs used for compliance be valued based upon the carbon emissions they avoid.

---

[182] Just as states should not be incentivized to choose rate-based systems over mass-based ones, they also should not be incentivized to choose single-state state plans over multi-state compliance regions. In this regard, EPA's proposal expressly considers the prospect of allowing single states to take credit for out-of-state emission reductions, but does not discuss allowing multi-state regions to take credit for out-of-region emission reductions. We presume this omission is inadvertent, for there is no reason to treat out-of-region reductions differently from out-of-state reductions. In the final rule, EPA should make clear that, just as a single state with its own state plan can take credit for reductions in other states, a multi-state compliance region can likewise take credit for reductions outside the region (so long as, of course, those reductions result from in-state or in-region compliance efforts).

[183] Goal-Setting NODA, 79 Fed. Reg. at 64,552-53.

ED_000419-0005668

As explained above, compliance with RPS standards is not a direct measure of carbon emission reductions. To the contrary, the emission-reduction effect of a single MWh of zero-carbon electricity (corresponding to a single REC) depends upon the carbon intensity of the resource it is displacing. For instance, one MWh of renewable generation would reduce CO_2 emissions by about 2,000 pounds if it displaced coal-fired generation, but only by about 800 pounds if it displaced new gas-fired generation. And it would not reduce CO_2 emissions at all if it displaced nuclear or other carbon-free generation. Likewise, a REC surrendered to California or a RGGI state will not reduce CO_2 emissions beyond those states' caps at all. Consequently, from the standpoint of emissions reductions, not all RECs are created equal. Yet the Clean Power Plan's goal is emissions reduction – not renewable generation as an end in itself. And for purposes of this goal, RECs are valuable only to the extent that the underlying zero-carbon electricity avoids CO_2 emissions from a carbon-emitting source.

It follows that EPA cannot rely on RECs (and RPS programs) as a surrogate for emissions reduction: such an approach would risk giving states credit beyond the extent to which their RPS programs actually reduce emissions. Instead, the final rule must ensure that states take credit only to the extent that compliance with those programs yields emissions reductions.[184] In practice, this means that in evaluating state plans and assessing compliance, EPA should require states to value RECs in accordance with the emissions that the underlying zero-carbon electricity avoids.

For purposes of compliance and evaluation of rate-based state plans, EPA's proposal contemplates two possible ways to value RECs: as MWh added to the denominator of a state's

[184] EPA's proposal properly recognizes that the relationship between RPS programs and emission reductions – including the interstate effects of such programs – requires careful regulatory consideration prior to issuance of a final rule. *See, e.g.*, NPRM, 79 Fed. Reg. at 34,922.

ED_000419-0005669

compliance equation, or as avoided emissions subtracted from the numerator. EPA should choose the latter approach.

First, and most fundamentally, valuing RECs as avoided emissions (however they are measured) would help ensure that state plans remain focused on the goal of achieving emission reductions – rather than simply encouraging the use of renewable energy sources. Valuing RECs as added MWh, by contrast, would only partially align with this goal. Moreover, valuing RECs as avoided emissions rather than as MWh is fully consistent with the suggestion, made above, that EPA calculate targets using a system-wide rate, to give states the incentive to adopt REC programs open to *all* zero-emissions generation resources, specifically including nuclear and hydropower.[185] These resources also avoid emissions, and states should be encouraged to place value on that environmental attribute in their REC programs, just as they currently do for wind and solar power.

Second, if RECs are valued as MWh instead of avoided emissions, each REC will be more valuable in states with higher emissions rates – regardless of the mass of emissions that the underlying renewable electricity actually avoids. For instance, assume that a state's retail electric suppliers purchase RECs in an amount equivalent to one percent of the state's generated electricity. If those RECs are incorporated as MWh, then the state's calculated emissions rate will fall by one percent. If the state's starting emissions rate is 2,000 lb CO_2/MWh, then the calculated reduction in that rate will be 20 lb CO_2/MWh. But if its starting emissions rate is only 1,000 lb CO_2/MWh, then the calculated reduction for those same RECs will be 10 lb CO_2/MWh. And that is true regardless of the extent to which the underlying renewable electricity actually

[185] *See supra* at Parts II.E.1, II.E.4.

ED_000419-0005670

reduces CO_2 emissions.[186] This result – flowing, again, from the treatment of RECs as MWh, rather than as avoided emissions – is illogical on its face. In addition, it would enable states with higher starting emissions rates to buy fewer RECs to achieve the same reduction in their calculated rates. This disparity, in turn, could reinforce the incentive for those states to adopt rate-based systems, which may not actually result in emissions reductions.

Third, although valuing RECs as MWh may be administratively simpler, valuing them as avoided CO_2 emissions is certainly feasible. One possibility, as EPA has suggested, is to use a marginal emissions rate approach to measuring avoided CO_2 emissions.[187] Such an approach would entail determining the carbon intensity of the last generating resource dispatched – and, thus, the resource whose generation is displaced by a MWh of carbon-free generation. Alternatively, EPA could use an average emissions rate.[188] Such an average might be computed or weighted in any number of different ways.[189] In the Goal-Setting NODA, EPA discusses an alternative in which avoided emissions are assumed to be those of the highest-emitting source, which results in the most stringent emissions rate goal.[190] Whatever the exact approach, valuing

---

[186] *See* NPRM, 79 Fed. Reg. at 34,919-20 & n.296; Technical Support Document: State Plan Considerations, Docket ID No. EPA-HQ-OAR-2013-0602-0463 ("State Plan TSD"), at 21-22.

[187] *See* State Plan TSD at 26-27.

[188] *See* Goal-Setting NODA, 79 Fed. Reg. 64552-53.

[189] *See* State Plan TSD at 24-25 (discussing an approach to quantifying CO_2 emissions avoided by weighted averaging of the emissions rates of all generators); *see also* NPRM, 79 Fed. Reg. at 34,920. As EPA has observed, state plans may need to distinguish between reductions in CO_2 emissions from affected EGUs and reductions from non-affected EGUs when crediting or adjusting CO_2 emissions rates based upon carbon-free generation. *See* NPRM, 79 Fed. Reg. at 34,920; State Plan TSD at 23.

[190] Goal-Setting NODA, 79 Fed. Reg. at 64,553.

ED_000419-0005671

RECs as avoided CO_2 emissions will appropriately align EPA's treatment of RPS programs with the Agency's statutory authority and ultimate goal of reducing emissions.[191]

D. The Problem of Double-Counting and a Proposed Set of Accounting Rules.

Under the trading programs that currently exist, there are straightforward mechanisms to prevent double-counting. In states with allowance-based emissions reduction programs, no generator may emit CO_2 without surrendering a commensurate number of allowances. And each such allowance can be used only once, by its ultimate purchaser, at which point it is retired. Similarly, when a REC is used for compliance with an RPS program, it can be used only by its ultimate purchaser, at which point it is retired. Thus, once the REC is transferred, the power is considered "null" power that has no environmental attribute.

EPA's Clean Power Plan, however, presents heightened potential for double-counting. Take, for instance, an interstate REC purchase. EPA envisions that a buyer state may comply with its emissions reduction obligations with purchases of out-of-state RECs. The buyer state, EPA suggests, could incorporate those RECs into its compliance equation to achieve a lower calculated emissions rate.[192] In the absence of appropriate safeguards, however, the seller state could *also* take credit for the zero-carbon attribute of the underlying clean electricity. If the seller state is a rate-based state, it could include that electricity in the denominator of its

[191] EPA might look to California's greenhouse gas abatement program as a model. Under that program, electricity imports generally trigger an obligation on the importer's part to remit carbon allowances; prescribed emissions factors are used to translate MWh of imported electricity into tons of carbon emissions. Procuring electricity from renewable sources, however, may entitle the importer to calculate a *reduction* in its allowance obligation by the amount of emissions thereby avoided. That calculation employs a default emissions factor set forth by regulation.

[192] More generally, EPA's proposal contemplates that a state could credit all emission reductions from carbon-free generation programs that it implements, regardless of where the carbon-free generation occurs. *See* NPRM, 79 Fed. Reg. at 34,922; State Plan TSD at 87 ("Consistent with existing state RPS policies, a state could take into account all of the CO_2 emission reductions from renewable energy programs and measures implemented by the state, whether they occur in the state and/or in other states.").

ED_000419-0005672

compliance equation, and thus use that electricity to reduce its calculated emissions rate. And if the seller state is a mass-based state, the zero-carbon attribute of the electricity would automatically be "counted" for purposes of the Clean Power Plan, simply by virtue of the fact that the underlying clean generation does not emit carbon.[193] This sort of double-counting could significantly undermine EPA's stated goal of reducing carbon emissions. Accordingly, EPA's proposal properly recognizes that "double-counting," particularly with respect to REC trading, is an issue requiring regulatory attention before issuance of a final rule.[194]

To address this issue, EPA's final rule – or, at a minimum, formal guidance to states – should include rules governing how states may account for interstate trades of zero-carbon credits and allowances. Set forth below is a proposed set of such rules. These rules seek to ensure that mass- and rate-based states alike can use trading to respond more nimbly to evolving market conditions, and can harness RPS and CO_2 allowance programs to this end. Yet the rules also seek to ensure that this flexibility does not come at the expense of EPA's desired emission reductions.

For purposes of these rules, each zero-carbon credit is assigned a mass value (here, assumed to be 0.5 ton of CO_2) corresponding to the emissions avoided by the underlying clean energy.[195] In addition, consistent with existing practice regarding the trading of RECs for purposes of RPS programs, each zero-carbon credit (and its underlying clean electricity) is counted only once – in the state where it is retired.

---

[193] *See* State Plan TSD at 87-90, 91 ("For ex post demonstration under a mass-based plan approach, performance would be determined based on reported stack CO_2 emissions from affected EGUs—no further analysis would be necessary."); *see* RGGI States' Comments at 10-12.

[194] *See* NPRM, 79 Fed. Reg. at 34,922.

[195] California provides for a similar default value in calculating the number of allowances that need to be surrendered where power is imported from non-specific sources. *See* Cal. Code Regs. tit. 17, § 95111.

ED_000419-0005673

The proposed rules are as follows:

- When a CO_2 allowance is sold from a mass-based state, the pool of available allowances in that state is reduced, and generators in that state thus must reduce their emissions by one ton.[196] The buyer state may deduct one ton of carbon from the numerator of its compliance function (if it has a rate-based system) or may emit one more ton of carbon (if it has a mass-based system)

- When a zero-carbon credit is sold from a rate-based state, that state may not take credit for the underlying zero-carbon generation, so as to avoid double-counting. The buyer state may deduct 0.5 ton of carbon from the numerator of its compliance function (if it has a rate-based system) or may emit another 0.5 ton of carbon (if it has a mass-based system).

- Zero-carbon credits issued in mass-based states that use CO_2 allowances may not be used for compliance in any other state. Using these credits for compliance outside their state of origin would necessarily result in double-counting of the emissions-reduction benefit, for the underlying zero-carbon generation would automatically "count" towards that state's mass-based emissions goal simply by not emitting carbon and not requiring the purchase of allowances.

- When a zero-carbon credit is sold from a mass-based state that does not use allowances, that state must reduce its emissions budget by 0.5 ton, so as to avoid double-counting.[197] The buyer state may deduct 0.5 ton of carbon from the numerator of its compliance function (if it has a rate-based system) or may emit another 0.5 ton of carbon (if it has a mass-based system).

[196] In practice, no special accounting treatment is necessary to accomplish this result: because an allowance-based system permits a generator to emit carbon only to the extent it holds allowances, the sale of an allowance to an out-of-state generator necessarily will reduce in-state carbon emissions.

[197] To be sure, states choosing mass-based systems are overwhelmingly likely to use an allowance system as their principal means of compliance, in which case this rule would be moot.

ED_000419-0005674

These rules are set forth below in tabular form:

Currency traded	*Seller state*	*Seller accounting*	*Buyer accounting*
CO_2 allowance	Mass-based	Allowance supply pool is reduced by one ton	Deduct one ton from compliance numerator (rate state) or emit one ton more (mass state)
Zero-carbon credit	Rate-based	No zero-carbon credit may be taken for generation producing the credit.	Deduct 0.5 ton from compliance numerator (rate state) or emit 0.5 ton more (mass state)
	Mass-based (allowances)	No interstate trading for Clean Power Plan compliance.	
	Mass-based (no allowances)	Reduce emissions budget by 0.5 ton	Deduct 0.5 ton from compliance numerator (rate state) or emit 0.5 ton more (mass state)

These rules are designed to count each emission reduction once and only once and can also be summarized as a set of eight accounting rules:

1. When a mass-based state sells a CO_2 allowance, the selling state's generators must reduce their emissions by one ton.
2. When a mass-based state buys a CO_2 allowance, the buying state's generators may emit one more ton of carbon.
3. When a rate-based state buys a CO_2 allowance, the buying state may deduct one ton of carbon from the numerator of its compliance calculation.
4. When a rate-based state sells a REC, the selling state may not take credit for the REC or the underlying zero-carbon generation.
5. When a mass-based state that does not use allowances sells a REC, the selling state must reduce its emissions budget by 0.5 tons (assuming that the mass value of a REC is 0.5 tons of CO_2).
6. A mass-based state that uses allowances may not sell a REC to be used for Clean Power Plan compliance in another state.
7. When a rate-based state buys a REC, it may deduct 0.5 tons of carbon from the numerator of its compliance calculation (assuming that the mass value of a REC is 0.5 tons of CO_2).
8. When a mass-based state buys a REC, its generators may emit another 0.5 tons of carbon (assuming that the mass value of a REC is 0.5 tons of CO_2).

These rules would not prevent any group of states from forming a multi-state compliance region. Nor would they apply within such a region, as long as the region as a whole

ED_000419-0005675

demonstrates that it will satisfy EPA's emission reduction goals. Trading between two multi-state regions, however – or trading between such a region and a single state outside the region – would be subject to the accounting rules in the same fashion as trading between two individual states.

VI. EPA SHOULD ADOPT MASS-BASED TARGETS.

EPA has expressed the degree of emission reduction achievable through the BSER in the form of an emissions rate for each state. Although EPA has provided guidance for converting those rates into a mass-based compliance mechanism, it appears that EPA will evaluate a state's plan using the state's rate-based target as the standard, rather than a mass-based target. There are innumerable problems associated with the use of a rate-based approach, some of which are identified above. Many, if not all, of these problems could be averted, however, if EPA were to evaluate state obligations based on the mass of pollutants emitted rather than the rate.

The Clean Air Act does not require EPA or states to express emission standards or emissions guidelines in the form of a rate, nor does it otherwise preclude EPA from expressing them in the form of a mass or another form, such as a price per ton of pollutant emitted. Nothing in section 111 tells EPA whether "the degree of emission limitation achievable" through the BSER must be expressed as a mass or rate or a price per ton of reduction. Section 111 is silent on the question. That silence means that EPA has discretion to make a reasonable choice between the two.[198]

[198] *See, e.g.*, *Chevron USA, Inc. v. NRDC*, 467 U.S. 837 (1984).

ED_000419-0005676

Section 111(d) requires EPA to create "a procedure similar to that provided by [section 110]" for each state to submit an implementation plan.[199] Section 110, in turn, provides that plans shall "include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as *fees, marketable permits, and auctions of emissions rights*)."[200] "[A]uctions of emissions rights" presuppose that there is a finite number of emissions permits to be auctioned – *i.e.*, a cap on the mass of pollutants that may be emitted. Likewise, a system of "marketable permits" is most consistent with an overall mass-based limit, not a rate-based limit.

This is also true of an emissions fee, which is most commonly imposed upon an amount or mass of pollutants, not a rate. Where Congress expressly imposed an emissions fee in the Clean Air Act, the fee is based on the tons of pollutants emitted, not the rate of emissions.[201] The concept of an emissions fee is also consistent with technology-based standards like those under section 111(d), where the measures defining BSER are evaluated based on the tons of pollutant reduction.[202] A price per ton of pollutant emitted corresponds directly to mass or a discrete amount, rather than a rate.

Thus, in other prior rules establishing emission reduction goals for the electricity generation based on the reductions that could be achieved by the response of the system – including the CSAPR, the Clean Air Interstate Rule (CAIR), the NO_x SIP Call, and the Clean Air

---

[199] 42 U.S.C. § 7411(d)(1)(A).

[200] *Id.* § 7410(a)(2)(A) (emphasis added).

[201] *See* 42 U.S.C. § 7511d (imposing an emissions fee at $5,000 "per ton of VOC emitted"); *id.* § 7651j (imposing excess emissions fee for failure to surrender sufficient allowances based on tons of pollutants emitted); *id.* § 7661a(b)(3)(B) (imposing permit emissions fee to fund operating permit program based on tons of regulated pollutants emitted).

[202] *See, e.g.,* NPRM, 79 Fed. Reg. 34,856-77 (identifying cost per ton of avoided emissions for various technologies).

ED_000419-0005677

Mercury Rule (CAMR) – EPA has expressed state or system-wide emissions reduction goals in the form of a targeted mass, rather than a targeted rate. In each of these rules, EPA, using IPM, modeled the emissions reductions that could be achieved at a price that was determined to be cost-effective in the electricity system.[203] These rules collectively demonstrate that mass-based standards constitute a reasonable basis for pollution control measures. Indeed, EPA's proposal itself recognizes the permissibility of mass-based standards insofar as it permits states to convert their rate-based targets into equivalent masses for purposes of compliance.

Given that EPA has statutory authority to express guidelines and establish standards as either a rate or a mass, EPA should choose the latter. Most fundamentally, mass-based goals are more closely tethered to the statutory directive to achieve emissions reductions. For instance, if a group of EGUs reduces its emissions rate by one-third but increases the number of MWh it generates by one-half, the total amount of carbon emissions will remain the same. Although EGUs with lower emissions rates may be preferable in many ways to ones with higher emissions rates, a *rate* reduction that is unaccompanied by a *mass* reduction does not result in the emissions reductions necessary to combat climate change.

Mass-based standards are also more consistent with what EPA proposes as Building Blocks 2, 3, and 4 of the BSER. Each of these components represents a different way to ensure that the highest-emitting generators operate less frequently in order to reduce the mass or amount of emissions. Building Block 2 does so by shifting generation towards less carbon-intensive fossil fuel EGUs; Building Block 3 does so by shifting generation towards EGUs that do not emit carbon at all; and Building Block 4 does so by reducing demand for electricity. For each of these

[203] Even when based on an underlying preferred emissions rate, such as CAIR.

ED_000419-0005678

building blocks, the objective is to reduce the *mass* of carbon emitted by the most carbon-intensive generators.

By contrast, a reduction in the emissions *rate* is evident only when emissions throughout the electricity system are artificially aggregated into a rate. Moreover, unless a system-wide rate is used that accounts for all generation sources, determining which variables should be included in the rate and which excluded involves a series of questionable judgments. The Proposed Rule demonstrates as much: EPA's baseline and target emissions rates count all existing coal and gas, all solar and wind, only six percent of nuclear generation, and no hydropower. Under a mass-based standard, by contrast, any fossil fuel-fired EGU would automatically "count" by virtue of emitting carbon. Any zero-carbon generating source would likewise automatically "count" by virtue of producing electricity without emitting carbon. At the compliance stage, meanwhile, EPA could readily assess whether a state has attained its goal simply by totaling emissions.[204] Any generator of clean power would automatically see the zero-carbon attribute of its generation fully valued.

Expressing emissions reduction guidelines in the form of a mass would also eliminate some of the inefficiencies that exist under rate-based standards. As between two states with the

---

[204] EPA's calculated target masses could be limited to existing EGUs, or both new and existing EGUs, as suggested by EPA's two alternative mass-based targets set forth in Technical Support Document: Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents ("Rate-to-Mass TSD"), *available at* http://www2.epa.gov/sites/production/files/2014-11/documents/20141106tsd-rate-to-mass.pdf. As discussed above in Part IV, a state might seek to skirt a mass-based limit applying solely to existing units by constructing new EGUs or modifying existing ones. This suggests that the mass-based target should include new and existing units. Alternatively, if EPA establishes a mass-based limit applying only to existing units, EPA could prevent such circumvention of the mass-based limit in reviewing proposed state plans and in assessing whether a state has complied with its goal. For instance, EPA could make clear that shifting existing load to new or modified EGUs is not a permissible means of compliance. In addition, EPA could provide that, in assessing compliance, it will adjust a state's calculated emissions mass upward (or adjust its targeted emissions mass downward) to account for existing load that has been shifted to new or modified EGUs.

ED_000419-0005679

same load but different starting emissions rates, for instance, the incentives to invest in a particular amount of emissions reduction will be higher in the state with the higher starting rate – even though that quantum of emissions reduction is no more environmentally beneficial in one state than in the other. When some states have mass-based standards and others have rate-based standards, moreover, mass-based states will have an incentive to comply simply by relying on imports from rate-based states. EPA can (and should) devise subsidiary rules to prevent these and other unattractive consequences of rate-based standards – but opting for mass-based standards instead would eliminate the need for such rules.

Even if EPA's final rule expresses each state's target as a rate rather than a mass, it still should incorporate mass at the stages where EPA evaluates a state's plan and assesses compliance. Specifically, EPA should provide that, if a state elects a rate-based standard as the basis for its state plan, its compliance with that standard will be subject to a mass-based check. Under such a check, the state's plan would be deemed compliant only if the mass of emissions produced under the plan is no greater than the mass corresponding to that state's rate-based goal set by EPA. Such a check is necessary because of the potential for gamesmanship inherent in a state's ability to choose between mass- and rate-based standards, and because of the potential for a state to manipulate its calculated emissions rate. In the face of these challenges, a mass-based check will ensure that a state reducing its calculated emissions rate will be deemed compliant only if it achieves commensurate real-world emissions reductions, which could include consideration of reductions that occur elsewhere.

The rate-to-mass translations that EPA has published in the Rate-to-Mass TSD confirm the need to apply a mass-based check to states that opt for rate-based standards.[205] For each

[205] Rate-to-Mass TSD, *supra* note 204.

ED_000419-0005680

state, EPA has calculated (1) a mass-based equivalent that covers only existing affected fossil fuel-fired sources; and (2) a mass-based equivalent that covers both existing and new sources. EPA has calculated these equivalents without reference to IPM modeling.[206] But EPA *also* has published – for each state – the mass of emissions that the IPM model predicts will result from that state's target emissions rate.[207] Thus, EPA has published three different calculations of the mass that corresponds to each state's rate goal. States could be expected to choose the compliance standard (mass-based excluding new units, mass-based including new units, or rate-based) that, for that state, is least stringent. If every state does so, the emissions reductions that EPA achieves will be substantially less than the 30 percent that EPA envisions; indeed, our analysis suggests that emissions would be reduced only 23 percent from 2005 levels, or hardly at all from current levels.[208]

A mass-based check – preferably based on EPA's "existing plus new" mass equivalents, the second approach set forth in the Rate-to-Mass TSD – would eliminate this problem. Even if a state chooses a rate-based standard, EPA's calculated mass equivalent would operate as a check to ensure that the state's selection of that standard does not meaningfully impair emissions reductions. Preferably, however, EPA would simply require all states to use mass-based standards in the first instance.

---

[206] *Id.*

[207] *See* EPA Analysis of the Proposed Clean Power Plan, http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html.

[208] For instance, in Kansas, the calculated target emissions mass is 24 million metric tons under the first approach described in the Rate-to-Mass TSD (counting only existing units); 27 million metric tons under the second approach described in the Rate-to-Mass TSD (counting existing and new units); and 35 million metric tons using IPM modeling of a rate-based approach. Kansas therefore would likely choose the rate-based approach, as it is least constraining.

ED_000419-0005681

CONCLUSION

Exelon strongly supports EPA's efforts to reduce carbon emissions from the power sector. In particular, Exelon agrees with EPA that the best system of emission reduction harnesses the interconnected electricity grid in order to reduce emissions from existing EGUs at least cost. Exelon urges that in the final rule:

- EPA should deem states compliant with their interim goals if they choose to participate in an optional "Smart System Dispatch" program that applies a uniform carbon fee to all emitting generation. Independent analyses, including by PJM, the nation's largest grid operator, suggest that a carbon fee in the range of $15 to $20 could result in emissions reductions sufficient to achieve compliance with interim goals.
- EPA should assure that the carbon-free generation provided by the existing nuclear fleet is fully valued by using a system-wide emissions rate to set state emissions rate targets (at least to the extent that EPA finalizes a rate-based standard instead of a mass-based standard), or take similar steps to ensure that states preserve existing nuclear generation when it is economic to do so.
- EPA should calculate state emissions goals in a manner that reflects states' ability to comply by relying on lower-emitting sources located in interconnected states, that recognizes that new renewable generation and energy efficiency should displace existing fossil fuel generation rather than simply add to total generation, and that reflects states' ability to reduce coal-plant emissions through co-firing with natural gas.
- EPA should clarify treatment of new NGCCs to prevent states from displacing existing EGUs with new NGCCs, without counting the emissions from the new NGCCs.

ED_000419-0005682

- EPA should adopt accounting rules for the interstate trading of RECs and emission allowances that will prevent double-counting of emissions reductions.
- EPA should adopt mass-based emissions targets rather than rate-based targets, which would greatly simplify the regulatory scheme while ensuring the full amount of targeted emission reductions.

ED_000419-0005683

APPENDIX

STATE	Emission-Free Generation, 2013 (MWh)a	Nuclear % of Emission-Free Generation, 2013	Nuclear as % of Total Generation, 2013	STATE	Emission-Free Generation, 2013 (MWh)a	Nuclear % of Emission-Free Generation, 2013	Nuclear as % of Total Generation, 2013
IL	106,924,222	91%	48%	AR	14,635,225	82%	20%
WA	92,797,842	9%	8%	OK	12,920,909	0%	0%
PA	84,287,116	93%	34%	NH	12,763,266	86%	56%
TX	75,383,453	51%	9%	ID	12,333,441	0%	0%
NY	73,670,882	61%	33%	MT	11,639,807	0%	0%
CA	72,367,035	25%	9%	MO	11,043,544	76%	9%
SC	56,161,661	97%	57%	MS	10,864,509	100%	21%
AL	53,213,916	77%	27%	NE	9,920,395	69%	18%
NC	46,875,957	86%	32%	CO	8,855,450	0%	0%
OR	41,012,267	0%	0%	ND	7,399,466	0%	0%
TN	40,042,308	71%	36%	SD	6,765,016	0%	0%
AZ	39,793,545	79%	29%	VT	6,528,256	74%	69%
GA	35,949,029	92%	27%	NV	6,495,857	0%	0%
NJ	33,713,444	99%	52%	MA	5,484,112	79%	13%
MI	31,614,005	91%	27%	WY	5,130,188	0%	0%
VA	29,455,105	100%	37%	ME	4,960,818	0%	0%
FL	26,954,891	98%	12%	IN	3,952,841	0%	0%
IA	21,597,615	25%	9%	KY	3,356,733	0%	0%
MN	19,203,167	56%	21%	WV	3,029,490	0%	0%
LA	17,998,955	94%	17%	NM	2,730,142	0%	0%
OH	17,806,588	91%	12%	UT	1,789,853	0%	0%
CT	17,607,299	97%	48%	AK	1,441,419	0%	0%
KS	16,616,555	43%	15%	HI	863,862	0%	0%
MD	16,197,824	88%	40%	DE	64,169	0%	0%
WI	14,841,432	79%	18%	RI	13,382	0%	0%
U.S.	**1,247,068,263**	**63%**	**19%**				

(a) Emission-Free Generation column includes wind, solar, nuclear, geothermal, and hydroelectric.

Source: EIA

ED_000419-0005684

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

	)	
Carbon Pollution Emission Guidelines	)	**Docket No. EPA-HQ-OAR-2013-0602**
for Existing Stationary Sources:	)	
Electric Utility Generating Units	)	*Via regulations.gov*
	)	*December 1, 2014*
	)	

Thank you for accepting these comments on EPA's proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 2, 2014).

We submit these comments on behalf of the Natural Resources Defense Council (NRDC). NRDC is a national nonprofit environmental organization representing 1.4 million members and online activists. NRDC uses law, science, and the support of its members to ensure a safe and healthy environment for all living things. One of NRDC's top priorities is to reduce emissions of the air pollutants that are causing climate change.

EXECUTIVE SUMMARY

NRDC strongly supports the U.S. Environmental Protection Agency's (EPA) proposed Clean Power Plan, which will establish landmark carbon pollution standards for existing fossil-fuel power plants. The Clean Power Plan is an essential step toward ending unlimited carbon pollution into our atmosphere from the largest source in the United States – existing power plants. It sets the first-ever national limits on how much carbon pollution the country's existing power plants can release, and is a groundbreaking step toward combating climate change before it's too late to avoid the worst impacts. The Clean Power Plan is flexible and affordable. NRDC's analysis shows that once updated cost and performance data for energy efficiency and renewable energy are factored in, the Clean Power Plan emission reduction targets proposed in June 2014 can be met at a net savings to Americans of $1.8 billion in 2020 and $6.6 billion in 2030.

EPA can and should strengthen the Clean Power Plan's targets, most importantly by more fully recognizing the vast potential for scaling up energy efficiency and renewable energy throughout the United States. NRDC has presented a number of ways to improve and strengthen the CPP and with just three of these major recommendations: 1) updated baseline and cost and performance data, 2) implementation of the noticed formula change to properly account for energy efficiency and renewables, and 3) adoption of a minimum transition from older steam generation to new natural gas combined cycle units, we find that EPA can significantly strengthen the proposal at reasonable cost. Emissions reductions of 36% below 2005 by 2020 and 44% by 2030 can be accomplished at a cost of $6.5 Billion in 2020 and $10.5 Billion in 2030 with net benefits estimated to be up to $70 Billion and $108 Billion respectively. These projections, along with results of other scenarios we analyzed, are

ED_000419-0006060

illustrated in Figures ES-1 and ES-2 below. We urge EPA to strengthen and finalize the Clean Power Plan on schedule by June 1, 2015.

Background

It is imperative that we dramatically reduce carbon pollution. The science is clear: rising concentrations of heat-trapping gases like carbon dioxide in the atmosphere will destabilize our climate and lead to severe impacts on our health and well-being and risk triggering catastrophic climate change.

We are already seeing the impacts of climate change on our communities and facing substantial costs from these impacts. But the costs that our children and grandchildren will face if we fail to act now are simply unacceptable.

In November 2014, the world's leading scientists released their gravest warning yet about the threat of climate change, saying we will face "severe, pervasive and irreversible impacts" unless we act now. This report from the United Nations Intergovernmental Panel on Climate Change confirms that climate change is already contributing to intense drought, flooding, and heat waves. And it says we will see widespread impacts worldwide including food shortages and armed conflict if the human community fails to reduce dangerous carbon pollution.

Here at home, the Third National Climate Assessment, released earlier this year, found that if greenhouse gas emissions are not reduced it is likely that American communities will experience:

- increased severity of health-harming smog and particulate pollution in many regions;
- intensified precipitation, hurricanes, and storm surges;
- reduced precipitation and runoff in the arid West;
- reduced crop yields and livestock productivity;
- increases in fires, insect pests, and the prevalence of diseases transmitted by food, water, and insects; and
- increased risk of illness and death due to extreme heat.

We must act now to reduce carbon pollution and mitigate these impacts. Fossil fuel-fired power plants are the largest source of greenhouse gases in our nation, and the solutions are at hand to reduce carbon pollution from the power sector. Reducing carbon pollution will also result in important reductions in health-harming co-pollutants such as sulfur dioxide, nitrogen oxides, particulates, and mercury, beyond the reductions to be delivered by other standards. Reducing these co-pollutants will reduce asthma attacks, heart attacks, hospital admissions, missed school and work days, and premature deaths.

For more than 40 years the Clean Air Act has been used successfully to reduce emissions of sulfur, nitrogen, and mercury, with benefits for Americans' health that far exceed the costs. Yet there are currently no national limits on the amount of carbon dioxide that power plants can pump into the air. The Clean Power Plan answers this need.

ED_000419-0006061

The Clean Power Plan's "Best System of Emission Reductions"

The Clean Air Act requires EPA to set standards of performance at the level that reflects the emissions reductions achievable by the "best system of emission reduction" that has been "adequately demonstrated" considering cost, energy requirements, and other health and environmental outcomes. The Clean Power Plan's proposed "best system of emission reduction" sets targets for each state's fossil fuel power plants by looking at the real-world potential to reduce their carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-polluting and less on the highest-emitting power plants.

NRDC strongly supports this approach, which fully comports with the Clean Air Act. EPA's proposed best emission reductions system in the Clean Power Plan is certainly "adequately demonstrated" because power companies and states across the country are effectively using each of the building blocks to cut emissions of carbon pollution and other dangerous air pollutants from fossil fuel-fired power plants. NRDC agrees with EPA that it is the "best" system as defined by the Clean Air Act because it has the potential to secure large reductions in carbon pollution at reasonable cost, and will provide companies and states with flexibility to manage energy requirements and identify the emission reduction pathways that make the most sense for them.

EPA's System of Emissions Reductions Can Achieve Even Greater Emission Reductions Than Reflected In EPA's Analysis

The emissions reductions Building Blocks proposed by EPA in the Clean Power Plan include:

1) Making existing coal plants more efficient;
2) Using existing natural gas plants more effectively;
3) Increasing renewable and non-fossil fuel generation; and
4) Increasing end-use energy efficiency

These four Building Blocks are appropriate and legally supported. However, in the proposed Clean Power Plan, EPA significantly underestimates the carbon pollution reductions that can be achieved at reasonable costs. NRDC's analysis of the emission reduction opportunities in the blocks identified by EPA demonstrates that even greater savings are available at reasonable cost, if not savings, from each of the four blocks. EPA should correct its analysis to reflect these greater opportunities in the states' targets. EPA must also fix the formula for calculating state targets to properly account for greater reductions from renewable energy and energy efficiency than the proposed Clean Power Plan assumes.

BSER Goal-Setting Equation and Treatment of Incremental Renewables and Energy Efficiency

In its October 27, 2014 Notice of Data Availability (NODA), EPA explains that the original formula used in its proposed rule failed to correctly account for the emission reductions generated by renewables and energy efficiency. As EPA explains, the formula used in the proposed rule failed to account for the reduction in generation at coal and gas power plants that will occur when additional renewables are added to the grid and when we improve energy efficiency. In setting state targets, EPA should employ a

ED_000419-0006062

formula that fully reflects the potential for zero-emitting resources and demand-side efficiency to reduce emissions from fossil generating units (as they have done with natural gas in Block 2). This will be achieved by basing targets on the use of available Block 3 and Block 4 resources to displace the highest-emitting fossil units (generally coal-fired power plants) first. This approach will achieve the greatest emission reductions from the available resources and thus comports with the Act's mandate to base standards on the best system of emission reduction.

Building Blocks 1 & 2 – Making Existing Power Plants More Efficient

EPA's analysis appropriately considered the potential for efficiency improvements at power plants – the opportunity to produce greater amounts of electricity using less fuel, thus reducing pollution emissions. EPA identifies opportunities for improvements that can be made based on specific power plant upgrades and also for operational and maintenance changes. EPA determined that coal-fired power plants can achieve at least a six percent improvement in performance. This is a conservative estimate. Analysis of carbon emissions at coal plants shows that even greater reductions would be available if power plants simply had to match the lowest emission rate actually achieved by the plant over the past decade.

EPA has also requested comment on whether it should consider the potential to shift electricity production from coal plants to existing natural gas combined cycle power plants, and the potential to co-fire existing coal plants with natural gas or convert them to natural gas. We believe that scaling up energy efficiency and renewable energy is the best and least-cost compliance pathway, and we will urge states to create state plans that rely, to the maximum extent possible, on energy efficiency and renewable energy. But it is also important that EPA set carbon pollution reduction targets that reflect the emission reduction opportunities presented by coal conversion options. These stronger reduction targets are amply justified under the Clean Air Act. Already all of the coal conversion pathways are being deployed across the country even without carbon pollution standards —and as such they are clearly adequately demonstrated, and reasonable in cost.

Securing the full benefit of the Clean Power Plan also requires effective measures to curb the high levels of methane leakage and venting upstream of gas-using power plants. Given the recent increases in the use and extraction of natural gas, it is imperative that EPA directly regulate emissions of methane, a potent climate pollutant, from the natural gas sector under section 111(b) and (d) of the Clean Air Act. President Obama committed to taking action on methane as part of the Climate Action Plan. It is vital that EPA follow through on this pledge by promptly setting standards limiting emissions of methane from new and existing sources in this sector.

Building Block 3 – Increasing renewable and non-fossil fuel generation

EPA appropriately included in the best system of emission reduction the potential to reduce emissions from fossil fuel power plants by deploying renewable energy. But EPA has significantly underestimated the amount of renewable energy that can be deployed at reasonable cost. In its proposal, EPA included two frameworks for analyzing the potential for emission reductions via renewable energy deployment—the use of regional averages of renewable energy policies and a technical-economic potential analysis. Both significantly underestimate the actual potential by using out-of-date data that fails to reflect

ED_000419-0006063

dramatic cost reductions in renewable energy sources such as solar and wind that have occurred in recent years. In order to properly assess the potential from renewable energy, EPA must use up-to-date data. Current data show that wind and solar costs are each approximately 45 percent lower than EPA assumed in its analysis. We urge EPA to use current data in order to evaluate the quantity of renewable energy that can be deployed at reasonable cost in each state. We further urge EPA to ensure that the rate of renewable energy deployment assumed in EPA's analysis is at least as fast as the historical rates of deployment.

Building Block 4 – Increasing End-Use Energy Efficiency

EPA's Clear Power Plan also properly included in the best system of emission reduction the potential to use improved demand-side energy efficiency to drive reductions in carbon pollution. Energy efficiency measures will also drive reductions in the harmful co-pollutants emitted by fossil fuel-fired power plants. By making investments to increase energy efficiency in our homes, businesses and factories, we can reduce carbon pollution while also lowering utility bills, creating jobs, and stimulating the economy.

Based on its analysis, EPA determined that energy efficiency can supplant 1.5 percent of retail electricity sales. This is an underestimation of energy efficiency's potential, which excludes a number of important additional opportunities for energy efficiency such as building codes, transmission and distribution, voltage optimization, and combined heat and power. EPA should include all available energy efficiency opportunities in its analysis. Energy efficiency can achieve savings equal to 2 percent of retails sales per year. The country's energy efficiency resource is vast, and grows continuously as new technologies are developed.

Further, EPA also underestimates the potential for energy efficiency by assuming that states will ramp up energy efficiency programs slowly. But new energy efficiency programs can be implemented more quickly than EPA assumes, as demonstrated by the faster expansion of efficiency programs achieved in many states. EPA should use a faster ramp up rate, allowing for greater overall emission reductions from energy efficiency.

NRDC notes in particular that energy savings from affordable multi-family housing programs should be credited in state compliance plans. More than 20 million American households, almost 18% of the nation's total, live in apartments and condominium communities. Energy efficiency is a key resource for maintaining and improving quality of life for residents and owners of affordable housing. The affordable multi-family sector is also a critical untapped resource for achieving widespread energy demand reductions, and thus emissions reductions, in the residential sector.

In addition to the potential energy savings, improving the energy efficiency of multifamily housing also improves the stability of vulnerable households. Most multifamily households are renters, whose average annual income is just over half that of homeowners. This means that nationally, the burden of the untapped savings in the older and less energy-efficient multifamily housing stock is being borne by the families with the fewest resources. As a result, renters typically pay a higher percentage of their income for energy. This lowers their discretionary income and makes them much more vulnerable to

ED_000419-0006064

fluctuations in energy prices. Thus, efficiency gains from multifamily retrofits have the concurrent benefit of relieving low- and middle-income families of some of their financial strain and uncertainty.

Unfortunately, only a fraction of the potential energy savings in the multifamily sector has been realized despite the economies of scale not available in single-family homes. By investing more resources into the multi-family sector, states can scale up energy efficiency programs much more rapidly than previously imagined, enabling real energy savings quickly.

A Strengthened Clean Power Plan is Cost Effective

NRDC's technical comments focus on how EPA can strengthen the Clean Power Plan and make even deeper cuts to dangerous carbon pollution. Through our analyses of several different policy scenarios, and associated sensitivity analyses, we demonstrate that there is ample room to strengthen the CPP and achieve even deeper emissions reductions at reasonable compliance costs, and that the benefits consistently outweigh the costs. It is important to note that we examined a few illustrative policy scenarios which do not reflect our full set of recommendations for strengthening the Clean Power Plan, and that there are some additional pieces of analysis still under development (we will submit additional material to the docket in the coming weeks).

First, we examined compliance with EPA's state targets, and then performed the same analysis with updated cost and performance data for renewables and efficiency. Further detail on this subject may be found in NRDC's November 2014 issue brief, titled, "The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030," available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf.

NRDC analyzed potential strengthening of state targets based primarily on the ideas put forth in EPA's October 28, 2014 Notice of Data Availability (NODA). We evaluated compliance for the resulting set of state targets under both approaches described in the NODA. These model runs are described below as "NODA Dirtiest First" and "NODA Pro Rata" cases. Under both "NODA Dirtiest First" and "NODA Pro Rata" target-setting approaches, we also analyzed a second list of state targets that accounts for a minimum generation conversion from higher-emitting sources to lower-emitting sources. These are referred to as "NODA Dirtiest First + Conversion" and "NODA Pro Rata + Conversion." Summary results from these policy runs are shown below.

ED_000419-0006065

Figure ES-1. Historical and Projected Electricity Sector CO2 Emissions

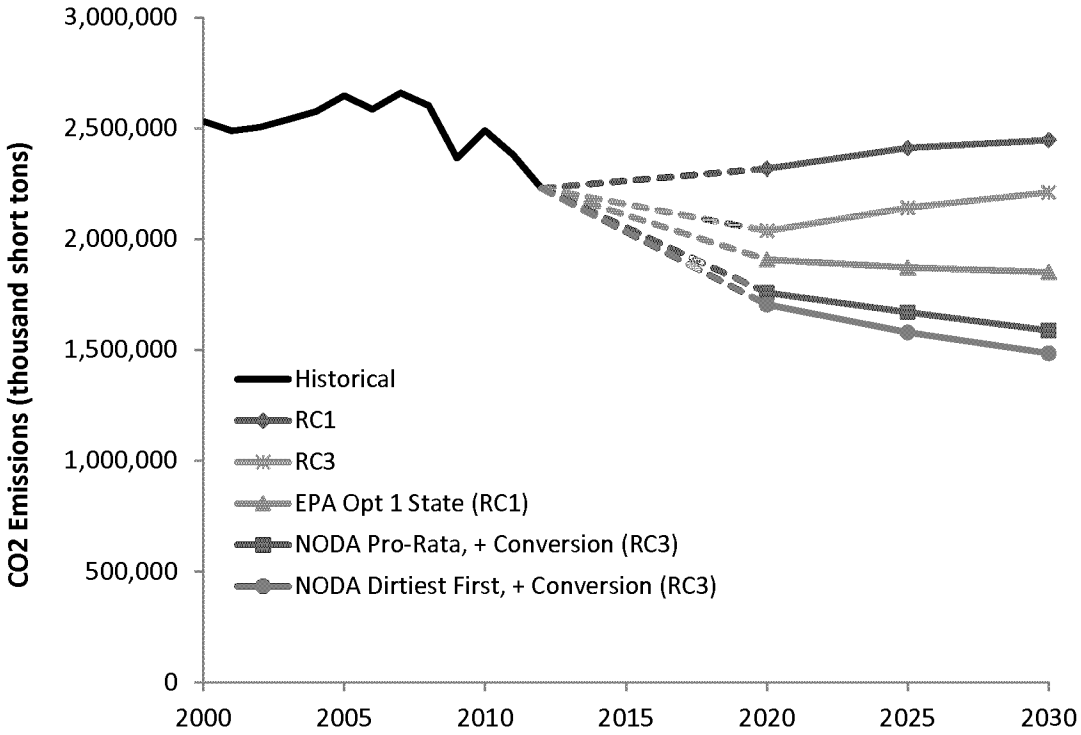
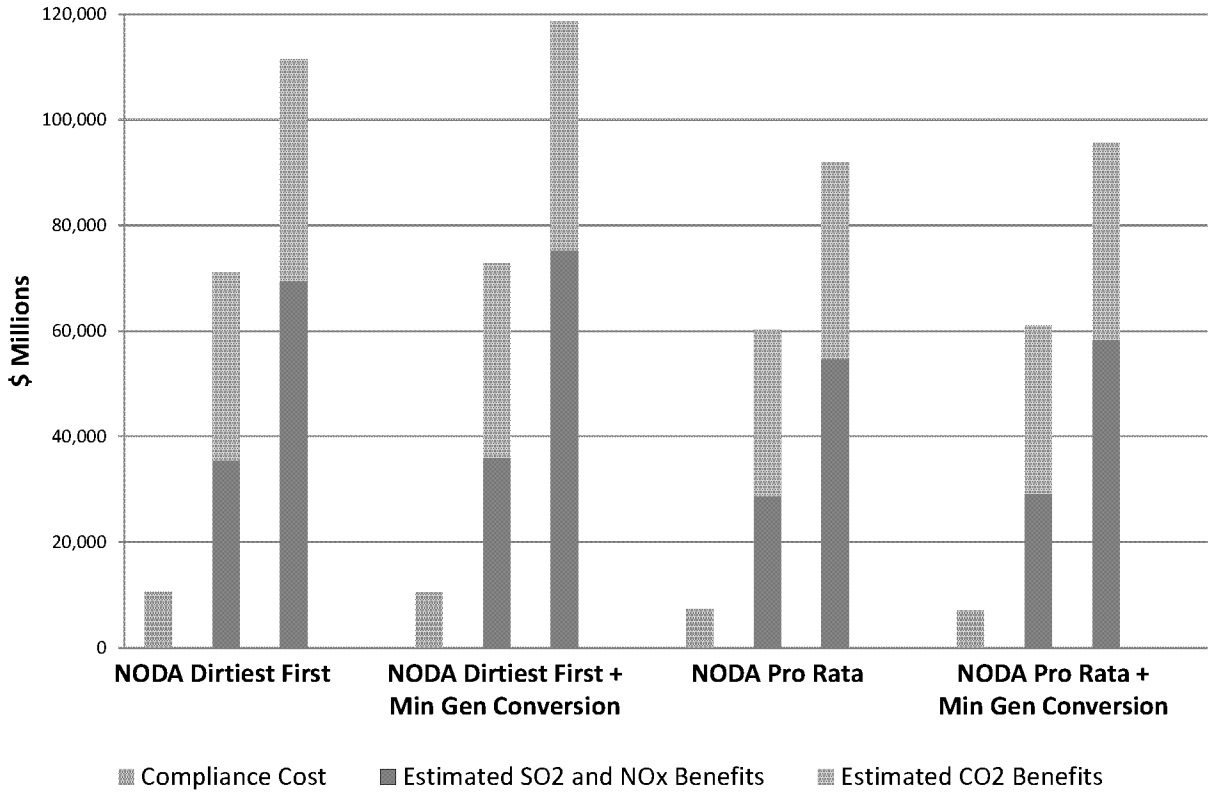


Figure ES-2. Compliance Costs and Net Benefits in 2030



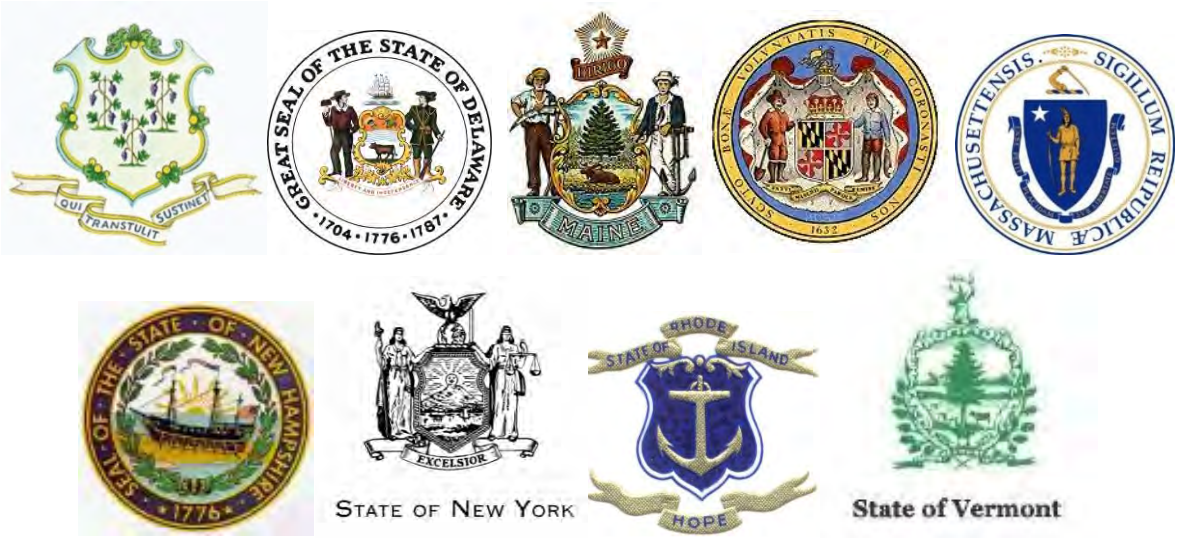
ED_000419-0006066

NRDC has presented a number of ways to improve and strengthen the CPP and with just three of these major recommendations: 1) updated baseline and cost and performance data, 2) implementation of the noticed formula change to properly account for energy efficiency and renewables, and 3) adoption of a minimum transition from older steam generation to new natural gas combined cycle units, we find that EPA can significantly strengthen the proposal at reasonable cost. Emissions reductions of 36% below 2005 by 2020 and 44% by 2030 can be accomplished at a cost of $6.5Billion in 2020 and $10.5 Billion in 2030 with net benefits estimated to be up to $70 Billion and $108 Billion respectively.

Environmental Justice Considerations

The Clean Power Plan will result in significant improvements in air quality across the country. EPA estimates that it will result in a twenty-five percent drop in the pollutants that lead to soot and smog. NRDC's suggested improvements will deliver even larger benefits. However, we urge EPA to include in the final rule a robust discussion of the ways in which state plans can be designed to ensure that pollution will be reduced in communities currently bearing a disproportionate share of ambient air pollution burdens. State plans will determine how the carbon pollution reductions required by the state targets are achieved—and those decisions will also determine how much reduction takes place in harmful co-pollutants, and where. This will be particularly important in the context of state planning for attainment of ozone ambient air quality standards and other clean air protections, enabling comprehensive planning to help states ensure that carbon pollution is reduced and other harmful air pollution problems are addressed.

ED_000419-0006067



December 1, 2014

VIA EMAIL

Environmental Protection Agency
EPA Docket Center (EPA/DC), Mail code 28221T
Attn: Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Ave. NW
Washington, DC 20460
A-and-R-Docket@epa.gov

Re: Docket ID No. EPA-HQ-OAR-2013-0602 – *RGGI States' Supplemental Comments on Proposed Clean Power Plan*

The nine states participating in the Regional Greenhouse Gas Initiative ("RGGI")[1] submit these supplemental comments on the U.S. Environmental Protection Agency's ("EPA's") proposed Clean Power Plan ("CPP"), which are respectfully submitted in addition to the comments offered by the RGGI states on November 5, 2014[2] ("November 5 Comments"). We once again take this opportunity to commend the EPA for its unprecedented stakeholder outreach, which has culminated in the release of additional information since the drafting of our initial comments. As such, in these comments we focus on issues raised by the EPA in three recently released documents: (1) *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice of Data Availability*[3] ("NODA"); (2) *Technical Support Document: Translation of the Clean Power Plan Emission Rate-based CO_2 Goals to Mass-based Equivalents*[4] ("RTM TSD"); and (3) *Carbon Pollution Emission Guidelines for Existing Stationary Sources: EGUs in Indian Country and U.S. Territories; Multi-Jurisdictional Partnerships*[5] ("Supplemental Notice").

---

[1] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont (collectively referred to as the "RGGI states").
[2] RGGI States CPP Joint Comments (Nov. 5, 2014) http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf.
[3] 79 FR 64543 (Oct. 30, 2014).
[4] November 6, 2014 and 79 FR 67406 (Nov. 13, 2014).
[5] 79 FR 65482 (Nov. 4, 2014).

The RGGI states continue to support the EPA's efforts to reduce the greenhouse gas ("GHG") emissions that cause climate change, especially given that the RGGI states are already feeling its effects. We commend the EPA for its continued efforts to improve and clarify the proposed CPP by considering the issues discussed in the NODA, RTM TSD, and Supplemental Notice. With the recommendations included in these comments, the EPA can further strengthen the final CPP rule.

1) **The RGGI States Reiterate Their Support for the Inclusion of the Potential for New Natural Gas Combined Cycle ("NGCC") in Building Block Two**

The RGGI states respectfully reiterate their support for consideration of the potential for new NGCC plants in Building Block Two. The significant increase in NGCC generation in the RGGI region in recent years is illustrative of the potential on a nationwide scale. In New York alone, 18 new NGCC units came on-line between 2004 and 2011, increasing the State's natural gas-fired nameplate capacity by approximately 150 percent in a seven-year period. This experience is typical of the RGGI region, which added more than 21 gigawatts of natural gas-fired generation capacity between 1997 and 2011.

As the EPA acknowledges in the NODA, including new NGCC in the goal computation methodology would reduce disparities in the proposed state targets, and would help to ensure that the potential for additional cost-effective emission reduction measures are reasonably reflected in states' targets. As discussed in our November 5 Comments, the RGGI states support consistency between target-setting and compliance tools in order to maintain the integrity and effectiveness of the overall program, and therefore recommend that the EPA strengthen Building Block Two by incorporating the potential for re-dispatch from existing coal-fired EGUs to new NGCC plants in the goal computation methodology for Building Block Two. The RGGI states respectfully observe that this methodological adjustment is particularly important for states that are not currently subject to the application of Building Block Two due to a lack of existing NGCC capacity, because absent this consistency the current structure of the CPP may create perverse incentives to build unnecessary new NGCC units. Including the potential for new NGCC capacity can reduce the cost of compliance attributable to the CPP, as well as the potential for shifts in generation from existing sources to new fossil fuel-fired electric generating units ("EGUs") that do not result in net carbon dioxide ("CO_2") emission reductions.

While the RGGI states support the inclusion of new NGCC in Building Block Two, the NODA's proposed 12 percent floor for re-dispatch in states with low or no existing NGCC capacity would have limited impact. Our analysis indicates that the proposed 12 percent floor would only apply to nine states and add a small amount of additional NGCC generation – 30,000 GWh nationwide. The RGGI states believe that more can be done to ensure that the effectiveness of the CPP is not diluted by the construction of new NGCC units.

In lieu of a floor, EPA should consider the approach suggested by the RGGI states in our November 5 Comments to derive new state NGCC capacity targets using the national compound average growth rate for natural gas projected by the U.S. Energy Information Administration's

Annual Energy Outlook. Other considerations could include the production capacity and construction plans for new natural gas pipelines, as well as the potential to re-power existing coal EGUs.

2) **The RGGI States Support Additional Flexibilities Around the "Glide Path" and Early Reductions, Provided Overall Stringency of the CPP is Maintained**

The RGGI states support the inclusion of flexibility throughout the CPP, including the potential for additional flexibility outlined in the NODA with respect to the timing of measures relied on as part of state compliance demonstrations. If the EPA were to recognize actions taken during the period from January 1, 2014 through the beginning of the proposed 2020 compliance period, greater recognition would be given to the substantial progress already achieved by early action states to reduce GHG emissions; such a provision could also provide incentives for additional early action. At the same time, the RGGI states urge the EPA to ensure that any recognition of action undertaken prior to the compliance period does not reduce the overall stringency of the rule on a national level. In the event that the EPA chooses to provide states with greater interim flexibility in a way that diminishes the emission reductions that would have otherwise been achieved in the interim period, the EPA should implement other changes such as those identified by the RGGI states that would achieve additional cost-effective reductions, such that the overall level of national stringency is maintained or increased.

3) **The RGGI States Comment on the Potential of EE and RE to Displace Fossil Generation**

Drawing from the demonstrated experience of the RGGI states as early adopters of climate change mitigation efforts, in our November 5 Comments, the RGGI states offered suggested modifications to the Building Block Three and Four methodologies to maintain, and ideally increase, the overall nationwide level of emission reductions required by the final rule.

Through implementation of energy efficiency ("EE") and renewable energy ("RE") measures, the RGGI states observe that EE and RE can displace a combination of existing and new fossil generation, as well as electricity imports and other sources of electricity. For purposes of computing state targets under the CPP, the NODA proposes to assume the displacement of existing fossil generation by incremental RE and EE generation. The RGGI states recognize that, were the EPA to move ahead with the NODA proposal, all states' proposed rates would become more stringent, particularly those states with greater Building Block Three and Four targets.

If the EPA were to move forward with the proposal to displace fossil fuel generation, we respectfully recommend modifications to the displacement assumption so that the final targets reflect what is reasonably achievable by the states. Specifically, while the displacement concept is contemplated by both the NODA and by the RTM TSD, we strongly recommend that the EPA adopt the displacement methodology in only one context so as to prevent a duplicative impact. In order to maintain consistency across rate-based and mass-based approaches, the displacement adjustment should apply only to the computation of the target rates. However, the EPA should

provide states opting to pursue a mass-based approach with the opportunity to justify the appropriate amount of existing and new fossil generation that should be displaced (rather than apply an assumption that all incremental RE and EE will displace existing fossil fuel-fired generation).

4) **The RGGI States Comment on the Alternative RE Approach for Building Block Three with the Flexibility to Reapportion the Technically and Economically Feasible Renewable Generation Targets Among States Involved in a Cooperative Regional Program**

While the RGGI states strongly support regional compliance approaches that are closely aligned with the regional nature of the electricity grids as the most cost-effective way for states to reduce power sector CO_2 emissions, we note that the EPA structured its building block methodologies to express the best system of emission reductions on an individual state basis.

The RGGI states note that while the derivation of a renewable generation target may be appropriately based on in-state technical and economic potential, the opportunities for *developing* renewable energy are regional in nature. Consistent with this observation, the NODA outlined an approach to computing Building Block Three state targets that, while derived using in-state technical and economic potential analysis, proposes a subsequent regional reallocation of the renewable generation goals.

The RGGI states observe that a regional reapportionment of appropriately derived renewable generation targets may reduce disparities between state targets. Specifically, given that the electricity produced by renewable resources will be utilized regionally, a resource-intensive state should not bear the full burden of developing these resources. A regional reapportionment, especially one that aligns with the regional nature of the grid or the existing (or likely) renewable energy standard markets of the states may reduce this disparity. Furthermore, in some instances, the technical potential of a renewable resource may exceed what a host state can develop. At the same time, to the extent that a state lacking substantial in-state renewable resource potential is required to rely on out-of-state renewable generation to comply with a regionalized target, such compliance will be subject to siting, permitting, and other regulatory actions of another jurisdiction that are beyond the state's ability to control. The EPA must provide clear guidance about how these contingencies affect compliance obligations.

5) **The RGGI States Support Mass-Based Compliance Approaches and Recommend that the Final Rule Maintain Flexibility with respect to the Rate-to-Mass Translation Methodology**

We have reviewed EPA's illustrative example of a Rate-to-Mass translation (*Projecting EGU CO_2 Emission Performance in State Plans*), the recently released computational methodology in the RTM TSD, and considered the RGGI states' own experience in developing and updating a mass-based emissions cap. The experience of the RGGI states demonstrates that a correctly determined mass-based target is the most cost-effective, transparent, and reliable

means of achieving the desired emission reductions, and we encourage EPA to continue to provide the opportunity, guidance, and resources that will enable other states to pursue this approach to compliance. In general, the RGGI states recommend that EPA develop rate-to-mass translation approaches that maintain flexibility on the methodology and data used to determine the translation, recognize the complexity and geographic connectedness of the electric grid, and provide enough oversight to ensure a meaningful equivalency of stringency between the rate-based and mass-based approaches.

In conducting the translation between the rate-based targets and a mass-based emissions cap, the RGGI states recognize the potential value of providing a simple calculation-based methodology, as has been requested by many stakeholders. As previously stated, the RGGI states firmly believe that a mass-based approach represents the most cost-effective method to demonstrate compliance with the CPP, and a simple translation methodology could facilitate this outcome by lessening administrative costs and uncertainties associated with the conversion process. Because of this potential, we suggest that EPA continue to analyze options for developing a simple translation approach, or at least streamlining aspects of the process.

However, because of the complexity of this nation's interdependent electricity grids and the dynamic nature of our energy markets, we are uncertain whether historically-based generation and capacity data can serve as the most reliable basis for building projections necessary to complete the translation process. A simple conversion process could yield results that do not account for the dynamics that result directly from the complexity and interconnectedness of the electric grid.[2]

Electricity system modeling offers crucial insights pertaining to how the system will respond to changes in policy or market forces, especially related to the type and location of generation among states. In fact, the RGGI states have found such modeling to be essential when analyzing environmental policies that may affect the electric sector. While a modeling-based approach would add cost and complexity to the translation process, EPA could address these issues by leveraging the large body of modeling experience and expertise that exists within EPA and the various state and regional organizations that routinely model the electric sector to support planning efforts, and by providing resources and technical assistance to states completing the rate-to-mass conversion process.

Whatever methodology is used, the EPA should work with individual states and regions to ensure adequate consideration is given to the states' information on assumptions and policy decisions that affect the outcome of the translation. States will need to have input on factors such as growth rate, as well as how the addition of incremental renewable energy and energy efficiency affect existing and new fossil generation and net imports based on the market

[2] In these comments, the RGGI states have outlined several concerns with the proposed rate to mass TSD calculation-based methodology. Maryland and Maine assert that these issues cannot be resolved solely with changes to the proposed calculation; rather, that dispatch modeling is necessary for the effective translation from rate-based targets to mass-based targets.

dynamics of their individual electricity systems. For example, the EPA should allow states to justify reliable growth rates, based on projections such as those developed by ISOs for planning purposes. In this dialogue, the EPA's consideration of state assumptions should rely on credible evidence (such as electricity system modeling and ISO projections) so that a meaningful translation of stringency is achieved.

The EPA should also avoid including projected energy efficiency programs in the calculation of a state's growth rate, or in modeling assumptions, if doing so would constitute double counting with the energy efficiency already included in setting the state's rate-based target. The EPA should also work with states to ensure that the growth factor accounts for an individual state's projected increase in electricity use resulting from policies to reduce GHG emissions from other sectors through electrification, such as electric vehicles and heat pumps.

6) **The RGGI States Support Participation of Jurisdictions Without Affected EGUs in Multi-Jurisdictional Plans**

The RGGI states strongly advocate that the EPA permit jurisdictions without existing fossil fuel-fired EGUs subject to the CPP guidelines to partner with jurisdictions that are subject to the CPP for purposes of developing a multi-jurisdictional plan. This provision, contemplated by the Supplemental Notice, is appropriate given the interconnectivity of the U.S. electricity grid and the participation of non-affected jurisdictions in our regional markets. A decision to the contrary would unnecessarily hamper multi-jurisdictional cooperation and may artificially preclude reliance on some cost-effective regional emission reduction strategies.

As discussed in our November 5 Comments, the RGGI states are proponents of inclusive multi-jurisdictional approaches to reduce GHG emissions, as we recognize that state boundaries do not always parallel the reality of regional, national and international energy production, distribution, and usage. Multi-jurisdictional approaches, such as but not limited to regional mass-based allowance trading programs like RGGI, foster greater innovation opportunities and provide additional flexibility for compliance as compared to a single state plan. Allowing for the participation of jurisdictions without affected EGUs, as discussed in the Supplemental Notice, will help to facilitate the use of these multi-jurisdictional partnerships.

Moreover, we note that the success of the RGGI program demonstrates that, by working together, groups of states can achieve greater emissions reductions more efficiently and cost effectively than by working separately. To build upon this historic success, the RGGI states anticipate that the development of a multi-state plan intended for compliance with the CPP will leverage the existing RGGI program and will encompass all RGGI participating states – including Vermont. While Vermont does not have any affected EGUs under the proposed CPP, Vermont does have two units that are subject to the RGGI program. Furthermore, its geographic and topologic location within the Independent Systems Operator ("ISO") New England region and bordering the New York ISO region renders Vermont a logical addition to the RGGI region's multi-jurisdictional compliance plan. Finally, while generation and emissions produced in-state comprise only a small share of the overall RGGI region, Vermont is in the process of developing

and implementing an ambitious program to source 90% of all energy (not just electricity) from renewable sources by 2050, an effort that complements other initiatives in the neighboring states and contributes to the expansion of renewable energy generation within the region.

The RGGI states support the EPA's position in the proposed rule that, assuming states successfully make an equivalency demonstration to the EPA as part of their regional plan submission, compliance and enforceability under this type of regional mass-based approach is straightforward[3]. We note that this position naturally extends to the inclusion of a jurisdiction without affected EGUs as part of a multi-jurisdictional compliance plan. Renewable energy, energy efficiency, and other lower non-emitting generation in any jurisdiction in the region would therefore facilitate overall regional compliance with the approved mass-based cap, and in turn, the CPP.

Finally, the RGGI states recommend that the EPA provide additional clarity in the final rule to avoid potential double counting of renewable energy and energy efficiency measures in CPP compliance demonstrations. This could be, for example, in the form of a prohibition of rate-based states taking credit for renewable energy or energy efficiency that is already accounted for under a mass-based program in another state or multi-state group. We recommend, however, that renewable energy and energy efficiency measures in a jurisdiction without any affected EGUs – where those measures have not otherwise been accounted for – should be able to be credited to another state, likely through a multi-state plan or other agreement.

7) <u>The RGGI States Support Regional Mass-Based Compliance Flexibility</u>

In our November 5 Comments, the RGGI states strongly support the EPA's inclusion of a mass-based compliance option in the CPP. The RGGI states have demonstrated that a regional mass-based approach is a cost-effective way to achieve substantial CO_2 emission reductions. Given these advantages, the RGGI states provided recommendations to the EPA to facilitate the use of regional mass-based approaches as a means of compliance with state targets. In addition, the EPA should clarify that if a group of states, like the RGGI states, translate the regional rate target to a mass-based target those states have the option of re-allocating the mass-based target.

[3] Proposed rule Section VIII(B)(1)(c) – Obligations on Affected EGUs: "A state plan that imposes a mass limit on affected EGUs that is sufficiently stringent to achieve the emission performance level would not need to include RE or demand-side EE measures as an enforceable component of the plan to assure the achievement of that performance level. The mass limit itself would suffice. However, the state may wish to implement RE and demand-side EE measures as a complement to the plan to support achievement of the mass limit at lesser cost."

Sincerely,

Rob Klee
Commissioner
Connecticut Department of Energy and Environmental Protection

John W. Betkoski III
Vice Chairman
Connecticut Public Utilities Regulatory Authority

David S. Small
Secretary
Delaware Department of Natural Resources Environmental Control

Dallas Winslow
Chairman
Delaware Public Service Commission

David Littell
Commissioner
Maine Public Utilities Commission

Robert M. Summers, PhD
Secretary
Maryland Department of the Environment

Kelly Speakes-Backman
Commissioner
Maryland Public Service Commission

David W. Cash
Commissioner
Massachusetts Department of Environmental Protection

Mark Sylvia
Undersecretary
Massachusetts Energy and Environmental Affairs

Thomas S. Burack
Commissioner
New Hampshire Department of Environmental Services

Robert R. Scott
Commissioner
New Hampshire Public Utilities Commission

Joseph Martens
Commissioner
New York Department of Environmental Conservation

Audrey Zibelman
Chair
New York Public Service Commission

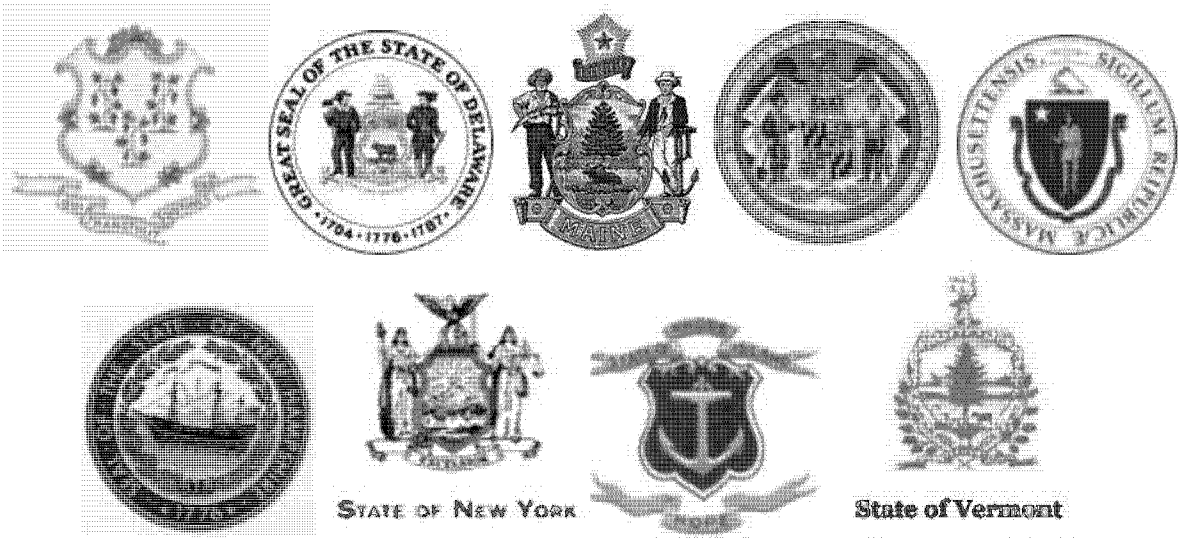
John B. Rhodes
President and CEO
New York State Energy Research and Development Authority

Janet Coit
Director
Rhode Island Department of Environmental Management

Marion S. Gold
Commissioner
Rhode Island Office of Energy Resources

Justin Johnson
Deputy Secretary
Vermont Agency of Natural Resources

James Volz
Chairman
Vermont Public Service Board



December 2, 2013

Ms. Regina McCarthy
Administrator
Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC, 20460

Re: Emission Standards Under Clean Air Act Section 111(d)

Dear Administrator McCarthy:

We applaud the commitment of the United States Environmental Protection Agency (EPA) to tackle head-on the challenge of reducing carbon emissions from existing power plants, which comprise the nation's largest source of greenhouse gas emissions. We write to you as commissioners, secretaries and directors of environmental or energy agencies of states that participate in the Regional Greenhouse Gas Initiative (RGGI) to offer our preliminary recommendations as EPA develops guidelines for state programs to reduce carbon dioxide (CO_2) emissions from power plants under Clean Air Act section 111(d). Given the dramatic success of the RGGI states in lowering carbon emissions from power plants while at the same time growing our economies, we believe that we have a unique perspective to offer.

We recommend that EPA use its authority under section 111 of the Clean Air Act to ensure significant overall reductions in carbon emissions, but to apply the standard in a flexible manner that empowers states to develop market-based greenhouse gas (GHG) emission reduction programs designed to work for their region(s). Our experience with RGGI demonstrates that regional cooperation can achieve the most cost-effective emission reductions, enable a transition to a lower-emitting and more efficient power sector and create economic benefits and jobs across the United States. We urge EPA to recognize these multiple benefits of RGGI, allow our states to use RGGI as a compliance mechanism, and encourage other states to follow suit by participating in RGGI or other regional programs.

ED_000419-0006068

In the attached report and recommendations, we respond to several of the questions posed by EPA on September 23, 2013. We also explain the benefits to regional economies, the power sector and the environment that can be reaped by allowing a flexible market-based compliance mechanism such as RGGI. Finally, we make seven specific recommendations for EPA to develop guidelines under section 111(d) that will enable all states to achieve significant emission reductions in a cost-effective manner.

Please let any of us know if you have any questions about the information provided. We look forward to continuing this dialogue as EPA develops an effective set of emission guidelines.

Sincerely,

Daniel C. Esty
Commissioner
Connecticut Department of Energy and Environmental Protection

John W. Betkoski III
Vice Chairman
Connecticut Public Utilities Regulatory Authority

Collin P. O'Mara
Secretary
Delaware Department of Natural Resources and Environmental Control

Dallas Winslow
Chairman
Delaware Public Service Commission

David Littell
Commissioner
Maine Public Utilities Commission

Patricia W. Aho
Commissioner
Maine Department of Environmental Protection

Robert M. Summers, PhD
Secretary
Maryland Department of the Environment

Kelly Speakes-Backman
Commissioner
Maryland Public Service Commission

ED_000419-0006069

Ken Kimmell
Commissioner
Massachusetts Department of Environmental Protection

Mark Sylvia
Commissioner
Massachusetts Department of Energy Resources

Thomas S. Burack
Commissioner
New Hampshire Department of Environmental Services

Robert R. Scott
Commissioner
New Hampshire Public Utilities Commission

Joseph Martens
Commissioner
New York Department of Environmental Conservation

Audrey Zibelman
Chair
New York Public Service Commission

Janet Coit
Director
Rhode Island Department of Environmental Management

Marion S. Gold
Commissioner
Rhode Island Office of Energy Resources

Justin Johnson
Deputy Secretary
Vermont Agency of Natural Resources

James Volz
Chairman
Vermont Public Service Board

Report on Emission Reduction Efforts of the States Participating in the Regional Greenhouse Gas Initiative and Recommendations for Guidelines under Section 111(d) of the Clean Air Act

Introduction

The states participating in the Regional Greenhouse Gas Initiative (RGGI) have successfully achieved substantial reductions in greenhouse gas (GHG) emissions from the power sector in a cost-effective manner, while promoting economic growth and vitality. The experience of the RGGI states provides a particularly relevant demonstration of the effectiveness of a multi-faceted suite of programs in reducing GHG emissions from the power sector. It also illustrates the potential for the power sector to reduce emissions by substantially more than 17% from 2005 levels, which will help the United States to achieve the targeted economy-wide reductions of 17% by 2020.

Experience of the RGGI States in Reducing Emissions[1]

The states involved in RGGI are demonstrating that environmental protection can go hand-in-hand with economic development and job creation. In operation since 2009, RGGI is the first *cap-and-invest* program in the United States – it *caps* GHG emissions from the power sector and reduces those emissions over time. The states participating in RGGI are *investing* the proceeds generated from auctioning emission allowances to further reduce emissions, lower the cost of compliance, and develop the clean energy economy in the region.

The RGGI cap-and-invest program is just one of the tools the RGGI states utilize to reduce emissions. The RGGI states are promoting renewable energy through some of the nation's most aggressive renewable portfolio standard programs and supporting investments in energy efficiency that have reduced the amount of electricity consumed and lowered bills paid by electricity consumers. The RGGI states are also implementing various regulatory programs directed at pollutants other than GHGs that, along with RGGI, are fostering the transition from high-emitting coal and oil to renewable energy and lower-emitting natural gas as a fuel for generating electricity.

1 This section responds to many of the questions posed by EPA under heading number 1 ("What is state and stakeholder experience with programs that reduce CO_2 emissions in the electric power sector?")

ED_000419-0006071

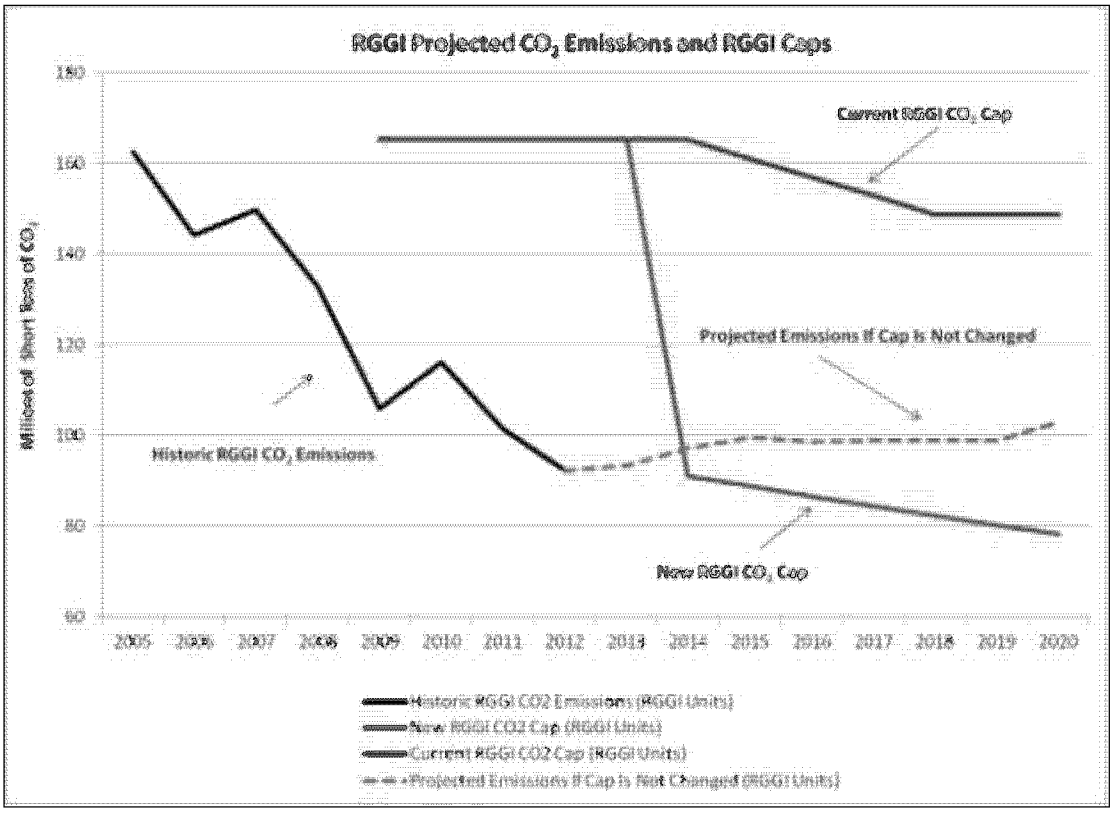
In this context, the RGGI cap-and-invest program plays three integral roles in achieving emission reductions. The declining cap and corresponding change in the cost of allowances provides a market signal that supports fuel switching, on-site efficiency improvements, the retirement of high-emitting plants, the construction of new more efficient plants, and other measures that reduce emissions. The auction mechanism provides a source of funding for complementary energy efficiency and renewable energy investments that further reduce emissions. The enforceable emissions cap ensures that the combined effect of the RGGI program and the suite of supporting policies is to actually reduce emissions to below the cap level.

The experience in the RGGI states shows the magnitude of emission reductions possible from the power sector: a projected 50% decline in tons of carbon dioxide (CO_2) emissions and a fossil fuel-fired generation fleet that is projected to achieve emission rates on par with the recently proposed new source performance standard for new electric generating units. Between 2005 and 2012, CO_2 emissions from the power sector in the nine participating RGGI states dropped more than 40%, from 162.5 million tons in 2005[2] to 92 million tons in 2012. The RGGI states are locking in this reduction by reducing the regional cap to 91 million tons in 2014, and reducing it an additional 2.5% each year thereafter to 78 million tons in 2020. In 2020, the RGGI emissions cap will ensure that regional emissions are 50% below 2005 emission levels (See Figure 1).

Some of this reduction is attributable to the successful energy efficiency programs implemented by each of the RGGI participating states. For example, New York's energy efficiency programs have reduced electricity use in New York by a cumulative total of 6.5% in 2012. As a result, CO_2 emissions associated with New York's electricity use are estimated to be 2.68 million tons lower in 2012 than they would have been otherwise. In the four years since it began in 2009, Maryland's EmPOWER program has reduced electricity consumption by 3.25%, reducing CO_2 emissions by 1.17 million tons. Massachusetts projects that its investment in energy efficiency will accelerate the reduction in electricity demand to approximately 2.5% each year from 2013-15. From 2005 through 2015, these energy efficiency investments will reduce Massachusetts' electricity demand by 17.1%, for a total annual reduction of 3 million tons of CO_2 in 2015. Similarly, Connecticut's energy efficiency programs have reduced electric consumption by over 10% since 2001, resulting in a total reduction of over 2 million tons of CO_2 emissions.

2 http://rggi.org/historical_emissions; https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi_summary_report_input&clearfuseattribs=true

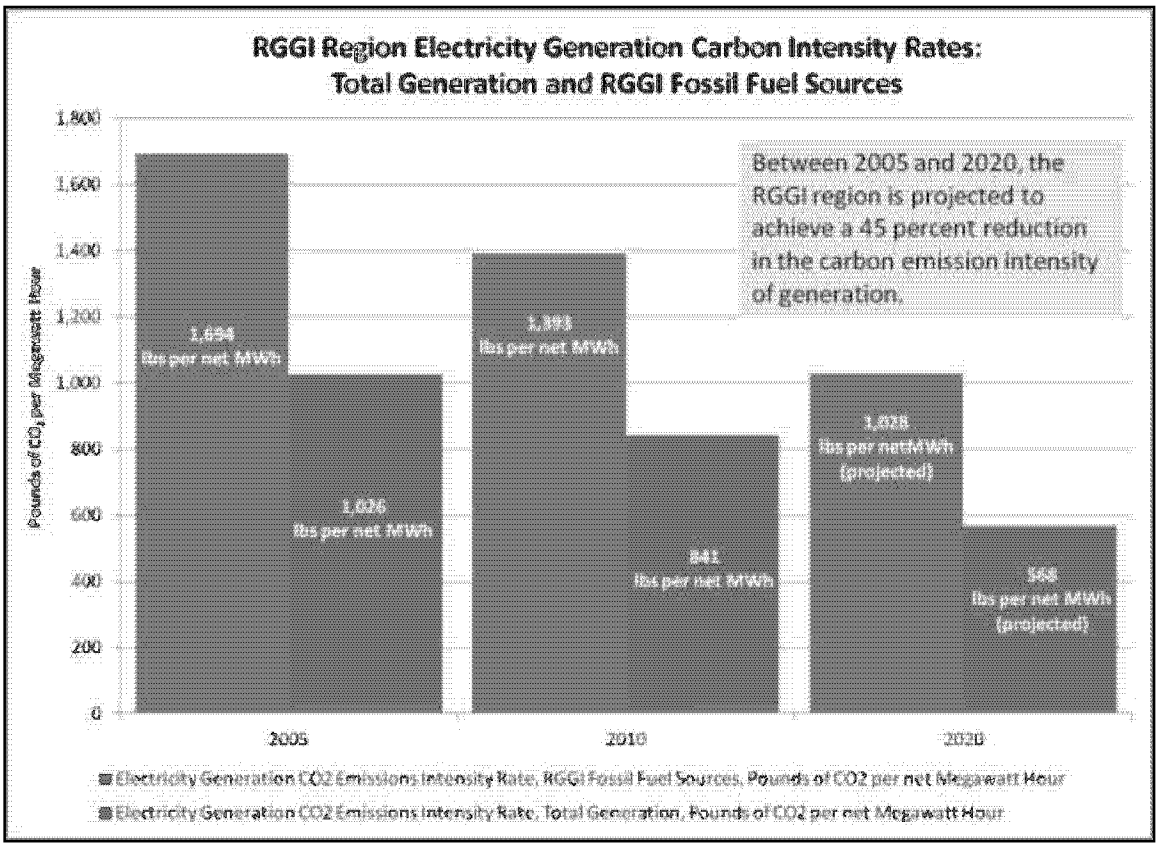
Figure 1: New RGGI Cap and Projected CO_2 Emissions Without Cap Reduction



Much of the reduction in power sector emissions is attributable to better utilization of a cleaner power system, resulting in a substantially reduced system-wide emission rate. Between 2005 and 2010, the overall CO_2 emission rate of the fossil fuel-fired power sector in the RGGI states declined from 1,694 lbs/MWh to 1,393 lbs/MWh (1026 lbs/MWh to 841 lbs/MWh, including zero emission sources).[3] By 2020, modeling of the new RGGI cap indicates that the fossil fleet emission rate will decline further to 1,028 lbs/MWh (568 lbs/MWh for all sources).[4] Thus, in the 15 years between 2005 and 2020, the RGGI states will have achieved a 39% reduction in the emission rate from fossil fuel-fired power plants and a 45% reduction in the emission rate of the entire power sector.

3 From data used to produce: http://rggi.org/docs/Documents/Elec_monitoring_report_2011_13_06_27.pdf
4 http://rggi.org/design/program_review

Figure 2: RGGI Region Electricity Generation Carbon Intensity Rates



This reduction in the emission intensity of electricity generation in the RGGI states is due in part to the ramping up of renewable energy sources, pursuant to state renewable portfolio standards that provide for steep increases in the percentage of renewable energy sold in each state, as the table below illustrates:

Table 1: RGGI State Renewable Portfolio Standards or Goals

State	Target Renewable Portfolio Standard or Goal	Target Year
Connecticut	27%	2020
Delaware	25%	2025
Maine	40%	2017
Maryland	20%	2022
Massachusetts	15%	2020
New Hampshire	24.8%	2025
New York	30%	2015
Rhode Island	16%	2019
Vermont	20%	2020

As the foregoing demonstrates, the RGGI states' experience can be an effective model for state programs under section 111(d):

- *It is extremely cost-effective*. RGGI enables compliance through market mechanisms that seek out the least expensive emission reductions across the region.[5]

- *It provides economic benefits*. According to an independent analysis, the RGGI states' investment of auction proceeds from just the first three years of the program (2009-2011) is creating thousands of jobs, reducing energy bills by over $1 billion and adding a net of $1.6 billion to the economies in the RGGI states.[6]

- *It aligns with the regional nature of the electricity grid*. The nation's regional electricity grids allow electricity to flow from the cheapest, most efficient producer to meet consumer demand, wherever located. As a result, generation and emissions within a region may not always trend in unison, such that emission increases in some locations due to market fundamentals may be offset by emission decreases elsewhere. The RGGI cap ensures that emissions decrease across the region, even as it allows increases in some locations in order to reap the benefits of more efficient sources in those locations.

- *It provides a simple, transparent, verifiable compliance system*. It can be difficult to document and verify the emission reductions attributable to programs that support renewable energy and energy efficiency. Under RGGI, the emissions are limited by the allowances that are distributed, providing certainty that the projected emission reductions will be achieved, including reductions attributable to energy efficiency and renewable energy.

The RGGI market-based model for achieving emission reductions is a well-established system of emission reduction. It is based on the models for reducing the pollutants that cause acid rain and ozone that are embodied in Title IV of the Clean Air Act and in the nitrogen oxide

5 This is consistent with recent analysis of the Organisation for Economic Co-operation and Development (OECD) that concludes that carbon markets are a highly efficient mechanism to mitigate carbon emissions. *See* OECD, Climate and Carbon, Aligning Prices and Policies, OECD Environment, Policy Paper, October 2013.
6 The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States, *Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period*. The Analysis Group, November 15, 2011.
http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Economic_Impact_RGGI_Report.pdf

trading program established by EPA in 1995 and 2003. But RGGI improved on those models by auctioning allowances and using the proceeds from those auctions to support complementary efforts to further reduce emissions and decrease compliance costs, such as investment in renewable energy and energy efficiency. This innovation has reduced the cost of complying with the cap and provided net economic benefits to the economies of the participating states.

Implications of RGGI for Development of EPA Guidelines under Section 111(d)[7]

EPA should recognize that the RGGI model is an effective system of emission reduction for GHG emissions from the power sector that combines various policy tools with an enforceable cap. Under the RGGI regional cap, the RGGI states will achieve a 50% reduction in CO_2 emissions from the power sector from 2005 levels by 2020. This reduction in emissions is projected to be realized in part through a 45% reduction in emission rates across the electricity system in the participating states, while the rest of the reductions come from complementary policies that reduce demand. Relying on an emission budget trading system, the RGGI states are ensuring that this level of reduction will in fact be achieved. The specific lessons of the RGGI experience include the following:

1. ***A system of emission reduction that is focused on the electricity system as a whole achieves the greatest emission reductions.***

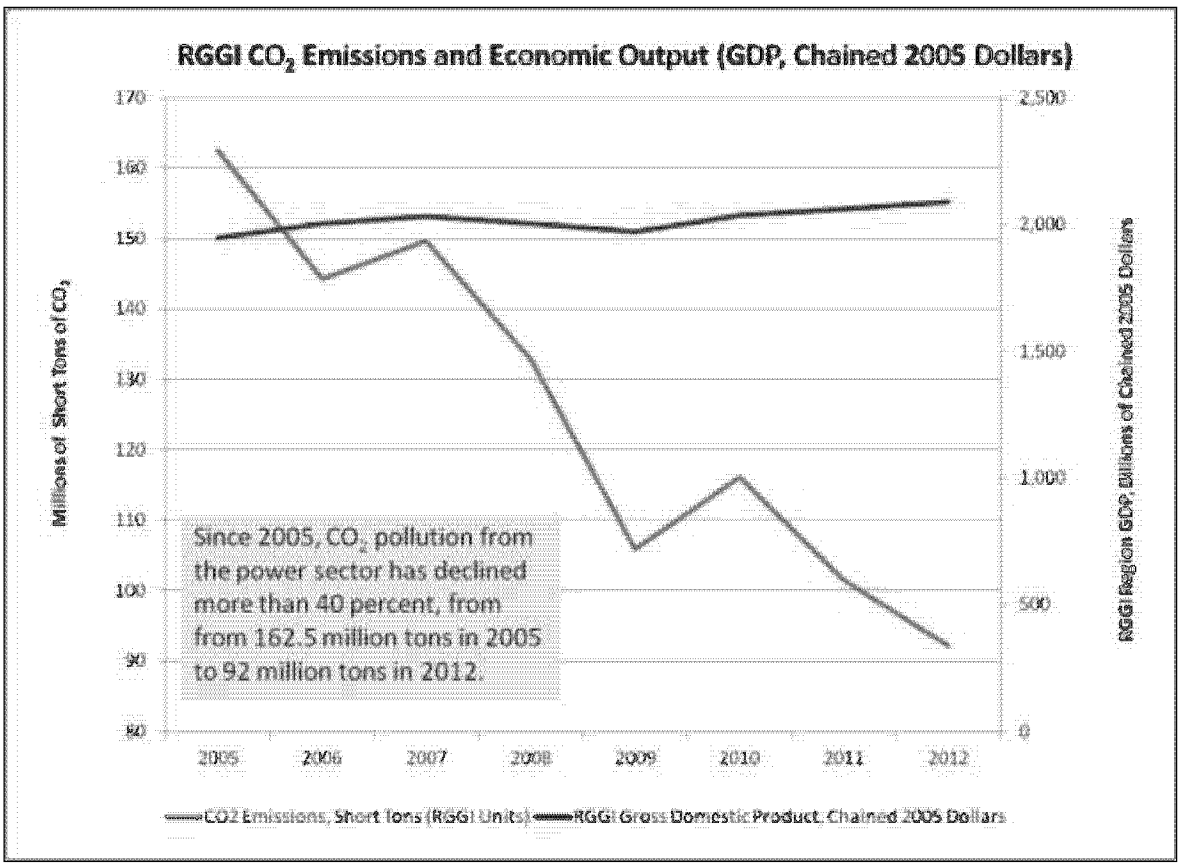
The RGGI states implement a suite of programs to pursue the best opportunities for emission reductions from the power sector. Programs within the system of emission reduction adopted by each RGGI state, such as energy efficiency goals and renewable energy standards, do not require emission reductions at any specific plant but focus on system-wide emission reductions. The price signal provided by the cost of RGGI allowances raises the relative cost of higher-emitting plants, leading to increased generation at lower-emitting, more efficient plants, even as overall system-wide emissions have declined substantially. A system-based approach is not only best-suited to realize the emission reduction potential of cleaner energy supplies and energy efficiency, it fits precisely within section 111(d)'s mandate to EPA to develop guidelines for states to implement the "best system of emission reduction."

7 This section responds to EPA's questions under heading number 2 ("How should EPA set the performance standard for state plans?")

2. *The RGGI states are demonstrating the feasibility of reducing emissions by 50%.*

Since 2005, CO_2 emissions from the power sector have declined more than 40% across the RGGI region, as energy efficiency programs have contributed to reduced demand and generation has shifted from coal and oil to gas and renewable power. Some states, like New York, achieved this level of reduction even though the energy system was already relatively clean in 2005, with nearly half of electricity provided by carbon-free sources. Even greater reductions should be achievable in states that rely more heavily on coal because of the low-cost alternatives that remain available. By reducing the cap to approximately 50% below 2005 levels by 2020, the RGGI states are ensuring that this transition to a lower-emitting power sector will continue. The RGGI states are achieving this reduction while continuing to grow the regional economy by more than 7% since 2005.[8]

Figure 3: RGGI CO_2 Emissions and Economic Output (2005-2012)



8 Bureau of Economic Analysis (BEA), Gross Domestic Product by State (chained 2005$); http://www.bea.gov/regional/index.htm

As mentioned above, the reinvestment of auction proceeds is contributing to this economic growth and analyses prepared for the RGGI states predict that over $8 billion and more than 125,000 job-years will be added to the RGGI states' economies as a result of the cap reduction through 2040.[9]

3. *An emissions cap is a reliable system for monitoring and verifying compliance.*

For states that rely on a suite of policies to reduce emissions, like the RGGI states, an emissions cap is a simple but rigorous method of ensuring and verifying that the policies have achieved the emission reductions targeted. Significantly, even though the required emission reductions are achieved on a regional basis, the point of compliance is with the source. Because sources cannot emit more than the number of allowances they hold at the relevant compliance deadline, the RGGI system ensures compliance. Verification is simple and routine: at the end of each compliance period, the amount of allowances in each source's compliance account must be adequate to cover that source's emissions. The measurement of CO_2 emissions at sources covered by the cap is easily accomplished utilizing existing emissions monitoring equipment and protocols already in place at these sources, and covered sources report CO_2 emissions in accordance with 40 CFR Part 75. If a source does not have adequate allowances to cover its emissions, enforcement can be taken directly against that source. Because of the simple and straightforward nature of determining whether the cap is met, budget trading programs obviate the need for EPA or states to conduct a complex analysis to determine whether a state meets its compliance requirements, as described below.

4. *Regional systems of emission reduction best reflect the regional nature of the electrical grid.*[10]

A program that corresponds with the borders of an electricity grid is potentially more efficient than programs that are constrained by state borders. If EPA only allows for compliance on a state-by-state basis, without regard to the scope of the electricity system, it may create inefficiencies and unnecessary complications for EPA, states, and regulated sources. A regional program like RGGI helps to ensure that the most cost-effective emission reductions occur across the region. For example, since the program was commenced, generation has shifted from coal-fired plants within the six state New England region covered by ISO New

9 http://rggi.org/design/program_review
10 This subsection responds to questions about how EPA should account for the regional nature of the electricity grid.

ED_000419-0006078

England to natural gas and renewable sources located elsewhere in that region. Indeed, emissions in Rhode Island actually increased because it is home to some of the more efficient natural gas-fired power plants in the region that had excess capacity. If Rhode Island's generation had been constrained by a Rhode Island-specific cap, one or more of the coal-fired plants that closed elsewhere in New England may have had to remain open to meet demand, thereby increasing emissions and costs to consumers.

Even if a program that encompasses an entire regional program is not feasible, a multi-state regional program like RGGI provides greater efficiency by allowing for the most cost-effective emission reductions among the states participating in the program.

Recommended Principles for EPA Guidelines[11]

The RGGI states offer the following recommendations for EPA's development of guidelines for state programs that would deliver the emission reductions needed as cost-effectively and equitably as possible.

1. *EPA's Guidelines should achieve meaningful nationwide emission reductions.*

In structuring its guidelines, EPA should take account of the emission reductions that are being achieved from the electricity system nationwide through a variety of programs, including RGGI and California's similar program, investments in energy efficiency, renewable energy programs, and switching to lower-carbon fuels, and also consider the potential for contributions from available technologies that are not yet widely deployed in the United States, such as offshore wind and carbon capture and sequestration technology. EPA should recognize that the best system of emission reduction considers the electricity system as a whole, and utilizes all the opportunities for reducing emissions from this system.

Conceptually, the methods of reducing emissions from the fossil fuel-fired electricity system can be grouped into two categories. The first category consists of systems of emission reduction that reduce the amount of electricity needed from fossil fuel-fired power plants, such as energy efficiency programs that reduce the demand for electricity, demand-side

11 This section responds generally to EPA's questions under heading numbers 2 ("How should EPA set the performance standard for state plans?") and 3 ("What requirements should state plans meet, and what flexibility should be provided to states in developing their plans?").

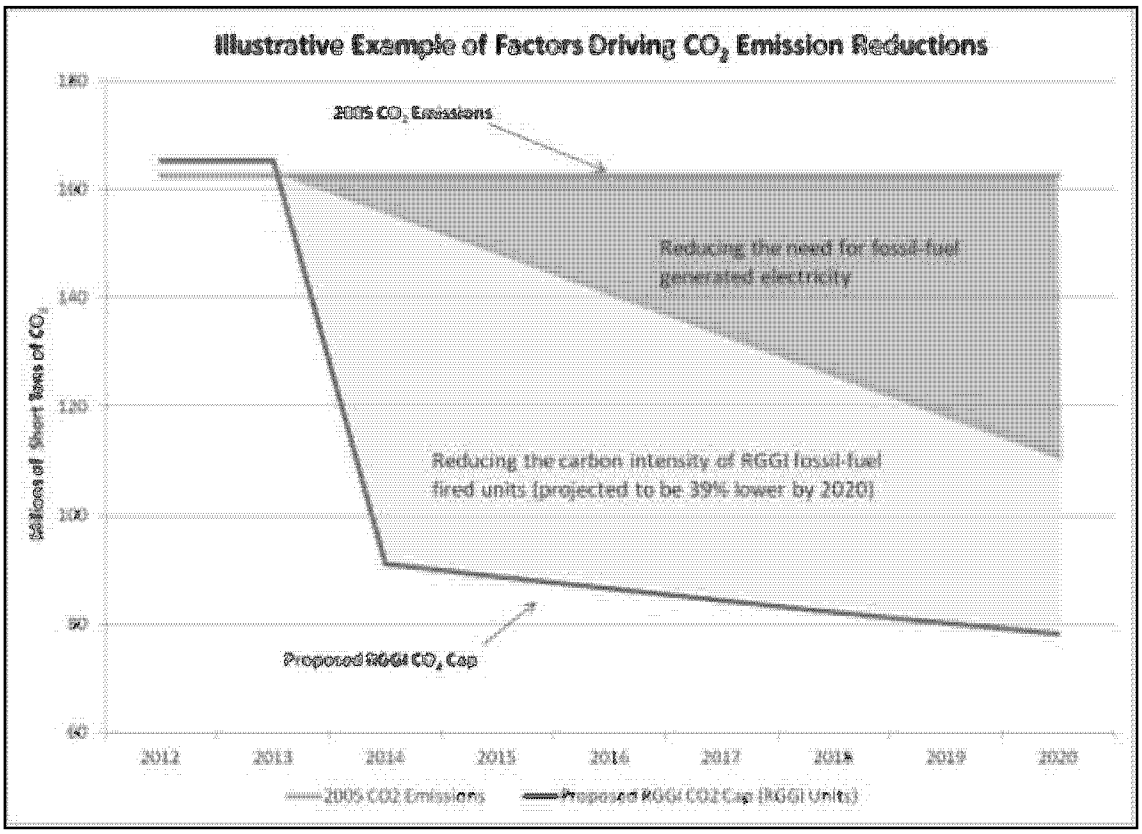
management, and investments in renewable energy that displace fossil fuel-generated electricity. Second, emissions can be reduced by lowering the carbon intensity of the electricity generated by fossil fuel-fired power plants. This is done through shifting generation from high-emitting plants to new or under-utilized lower-emitting plants, and using the latest technology to reduce emissions at existing plants. [12]

Combined, these two categories, or *wedges,* of emission reductions can be substantial. The RGGI states' 40% emission reduction is due to a suite of actions that address both *wedges*, including the RGGI mechanism, investments in energy efficiency and other demand-side programs, support for renewable energy, and regulatory programs directed at criteria air pollutants and air toxics that have reduced the amount of electricity generated by higher-emitting plants. These programs have combined with market forces that have supported a major shift in electricity generation from coal-fired to natural gas-fired plants to transform the regional electricity system in the past eight years.

By investing in energy efficiency and renewable energy and shifting generation to more efficient plants, other states and regions should be able to approach the level of performance that the RGGI states are already demonstrating. EPA should evaluate whether and when this level of performance can be achieved throughout the United States using the various tools at the disposal of the states. While it may take longer for some regions of the nation to achieve comparable levels of performance, EPA should structure the emission guidelines to require that states make significant progress in the next decade toward achieving the reductions and performance level demonstrated by RGGI to be readily achievable by the best systems of emission reduction.

12 Currently available options for reducing carbon dioxide emissions through measures implemented "on-site" at existing fossil fuel-fired power plants have the potential to reduce emissions from individual power plants by 20% or more, especially if used in combination. In addition to improving the efficiency or "heat rate" of the plant, these options include, but are not limited to, co-firing or re-powering with lower-carbon fuels such as sustainable biomass and natural gas; utilizing renewable energy sources such as solar power to provide supplemental steam heating; implementing combined heat and power (CHP) systems at plants near industrial facilities or district heating systems; and carbon capture technology.

Figure 4: Illustrative Example of Factors Driving CO_2 Emission Reductions



2. EPA should provide equitable treatment to early movers.

Many states, including the RGGI states, have already made substantial progress in reducing emissions from their power sector. EPA should structure the guidelines in a way that recognizes this progress and provides equitable treatment to those states. EPA should avoid any approach that imposes inequitable or disproportionate burdens on early mover states and fails to recognize their substantial progress. For example, requiring an equivalent percentage reduction for state A, which has already achieved most cost-effective reductions, and state B, which has taken little action and finds many inexpensive emission reduction opportunities still available, would effectively disadvantage state A for having taken early action.

One approach that EPA should consider is setting a single emission intensity target (e.g., a system-wide average of 1100 lb/MWh) that would apply to each state, individually or as part of a region. That approach would require all states to reduce emissions but it would be equitable to those states that have already made progress toward meeting the emission

intensity target. EPA could consider providing more time to states that have more work to do to meet the target.

3. EPA should allow states to use a mass-based system of compliance.

A mass-based approach has a number of advantages, including simplicity and its ability to accommodate many emission reduction strategies, including energy efficiency and renewable power, and add-on controls should they become technically and economically viable. An emission rate target, in contrast, does not easily provide credit for energy efficiency investments that reduce energy demand without reducing the emission rate of the units operating. Thus, requiring the regulated fossil fuel-fired power plants to meet a specific emission rate, or achieve a set reduction in their emission rate, does not credit investments in energy efficiency.

Therefore, EPA should allow states to utilize a mass-based system of compliance, applied to the energy system as a whole. Indeed, if EPA does not establish mass-based targets in its guidelines, it should provide the states with clear direction in developing mass-based emission budgets based on emission rates designated by EPA. That direction could include designation of factors (e.g., rate of economic growth) and consistent data sources that would allow for conversion of an emission rate target into an emission budget.

4. EPA should allow states to demonstrate compliance on a regional basis.

EPA should allow and encourage compliance on a regional basis, while providing individual states the opportunity to determine how to achieve compliance with each state's emission budget within its state implementation plan. Under a mass-based regional system of compliance like RGGI, states would pool their individual state emission budgets and comply with those emission budgets on a regional basis, while still allowing for enforcement by states against their own sources that do not have sufficient allowances. As long as the overall regional emissions cap complies with the guidelines, it should be immaterial to EPA how the participating states elect to apportion the regional emissions cap among the states. Although a particular state's actual emissions could theoretically exceed its individual state emission budget in a particular year, this should not affect EPA's willingness to accept a regional program as a pathway for compliance. As long as the regional program demonstrates that emissions from sources within the region will collectively meet EPA's emission guideline, it can still serve as the basis for each state's implementation plan.

A regional program has the benefit of addressing some of the interstate issues raised by EPA in its questions. For example, under a state-by-state approach, if an energy efficiency policy in State A leads to a reduction in emissions in neighboring State B, State A cannot necessarily take direct credit for those emission reductions outside its borders in its section 111(d) implementation plan. Likewise, because State B would have no basis for enforcing State A's energy efficiency program, State B cannot necessarily include State A's efficiency policy in its plan. For any state that is part of a multistate electricity grid, it may be challenging to make a rigorous demonstration that investments in energy efficiency or renewable energy result in any quantifiable level of emission reductions within the state. On the other hand, a regional program that encompasses both the state that invests in efficiency and the state in which emissions decline as a result would avoid these complications. In a regional budget trading program, emission reductions anywhere in the region reduce the overall demand for emission allowances, as regulated sources require fewer allowances for compliance. As a result, the cost of allowances, or the cost of complying with that regional emissions cap, is reduced.

Thus, allowing regional compliance can avoid market distortions that would result in less than optimal policy decisions. For example, a state that is not participating in a regional program might choose not to invest in energy efficiency or renewable energy if it would not be able to fully credit the benefits of doing so in its section 111(d) compliance plan. Instead, it might choose to make less than optimal investments in fuel-switching or plant-specific improvements in order to ensure that the emissions of its power plants are reduced. The result would be less than optimal allocation of limited resources and less reduction of emissions for a given level of effort. EPA should avoid that inefficient outcome by supporting (but not requiring) the development of regional compliance plans.

5. EPA should permit states to demonstrate compliance on a multi-year basis.

Emissions across an electricity system can vary between years depending on factors outside the ability of plant operators to influence, including weather, economic conditions, and unexpected shutdowns. EPA can require a more substantial level of cost-effective reductions if it allows states to average emissions over a multi-year period and enables states to bank, or carry-over, early reductions. Unlike other pollutants that may have short-term impacts, the environmental harm caused by CO_2 and other GHG pollutants have much longer periods of impact. Therefore, allowing compliance on a multi-year basis would not reduce the environmental benefits of the program.

The RGGI program uses a three-year compliance approach. The RGGI states' experience is that this approach has the benefit of allowing sources to take advantage of multi-year compliance strategies. By allowing sources three years, the regulated units have flexibility to address variations in emissions, unexpected shutdowns, or uneconomic dispatch orders, without impacting the enforceability or environmental effectiveness of the program's requirements.

6. ***EPA's should provide clear guidelines for a rigorous demonstration of equivalency of state programs.***[13]

EPA should provide clear direction to the states regarding demonstrating equivalency of state programs. EPA's guidelines should identify the tools that states can use to demonstrate that state emission reduction programs will achieve equal or greater reductions in pollution than the base standards set by EPA. For a mass-based budget trading program like RGGI, that process is straightforward. As long as EPA provides a mechanism that enables states to potentially have an annual mass-based emissions budget under section 111(d), then determining whether a regional budget trading program like RGGI is equivalent to EPA's emission guideline will be a simple matter. In particular, the participating states will have to demonstrate that the annual regional emissions cap under the regional program achieves emission reductions equal to or greater than those allowed by EPA's guidelines.

To evaluate programs that are not mass-based, EPA should build on current program evaluation guidance such as the "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans" or the "State and Local Energy Efficiency Action Network. 2012. *Energy Efficiency Program Impact Evaluation Guide.*" These guides describe the terminology, structures, and approaches used for evaluating energy and demand savings as well as avoided emissions and other non-energy benefits resulting from energy efficiency programs that are implemented by local governments, states, utilities, private companies, and nonprofits. These guides provide context, planning guidance, and discussion of issues that determine the most appropriate evaluation objectives and best practices approaches for different efficiency portfolios. By using standard evaluation terminology and structures and best practices approaches, evaluations can support the adoption, continuation, and expansion of effective efficiency actions for consistent inclusion in State Plans.

13 This section responds to EPA's questions under heading number 3 ("What requirements should state plans meet, and what flexibility should be provided to states in developing their plans?").

ED_000419-0006084

7. ***EPA should ensure that state plans are enforceable.***

EPA should require state plans to demonstrate that the requirements are legally and practically enforceable. Under a budget trading program like RGGI, enforceability, measurement, and verification are already incorporated into the program in a straightforward manner. Based on consistent regulations adopted in each RGGI state, sources subject to RGGI are required to obtain and hold a sufficient amount of allowances by the relevant compliance deadline to cover emissions over the relevant compliance period. Under the existing terms of RGGI states' respective implementing regulations, this regulatory requirement is generally incorporated as a condition of each source's operating permit. Thus, RGGI is enforceable directly against individual sources by the state where the sources are located, and the failure of a source to hold sufficient allowances constitutes violations of the state's program and of the source's permit. Under an approved section 111(d) plan, this obligation of each individual source to comply with RGGI would become a federally enforceable condition of an individual source's Title V permit. At the end of the compliance period, the "true-up" process, in which states deduct allowances to cover sources' emissions, provides verification that the emission reductions included as part of the participating states' section 111(d) plans are actually achieved.

State plans that rely on a suite of strategies including energy efficiency, renewable energy, and changes in dispatch should be encouraged, as long as a mechanism is available to ensure that the promised emission reductions are achieved. If the emission reductions anticipated from those strategies are encompassed within a federally enforceable emission budget program, the various strategies themselves would not have to be federally enforceable.

Conclusion

The states participating in RGGI have demonstrated that significant emission reductions are feasible through a suite of clean energy activities, complemented by an enforceable emissions cap. EPA should consider this record of success in developing guidelines for state plans that require and empower states to achieve meaningful reductions through a comprehensive package of activities, including market-based emission budget programs like RGGI.

COMMENTS OF THE UTILITY AIR REGULATORY GROUP

on the

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY'S

CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS; PROPOSED RULE

79 Fed. Reg. 34,830 (June 18, 2014)
Docket ID No. EPA-HQ-OAR-2013-0602

Hunton & Williams LLP

F. William Brownell
Lauren E. Freeman
Allison D. Wood
Ted J. Murphy
Craig S. Harrison
Tauna M. Szymanski
Aaron M. Flynn
Andrew D. Knudsen

2200 Pennsylvania Ave., NW
Washington, D.C. 20037
(202) 955-1500

Counsel for the Utility Air Regulatory Group

Dated: December 1, 2014

TABLE OF CONTENTS

Page

I. Introduction 2

II. Executive Summary 5

III. The Proposed Guidelines Are Fundamentally Divorced from the Narrow and Exclusive Focus of Section 111 of the CAA on Stationary Sources in Listed Source Categories. 17

A. Section 111 Authorizes Standards of Performance That Are Achievable for Individual Sources in a Source Category Based on Measures Those Sources Can Implement Themselves. 18

1. The Text of Section 111 19

2. CAA Context for Section 111 22

3. The History of EPA's Implementation of Section 111 25

B. EPA's Proposed Action Deviates So Far from the CAA as To Be Unrecognizable as an Exercise of Section 111 Authority. 29

1. EPA's Proposed Guidelines Impermissibly Base Standards of Performance on Measures that Go Beyond the Regulated Source. 30

2. EPA Cannot Consider Reduced Utilization of Regulated Sources as BSER. 38

3. The Proposed Guidelines Are Based on Measures that States and EPA Cannot Enforce Against Regulated Sources. 42

IV. EPA Is Prohibited from Regulating Pollutants from a Source Category Already Regulated Under Section 112 of the CAA. 52

A. EPA's Interpretation of the Act Is Inconsistent With the Plain Language of Section 111(d), Which Contains No Ambiguity. 52

B. EPA's Proposed Construction Does Not Accord With Either Provision or With Legislative Intent. 56

V. EPA Lacks the Sufficient Legal Prerequisites To Propose and Finalize the Proposed Guidelines. 59

A. EPA's Proposed NSPS for New Coal-Fired EGUs Is Unlawful and Cannot Support Section 111(d) Emission Guidelines. 59

B. The Proposed NSPS for New Sources Does Not Address the Same Type of Facilities as the Proposed Guidelines. 61

VI. Definition of "Affected EGU" 66

ED_000419-0005686

A. EPA's Definition of "Affected EGU" in the Proposed Guidelines Must Retain the Exclusions for Subpart Da Units That Were Proposed for New Subpart Da Units. 68

B. The "Broad Applicability" Approach to the Proposed NSPS Would Not Support Regulating a Broader Universe of Sources Under the Proposed Guidelines. 69

VII. EPA Has Unlawfully Ignored the Federal Power Act's Division Between State and Federal Authority and Arbitrarily and Capriciously Ignored the Realities of Wholesale Electric Markets, Regional Transmission Grids, and Bulk Power System Reliability. 73

A. The Proposed Guidelines Are Inconsistent With the FPA and Violate Section 310(a) of the CAA Because They Would Override the Division of Regulatory Authority Over the Generation, Transmission, Distribution, and Sale of Electric Energy Between the States and the Federal Government. 75

1. The Proposed Guidelines Unlawfully Usurp Authority Over the Generation of Electricity, Resource Planning, and Related Matters that the FPA and Tenth Amendment Reserve to the States. 76

2. The Proposed Guidelines Usurp Regulatory Authority that the FPA Gives Exclusively to FERC. 81

a. The Proposed Guidelines Would Impermissibly Interfere With FERC's Exclusive Authority Under Sections 205 and 206 of the FPA To Regulate Interstate Transmission and Wholesale Sale of Electric Energy. 82

b. The Proposed Guidelines Conflict With Section 202(a) of the FPA and Impermissibly Intrude on FERC's Authority To Coordinate Regional Transmission. 89

c. The Proposed Guidelines Unlawfully Intrude on FERC's Authority Under Section 215 of the FPA To Ensure Reliability of the BPS. 92

B. EPA Has Arbitrarily and Capriciously Ignored the Realities of the FERC-Regulated Wholesale Electric Markets and Bulk Power System. 94

1. EPA Has Unreasonably Failed To Consult With FERC Regarding the Proposed Guidelines' Technical Feasibility and Impacts on Reliability and Markets. 95

2. EPA's Erroneous Assumption that States Control the Dispatch of EGUs Is Likely to Result in Serious Distortions and Unintended Consequences. 97

ED_000419-0005687

3. EPA Underestimates the Challenges of Energy Infrastructure Development and the Impact of Transmission Constraints. 98

4. EPA Relies on Assumptions that Independent Expert Analyses Demonstrate Are Faulty. 101

5. EPA Has Not Accounted for the *EPSA* Decision's Potential Impact on Demand-Side Resources. 109

6. EPA Inaccurately Describes RTO Capacity Markets and Overstates Their Potential To Advance the Proposed Guidelines' Goals. 110

VIII. If Lawful, The Proposed Guidelines Would Violate the Fifth Amendment Because Uncompensated Takings of Property Will Result. 112

A. The Proposed Guidelines, if Lawful, Would Result in a Total Taking of Any EGU Forced To Shut Down To Ensure Compliance with the Guidelines. 114

B. The Proposed Guidelines, if Lawful, Would Result in a Partial Regulatory Taking of Any EGU That Must Significantly Curtail its Operation or Remaining Useful Life To Ensure Compliance with the Proposed Guidelines' Emission Goals. 115

1. The Character of the Proposed Guidelines Weighs in Favor of a Takings Claim. 116

2. The Proposed Guidelines Would Cause Severe Economic Impacts. 119

3. The Proposed Guidelines Would Significantly Interfere With Reasonable Investment-Backed Expectations. 120

IX. EPA Usurps the Role of States and Treads Into Areas that Are Quintessentially Within the Purview of State Control in Violation of Section 111(d). 122

A. State Primacy Under Section 111(d) and EPA's Regulations Implementing Section 111(d) 122

B. The "Flexibility" EPA Claims Exists in the Proposed Guidelines Is Illusory. 131

C. The Proposed Guidelines Conflict With State Laws and Fail To Take Account of Other CAA Requirements. 135

D. Selecting a Rate-Based or Mass-Based Goal 138

E. Types of State Plans 140

F. Timing for Plan Implementation and Achievement of State Emission Performance Goals 143

G. State Plan Approvability Criteria and Components of Approvable Plans 147

ED_000419-0005688

H. Process and Timing for Submittal of State Plans....150
I. Key Considerations for States....152
1. Affected Entities Other Than Affected EGUs....153
2. Treatment of Existing State Programs....153
3. Incorporating RE and Demand-Side EE Measures Under a Rate-Based Approach....156
4. Quantification, Monitoring, and Verification of RE and Demand-Side EE Measures....156
5. Reporting and Recordkeeping for Affected Entities Implementing RE and Demand-Side EE Measures....157
6. Treatment of Interstate Effects....158
7. Projecting Emission Performance....158
8. Potential Emission Reduction Measures Not Used To Set Proposed Goals....159
9. Consideration of a Facility's "Remaining Useful Life" in Applying Standards of Performance....160
J. Multi-State Plan Considerations....163
X. EPA Cannot Require States To Regulate EGUs Simultaneously Under Sections 111(b) and 111(d) of the CAA....165
XI. New Source Review Issues....170
XII. The Proposed Guidelines Are Not Justified by Their Purported Benefits When Those Benefits Are Characterized Properly....177
A. Costs....178
B. Social Cost of Carbon....181
C. Public Health Benefits....186
D. Summary....190
XIII. EPA's Calculation of the State Goals Impermissibly Limits the States' Discretion and Is Error-Ridden....191
A. Despite EPA's Claims, States Have Little to No Flexibility in Their Ability To Meet the State Goals Contained in the Proposed Guidelines....191
B. EPA Should Not Include Hypothetical Generation From Units that Are Under Construction When Implementing Building Block 2 in State Goal Calculations....196
C. EPA Should Not Penalize States that Have Invested in Nuclear Generation by Including "At Risk" and Under-Construction Nuclear Capacity in State Goals....198
D. EPA's Goal Calculation Methodology Is Riddled With Errors....200

ED_000419-0005689

1. EPA Applies the Building Blocks to Non-Affected Units....200
2. Errors Regarding 2012 Generation Data....204
3. EPA Assumes Unrealistic Emission Rates for NGCC Units and Subpart Da Units....209
XIV. EPA's Building Blocks....211
A. Building Block 1 Is Not Achievable....211
B. Building Block 2 Is Not Achievable....228
C. The Renewable Energy Component of Building Block 3 Is Not Achievable....241
1. EPA's Method for Calculating the Renewable Energy Targets for Building Block 3 Is Flawed....242
2. EPA Has Not Provided All of the Data Needed To Evaluate the Proposed Guidelines in Violation of Section 307(d)(3) of the CAA....249
D. EPA Correctly Excluded Natural Gas Conversion and Co-Firing From Its Proposed BSER Determination....251
XV. Issues Raised by EPA's October 30, 2014 Notice of Data Availability....251
A. General Issues....252
B. Building Block 2 Issues: New NGCC and Co-Firing as Components of BSER....254
C. Issues Regarding an Alternative "Glide Path" to Compliance....258
D. Regionalized Approach to Building Blocks 2 and 3....262
E. Goal-Setting Methodology....264
XVI. Monitoring, Recordkeeping, and Reporting Requirements for EGUs....267
A. Proposed CO_2 Monitoring Methods....271
1. The CEMS Option....271
2. The Heat Input and Fuel Factor Option....274
3. Monitoring of CO_2 Mass Emissions From Integrated Equipment....275
B. Monitoring and Reporting of Electric Output....276
C. Monitoring and Reporting of Useful Thermal Output....280
D. Monitoring Plan and QA/QC Testing....282
E. Use of Specific Methods for Flow RATAs and Baseline Adjustments Following a Change in Method....283
F. EGU Recordkeeping Requirement....286
XVII. Objection to Promulgation of Rules Not Proposed....287

ED_000419-0005690

Comments of the Utility Air Regulatory Group
on the
United States Environmental Protection Agency's
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule

79 Fed. Reg. 34,830 (June 18, 2014)
Docket ID No. EPA-HQ-OAR-2013-0602

December 1, 2014

The Utility Air Regulatory Group ("UARG") submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA" or "Agency") proposed rule entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,830 (June 18, 2014) ("Proposed Guidelines"). Attached to these comments are several technical reports prepared in support of these comments. UARG is also filing separately its "Supplemental Materials for the Rulemaking Record," which contains a variety of secondary materials to which these comments refer.[1]

UARG is an *ad hoc*, unincorporated association of individual electric generating companies and industry groups. UARG's purpose is to participate on behalf of its members collectively in EPA's rulemakings and other Clean Air Act ("CAA" or "Act") proceedings that affect the interests of electric generators and in litigation arising from those proceedings.

---

[1] On October 16, 2014, UARG filed comments on a related EPA proposed rule entitled "Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,960 (June 18, 2014) ("Proposed Standards"). Docket ID No. EPA-HQ-OAR-2013-0603-0215 ("UARG Modified/Reconstructed Comments"). UARG also filed comments on a related EPA proposed rule entitled "Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (Jan. 8, 2014) ("January 2014 NSPS Proposal"). Docket ID No. EPA-HQ-OAR-2013-0495-9666 ("UARG New Source Comments"). Both sets of comments are incorporated by reference and are included in UARG's separately filed Supplemental Materials for the Rulemaking Record.

ED_000419-0005691

The electric generating companies that are members of UARG construct, own, and operate power plants, including fossil fuel-fired plants, and other facilities that generate electricity for residential, commercial, industrial, institutional, and government customers. Operation of fossil fuel-fired power plants results in emissions of carbon dioxide ("CO_2"), the constituent greenhouse gas ("GHG") that the Proposed Guidelines address. UARG therefore has a clear and significant interest in the present rulemaking as well as the other EPA rulemakings that are part of the Agency's overall effort to regulate CO_2 and other GHG emissions under the CAA, including GHG emissions from stationary sources.

I. Introduction

Imagine that EPA proposes regulations under a section of the CAA authorizing the Agency to develop standards of performance for tailpipe emissions from motor vehicles that burn fossil fuels. One might expect that these regulations would require vehicles to be equipped with emission control equipment (such as catalytic converters) or other equipment (such as on-board diagnostic computers) to limit each vehicle's tailpipe emissions per mile. But what if EPA went further? Imagine that these regulations also attempted to reduce vehicle tailpipe emissions by requiring car owners to shift some of their travel to buses, or by requiring there to be more electric vehicle purchases, or by requiring individuals to reduce vehicle use altogether by working from home once a week. Can a "standard of performance" reasonably include measures like these? Would the CAA permit such requirements?

To many, such broad requirements would seem entirely out of place and beyond the scope of EPA's authority to limit air pollution from motor vehicles, despite the fact that these types of measures would indirectly reduce tailpipe emissions from vehicles. That is because they would have no effect on the emissions rate of the individual vehicles themselves, and they are completely beyond the control of the vehicle manufacturer.

ED_000419-0005692

Although this imagined scenario seems fanciful, it is precisely what EPA proposes to do in the Proposed Guidelines. Rather than limit itself to emission control or other production process-related measures to lower the CO_2 emissions rates of existing electric generating units ("EGUs"), EPA instead proposes to require electricity generation to be shifted from coal- and oil-fired EGUs to natural gas-fired EGUs (akin to requiring car owners to take the bus more), mandate the building of additional renewable energy (akin to requiring the purpose of more electric vehicles), and require programs that will result in customers using less electricity (akin to requiring drivers to work from home one day a week). This approach violates common sense and the CAA.

Section 111 of the CAA authorizes EPA and states to promulgate standards of performance for new and existing sources within certain source categories. At its heart, section 111 is quite simple. It provides for the regulation of sources through standards that are based on what an individual source can do to reduce the source's emissions at a given level of operations. Nothing in Building Blocks 2, 3, or 4 of the Proposed Guidelines would reduce the pounds per megawatt hour ("lb/MWh") of CO_2 emitted from any EGU. Efforts to require aggregate emission reductions by targeting entities outside the designated source category exceed the scope of section 111; a "standard of performance" cannot ask another source to operate more (or ask other entities to reduce demand for a product) so that the source in the designated source category must curtail its operations or not "perform" at all.

EPA's novel, first-time interpretation in the Proposed Guidelines of the "best system of emission reduction" ("BSER") relies on a distension of the word "system" to broaden the scope of the section 111 program beyond the EGU itself. EPA claims that it may base a standard of performance on *any* "set of things" that leads to reduced emissions from the source category

ED_000419-0005693

overall, ranging from utilization limits at certain units to enforceable obligations for other entities that indirectly reduce utilization of some sources. This interpretation is unlawful. The plain language, the statutory context, and the regulatory history of section 111 are clear and unambiguous. A "system of emission reduction" must begin and end at the source itself.

Although it is true that section 111(d), which governs existing sources, provides more flexibility than section 111(b), which governs new sources, that flexibility does not extend to the setting of the performance standard. Once an emission guideline has been established, section 111(d) does give states flexibility to determine how sources may comply with the standard or whether that standard should be modified for individual sources. This is how EPA's 2005 Clean Air Mercury Rule ("CAMR"), which also established emission guidelines under section 111(d), would have worked.[2] Although CAMR authorized a flexible means of complying with the standards of performance in the form of an emissions trading program, the "system of emission reduction" that was used to set the emission guidelines themselves conformed to section 111's focus on individual sources and was based on specific pollution control technology that could be installed at individual sources. 70 Fed. Reg. 28,606, 28,617-20, 28,621 (May 18, 2005).

The Supreme Court has just recently reminded EPA of the limitations on its authority to regulate GHGs under the CAA. In *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) ("*UARG v. EPA*"), EPA's Tailoring Rule, which was also aimed at controlling emissions of CO_2 under the Act's prevention of significant deterioration ("PSD") program, was declared invalid because EPA had attempted to seize far more power than the CAA granted the Agency. In its ruling, the Court urged EPA to proceed with more caution—a lesson EPA should heed now in

---

[2] The D.C. Circuit vacated CAMR for reasons having nothing to do with how the standards of performance were established or the flexible mechanisms that were permitted for complying with them. *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

ED_000419-0005694

these proceedings. Indeed, the Court stated that EPA cannot regulate GHGs in a manner that is "'extreme,' 'counterintuitive,' or contrary to 'common sense.'" *Id.* at 2441 (quoting *Massachusetts v. EPA*, 549 U.S. 497, 531 (2007)). The Proposed Guidelines are all of these things.

Further, the Court warned EPA against interpreting its statutory authority in a way that "would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization." *Id.* at 2444 (citing *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 160 (2000)). The Supreme Court further stated that "[w]hen 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." *Id.* (quoting *Brown & Williamson*, 529 U.S. at 159). Here, EPA has chosen an obscure and little used provision of the CAA as the basis for an unprecedented regulatory program that will undeniably alter the nation's economy. *UARG v. EPA* makes clear that EPA's choice is not only unwise but unlawful. EPA should withdraw the Proposed Guidelines.

II. Executive Summary

Many legal, technical, and policy-based shortcomings render the Proposed Guidelines arbitrary, capricious, and contrary to law. These issues, described in detail in these comments, are summarized here:[3]

The Proposed Guidelines are fundamentally divorced from section 111's narrow and exclusive focus on stationary sources.

- Standards promulgated under section 111 must be source-based and reflect measures that the source's owner can integrate into the design or operation of the source itself.

---

[3] This Executive Summary is provided for the convenience of the reader. It does not summarize every point made within these comments and should not be a substitute for reading the comments in their entirety.

ED_000419-0005695

A standard cannot be based on actions taken beyond the source itself that somehow reduce the source's utilization. Nor can it be based simply on requiring a source to reduce its operations. A "standard of performance" cannot mandate "non-performance." Moreover, requiring a source to operate at reduced capacity would effectively order a fundamental redesign of the facility, which EPA has no authority to do.

- Standards of performance apply to sources within listed categories and cannot regulate categories or subcategories in the aggregate or in combination with other entities outside the source category. The Act narrowly confines the stationary sources that may be regulated under section 111 to any individual "building, structure, facility, or installation which emits or may emit any air pollutant." This definition of "stationary source" does not extend to combinations of these facilities or to non-emitting entities such as states or consumers of electricity.

- EPA's Proposed Guidelines would unlawfully impose federally enforceable obligations on a broad, undefined class of "affected entities" beyond the regulated category of existing EGUs in order to effectuate the Agency's policy goal of reducing aggregate CO_2 emissions.

- Section 111 of the CAA also requires that any standard of performance be "achievable" by the sources to which it applies based on applying an "adequately demonstrated" system of emission reduction. A standard cannot be "achievable" for a source if, in order to achieve the standard, the source must rely on measures taken by some other entity that it does not control, or must simply cease to operate.

- The Agency's past rulemakings pursuant to section 111 reflect the provision's singular focus on individual sources. In over 40 years of EPA's implementation of the CAA, every single standard of performance has been based on a "system of emission reduction" that is incorporated into the design or operation of individual sources.

- The Agency's radical redefinition of what measures may constitute a "system of emission reduction" is impermissible in light of the past four decades of contrary implementation and section 111's exclusive focus on what individual sources can achieve.

- The broad program of energy resource management and economy-wide demand reduction that EPA has proposed to create and administer in the Proposed Guidelines bears no resemblance to the source-focused regulatory program that Congress established in section 111.

- The Proposed Guidelines would violate the D.C. Circuit's holding in *ASARCO Inc. v. EPA*, 578 F.2d 319 (D.C. Cir. 1978). There the court invalidated EPA's attempt to change the basic unit to which the section 111's new source performance standards ("NSPS") apply from a single building, structure, facility, or installation to a

combination of such units. The D.C. Circuit held that EPA "has no authority to rewrite the statute in this fashion."

EPA is prohibited from regulating pollutants from a source category already regulated under section 112 of the CAA.

- Section 111(d) prohibits EPA from adopting emission guidelines for existing sources from a source category when the Agency has already regulated that source category under section 112. EPA listed coal- and oil-fired EGUs as a "source category" under section 112 in 2000, and regulated emissions from these sources in 2012 under the Mercury and Air Toxics Standards ("MATS").

- Section 111 is not ambiguous, and EPA therefore is not entitled to deference in interpreting that provision. The plain language of the Act prevents EPA from regulating EGUs under section 111(d). A drafting error in the 1990 CAA amendments does not vest the Agency with the authority it claims.

EPA lacks the sufficient legal prerequisites for the Proposed Guidelines.

- EPA may not finalize guidelines for existing sources unless new sources of the same type of entity are already subject to a section 111(b) performance standard.

- EPA's proposed NSPS for new coal-fired EGUs fails to meet the statutory requirements for a "standard of performance" under section 111(b) of the Act because partial carbon capture and storage is not "adequately demonstrated" and the proposed NSPS does not actually require a reduction in CO_2 emissions. As a result, the NSPS does not satisfy the legal prerequisite for the Proposed Guidelines.

- The Proposed Guidelines do not address the "same type" of facility that EPA's proposed new source NSPS would address, and thus on this basis alone the Proposed Guidelines lack the legal prerequisite that a standard of performance for the same type of facility must have been proposed concurrently with, or before, a proposal for existing source emission guidelines under section 111(d).

- EPA violates its section 111(d) Subpart B regulations by failing to identify the "designated facilities" subject to the Proposed Guidelines. EPA instead proposes to regulate a wide range of "affected entities" and states—sources that extend far beyond the coal- and gas-fired EGUs EPA would regulate under its new source NSPS proposal.

- The section 111(b) proposals for modified and reconstructed facilities also do not provide a valid basis for the Proposed Guidelines because those proposed rules define the affected facility as a fossil fuel-fired EGU. The Proposed Guidelines would regulate sources far beyond a fossil fuel-fired EGU.

EPA's proposed definition of "affected EGU" is broader than the scope of new sources covered by EPA's proposed NSPS for new EGUs.

- EPA's definition of "affected EGU" in the Proposed Guidelines improperly includes EGUs that were excluded from the proposed new source NSPS. Specifically, EPA has unlawfully included EGUs that meet the new source NSPS's "low fossil use criterion" and its "one-third sales criterion." That action would expand the source category beyond EPA's January 2014 NSPS Proposal, and it is therefore unlawful.

- EPA should abandon the "Broad Applicability" approach to defining the category of sources it would regulate through the Proposed Guidelines. This approach would eliminate many of the applicability criteria that were proposed for new, modified, and reconstructed sources.

The Proposed Guidelines are inconsistent with the Federal Power Act ("FPA"), violate section 310(a) of the CAA, unlawfully encroach on state authority in violation of the Tenth Amendment, and ignore the realities of wholesale electric markets, regional transmission grids, and bulk power system ("BPS") reliability.

- The Proposed Guidelines ignore the careful division of responsibilities embodied in the FPA and unlawfully intrude into the sphere that the FPA reserved for state regulation in violation of the Tenth Amendment of the United States Constitution.

- The Proposed Guidelines violate section 310(a) of the CAA because they conflict and interfere with the Federal Energy Regulatory Commission's ("FERC") exclusive authority under the FPA to: (1) regulate interstate transmission and the wholesale sale of electric energy (sections 205 and 206 of the FPA); (2) promote the voluntary regional coordination of generation and transmission facilities (section 202(a) of the FPA); and (3) ensure reliability of the BPS (section 215 of the FPA).

- EPA has ignored the realities of the FERC-regulated wholesale electric market and the BPS. EPA has engaged in only limited consultation with FERC, which had no role in EPA's assumptions.

- EPA has incorrectly assumed that states can exercise command and control authority over the dispatch of EGUs. EPA has ignored both the conflicts between "environmental dispatch" and FERC's current dispatch policies and the difficulties of changing existing FERC-jurisdictional dispatch regimes to accommodate the Proposed Guidelines.

- FERC commissioners, the North American Electric Reliability Corporation ("NERC"), regional transmission organizations ("RTOs"), and independent system operators ("ISOs") have all noted that EPA has underestimated energy and electricity infrastructure constraints and have all expressed reliability concerns. Finding ways to finance new infrastructure may prove more challenging than EPA has assumed.

- The Proposed Guidelines do not account for the D.C. Circuit's ruling in *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), which limits the ability of demand-side resources to participate in FERC-jurisdictional markets. EPA also incorrectly assumes that all markets managed by regional transmission organizations are "forward capacity markets."

The Proposed Guidelines violate the Fifth Amendment because uncompensated takings of property will result.

- The Proposed Guidelines are unconstitutional because they will result in the taking of property without just compensation. EPA acknowledges that numerous coal- and oil-fired EGUs will need to shut down to comply with this rule, and many coal-fired EGUs that do remain open will have their operations so severely curtailed that it will result in a partial taking.

- The premature retirement of coal- and oil-fired EGUs constitutes a total taking because it will completely deprive the owners of these EGUs of all economically beneficial use of their property.

- The severe restriction in operations of coal- and oil-fired EGUs will also constitute a taking under the test set forth in *Penn Central Transportation Co. v. City of New York*, 438 U.S. 104, 124 (1978). The character of the Proposed Guidelines, their severe economic impacts, and their interference with reasonable investment-backed expectations all weigh in favor of finding a taking.

EPA treads into areas that are quintessentially within the purview of state control in violation of section 111(d).

- Section 111(d) gives states the primary authority to develop standards of performance for existing sources. EPA is limited to establishing procedures for the development and submission of state plans regarding the implementation of the standards of performance. The Proposed Guidelines, by prescribing non-negotiable emission standards, upend this statutory division of responsibility and would limit the significant discretion that states have to vary from EPA's emission guidelines. Case law governing state implementation plans under section 110, which is informative in this context, confirm that EPA cannot second-guess state plans.

- EPA is obligated to establish highly subcategorized emission guidelines within a broad source category like existing fossil fuel-fired EGUs, but it has failed to do so in the Proposed Guidelines.

- EPA touts the "flexibility" the Proposed Guidelines would provide to states, but that flexibility is illusory. In most cases, there is no way for a state to meet its goal without adopting all four Building Blocks and implementing them in line with EPA's assumptions.

ED_000419-0005699

- The Proposed Guidelines conflict with key state laws and constitutions. There is no evidence of congressional intent to authorize EPA to preempt these state laws.

- The selection between a rate-based and mass-based emission goal does not provide any flexibility to states. EPA should confirm that states have authority to perform their own conversions to a mass-based goal and have the flexibility of demonstrating that different methods of making this calculation are appropriate, as was suggested in the preamble to the Proposed Guidelines. The lack of flexibility in Proposed Guidelines' goals should have become apparent to EPA after it calculated draft mass-based goals for each state.

- EPA generally describes four different types of state plans, but does not provide adequate guidance as to what each type should contain. EPA should recognize that states are free to design their plans as they see fit, and EPA cannot limit state discretion.

- The timeframes established in the Proposed Guidelines are too short. Even with the potential extensions EPA has proposed, the timeframe for developing state plans is inadequate. Once plans are approved, states will have very little time to implement the extensive measures required by the rule. Further, most states will be required to take significant action by 2020 in order to comply, obviating the Proposed Guidelines' purported flexibility. At a minimum, EPA should eliminate the interim goals.

- The Proposed Rule suggests achievement demonstrations will require substantial modeling. EPA is not authorized to impose such a requirement. Moreover, EPA is not authorized to require state plans to be "self-correcting" or to impose additional emission reduction requirements as punishment for failure to achieve an emission goal.

- EPA cites no authority to restrict the ability of states to modify their plans. If a modified plan will achieve a state goal, the modification should be allowed.

- Many of the "key considerations" listed in the Proposed Guidelines for states to consider in their plans raise significant concerns.

    - EPA admits that the Proposed Guidelines will be challenging to implement and leaves it to states to determine if entities other than affected EGUs can be included in the program. EPA must resolve the issue of whether entities other than affected EGUs can be included in the program itself.

    - EPA should give the most favorable treatment possible to energy efficiency programs adopted prior to the proposal of the Proposed Guidelines and should ensure adequate recognition and credit is given to states that have already undertaken other significant measures that limit CO_2 emissions.

- EPA's complicated proposed methods for addressing interstate effects demonstrates that the Proposed Guidelines are untethered to the requirements of section 111.

- EPA should allow states broad flexibility to use emission reductions from new natural gas combined cycle ("NGCC") units, including incremental emission reductions beyond what is required of new units under section 111(b), to comply with the Proposed Guidelines.

- EPA cannot limit state consideration of remaining useful life, and EPA has failed to take into account requirements the Agency has imposed under the Regional Haze Program and MATS.

EPA cannot require states to regulate EGUs simultaneously under section 111(b) and section 111(d) of the CAA.

- EPA cannot compel states to regulate an EGU as both an existing and new source. Under the CAA, sources are defined as either new or existing. The terms are mutually exclusive and determine which provisions of the Act apply.

- It would be permissible, however, for a state that employs the rate-based approach under section 111(d) to allow the megawatt hours generated by a newly constructed unit to be included in the denominator for a state's rate.

- EPA's policy reasons for trying to force states to regulate sources under both section 111(b) and section 111(d) are invalid. They do not authorize EPA to rewrite statutory requirements.

EPA has failed to address significant New Source Review ("NSR") issues presented by the Proposed Guidelines.

- The projects contemplated in Building Block 1 to improve heat rates at EGUs have been targeted by EPA and others as triggering NSR.

- EPA asserts incorrectly that there will be few instances when an NSR permit will be required. Although UARG agrees that measures taken to implement Building Block 1 do not trigger the Act's NSR requirements, Attachments A and B to these comments demonstrate that such projects have been challenged as NSR violations by EPA's enforcement arm, by states, and by environmental organizations.

- EPA should eliminate the threat of protracted NSR litigation and provide a clear statement that any upgrades necessary to implement Building Block 1 of EPA's Clean Power Plan do not trigger NSR.

The Proposed Guidelines are not justified by their purported benefits when those benefits are characterized properly.

- EPA never connects the Proposed Guidelines to any impact on climate change, raising questions about the purpose of the rule. The Proposed Guidelines would, if fully implemented, control only about 1 percent of global emissions and do nothing to mitigate climate change.

- EPA has significantly underestimated the costs of the Proposed Guidelines. Because the Building Blocks are based on unreasonable assumptions, they will be much more costly to implement than EPA assumes. EPA has also failed to accurately estimate the impacts of broad disruptions to the economy, energy security, and the reliability of the U.S. power system.

- EPA's cost-benefit analysis is based on the Proposed Guidelines' purported global benefits, but a cost-benefit analysis for domestic policy should examine domestic costs and benefits alone. Analyzing the costs and benefits of the Proposed Guidelines on a domestic basis reveals compliance costs will exceed the purported benefits of EPA's proposal.

- EPA has improperly excluded higher discount rates recommended by the Office of Management and Budget ("OMB") to inflate projected benefits. A proper analysis would likely reduce any estimated benefits to marginal levels.

- EPA has improperly included co-benefits from reductions of pollutants other than CO_2, such as fine particulate matter and ozone, that are regulated to levels protective of public health under other provisions of the CAA.

EPA's calculation of the state goals impermissibly limits the states' discretion and is error-ridden.

- The Agency's goal calculation methodology contains numerous errors, inconsistencies, and oversights that substantially impact each state's goals. EPA has, for instance, applied its BSER Building Blocks to sources that cannot be regulated under section 111(d). EPA's error would force affected NGCC units to operate at capacity factors significantly above 70 percent in order to accommodate the expected generation that states cannot require from non-affected EGUs.

- EPA has failed to account for the electricity that the U.S. imports from non-emitting sources in Canada. If the Proposed Guidelines do not recognize the benefit provided by this imported power, the rule could be construed as an unlawful trade barrier.

- In calculating state goals, EPA improperly assumed that NGCC units that were under construction in 2012 have available generating capacity. EPA has no basis on which to determine what generating capacity from these units will be available for redispatch. These units should not be included in EPA's application of Building Block 2.

- EPA's goal calculation methodology is defective because it applies the measures identified as BSER to sources that do not qualify as "affected EGUs" for the purposes of the Proposed Guidelines. EPA can, and must, examine historical data for existing EGUs in order to determine which units would be exempt from regulation under the one-third sales exclusion before calculating each state's goal.

- EPA's 2012 data regarding existing and under-construction EGUs contain numerous errors and invalid assumptions that affect the Agency's state goal calculations. EPA has: (1) improperly used nameplate capacity to calculate generation available for redispatch from NGCC units; (2) double-counted some NGCC units as both existing and under-construction; (3) identified some under-construction NGCC capacity that does not appear to exist; and (4) improperly counted as "existing" some EGUs that retired or began operation in 2012 or shortly thereafter.

- In calculating the state goals, EPA unreasonably assumes that each state's coal-fired units will emit CO_2 at an average rate that is 6 percent lower than their average rate in 2012, and that NGCC units will emit CO_2 at an average rate that is the same as 2012, even after generation from those EGUs is redispatched under Building Block 2. EPA's Proposed Guidelines will in fact likely increase EGU heat rates.

EPA's assessment of the Building Blocks is seriously flawed.

- Building Block 1, which envisions a 6 percent overall heat rate improvement is unlawful, unachievable, and unsupported by the record. EPA would require efficiency improvements in equipment that is not subject to regulation.

    - EPA's reliance on a 2009 Sargent & Lundy report is misguided. For instance, EPA does not account for the fact that the efficiency benefits associated with the measures identified in the report are highly variable by unit, are not cumulative, and are only temporary. EPA has also overlooked the negative impact on coal-fired EGU efficiency of EGUs' obligations under the remaining components of its proposed BSER and under other CAA programs.

    - EPA's "model" assessing potential heat rate improvements via "best practices" is unfounded, arbitrary, and misleading. EPA does not actually assess the feasibility of a 6 percent heat rate improvement requirement, and EPA has failed to account for unavoidable heat rate variability.

    - EPA's assessment of available heat rate improvements through "equipment upgrades" is arbitrary. EPA erroneously assumed that the heat rate improvements from these upgrades are cumulative and that they provide consistent long-term benefits.

    - EPA's analysis of heat rate improvements at 16 EGUs is deeply flawed. The reported improvements resulted almost exclusively from changes in continuous emission monitoring system ("CEMS") reporting methodology and were not the result of purposeful efforts to improve unit efficiency.

- Building Block 2, which envisions a shift in generation from existing coal- and oil/gas-fired steam EGUs to existing NGCC units until those NGCC units reach a statewide maximum capacity factor of 70 percent, is unachievable.
    - EPA has miscalculated the amount of NGCC generating capacity in each state.
    - EPA has not accounted for factors limiting the ability of EGU owners to increase utilization of their NGCC units, including technical limitations, permit limits, or gas and transmission infrastructure constraints.
    - EPA has assumed that all NGCC units can meet a 70 percent capacity factor without assessing the differences between high- and low-capacity factor NGCC units.
    - EPA's assessment of historic trends does not justify its claim that sufficient infrastructure exists to support Building Block 2.
    - EPA has failed to consider the effect of widespread redispatch to NGCC units on states' ability to meet demand during periods of peak load.
    - EPA's Building Block 2 is based on the faulty premise that generation from any NGCC unit located within a state may be redirected by a utility or state within the state's borders to offset reduced generation from coal-fired units elsewhere in the state. In most states, electric generation is dispatched by an RTO or ISO, which calls up generation from EGUs within its system such that the lowest cost generating sources are dispatched first. Even where electricity dispatch is governed by individual utilities, similar limitations on in-state redispatch arise where a state is served by multiple utilities or where a utility spans multiple states.
    - EPA does not appear to understand how the natural gas system interfaces with the electric system and how that interface impacts reliability.
- The renewable energy generation goals that EPA has calculated for each state in the Proposed Guidelines and applied in Building Block 3 are unachievable.
    - EPA's proposed approach is arbitrary because it does not take each state's actual renewable energy growth potential into account.
    - EPA's own Integrated Planning Model ("IPM") results indicate that renewable energy generation by the end of the compliance period cannot even come close to the renewable energy targets EPA used in its goal calculation.
    - EPA simplifies its analysis of renewable portfolio standards ("RPS") in a manner that inflates renewable energy generation targets. For instance, EPA incorrectly assumes that each state's most stringent primary goals apply to all in-state generation and treats all goals as mandatory.

- EPA's proposed rule would require states to begin implementing the renewable energy portions of their plans in 2017, before many states have even received plan approval from EPA.

- By including nuclear capacity that is under construction or "at risk" in state goals, EPA merely penalizes states that have invested in nuclear generation.

- UARG agrees that natural gas conversion and co-firing are not BSER for coal-fired EGUs and should not be included in determining the proposed emission guidelines.

EPA's October 30, 2014 Notice of Data Availability ("NODA") does not contain any specific EPA proposals or proposed regulatory language and for the most part cannot be included in any final guidelines.

- The NODA contains virtually no "data," and is rather a series of questions and musings about different policies the Agency could employ. The content in this document is more appropriate for an advance notice of proposed rulemaking.

- EPA provided insufficient time to allow stakeholders to provide fully informed and well-considered comments on the NODA. The Proposed Guidelines are extraordinarily complex, and the issues raised in the NODA are broad and seem to contain some approaches that are either new or that contradict its previous positions.

- EPA asks for comment on how Building Block 2 could be expanded to include new NGCCs and natural gas co-firing at existing coal-fired boilers. This is not formally proposed in the NODA and EPA cannot finalize this approach. Moreover, EPA has no authority under section 111(d) to impose federally enforceable obligations on new sources or to require the construction of a new source. The suggestion that natural gas co-firing can be designated as BSER is wrong as both a matter of fact and of rulemaking procedure.

- If the final emission guidelines contain interim goals, which UARG does not support, then they should be flexible and allow states to comply using a reasonable "glide path." Each state should have the authority to define its own glide path using criteria such as costs, energy impacts, and remaining useful life. Allowing the interim goals to be met using a glide path would be a logical outgrowth of the Proposed Guidelines. States should be allowed to determine the timing and to have a gradual phase-in of Building Blocks 1 and 2.

- The regionalized approach to Building Block 3 and the regional approach to redispatch under Building Block 2 were not included in the Proposed Guidelines and are not actually proposed in the NODA. There is insufficient information such as technical analyses and the other items required by section 307(d)(3) of the CAA that would allow UARG to comment on these approaches in a meaningful way.

- The NODA solicits comment on EPA's goal-setting methodology but does not actually propose this change in the NODA, and EPA cannot finalize it as part of any

final emission guidelines. UARG opposes this approach for three reasons: (1) EPA has no authority to establish a standard of performance based on reduced utilization or retirement of a source; (2) if EPA wants to pursue such a dramatic change, it must undertake a thorough evaluation of costs and other implications, as required by section 307(d)(3), and allow UARG sufficient time to evaluate and comment on those studies; and (3) this is a nonsensical approach to EPA's overarching goal of reducing fossil fuel-fired generation because it would have the counterintuitive effect of encouraging the construction of new fossil fuel-fired EGUs.

EPA must revise the Proposed Guidelines to address problems with the monitoring, recordkeeping, and reporting provisions for EGUs.

- EPA's proposed regulatory language regarding EGU monitoring, recordkeeping, and reporting provisions in some cases is overly broad or duplicative.

- UARG objects to the proposed elimination of one of the Part 75 monitoring options and the proposed imposition of additional measurement requirements on existing units. EPA has provided no justification for requiring EGUs to perform monitoring that is different from, let alone more stringent than, Part 75. The proposed requirement to measure stack diameter at three distinct locations may not even be possible without installing new sampling ports. UARG also objects to the Agency's failure to make clear that use of Part 75 missing data substitution procedures is not appropriate in compliance calculations.

- EPA proposes that affected EGUs also could report hourly net electric generation under Part 75 via an Emission Collection and Monitoring Plan System ("ECMPS"). It is not clear whether EPA is proposing that Part 75 be revised to simply provide a mechanism for such reporting in the event a state chooses to require or allow it, or whether EPA is suggesting that source reporting under Part 75 be required to report net electric generation. UARG would oppose the latter requirement.

- For integrated equipment that is not monitored under Part 75 or an NSPS, UARG suggests that EPA include a provision allowing submission and approval of a petition for exemption from the compliance calculation of any de minimis CO_2 emissions, or for an alternative means of accounting for any resulting emissions. Because use of such equipment, which either has very few emissions or operates very infrequently, is uncertain, the Agency should not spend resources specifying monitoring requirements in the rule.

- If EPA intends sources to include partial unit operating hours in compliance calculations, the output values already being reported under Part 75 (in megawatts ("MW") or steam load) will need some adjustment for use in EPA's proposed compliance calculations. EPA should clarify whether it intends that partial hours be included in state calculations. And, if EPA anticipates that states rely on data reported to ECMPS, EPA must address the discrepancies.

- EPA has not justified the proposed burdensome requirement to comply with the American National Standards Institute ("ANSI") 2010 C12.20 standard for electricity meters in this rulemaking.

- UARG agrees that if EPA requires the monitoring of net electric output, the Agency must allow EGUs to use existing equipment and methods for metering station service, and to apportion common station service to individual units using unit generation.

- Combined heat and power ("CHP") facilities should not be required to employ any specific technology or quality assurance ("QA") procedures for equipment used to measure useful thermal output. Appropriate technologies and procedure vary according to application, and any gains in accuracy from employing different technologies or procedures likely would be insignificant relative to other uncertainties in EPA's calculation of creditable output.

- UARG does not believe that there is any benefit to including equipment used to measure electric and energy output in the Part 75 monitoring plan or to requiring additional quality assurance and quality control ("QA/QC") for that equipment. EGUs already have sufficient incentives to ensure that their equipment for measuring output is accurate, and EPA has not provided any information to suggest that additional QA is warranted.

- EGUs should be allowed to choose which version of the flow method is best for the particular application and should not be required to perform 3-D testing where it is not needed. With respect to EPA's suggestion that it might develop "adjustment factors" that would be applied if an EGU changed flow methods, EPA has not provided sufficient information for UARG to comment on the reasonableness of such a requirement. As a result, UARG opposes it. To proceed with that approach, EPA would need to issue a more complete rulemaking proposal.

- UARG opposes the proposed ten-year record retention period for supporting information, unless EPA can show a special need as required under Paperwork Reduction Act regulations. UARG also opposes the proposed on-site requirement if it means that electronic records that can be accessed "onsite" (even if they are physically located offsite) would not be sufficient.

III. The Proposed Guidelines Are Fundamentally Divorced from the Narrow and Exclusive Focus of Section 111 of the CAA on Stationary Sources in Listed Source Categories.

Section 111 of the CAA speaks with absolute clarity as to the subject and nature of standards of performance for new and existing sources. A standard of performance under section 111 must be achievable for individual sources based on measures that the source's owner can integrate into the design or production process of the source itself. Section 111 has existed, with

only minor changes, for over 40 years, and in that time EPA has applied it with total consistency on this fundamental point. A standard of performance cannot be based on actions taken beyond the source itself that somehow reduce the source's utilization. Nor can it be based simply on requiring a source to reduce its operations.

Yet EPA is proposing a rule that departs so far from the Act's clear directions as to be unrecognizable as a section 111 rulemaking. The Agency's proposed approach has inverted the lawful order of standard-setting under section 111. Instead of defining a category of regulated sources, identifying the BSER that any individual source can incorporate into its design, and then allowing states to determine what standards are achievable for sources based on that BSER and other factors, EPA has started at the end by defining an inflexible emissions goal for each state and then requiring states to impose whatever obligations are necessary to achieve that goal. To effectuate this unprecedented approach, EPA proposes to base its "emission guidelines" on actions that reach beyond individual regulated sources and impose obligations on entities with no emissions at all, or to simply mandate that regulated sources curtail operations or cease operations altogether. EPA's proposed approach has no basis in the statute. Indeed, it defies reason and is flatly inconsistent with the CAA and with the Agency's own 40-year history of consistently contrary implementation. EPA has exceeded its authority and must withdraw the Proposed Guidelines.

A. Section 111 Authorizes Standards of Performance That Are Achievable for Individual Sources in a Source Category Based on Measures Those Sources Can Implement Themselves.

To fully appreciate how dramatically EPA has departed from its authority in this rulemaking, one must first understand the nature and limits of the CAA's section 111 regulatory program as it has been defined by the text of that provision, by its context within the remainder of the CAA, and by 44 years of consistent EPA implementation. This program begins and ends

ED_000419-0005708

with the regulated source itself. It provides for the regulation of individual emission sources through performance standards that are based on what design or process changes an individual source's owner can integrate into its facility. The nature of any standard of performance under section 111 is that, at a given level of operations, the regulated source emits less when subject to the standard than when not.

1. The Text of Section 111

Section 111's regulatory program is narrow, limited, and ultimately quite simple. Under section 111(b), EPA is to publish "a list of categories of stationary sources" that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 111(b)(1)(A). Once EPA lists a source category, the Agency "establish[es] Federal standards of performance for new sources within such category." *Id.* § 111(b)(1)(B). Meanwhile, under section 111(d), EPA is also directed to

> establish a procedure . . . under which each State shall submit to the Administrator a plan which . . . establishes standards of performance for any existing source for any air pollutant . . . to which a standard of performance under [section 111] would apply if such existing source were a new source.

Id. § 111(d)(1). In other words, after EPA promulgates an NSPS for new sources in a category under section 111(b), EPA may require states to develop plans adopting standards of performance that apply to existing sources in that category under section 111(d). Under EPA's Subpart B regulations, which implement section 111(d), the Agency publishes emission guidelines to inform the states' development and submittal of these state plans. *See* 40 C.F.R. §§ 60.20-60.29.

The statute adopts the same definition of "standard of performance" for both new and existing sources:

> 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 (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

CAA § 111(a)(1). Thus, the Administrator's analysis for establishing standards of performance for new sources will inform a state's development of a plan establishing performance standards for existing sources. The actual standards for existing sources in a category will typically differ, however, from the new source standards developed by EPA due to the disparate costs, energy impacts, and other factors associated with regulating each. *See* 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975) (promulgating and explaining Subpart B). In addition, the CAA directs states (and EPA, in the case of a federal plan) to consider, "*among other factors*, the remaining useful life of the existing source to which such standard applies" when adopting standards of performance for existing sources. CAA § 111(d)(1) (emphasis added).

On its face, section 111 provides only for standards that regulate the emissions performance of individual stationary sources in a category listed under section 111(b). The plain text of this section makes it clear that standards of performance apply to sources within listed categories as individual facilities and do not regulate categories or subcategories as a whole: NSPS apply only to "new sources within [a listed] category," while state standards under section 111(d) apply to "any existing source . . . to which a [NSPS] . . . would apply if such existing source were a new source." *Id.* § 111(b)(1)(B), (d)(1). Further, the Act narrowly confines the stationary sources that may be regulated under section 111 to any individual "building, structure, facility, or installation which emits or may emit any air pollutant." *Id.* § 111(a)(3). This definition notably does not extend to combinations of these facilities or to other non-emitting entities. *See ASARCO*, 578 F.2d at 319. In addition, section 111(d) explicitly directs states (and EPA, in the case of a federal plan) to consider the "remaining useful life" of existing sources

ED_000419-0005710

when applying any standard of performance, further demonstrating that this section focuses solely on what individual sources can do to improve their performance at reasonable cost rather than what the entire source category (or even other entities) can do collectively to reduce overall emissions. CAA § 111(d)(1), (d)(2). Even the titles used in these provisions indicate their narrow focus on individual sources. Section 111 is titled "[s]tandards of performance for new stationary sources," and section 111(d) is designated "[s]tandards of performance for existing sources; remaining useful life of source." *Id.* § 111, 111(d).

Importantly, section 111 also requires that any standard of performance be "achievable" by the sources to which it applies based on application of an "adequately demonstrated" system of emission reduction. *Id.* § 111(a)(1). The achievability requirement clearly indicates that Congress intended standards of performance to be based on systems of emission reduction that are within the control of (and thus, incorporated into the design or production process of) an individual source. A standard cannot be "achievable" for a source if the source must rely on measures taken by some other entity that it does not control, or if the source must not operate, in order to achieve the standard. Moreover, a "standard of performance" by its terms assumes that the source will continue to "perform." A "standard of performance" cannot mandate "non-performance."

This focus on measures incorporated into individual sources pervades other parts of section 111 as well. For example, section 111(h) authorizes EPA to promulgate a design, equipment, work practice, or operational standard in cases where "it is not feasible to prescribe or enforce a standard of performance," and defines exactly when Congress considered it "not

ED_000419-0005711

feasible" to establish a standard of performance.[4] *Id.* § 111(h)(1). One such situation is where the regulated pollutant "cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant." *Id.* § 111(h)(2)(A). This provision equates a "standard of performance" with the use of a conveyance at the regulated source to capture and to control a portion of the source's emissions.

2. CAA Context for Section 111

The CAA's other provisions confirm the narrow scope of what and how EPA may regulate under section 111. Nothing in the remainder of the Act authorizes EPA to regulate emissions from stationary sources by basing standards of performance on measures that are not implemented by the regulated source itself. Likewise, there is no provision of the CAA under which the Agency may base a standard of performance on reduced operations. Standards of performance cannot be based on enforceable limitations on hours of operation or on electricity production.

---

[4] EPA invites comment on whether it can include in its BSER determination (and allow state plans to require) "design, equipment, work practice, or operational standard[s]" under its section 111(d) program. 79 Fed. Reg. at 34,926-27. If EPA finalizes the Proposed Guidelines as a conventional section 111(d) program, it may not. Congress specifically excluded these methods from the definition of "standard of performance" under section 111(a)(1) and relegated them under section 111(h) as an "alternative" in instances where standards of performance are not "feasible." CAA § 111(h)(1) ("[I]f in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, [s]he may *instead* promulgate a design, equipment, work practice, or operational standard, or combination thereof . . . .") (emphasis added). If EPA decides to promulgate work practice or operational standard-based emission guidelines for existing fossil fuel-fired EGUs at some point in the future (after notice-and-comment rulemaking in a separate proceeding), then it must make the section 111(h) findings that are preconditions to setting a section 111(h) standard and then adhere to the requirements of section 111(h), which mandate that a section 111(h) standard be feasible, reflect the best technological system of continuous emission reduction, be cost-effective, and adequately demonstrated. *See id.* § 111(h).

ED_000419-0005712

The CAA's other programs establishing emission standards for new and existing sources focus solely on achieving emission reductions at individual sources. These programs regulate emissions from sources based on what other individual sources can or already have achieved. For example, emission standards for hazardous air pollutants must be based on the maximum achievable control technology and reflect the application of "measures, processes, methods, systems or techniques" directly to individual sources.[5] *Id.* § 112(d)(2). Standards for visibility-impairing pollutants must reflect the "best available retrofit technology . . . for controlling emissions from [each eligible] source," considering the costs, existing control technology, and remaining useful life for that source. *Id.* § 169A(b)(2)(A). And under the CAA's PSD program, new and modified sources must implement the "best available control technology" ("BACT"), which the permitting authority must identify on a case-by-case basis for each source and which must reflect "application of production processes and available methods, systems, and techniques" at the source. *Id.* §§ 165(a)(4), 169(3). Although a source may accept operational limits in its preconstruction permit under the PSD provisions in order to avoid qualifying as a "major emitting facility" and having to implement BACT, under no circumstances may the BACT standard itself be based on reduced utilization of the unit. *See id.* § 169(3), 40 C.F.R. § 52.21(b)(12).

The BACT program is particularly relevant as evidence of section 111's scope because Congress explicitly tied the BACT emission standards to section 111. Standards of performance

---

[5] These measures include those that: "(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications, (B) enclose systems or processes to eliminate emissions, (C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point, (D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) . . ., or (E) are a combination of the above." CAA § 112(d)(2). Notably, all of these measures can be implemented at an individual source.

ED_000419-0005713

under section 111 provide a regulatory floor for BACT standards. CAA § 169(3). But if a standard of performance relies on a "system of emission reduction" that goes beyond the source itself, it cannot meaningfully inform a BACT standard for sources in that category.

In contrast, in the few regulatory programs where Congress did authorize emission control measures that go beyond a specific source for the purpose of meeting aggregate emission reduction goals, it spoke clearly and precisely. For example, when Congress took action in the 1990 CAA Amendments to cap sulfur dioxide emissions and establish a program for emissions allowances and trading, it added an entirely new title to the Act (Title IV) spelling out the requirements and implementation procedures for that program in great detail. *See id.* §§ 401-416. Unlike Title I of the CAA, in which section 111 is found, Congress's statement of purpose in Title IV specifically includes "encourag[ing] energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of this subchapter, for reducing air pollution." *Id.* § 401(b). Congress also gave EPA explicit instructions on how to credit sources for compliance with emission requirements based on avoided emissions from renewable energy and energy conservation. *Id.* § 404(f). Section 111 contains no such instructions.

Likewise, the CAA's provisions regarding implementation of the national ambient air quality standards ("NAAQS") authorize states to take broad measures to attain and maintain compliance with those standards, and even contemplate that some existing stationary sources may need to reduce operations or retire in order for an area to achieve those standards. *See id.* § 110. But in establishing the NAAQS program, Congress explicitly authorized EPA to promulgate health-based standards for ambient concentrations of certain pollutants at a level "requisite to protect the public health" with "an adequate margin of safety." *Id.* § 109(b). And

ED_000419-0005714

Congress directed states to enact any "emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights) . . . as may be necessary or appropriate to meet" these standards, without singling out for regulation any specific sources of the regulated pollutants. *Id.* § 110(a)(2)(A).

In contrast, section 111 regulates emissions from specific *sources*, not overall concentrations or amounts of *pollutants*. Its technology-based standards of performance are driven by what emission limitation those sources can achieve during their performance at reasonable cost, using adequately demonstrated measures, rather than by requirements dictated by public health or welfare.

3. The History of EPA's Implementation of Section 111

EPA's long and consistent history of implementing section 111 confirms the plain language of the statute and has also given shape to this regulatory program. The Agency's past rulemakings reflect the program's singular focus on individual sources. In fact, in the 44-year history of the Act, EPA has limited the scope of section 111 to the regulated source in *every rulemaking it has undertaken*.

First, the Agency's 1975 Subpart B regulations—in which EPA established a procedural framework for states to adopt standards of performance for existing sources—share the statute's exclusive focus on standards that are achievable by individual sources. Subpart B directs EPA to publish a "guideline document containing information pertinent to control of the designated pollutant form [*sic*] *designated facilities* [i.e., existing sources subject to regulation under section 111(d)]." 40 C.F.R. § 60.22(a) (emphasis added). Echoing the statutory text, emission guidelines under Subpart B must "reflect[] the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated *for designated facilities*." *Id.* § 60.22(b)(5) (emphasis added). Acknowledging section 111's

statutory command to consider the "remaining useful life" of regulated existing sources, Subpart B also notes that states may tailor standards of performance for individual designated facilities to account for "[u]nreasonable cost of control resulting from plant age, location, or basic process design," "[p]hysical impossibility of installing necessary control equipment," or "[o]ther factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable." *Id.* § 60.24(f). In adopting this provision, EPA noted that such flexibility to depart from emission guidelines was necessary because "controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases." 40 Fed. Reg. at 53,344. This discretion reflects Subpart B's focus on identifying what emission reductions individual existing sources can achieve themselves.

Subpart B also specifies that compliance with any state standard of performance for existing sources will be shown through a series of "[i]ncrements of progress," which are "steps to achieve compliance which must be taken by an owner or operator of a designated facility." 40 C.F.R. § 60.21(h). These increments of progress include awarding contracts, initiating on-site construction or installation, and completing on-site construction or installation of emission control equipment or process changes. Thus, Subpart B makes clear that compliance with standards of performance is achieved through on-site measures taken by regulated sources.

Second, out of the nearly 100 NSPS and emission guidelines EPA has promulgated and subsequently revised since 1970, *every single standard of performance* has been based on a "system of emission reduction" that is incorporated into the design or operation of individual sources. For example, when the Agency promulgated and later revised NSPS for kraft pulp mills, it never considered basing the standard of performance on requiring increased use of

recycled paper to reduce kraft pulp mill operations, even though such a measure arguably would have reduced emissions from kraft pulp mills. *See* 43 Fed. Reg. 7568 (Feb. 23, 1978); 79 Fed. Reg. 18,952 (Apr. 4, 2014). Likewise, on each past occasion in which EPA has promulgated or revised NSPS for the categories of EGUs at issue in this proposed rulemaking—a timeframe spanning from 1971 to 2012—the Agency's analysis has focused entirely on the use of emission control technology or low-sulfur fuels at individual sources.[6] Despite pervasively regulating EGUs under section 111 over the past forty years, EPA has never before even considered basing a standard of performance for emissions from these sources on reduced utilization or shifting generation to lower-emitting sources. Nor has EPA's focus on individual sources changed in recent years. In an NSPS rulemaking that took place *just weeks* after the Proposed Guidelines were published, EPA once again reaffirmed that standards of performance "apply to sources" and must be "based on the BSER *achievable at that source*." 79 Fed. Reg. 36,880, 36,885 (June 30, 2014) (emphasis added).

Because of the nature of section 111(d), EPA has conducted very few rulemakings under that provision. But on the few occasions that EPA has issued emission guidelines for existing sources, it has maintained the same focus on measures that the regulated source can incorporate into its design or otherwise implement by itself. Adopting the same approach is not only appropriate but required, given that the CAA defines "standard of performance" identically for new and existing sources. Since 1970, EPA has only published valid emission guidelines under section 111(d) for five source categories, and in all five of these rulemakings the emission

---

[6] *See, e.g.*, 36 Fed. Reg. 24,876 (Dec. 23, 1971) (promulgating Subpart D); 44 Fed. Reg. 33,580 (June 11, 1979) (promulgating Subpart Da); 44 Fed. Reg. 52,792 (Sept. 10, 1979) (promulgating Subpart GG); 63 Fed. Reg. 49,442 (Sept. 16, 1998) (amending Subpart Da); 71 Fed. Reg. 38,482 (July 6, 2006) (promulgating Subpart KKKK); 77 Fed. Reg. 9304 (Feb. 16, 2012) (amending Subpart Da).

ED_000419-0005717

guidelines were based on the application of pollution control technology or other process controls at individual sources.[7] Even EPA's short-lived CAMR under section 111(d) did not adopt a broader approach to establishing standards of performance. Although CAMR did authorize an emissions trading program as a tool for *compliance* with standards of performance, the "system of emission reduction" that was used to set the emission guidelines themselves was limited to pollution control technology that could be installed at individual sources. 70 Fed. Reg. at 28,617-20, 28,621 (final guideline was "based on the level of Hg emissions reductions that will be achievable by the combined use of co-benefit (CAIR) and Hg-specific controls").

In sum, the plain text of section 111 of the CAA establishes a program that is focused on reducing the rate of emissions from new and existing stationary sources through the application of systems that can be integrated into the design or operation of the source itself. The overall context of the CAA and EPA's unwavering commitment to this approach outside of the present rulemaking confirm this focus. The notion that a source must be able to comply with a standard of performance through measures under its own control is so fundamental to section 111 that it pervades every aspect of that provision's language and history of implementation.

---

[7] 41 Fed. Reg. 19,585 (May 12, 1976) (guidelines for phosphate fertilizer plants based on "spray cross-flow packed scrubbers"); 41 Fed. Reg. 48,706 (Nov. 4, 1976) (guidelines for sulfuric acid production units based on "fiber mist eliminators"); 43 Fed. Reg. 7597 (Feb. 23, 1978) (guidelines for kraft pulp mills based on process controls and two-stage black liquor oxidation system); 45 Fed. Reg. 26,294 (Apr. 17, 1980) (guidelines for primary aluminum plants based on "effective collection of emissions, followed by efficient fluoride removal by dry scrubbers or by wet scrubbers"); 61 Fed. Reg. 9905, 9907 (Mar. 12, 1996) (guidelines for municipal solid waste landfills based on "(1) [a] well-designed and well-operated gas collection system and (2) a control device capable of reducing [non-methane organic compounds] in the collected gas by 98 weight-percent").

ED_000419-0005718

B. EPA's Proposed Action Deviates So Far from the CAA as To Be Unrecognizable as an Exercise of Section 111 Authority.

The broad program of energy resource management and economy-wide demand reduction that EPA proposes to create and administer in this rule bears no resemblance to the source-focused regulatory program that Congress established in section 111 and that EPA has consistently implemented over the past four decades. In the Proposed Guidelines, the Agency has defied precedent and logic by rewriting some parts of the Act and completely ignoring others in order to embark on a "multiyear voyage of discovery" that far exceeds EPA's lawful authority. *See UARG v. EPA*, 134 S. Ct. at 2446.

Indeed, as noted in the introduction to this section of UARG's comments, EPA's proposal would invert the Act's regulatory process under section 111 for controlling emissions from existing sources. In the lawful course of regulation, reducing emissions from existing sources under section 111(d) would proceed such that: (1) EPA specifies a source category and identifies achievable source-based performance measures that can reduce sources' emissions through design or process changes; (2) the state determines which measures are appropriate for particular sources based on cost, remaining useful life, and other factors; (3) individual regulated sources implement those measures based on standards of performance promulgated by states; and (4) emission reductions result from individual sources operating at a reduced emission rate. Yet EPA's Proposed Guidelines would begin at the end, by mandating a specific level of CO_2 emissions from each state at the outset, and only deviate farther from the Act from there. EPA's approach is that: (1) the Agency specifies a permissible CO_2 emissions rate for each state expressed in lb/MWh; (2) the state determines what entities—whether EGUs or other commercial, institutional, corporate, or governmental entities—it will subject to enforceable obligations; and (3) the state requires a broad and undefined range of emission-reducing or

operational measures at those entities as necessary to achieve the desired emissions level. This backwards approach plainly exceeds the Agency's authority under the CAA.

Nearly every aspect of the Proposed Guidelines is inconsistent with the Act and with EPA's binding legislative rules. In particular, the Agency's radical redefinition of what measures may constitute a "system of emission reduction" is plainly impermissible in light of section 111's exclusive focus on what individual sources can achieve and the past four decades of contrary implementation. Likewise, EPA's claim that it may apply BSER to a state as a whole rather than to individual sources in a source category lacks any legal merit. And, finally, the fact that the Proposed Guidelines' required emission reductions cannot be enforced without dramatically expanding the universe of entities subject to obligations under section 111 underscores the extent to which EPA has strayed from the scope of regulation permitted under the CAA. Together, these defects reflect the Agency's disregard for the statutory and administrative bounds of its own authority. The Proposed Guidelines "would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization," and therefore it must be withdrawn. *Id.* at 2444.

1. EPA's Proposed Guidelines Impermissibly Base Standards of Performance on Measures that Go Beyond the Regulated Source.

Perhaps the most fundamental departure from the law in EPA's Proposed Guidelines is the Agency's assertion that the "best system of emission reduction" for the sources in a designated source category under section 111 may include measures that would (either directly or indirectly) reduce a source's utilization and that are not within the control of individual sources. Of the four "building blocks" that make up EPA's proposed statewide BSER for existing EGUs, only Building Block 1 (heat rate improvements at coal-fired EGUs) falls within the scope of measures contemplated in the Act and could therefore provide the foundation for a

ED_000419-0005720

legally defensible emission guideline. The others—mandating redispatch of generation from coal-fired units to NGCC units, displacing generation from affected EGUs with generation from renewable energy sources, and reducing electricity demand through energy efficiency measures—all impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators. The measures in Building Blocks 2, 3, and 4 are all based on implementation of statewide energy policies that would confiscate the available generating capacity of existing EGUs. Indeed, the Proposed Guidelines impose undefined regulatory obligations on a broad swath of unspecified "affected entities" in addition to the fossil fuel-fired EGUs that are the source category for this rule. Many of these "affected entities" do not emit CO_2 in any appreciable amount. This "beyond-the-source" approach would allow EPA to restructure every aspect of the states' electric power markets and regulate any electricity user—effectively, to administer the entire national economy—for the purposes of reducing demand for and generation by sources in the listed source category (i.e., existing fossil fuel-fired EGUs). This is impermissible and would transform section 111 into something untethered to its statutory language and unrecognizable to the Congress that created it.

The genesis of this novel claim to regulatory power lies in the Agency's attempt to rewrite what constitutes a "system of emission reduction" for the purposes of section 111. As noted above, under that section, a standard of performance must "reflect[] the degree of emission limitation achievable through the application of the best *system of emission reduction*" that has been adequately demonstrated for sources in the regulated category. CAA § 111(a)(1) (emphasis added). In this rulemaking, however, EPA "claims to [have] discover[ed] in [this] long-extant statute an unheralded power to regulate 'a significant portion of the American economy,'" a

practice that courts have looked upon skeptically in the past. *UARG v. EPA*, 134 S. Ct. at 2444. EPA asserts here that because the word "system" is not explicitly defined in the CAA, the Agency may freely apply that word's abstract dictionary definition: "'a *set of things* working together as parts of a mechanism or interconnecting network; a complex whole.'" *Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units* at 51 (undated) (emphasis added), Docket ID No. EPA-HQ-OAR-2013-0602-0419 ("EPA Legal Memorandum"). EPA applies this definition in the abstract to conclude that a "system of emission reduction" can be "virtually *any 'set of things'* that reduce emissions," including anything from "add-on controls . . . to measures that replace production or generation at the affected sources." *Id.* at 51-52 (emphasis added). The Agency even claims that it may require "reduced utilization" of a source as part of a "system of emission reduction," presumably including a prohibition on utilizing a specific regulated source. *Id.* at 79; 79 Fed. Reg. at 34,889.

The breadth of EPA's unprecedented assertion of authority is staggering, particularly in light of section 111's singular focus on regulating individual sources of emissions. Under EPA's asserted definition of a "system of emission reduction," standards of performance for sources in a regulated source category would become a mere pretext for imposing a wide range of demand-reducing obligations on countless entities across the entire nation. Under EPA's interpretation, EPA would be able to require any "affected entity" to implement any "set of things" that the Agency believes would reduce the operation of sources in the listed source category—and hence emissions from that category—no matter how far removed the required actions are from the source itself.

In the context of EGUs, these measures could include anything from capping annual generation from certain EGUs, to ordering the shutdown of some EGUs or other affected entities

ED_000419-0005722

altogether, to regulating how individuals use electricity or consume other goods and services that require electricity. Applying this "beyond-the-source" approach to other source categories—as this rulemaking suggests EPA is likely to attempt—leads to similarly expansive outcomes. For example, this approach could lead EPA to adopt standards of performance for kraft pulp mills that are based on efforts to reduce demand for new paper, such as requiring office buildings to implement paper recycling programs or encouraging credit card companies to provide paperless billing to customers. Or it could allow EPA to adopt standards of performance for oil and gas production facilities that are based on reducing demand for gasoline, such as mandating carpooling programs or requiring additional state investments in public transportation infrastructure.

These beyond-the-source measures are inconsistent with the regulatory program Congress provided for in section 111 of the CAA. Although the dictionary definition of "system," if considered in the abstract and devoid of any statutory or historical context, might theoretically embrace statewide, regional, or even national reduction programs, the word as used in section 111 can refer only to reductions resulting from measures that are incorporated into the source itself. EPA's claim that nothing in the language or context of section 111 limits the Agency's expansive redefinition of "system of emission reduction" is patently false, and it suggests that EPA has ignored the statute and its own past rulemakings. *See* EPA Legal Memorandum at 51-52. Indeed, section 111's clear focus on measures that are achievable by the regulated source itself pervades every aspect of that provision's language, its statutory context, and EPA's legislative rulemakings implementing that provision. As described above in Section III.A, section 111 is a narrow program designed to improve the emissions performance of new and existing sources in specific categories based on the application of *achievable* measures

ED_000419-0005723

implemented in the *design or production process of the source* at reasonable cost. EPA completely ignored these factors when addressing the meaning of the word "system" as it is used in section 111, and in developing its proposed BSER. Building Blocks 2, 3, and 4 of the proposed BSER are based on beyond-the-source measures that cannot be achieved by individual sources, and accordingly, they cannot be used to support a rulemaking under section 111 of the CAA.

As noted above, section 111 requires that emission guidelines and standards of performance be "achievable" by "*any* existing source" in the regulated category—not by only some sources, by a state, or by the category in the aggregate or in combination with other "entities." An emission guideline that requires regulated sources to obtain emission reductions offsite in order to comply with an otherwise unachievable standard would unambiguously contravene the plain text of the CAA. Yet EPA failed to acknowledge how the achievability requirement limits the systems of emission reduction that may provide the basis for section 111 regulation. Building Blocks 2, 3, and 4 of the proposed BSER require measures that go beyond individual existing EGUs. The owner of an individual coal-fired utility boiler cannot control the dispatch of NGCC units relative to other fossil fuel-fired EGUs. Nor can it make changes in the design or production process of its boiler to generate renewable energy or to lead consumers to use less electricity. Therefore, Building Blocks 2, 3, and 4 cannot support an achievable emission guideline.

Indeed, when EPA has attempted in the past to group individual sources together for the purposes of applying standards of performance, these attempts have been soundly rejected by the courts. *See ASARCO*, 578 F.2d at 327. In *ASARCO*, the D.C. Circuit invalidated EPA's attempt to "change the basic unit to which the NSPSs apply from a *single* building, structure, facility, or

ED_000419-0005724

installation—the unit prescribed in the statute—to a *combination* of such units," holding that EPA "has no authority to rewrite the statute in this fashion." *Id.* (emphasis in original). The Agency must be "guided by a reasoned application of the terms of the statute it is charged to enforce, not by an abstract 'dictionary' definition." *Id.* at 324 n.17. If the Agency is concerned about the need for flexibility in order for sources to comply with a standard, the solution is to alter the *stringency* of the standard rather than the *scope* of the source to which that standard applies. *Id.* at 328-29.

Moreover, EPA failed to acknowledge the other ways in which the language and overall statutory context of section 111 render its beyond-the-source approach unreasonable. It is a "fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme." *UARG v. EPA*, 134 S. Ct. at 2441 (internal quotation marks omitted). Yet EPA myopically limits its discussion of the "context in which . . . 'system of emission reduction' is found" to section 111(d)(1) of the CAA in isolation, and states that nothing in that subsection constrains the Agency from applying a beyond-the-source regulatory approach. EPA Legal Memorandum at 52. As an initial matter, this conclusion is simply inaccurate. Section 111(d)(1) specifies that its standards of performance must apply to "any existing source" and directs states to account for the remaining useful life of each regulated source when applying these standards to the source, demonstrating that section 111(d) is concerned with achievable measures that *individual sources* can take to reduce their rate of emissions. But more importantly, it is unreasonable for EPA to limit the context of this statutory provision to a single paragraph in section 111, or even to a single section of the CAA, particularly when that term is used repeatedly throughout the Act. As discussed above, section 111 unambiguously limits standards of performance, and thus the systems of

ED_000419-0005725

emission reduction on which they are based, to individual sources. Likewise, the CAA's other similar programs for regulating emissions from stationary sources—including programs for hazardous air pollutants, visibility-impairing pollutants, and prevention of significant deterioration of air quality—are limited to measures incorporated into the design or production processes of individual sources.

Nowhere in the Proposed Guidelines does EPA acknowledge that its claimed authority to base standards on beyond-the-source measures fundamentally conflicts with its entire 44-year history of rulemaking under section 111. EPA's Subpart B regulations speak exclusively in terms of requirements that apply to, and are implemented by, individual designated facilities. Emission guidelines must be based on "the application of the best system of emission reduction . . . that has been adequately demonstrated for *designated facilities*," and EPA committed itself to address "different sizes, types, and classes" of existing sources by "specify[ing] different emission guidelines or compliance times" when "costs of control, physical limitations, geographical location, or similar factors" warrant the application of different guidelines. 40 C.F.R. § 60.22(b)(5) (emphasis added). In addition, *every single NSPS or emission guideline* that EPA has ever issued—spanning over four decades, multiple comprehensive amendments to the CAA, and nearly 100 subparts within EPA's regulations—has been based on measures that individual sources can implement through design or process measures at the source itself.

The Agency's only reference to precedent is to note that some of its emission guidelines for municipal waste combustors, which were promulgated jointly under sections 111 and 129 of the CAA, have included provisions concerning emission rate averaging, tradable emission credits, and waste management plans. EPA Legal Memorandum at 63. These rules do not support the position EPA has adopted in the Proposed Guidelines. Contrary to the Agency's

ED_000419-0005726

implication, none of the emission guidelines for municipal waste combustors were based on measures similar to Building Blocks 2, 3, and 4. Rather, the emission guidelines for existing hospital/medical/infectious waste incinerators were based on "good combustion" and wet scrubbers of varying efficiency levels, 62 Fed. Reg. 48,348, 48,371 (Sept. 15, 1997), while the emission guideline for existing commercial and industrial solid waste incinerators was based on "the use of a wet scrubbing system, or other equivalent emission control technology," 65 Fed. Reg. 75,338, 75,344 (Dec. 1, 2000). Critically, the emission rate averaging and tradable emission credits that EPA included in its emission guidelines for municipal waste combustors were merely flexible *compliance* tools and were not used to determine the stringency of the *standard itself*, as EPA seeks to do here. Thus, these rulemakings only serve to *reinforce*—not to contradict—section 111's narrow focus on measures that individual sources can implement (and have implemented in the past). This focus is unsurprising in joint rulemaking under sections 111 and 129, given that standards of performance under both provisions are required to reflect the "*degree* of reduction in emissions of air pollutants" that the Administrator determines is "*achievable*" for individual sources. *Compare* CAA § 111(a)(1) *with* CAA § 129(a)(2) (emphases added).

EPA also points to the now-defunct emission guidelines under CAMR as an example of regulations under section 111 that EPA claims are based on a beyond-the-source emission trading program. EPA Legal Memorandum at 63 n.51. But like the emission guidelines for municipal waste combustors described above, CAMR's trading program was merely a tool for compliance: the actual standards were set based on the application of pollution control technology at individual EGUs. The systems of emission reduction that were used to set CAMR's emission guidelines were (1) the co-benefit mercury reductions of installing scrubbers

ED_000419-0005727

and selective catalytic reduction ("SCR") at individual units under the Clean Air Interstate Rule ("CAIR") (for the first phase of CAMR) and (2) the installation of mercury-specific pollution control technologies such as activated carbon injection (for the second phase). 70 Fed. Reg. at 28,617-20, 28,621. Thus, EPA's reasoning in CAMR does not support a beyond-the-source approach to standard-setting under section 111. It confirms the source-focused nature of section 111, and further demonstrates that, after setting achievable emission standards for individual sources, EPA may allow states to adopt flexible programs (such as emissions trading) to comply with standards that those individual sources are otherwise capable of achieving *without* resorting to those flexible programs.

Section 111 could not be more clear that its standards of performance for new and existing sources must be achievable by individual sources using measures that are implemented into the sources themselves. When compared to the narrow regulatory program that Congress created in section 111 and to which EPA has given shape through its consistent administrative implementation, the authority that the Agency now claims under its novel redefinition of "system of emission reduction" is plainly unlawful. EPA's beyond-the-source approach "would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization"—indeed, despite clear congressional language and regulatory history contradicting that claim of authority. *See UARG v. EPA*, 134 S. Ct. at 2444. Therefore, EPA must withdraw the Proposed Guidelines.

2. EPA Cannot Consider Reduced Utilization of Regulated Sources as BSER.

These same fundamental flaws extend to EPA's proposed "alternative approach to BSER," under which BSER is, "in addition to [B]uilding [B]lock 1, the reduction of affected fossil fuel-fired EGUs' mass emissions *achievable through reductions in generation* of specified

amounts from those EGUs." 79 Fed. Reg. at 34,889 (emphasis added); EPA Legal Memorandum at 15. Under this approach, "the measures in [B]uilding [B]locks 2, 3, and 4 would not be components of the system of emission reduction but instead would serve as bases for quantifying the reduced generation (and therefore emissions) at affected EGUs, and assuring that . . . the reduced generation can be achieved while the demand for electricity services can continue to be met in a reliable and affordable manner." 79 Fed. Reg. at 34,889. EPA has no authority to establish a standard of performance based on reduced utilization of a source.

A standard of performance regulates a source's emission *performance*—i.e., its emissions at a given level of operation—and not its total emissions of a pollutant. Any standard of performance under section 111 must be based on measures that can reduce an individual source's emission capacity when operating. This is evident from the fact that Congress clearly distinguished between an "emission standard" or "emission limitation" and a "standard of performance." CAA § 302(k), (*l*). The former may limit the "quantity . . . of emissions of air pollutants," while a standard of performance must require "continuous emission reduction," which requires imposing a limit on the rate at which the source emits an air pollutant (i.e., improving its emissions "performance"). *See id.* In addition, section 111(a)(1) further specifies that a "standard of performance" for the purpose of section 111 must be a "standard for *emissions of air pollutants* which reflects the *degree* of emission limitation achievable through the application of" BSER. *Id.* § 111(a)(1) (emphases added). Thus, the standard of performance must set forth the degree of emission limitation—i.e., the relative intensity or rate of emissions—for a source that is achievable by applying a system of emission reduction to that source. Further, the performance standard is a standard "for *emissions* of *air pollutants*," and not one for *operation* of the *source*. There is no room in this language for a reading that Congress

authorized EPA to tell companies how much to operate their sources (or not to operate their sources at all). Indeed, even with respect to measures to control emissions applied to a source, Congress explicitly prohibited EPA from requiring "any particular technological system of continuous emission reduction to comply with any [NSPS]"—a requirement that would be far less intrusive than telling companies how much to run (or not to run) their sources. *Id.* § 111(b)(5). Tellingly, EPA has never proposed reduced utilization or operation of the source as a system of reduction under section 111—despite the fact that reducing utilization or operation of the source would always result in fewer total emissions from the source simply because the source does not have any emissions during periods of non-operation.

The reductions in generation that EPA contemplates under the alternative BSER approach would not improve the emission performance of affected EGUs at any given level of operation, and thus cannot be the basis of a standard of performance. Limiting operations does not yield "continuous emission reduction." It limits emissions only during times when a source is not running. Likewise, a standard of performance cannot be "achievable" if it can be met only by reducing utilization of the source. A source does not "achieve" a specified emissions performance level by curtailing operations; it merely ceases to "perform" at all.

Congress knew how to address intermittent control strategies such as shutting down or reducing utilization of regulated sources—and when it did, it explicitly rejected their use. For example, in section 123 of the CAA, Congress provided that "dispersion techniques"—defined to include "intermittent . . . control of air pollutants varying with atmospheric conditions"—"shall not . . . affect[] in any manner" the "degree of emission limitation required for control of any air pollutant under an applicable implementation plan." *Id.* § 123(a), (b). In other words, Congress rejected control strategies that vary utilization based on atmospheric conditions in favor of

ED_000419-0005730

strategies that reduce the rate of emissions. The "standard of performance" language of section 111 is inconsistent with the concept of "intermittent control" strategies, and Congress's explicit rejection of these strategies in the context of implementation plans counsels against any reading of section 111(d) to authorize their use.

An emission standard based on reducing utilization of EGUs would constitute the unlawful confiscation of generating capacity from affected EGUs. Moreover, requiring a 100 MW EGU to operate as a 50 MW EGU would effectively "order a fundamental redesign of the facility," which EPA has no authority to do when regulating stationary sources. *See UARG v. EPA*, 134 S. Ct. at 2448 (discussing BACT standards). EPA's references to other provisions of the CAA that may require some sources to reduce operations, such as the NAAQS program and the residual risk provisions of section 112, are inapposite. As these comments explain, those provisions are based on requirements driven by public health and welfare standards, whereas Congress explicitly required that section 111's technology-based standards of performance be achievable by individual sources in a listed source category.[8] EPA Legal Memorandum at 81-82. Notably, EPA has never before claimed this authority in a CAA § 111 rulemaking. As with the other beyond-the-source measures that EPA attempts to impose in the Proposed Guidelines, EPA has never even considered capping a source's operations as part of a system of emission reduction in any of its previous NSPS or emission guideline rulemakings. If it did, the result would be bizarre, unreasonable, and unlawful. EPA is claiming authority to effectively cap the size of any new source in a category by basing its NSPS on operational limits at new sources in

---

[8] Likewise, EPA's reference to commitments to retire individual EGUs in NSR settlement agreements is inexplicable and irrelevant. EPA Legal Memorandum at 83. The fact that some EGUs may voluntarily decide to retire or limit operations in lieu of implementing NSR requirements bears no relation to whether EPA may *require* such measures as the basis for a standard of performance that applies to all sources in a source category.

ED_000419-0005731

that category. This is dissimilar from PSD review, in which a source may accept permit limits on its operations to avoid becoming subject to a stringent BACT standard as its emission rate. Under EPA's alternative BSER proposal, *the standard itself* would be an operational limit, and sources would have no way to avoid becoming subject to that limit.

Further, EPA's "alternative BSER" approach is defective in that it still relies on the beyond-the-source measures that constitute Building Blocks 2, 3, and 4 of its proposed BSER. Under the alternative BSER, EPA relies on Building Blocks 2, 3, and 4 to "determine . . . the amount of the generation reduction component of the BSER" that is achievable for affected EGUs, by assuming that the beyond-the-source measures supporting those building blocks provide available means to ensure that energy demand will still be met. 79 Fed. Reg. at 34,889. But, as discussed above, the measures in Building Blocks 2, 3, and 4 are beyond the control of individual affected EGUs, and therefore cannot render a standard of performance achievable for individual sources.

3. The Proposed Guidelines Are Based on Measures that States and EPA Cannot Enforce Against Regulated Sources.

EPA's impermissible redefinition of a "system of emission reduction" is not the Agency's only departure from the regulatory program Congress established in section 111. Indeed, in its attempt to accommodate this dramatic expansion of regulatory authority, the Agency is forced to deviate even further from the statute and its own past rulemakings in numerous other ways that also highlight the unlawfulness of the Proposed Guidelines. In particular, EPA's proposal attempts to impose federally enforceable obligations on a broad, undefined class of "affected entities" beyond the regulated category of existing EGUs in order to effectuate the Agency's policy goal of reducing aggregate CO_2 emissions by reducing the operation of existing EGUs. This approach is untethered from any regulatory program under the

ED_000419-0005732

CAA. Nothing in the Act authorizes the states or EPA to impose obligations on any entity under section 111 other than a source in a listed source category. In fact, nothing in the Act gives EPA the authority to establish and enforce standards of performance based on its pursuit of aggregate emission reductions from a designated source category *at all*—a fact that should have led the Agency to abandon this misguided, *ultra vires* rulemaking.

In this rulemaking, EPA unlawfully employs beyond-the-source measures to effectuate an "aggregate emission reduction" approach to standard-setting, in which the Agency defines an aggregate amount of emissions that it desires to remove from the entire source category's emissions inventory, and then imposes a broad range of requirements on whatever entities are necessary to obtain those reductions. That this aggregate emission reduction approach requires emission reductions that cannot possibly be implemented through standards of performance that apply to existing EGUs alone is apparently legally irrelevant in EPA's view. The aggregate emission reductions associated with Building Blocks 2, 3, and 4 cannot be expressed as part of a standard of performance that applies to regulated sources because they do not reduce the emission rate of individual EGUs and cannot be implemented by individual sources. The owner of an individual existing EGU cannot implement measures at that EGU that increase the share of a state's overall fossil fuel-fired generation that is provided by NGCC units. Nor can it implement measures at that EGU that increase generation from renewable energy sources. And it cannot implement measures at the EGU that cause electricity consumers to use energy more efficiently, or ensure that any efficiency improvements actually lead to reduced energy consumption. Likewise, EPA and states have no authority under section 111 to base a standard of performance on the reduced utilization of a source, and even if they had such authority, the

aggregate emission reductions associated with that reduced utilization would not be reflected in a "standard of performance" as an improvement in the EGU's emission rate.

At the same time, nothing in section 111 authorizes EPA or the states to impose legally enforceable obligations on *other* entities in order to effectuate the aggregate emission reductions that EPA has concluded could be obtained under Building Blocks 2, 3, and 4. To the contrary, the statute could not be more clear that the *only* emission control obligations that it authorizes EPA and states to impose are standards of performance that apply to new and existing sources in listed source categories. Section 111 provides that legal requirements will apply only to regulated sources themselves. Under section 111(b), EPA may "establish[] Federal standards of performance *for new sources*" within "a category of stationary sources in a list under subparagraph (A)." CAA § 111(b)(1)(B) (emphasis added). And under section 111(d), states may submit plans that "establish[] standards of performance *for any existing source* for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source." *Id.* § 111(d)(1)(A) (emphasis added). *Nowhere else in that section* does Congress authorize the imposition of binding legal obligations for entities other than the regulated source.

Accordingly, only a narrow set of entities may be subject to requirements under section 111(d). First, the entity must be a "stationary source," meaning a "building, structure, facility, or installation which emits, or may emit any air pollutant." *Id.* § 111(a)(3). Second, that stationary source must be an existing source that falls within the "category of sources" that EPA has listed as eligible for regulation because that category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id.* § 111(b)(1)(A). And finally, EPA must have promulgated a standard of performance for new

sources in that category that applies to the relevant pollutant.[9] *Id.* § 111(d)(1)(A)(ii). If an entity is not a stationary source of pollutants in a category for which the Agency has promulgated an endangerment finding and an applicable NSPS, then neither EPA nor the states have authority to impose any obligation on that entity under section 111(d).

Thus, the statute unambiguously does *not* authorize EPA to impose obligations on the types of entities that the Agency would need to regulate in order to implement the beyond-the-source measures underlying the Proposed Guidelines. For that reason, "the need to rewrite clear provisions of the statute should have alerted EPA that it had taken a wrong interpretive turn" when it adopted its overly broad redefinition of "system of emission reduction." *UARG v. EPA*, 134 S. Ct. at 2446. But instead, the Agency proposes to take another wrong turn away from the regulatory program established in section 111 and to direct states to impose legal obligations on "affected entities" other than EGUs to obtain the aggregate emission reductions that cannot be achieved by adopting proper standards of performance for existing EGUs. 79 Fed. Reg. at 34,901-03.

EPA's proposed definition of affected entity is circular and astonishingly broad. It includes any "entity with obligations under this subpart for the purpose of meeting the emissions performance goal requirements in these emission guidelines." 79 Fed. Reg. at 34,956, Proposed 40 C.F.R. § 60.5820. In other words, under EPA's so-called "portfolio approach," the Proposed Guidelines would allow a state to impose enforceable requirements upon *any* entity that the state believes could directly or indirectly reduce energy demand, and thus emissions, from existing

---

[9] As discussed in more detail in Section IV, regulation under section 111(d) also is permissible only when the pollutant in question is not listed as a criteria air pollutant and regulated under the NAAQS program and when the source category is not regulated under section 112's hazardous air pollutant program. CAA § 111(d)(1)(A).

ED_000419-0005735

fossil fuel-fired EGUs. By EPA's own admission, the standards of performance applicable to individual affected EGUs—i.e., the standards actually contemplated by section 111—"would not, on their own, assure, or be required to assure, achievement of the emission performance level" that is determined to represent the application of BSER to affected sources. 79 Fed. Reg. at 34,901. Instead, "the state plan would include measures enforceable against other entities that support reduced generation by, and therefore CO_2 emission reductions from, the affected EGUs." *Id.* These measures "would be federally enforceable because they would be included in the state plan." *Id.* The Agency suggests that affected entities could include "electric distribution utilit[ies]," "private or public third-party entit[ies]," or "a state agency, authority or entity." *Id.* at 34,917. There is virtually no limit on the types of "affected entities" that EPA or states might choose to regulate under section 111, potentially including "retail stores, offices, apartment buildings, shopping centers, schools, and churches." *UARG v. EPA*, 134 S. Ct. at 2446. The Supreme Court recently rejected a similar attempt by EPA to "assert[] newfound authority" over such entities and then "decide, on an ongoing basis . . . how many of those sources to regulate." *Id.*

EPA's attempt to authorize regulation of these "affected entities" under a program to establish performance standards for a source category of EGUs has no basis in the CAA. Much like the Agency's novel redefinition of "system of emission reduction," EPA has never applied this "portfolio approach" in any of its previous NSPS or emission guideline rulemakings over the past four decades. The Agency's primary argument for this departure is that "[t]here is no specific language in CAA section 111(d) or elsewhere in the Act that *prohibits* states from including measures other than performance standards and implementation and enforcement measures" in state plans for existing sources. 79 Fed. Reg. at 34,903 (emphasis added). But this

ED_000419-0005736

argument erroneously assumes that, under the CAA, any action that Congress did not explicitly prohibit is permitted. In fact, just the opposite is true. Congress must "speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.'" *UARG v. EPA*, 134 S. Ct. at 2444. A reading of the CAA that gives EPA and states the authority to potentially impose obligations on any entity that uses electricity would unquestionably bear vast economic and political significance. As EPA freely admits, "the terms of CAA section 111(d)(1) do not explicitly address whether, in addition to emission limits on affected EGUs, state plans may include other measures for achieving the emission performance level." 79 Fed. Reg. at 34,902. Without such explicit authorization, EPA may not seize regulatory authority over a swath of affected entities so broad that it eclipses the affected sources on which section 111's narrow regulatory program is focused.

As EPA also acknowledges, its proposal to include enforceable requirements for affected entities as part of the emission guidelines raises significant practical enforcement concerns that are not addressed in the Proposed Guidelines. *See id.* at 34,909 ("[A] portfolio approach may result in enforceable state plan obligations accruing to a diverse range of affected entities beyond affected EGUs, and . . . there may be challenges to practically enforcing against some such entities in the event of noncompliance."). In order to receive EPA approval, a state plan must contain "enforceable measures that reduce EGU CO_2 emissions." *Id.* Once a state plan is approved by the Agency, its provisions—including its requirements for affected entities—would then generally become federally enforceable by EPA and by private individuals in citizen suits. *See* CAA §§ 113, 304(a). Yet it is unclear what kind of "enforceable" obligations a state could impose on affected entities in order to implement Building Blocks 2, 3, and 4, or how those

ED_000419-0005737

requirements could be enforced in the event they are not implemented. Accordingly, it may well prove impossible for states to submit plans that are "approvable" under EPA's criteria.

For example, EPA suggests that in order to implement Building Blocks 2, 3, and 4, "affected entities" may include "a state agency, authority or entity," such as a state environmental management agency or public utilities commission. 79 Fed. Reg. at 34,917. In some states, these may be the only entities with authority to implement the redispatch of generation from existing coal-fired units to NGCC units or to coordinate investments in renewable energy generation or demand-side energy efficiency campaigns. These state agencies, however, are immune from suit under the CAA's citizen suit provision. *Sierra Club v. Korleski*, 681 F.3d 342, 351 (6th Cir. 2012) ("The text and structure of the CAA make plain that [section 304(a)(1)] does not permit citizen suits against state regulators *qua* regulators."). Thus, it would not be possible to enforce emission-reducing measures that are the responsibility of state agencies. In such a case, under the plain terms of EPA's proposal, the state's plan submission would not be approvable unless the state adopts legislation expressly opening its agencies to citizen suits seeking to enforce these obligations, which would plainly exceed the scope of measures EPA may require in a state plan.

Even where "affected entities" are not state agencies that are immune from CAA citizen suits, it is unclear what would constitute a "violation" warranting an enforcement action or how a court would enjoin that violation. For example, a state might assign responsibility for implementing Building Block 3 (increased renewable energy generation) to a third party, such as an electric distribution utility, and require that utility to invest a certain amount of money each year into new renewable energy development. Even assuming *arguendo* that such an investment requirement is legally enforceable, is there any guarantee that those investments will result in the

ED_000419-0005738

required reduction in EGU CO_2 emissions to render the state plan approvable? Can the utility demonstrate compliance with that obligation by simply making the required investments, or must it also show that the contemplated amount of renewable energy was produced as a result? Would the utility "violate" its obligation if new renewable energy capacity failed to materialize, or if that renewable capacity was not utilized enough (e.g., due to variations in weather) to generate the contemplated amount of renewable energy? If so, how would a court enjoin that violation—by requiring greater investments, or by requiring increased renewable generation? Would the owners of renewable energy projects receiving investments under the state plan also be "affected entities" subject to enforceable obligations requiring a minimum amount of generation each year? If so, would it be a violation of that requirement if a solar or wind-powered energy source did not meet its generation target because of insufficient sun or wind? The same or similar questions arise in the context of Building Blocks 2 and 4.

EPA has not answered *any* of these essential implementation questions. Nor can the CAA or EPA's past rulemakings under section 111 provide answers to any of these questions. That is because the types of aggregate emission reduction measures and the broad universe of affected entities that EPA asserts authority over in the Proposed Guidelines are so far removed from section 111's narrow source-focused regulatory program as to be completely unrecognizable as a program under section 111(d) of the CAA. The CAA "do[es] not explicitly address" any of these issues, 79 Fed. Reg. at 34,902, for the same reason that section 111 does not explicitly address mobile source regulation or endangered species protection: because such language would be nonsensical in a statutory provision that has nothing to say about those issues. Section 111, on its face, is singularly concerned with design or process changes that individual new and existing stationary sources within specific categories can implement to reduce their own

emissions. That EPA is now grappling with the complex question of how to impose enforceable obligations on *other* affected entities in order to reduce *aggregate* emissions by reducing utilization of affected sources simply demonstrates that EPA has strayed far off the CAA's regulatory path.

If these issues were not enough, the extent to which EPA has deviated from the statute is also evident from the fact that if a state does not submit an "approvable" plan, EPA would have no authority to promulgate a federal plan that includes the measures it would require of states (i.e., beyond-the-source measures contemplated under Building Blocks 2, 3, and 4). In this regard, EPA cannot adopt a plan that imposes a federally enforceable energy resource development and dispatch program upon states. The Agency has no authority over independent system operators, state public utility commissions, or other entities responsible for managing the dispatch of EGUs to meet load requirements. EPA has no inherent police powers and lacks authority to require states to exercise their police powers. Notably, even under section 110 of the CAA—a provision that, in contrast to section 111, gives the states and EPA broad authority to require aggregate emission reductions from diverse sources—EPA has no power under a federal implementation plan to require that states enact specific statutes and regulations or to administer and enforce programs contained in EPA regulations. *Dist. of Columbia v. Train*, 521 F.2d 971, 983, 984 (D.C. Cir. 1975) ("Had Congress intended to adopt the novel approach of empowering a federal agency to order unconsenting states to enact state statutes and regulations, thereby converting state legislatures into arms of the EPA, it most likely would have made that intent clear in the statute."), *vacated as moot, EPA v. Brown*, 431 U.S. 99 (1977); *Maryland v. EPA*, 530 F.2d 215, 228 (4th Cir. 1975) (CAA does not authorize EPA "to require Maryland to establish the programs [described in EPA's regulations] and furnish legal authority for the

ED_000419-0005740

administration thereof"), *vacated as moot*, *Brown*, 431 U.S. at 103-04. Indeed, if any provision of the CAA did purport to authorize EPA to require that states implement and enforce new statutes or regulations, it would present serious constitutional problems. *See Maryland*, 530 F.2d at 225 (observing that "how an Act of Congress may be construed to permit an agency of the United States to direct a state legislature to legislate is difficult to understand"). Those same constitutional concerns are implicated where, as here, EPA would require state plans to include measures that can *only* be implemented and enforced (whether by the state or by EPA) if the state enacts new legislation. And importantly, as noted above, section 111 gives EPA no authority to base a standard of performance on reduced utilization or operation of a source.

In sum, section 111 of the CAA creates a narrow regulatory program in which EPA—or in the case of existing sources, states—adopts standards of performance for stationary emission sources in specified categories that reduce each source's emissions at a given operational level based on the implementation of achievable measures that can be incorporated into the design or production process of the source itself. EPA has consistently applied the program in this manner for over forty years. By contrast, the Proposed Guidelines require states to enact measures that reduce aggregate emissions from each state's fleet of existing EGUs overall, based on measures that are beyond the control of individual EGUs and that can be achieved only by imposing obligations on other "entities" the state identifies that produce or consume electricity or by requiring existing EGUs to curtail operations altogether. The contrast could not be more clear. EPA's Proposed Guidelines are inconsistent with the plain language of section 111(d), as well as "the design and structure of the statute as a whole," and must be withdrawn. *UARG v. EPA*, 134 S. Ct. at 2442 (internal quotation marks omitted).

ED_000419-0005741

IV. EPA Is Prohibited from Regulating Pollutants from a Source Category Already Regulated Under Section 112 of the CAA.

The Proposed Guidelines contravene the express terms of section 111(d), which prohibits EPA from adopting emission guidelines for existing sources from a source category when the Agency has already regulated that source category under section 112. CAA § 111(d)(1)(A)(i). EPA listed coal- and oil-fired EGUs as a "source category" under section 112 in 2000, 65 Fed. Reg. 79,825, 79,826, 79,831 (Dec. 20, 2000), and regulated emissions from these sources in 2012 under the MATS rule, 77 Fed. Reg. 9304 (Feb. 16, 2012). Because EPA has already promulgated a national emission standard for existing coal-fired power plants under section 112, it may not promulgate the emission guidelines it has proposed here.

A. EPA's Interpretation of the Act Is Inconsistent With the Plain Language of Section 111(d), Which Contains No Ambiguity.

EPA argues in its Legal Memorandum that accompanies the Proposed Guidelines that section 111(d) is "ambiguous" about whether the Agency can regulate sources under both section 112 and section 111(d), and that this ambiguity allows EPA to interpret the statute in any reasonable manner. EPA Legal Memorandum at 23 ("The two versions conflict with each other and thus render the Section 112 Exclusion ambiguous. Under these circumstances, the EPA may reasonably construe the Section 112 Exclusion to authorize the regulation of GHGs under section 111(d).").

Courts grant agencies deference in interpreting the meaning of ambiguous statutes. *See, e.g., Chevron, U.S.A., Inc. v. Natural Res. Defense Council*, 467 U.S. 837 (1984). But there is no ambiguity in section 111(d). Section 111(d) says plainly that EPA has no authority to regulate a source category already regulated under section 112.

The basis of EPA's argument that section 111(d) is ambiguous is the existence in the Statutes at Large of two amendments to section 111(d) in the 1990 amendments to the Clean Air

ED_000419-0005742

Act. One amendment was a technical amendment not codified in the U.S. Code because it was obvious to the codifier that the substantive amendment that was enacted superseded and rendered unnecessary the technical amendment. The U.S. Code therefore notes that the clerical entry "could not be executed." Revisor's Note, 42 U.S.C. § 7411. The technical amendment included in the Statutes at Large sought to update a cross-reference to section 112(b)(1)(A) after section 112(b)(1)(A) was eliminated by another 1990 amendment to the Act. This non-substantive, ministerial revision was included in a section in the Statutes at Large entitled "Conforming Amendments." Clean Air Act Amendments, Pub. L. No. 101-549, § 302(a), 104 Stat. 2399, 2574 (1990). But this revision was superseded and became moot when the second, substantive amendment to section 111(d) passed nearly two months later. H.R. 3030 (containing the substantive provision) passed on May 23, 1990, while S. 1630 (containing the ministerial cross-reference) passed on April 3, 1990. *See* H.R. REP. NO. 101-490, at 454 (1990), *reprinted in* 2 A LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1990 ("Leg. History"), at 3021, 3478 (1993) (report to accompany H.R. 3030); S. 1630, 101st Cong. § 112(e)(4)-(5)(D) (as passed by Senate, Apr. 3, 1990), *reprinted in* 3 Leg. History, at 4119, 4431-33.

Although the technical amendment had a role to play prior to the substantive amendment to section 111(d) that was eventually adopted, once that amendment was adopted, inclusion of the technical amendment in the Statutes at Large was simply a "drafting error," as EPA has properly recognized. 70 Fed. Reg. 15,994, 16,031 (Mar. 29, 2005). As EPA stated, it was "hard to conceive that Congress would have adopted section 112(n)(1)(A), yet retained the [clerical] amendment to section 111(d)." *Id.* at 16,031. It does not conflict with and need not be reconciled with the substantive amendment which, in "a literal reading," EPA admits, means that the Agency "c[an] not regulate *any* air pollutant from a source category regulated under section

ED_000419-0005743

112." EPA Legal Memorandum at 26 (emphasis added). The Supreme Court has interpreted the provision in the same way: "EPA may not employ § 7411(d) if existing stationary sources of the pollutant in question are regulated under . . . the 'hazardous air pollutants' program, § 7412." *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537 n.7 (2011). And yet, in an effort to expand its regulatory reach and to invoke judicial deference in doing so, the Agency attempts to fabricate ambiguity in the statute.

The D.C. Circuit has explained that it will not "read[] too much into a mere clerical error" and notes that incorrect conforming amendments (or the lack thereof) are common and can often be "the result of a scrivener's error." *Am. Petroleum Inst. v. SEC*, 714 F.3d 1329, 1336, 1337 (D.C. Cir. 2013). Such errors should thus not be interpreted as giving rise to an "ambiguity." *Id.* at 1336. EPA is not required to reconcile obvious mistakes—editorial vestiges that were never executed in the U.S. Code—with substantive, intentional amendments to the Act. EPA should simply disregard obvious mistakes in the Statutes at Large that, because they were mistakes, "could not be executed" in the U.S. Code.

Even if there were ambiguity in the presence of the two provisions in the Statutes at Large, however, agencies have deference only to interpret the ambiguous *meaning* of a statute, not to divine what the text of a statute actually *is*. In this case, if there is any uncertainty at all (which there is not), it centers on what the language of the statute actually *is*: why Congress neglected to reconcile both a substantive and a superseded clerical provision before they were entered in the Statutes at Large. The *meaning* of each of the substantive and clerical amendments is clear, not ambiguous. EPA inexplicably argues that both amendments should be read together even when there is no doubt that Congress did not intend for a superseded technical amendment to remain in the statute. Disregarding this obvious intent, the Agency insists it

ED_000419-0005744

should "give some effect to both amendments." EPA Legal Memorandum at 26. But even if two provisions in a statute are irreconcilable, "*Chevron* is not a license for an agency to repair a statute that does not make sense." *Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2214 (2014) (Roberts, C.J., concurring). In other words, "[d]irect conflict is not ambiguity, and the resolution of such a conflict is not statutory construction but legislative choice." *Id.* Courts will grant agencies deference only "because we presume that Congress intended to assign responsibility to resolve the ambiguity to the agency." *Id.* If it is clear that Congress did not assign such responsibility to an agency, but merely made a drafting mistake (which it does with some frequency), it is equally clear that such mistakes do not confer to agencies the license to rewrite the statute. *UARG v. EPA*, 134 S. Ct. at 2446 ("[A]n agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate.").

EPA in fact cites no authority for the deference it implies it should receive to reconcile the "conflict" in section 111(d) it purports to have discovered. In the litigation challenging CAMR, however, which also attempted to regulate coal-fired EGUs under section 111(d), EPA cited *Citizens to Save Spencer County v. EPA*, 600 F.2d 844 (D.C. Cir. 1979), to support its creative interpretation of section 111(d). Final Br. of Resp't EPA at 102-03, *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008) (No. 05-1097). This is a very different situation from *Citizens to Save Spencer County*, where two different statutory provisions had different, mutually exclusive dates for regulatory action. Those provisions could not be reconciled and the Agency was found to have reasonably "pursue[d] a middle course." *Citizens to Save Spencer Cnty.*, 600 F.2d at 871. By contrast, the amendments at issue here can easily be reconciled, first and foremost by recognizing that the clerical amendment was inserted in the Statutes at Large by mistake and, therefore, should be disregarded. Even if one desires to infuse the clerical amendment with

ED_000419-0005745

substantive intent, as discussed below, the two provisions are most clearly read as prohibiting the duplicative regulation of sources under both section 111(d) and section 112.

B. EPA's Proposed Construction Does Not Accord With Either Provision or With Legislative Intent.

Even if one were to attempt to treat the clerical amendment as substantive, as EPA does, the two provisions can be read in harmony. One can easily give effect to both provisions, which when read together simply say that no source category and no pollutant that are regulated under section 112 can be regulated under section 111. In other words, reading both amendments together, EPA is prohibited from regulating under section 111(d) any pollutant or any source category that is regulated under section 112. This construction is the only one that construes both provisions substantively and that is also faithful to the plain text of both.

The substantive amendment in the Statutes at Large reads: "Regulation of Existing Sources.—Section 111(d)(1)(A)(i) of the Clean Air Act . . . is amended by striking 'or 112(b)(1)(A)' and inserting 'or emitted from a source category which is regulated under section 112.'" Clean Air Act Amendments, Pub. L. No. 101-549, § 108(g), 104 Stat. 2399, 2467 (1990). The clerical amendment reads: "Conforming Amendments. (a) Section 111(d)(1) of the Clean Air Act is amended by striking '112(b)(1)(A)' and inserting in lieu thereof '112(b).'" *Id.* § 302(a), 104 Stat. at 2574.

In the CAMR rulemaking, the Agency adopted an interpretation of the two amendments in its attempt "to give some effect to both." EPA Legal Memorandum at 26. It proposes to do so again here, though with a slightly different hurdle to maneuver. In CAMR, EPA sought to regulate a hazardous air pollutant under section 111(d), and as part of that effort, "delisted" the source category of coal- and oil-fired EGUs from regulation under section 112. In 2005, EPA interpreted the two amendments together to mean:

ED_000419-0005746

> Where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category. Thus, if EPA is regulating source category X under section 112, section 111(d) could not be used to regulate any HAP emissions from that particular source category.

70 Fed. Reg. at 16,031-32. In this interpretation, rather than giving effect to both amendments, the Agency in fact *limited* the reach of each and constrained its authority to regulate to a world much smaller than either the clerical or substantive amendment alone contemplated.[10] EPA thus gave effect to *neither* provision and proposes the same interpretation now. EPA ignores the statutory text, despite being required "to give effect, if possible, to every word Congress used." *Reiter v. Sonotone Corp.*, 442 U.S. 330, 339 (1979). EPA did not then and does not now explain how altering the intent of both amendments by limiting their individual reaches "gave effect" to each amendment. EPA's interpretation expressly contravenes the first amendment (under section 108(g) of the Statutes at Large, 104 Stat. at 2467) because it would allow EPA to regulate the same source category it is regulating under section 112. EPA's approach would also expressly contravene the second amendment (under section 302(a) of the Statutes at Large, 104 Stat. at 2574) because it would allow the Agency to use section 111(d) to regulate hazardous air pollutants from a source category that is not already subject to section 112 standards. But perceived ambiguity or conflict "gives no license to a court or agency to indulge in unrestrained and fanciful flights of constructional imagination to arrive at artful but artificially consistent interpretations." *Citizens to Save Spencer Cnty.*, 600 F.2d at 870.

---

[10] The substantive amendment addresses source categories, without regard to pollutant ("Universe A"). The clerical amendment, read substantively, addresses pollutants, without regard to source category ("Universe B"). By artificially merging the two, EPA created not Universe A + B, but Universe C, a potential regulated universe much smaller than either Universe A or Universe B, thereby ignoring the intents of both amendments rather than choosing to give effect to both or at least one.

ED_000419-0005747

Besides limiting the universe of sources and gases that EPA can regulate under section 111(d) beyond what either the House or Senate intended with their amendments alone, the Agency's interpretation also unreasonably constrains the plain meaning of the substantive amendment in the mistaken interest of giving some meaning to the clerical amendment, which again EPA admits was likely a non-substantive "drafting error." 70 Fed. Reg. at 16,031. Although EPA argued that its 2005 interpretation "gives effect to the House's desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of [hazardous air pollutants] for a particular source category," *id.* at 16,032 (citing 136 Cong. Rec. H12911, 12934 (daily ed. Oct. 26, 1990)), it also acknowledged the interpretation "does not give full effect to the [substantive amendment], because a literal reading . . . would mean that EPA could not regulate [hazardous air pollutants] or non-[hazardous air pollutants] emitted from a source category regulated under section 112," *id.*

It is not surprising that Congress would have confirmed and clarified the limited reach of section 111(d). Prior to the 1990 Amendments, section 111(d) looked solely to whether the pollutant at issue was already regulated under section 108 or section 112. With the 1990 amendments, section 112 was transformed from a little used provision into a comprehensive control technology program. *See* EPA, "Summary of the Clean Air Act," http://www2.epa.gov/laws-regulations/summary-clean-air-act; H.R. REP. NO. 101-490, at 151 (1990), *reprinted in* 2 Leg. History, at 3175; S. REP. NO. 101-228, at 148 (1990), *reprinted in* 5 Leg. History, at 8338, 8488. Congress fundamentally changed section 112 so that those standards now "apply to sources in a category . . . rather than to pollutants individually." S. REP. NO. 101-228, at 148 (1990), *reprinted in* 5 Leg. History at 8488. To avoid onerous duplication, Congress then amended section 111, which is also technology-based and also applies to source categories rather

ED_000419-0005748

than to pollutants. If an entity is regulated under section 112, it cannot also be regulated under section 111(d).

For all the reasons discussed above, EPA's interpretation of section 111(d) does not accord with either the plain statutory language or its legislative history. EPA lacks authority to regulate coal- and oil-fired EGUs under section 111(d). EPA must withdraw the Proposed Guidelines because they violate both the text and Congress's clear intent in the 1990 Amendments.

V. EPA Lacks the Sufficient Legal Prerequisites To Propose and Finalize the Proposed Guidelines.

Section 111(d) makes clear that EPA may not finalize guidelines for an existing source unless new sources of the same type of entity are already subject to a section 111(b) performance standard. CAA § 111(d)(1). EPA's Subpart B regulations spell this requirement out in more detail and extend it to the proposal stage: Only "[c]oncurrently upon or after" standards have been proposed for "a designated pollutant from [new] facilities" may EPA propose draft emission guidelines for the same pollutant for "designated facilities." 40 C.F.R. § 60.22(a). A "designated facility" is an "existing facility" of the "same type" that is subject to a standard of performance under section 111(b). *Id.* § 60.21(b); 40 Fed. Reg. at 53,341. Thus, in order for EPA to lawfully propose and finalize section 111(d) emission guidelines for EGUs, it first must have lawfully proposed and finalized standards of performance for new EGUs of the same type. The legal prerequisites for lawful emission guidelines governing CO_2 emissions from EGUs have not been met, and the Proposed Guidelines are therefore unlawful and may not be finalized.

A. EPA's Proposed NSPS for New Coal-Fired EGUs Is Unlawful and Cannot Support Section 111(d) Emission Guidelines.

Because EPA's proposed NSPS for new coal-fired EGUs fails to meet the statutory requirements for a "standard of performance" under section 111(b) of the Act, it cannot satisfy

the legal prerequisite for the Proposed Guidelines. The CAA requires a "standard of performance" to be "achievable" and based on a "best system of emission reduction" that must be "adequately demonstrated" for sources within a category or subcategory. CAA § 111(a)(1). The BSER must be a design or process measure that is available for each source type to which the standard will apply. EPA's proposed NSPS for new Subpart Da fossil-fired units is based on the use of carbon capture and storage ("CCS"), a technology that, as UARG exhaustively demonstrated in its May 2014 comments to EPA on that proposed rule, is neither available nor adequately demonstrated. *See* UARG New Source Comments at 18-85.

Furthermore, an NSPS must reduce emissions from a source by incorporating a system of continuous emission reduction into the design of the source itself. EPA's proposed NSPS for new Subpart Da sources failed this most basic test; the proposed Subpart Da standard would not reduce emissions. The proposed NSPS for new Subpart Da sources, which is based on one element of CCS, would mandate no reduction in the CO_2 generated by a source. Instead, it merely requires that a new source separate some percentage of the CO_2 from its flue gas stream, without imposing any requirements regarding the CO_2's ultimate fate. The proposed NSPS for new Subpart Da units is a "carbon separation" system, not a "carbon capture and sequestration" system, and therefore it does not reduce emissions. The proposed 1,100 lb CO_2/MWh standard merely reflects the amount of unseparated CO_2 a source would be limited to releasing from its stack. Yet the total CO_2 generated by the source would not change. The remainder of the CO_2 generated by the source and not emitted from the stack would be sent off-site with the expectation that it would be sequestered. But it would not violate the proposed NSPS if 100 percent of the CO_2 separated by the capture technology subsequently were released to the atmosphere. Thus, the proposed NSPS for Subpart Da units would not reduce emissions.

ED_000419-0005750

Moreover, in the proposed NSPS for new EGUs, EPA failed to show that the proposed separation-based standard is achievable for sources within the category as a whole because its limited discussion of achievability considers only integrated gasification combined cycle ("IGCC") units, which make up only one type of source covered by the proposed standard. A standard based solely on "IGCC with a single-stage [water gas shift] reactor and a two-stage acid gas removal system," 79 Fed. Reg. at 1470, a form of pre-combustion CO_2 separation, cannot support a standard for pulverized coal ("PC") or circulating fluidized bed units, which require post-combustion separation. EPA did not analyze or even assert that the proposed separation standard is achievable for coal-fired units using post-combustion capture methods. Any standard that applies to PC units based on a finding that it is achievable with a technology that only IGCC units can use is contrary to law.

Because there is no lawful proposed standard of performance for new coal-fired EGUs, EPA lacks the legal prerequisite to propose or promulgate the Proposed Guidelines for those sources. A standard of performance under section 111(b) of the Act must be "achievable" and "adequately demonstrated" for sources in a source category. Because EPA's January 2014 NSPS Proposal for new sources is neither, the section 111(b) new source rule does not meet the requirements to be a standard of performance for new coal-fired units. Without an effective standard for new units, EPA cannot propose a standard for existing units. *See* CAA § 111(d)(1); 40 C.F.R. § 60.22(a).

B. The Proposed NSPS for New Sources Does Not Address the Same Type of Facilities as the Proposed Guidelines.

Even if EPA could demonstrate that it proposed a lawful NSPS for new EGUs, which it cannot do, its Proposed Guidelines do not address the "same type" of facility that the proposed NSPS for new EGUs would address. On this basis alone the Proposed Guidelines lack the legal

prerequisite that a standard of performance for the same type of facility will have been proposed concurrently with or before the section 111(d) proposal. *Id.* Under the Agency's own Subpart B regulations, emissions guidelines may apply *only* to designated facilities—the same type of facility regulated under the new source NSPS rule. In this context, that would mean that EPA could propose emission guidelines only for fossil fuel-fired EGUs that meet the threshold requirements set forth in the new source NSPS proposal.

In the Proposed Guidelines, however, EPA *never* defines what the regulated "designated facility" would be. In an attempt to accomplish its novel, systems-based approach to BSER, EPA dodges the question of what the "designated facility" is and instead has introduced a new term: "affected entity." *See, e.g.*, 79 Fed. Reg. at 34,951, Proposed 40 C.F.R. § 60.5740(a)(3) (State plans must identify "the state emission performance level for *affected entities* that will be achieved through implementation of the plan."); *id.*, Proposed 40 C.F.R. § 60.5740(a)(3)(ii)(B) ("For a mass-based CO_2 emission performance level, the identified level of performance must represent the total tons of CO_2 that will be emitted by *affected entities* during each plan performance period.") (emphasis added). EPA defines "[a]ffected [e]ntities" to mean "any of the following: An affected EGU, *or another entity with obligations under this subpart* for the purpose of meeting the emissions performance goal requirements in these emission guidelines." *Id.* at 34,956, Proposed 40 C.F.R. § 60.5820 (emphasis added). The CAA and EPA's Subpart B regulations prohibit EPA from expanding the universe of covered sources under section 111(d) beyond those regulated as new sources under section 111(b). CAA § 111(d)(1); 40 C.F.R. § 60.22(a).

The Subpart B regulations limit EPA to proposing and finalizing emission guidelines for "designated facilities," not "affected entities," which EPA has defined to be a world much larger

than "designated facilities." *See, e.g.*, 40 C.F.R. § 60.21(e) ("*Emission guideline* means 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*.") (second emphasis added); *id.* § 60.22 (a) ("Concurrently 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 pertinent to control of the designated pollutant [from] *designated facilities*.") (emphasis added); *id.* § 60.22(b)(5) ("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.") (emphasis added). EPA insists it is "following the requirements of" the Subpart B regulations and is not amending or reopening them, 79 Fed. Reg. at 34,844, and yet it fails to adhere to the most basic of the Subpart B requirements: identifying the regulated source category, which by law must be identical to the source category regulated under the section 111(b) NSPS. In fact, the very first non-definitional sentence of the Subpart B regulations states that EPA's guideline document must contain "information pertinent to control of the designated pollutant [from] designated facilities." 40 C.F.R. § 60.22(a).

Indeed, the Proposed Guidelines would regulate sources that extend far beyond the coal- and gas-fired EGUs EPA would regulate under its January 2014 NSPS Proposal. EPA does at times use the term "affected EGU" but such term is not used interchangeably or as a synonym with the term "affected entity." It is clear that EPA intends for the section 111(d) emission

guidelines to apply to "affected entities," not only to "affected EGUs." *See, e.g.*, 79 Fed. Reg. at 34,953, Proposed 40 C.F.R. § 60.5780(a) ("Your state plan shall include emission standard(s) that are quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each *affected entity*.") (emphasis added); *id.* at 34,953-54, Proposed C.F.R. § 60.5780(f) ("An emission standard is enforceable against an *affected entity* if: (1) A technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2) Compliance requirements are clearly defined; (3) The *affected entities responsible for compliance and liable for violations* can be identified; (4) Each compliance activity or measure is enforceable as a practical matter; and (5) The Administrator and the state maintain the ability to enforce violations and secure appropriate corrective actions . . . .") (emphases added). Only after EPA discusses the requirement that state plans apply standards to "affected entities," EPA inserts a separate section in its proposed regulatory language discussing the "Applicability of State Plans to Affected EGUs." *Id.* at 34,954. States must address emissions from affected EGUs in their state plans, but it is abundantly clear that EPA's design envisions emissions-related requirements under section 111(d) applying to a much broader range of sources than the sources that would be regulated under its section 111(b) NSPS proposal. EPA explains in the preamble that state plans may apply "enforceable measures" that "are implemented by the state or by *another entity*" in addition to EGUs. *Id.* at 34,837 (emphasis added); *see also id.* at 34,853 ("Based on requests from stakeholders, the EPA is proposing that states be authorized to submit state plans that do not impose legal responsibility on the affected EGUs for the entirety of the emission performance level, but instead, by adopting what this preamble refers to as a 'portfolio approach,' *impose requirements on other affected entities* (e.g., renewable energy and demand-side energy efficiency measures) that would reduce CO_2 emissions from the affected EGUs.")

(emphasis added). Thus, under EPA's Proposed Guidelines, the "designated facility" would be EGUs, the state (the entity to which EPA is in fact applying a numeric rate-based emissions goal), *and* other entities, including any "private or public third-party entity." *Id.* at 34,917.

Moreover, as discussed in Section IX.A, EPA has no authority, under either section 111(d) or the Subpart B regulations, to adopt nonnegotiable, binding "emission goals" for states as it proposes to do. Subpart B does not even mention the term "emission goal." Both Subpart B and section 111(d) speak in terms of "standards of performance." Under section 111(a)(1), the standard of performance must reflect the degree of "emission limitation" that is achievable with the BSER. Under section 111(d), *states* are to establish standards of performance applicable to *sources*. EPA's convoluted approach disregards both the statute and its own implementing regulations and would apply to *states* a binding emission limitation, and states would then be free to apply standards of performance to any "affected entity" it wishes, without fealty to the restriction that the regulated entity must be identical in the section 111(b) and section 111(d) regulations. EPA's interpretation of its own regulations does not accord with the statute. Moreover, because EPA acts contrary even to its own regulations, it is entitled to no deference in interpreting them.

Finally, for the same reasons, EPA's proposal for modified and reconstructed sources under section 111(b) is also not sufficient to justify the section 111(d) proposal. *See* 79 Fed. Reg. at 34,852 ("The EPA intends to complete two CAA section 111(b) rulemakings regulating CO_2 from new fossil fuel-fired EGUs and from modified and reconstructed fossil fuel-fired EGUs before it finalizes this rulemaking, and either of those section 111(b) rulemakings will provide the requisite predicate for this rulemaking."). Although the CAA defines the term "new source" to include a modified source, CAA § 111(a)(2), as discussed above, the Proposed

ED_000419-0005755

Guidelines seek to regulate systems, states, and sources other than individual EGUs. The Proposed Guidelines define an "Affected Entity" as any entity with an enforceable obligation under a state plan. 79 Fed. Reg. at 34,956, Proposed 40 C.F.R. § 60.5820. This could include nearly any type of entity, "e.g., an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity." *Id.* at 34,917. By contrast, the section 111(b) proposals for modified, and reconstructed facilities define the designated facility as a fossil fuel-fired EGU. This is a mismatch. EPA cannot regulate a different type of source under section 111(d) than the type of source that is regulated as a new (or modified or reconstructed) source under section 111(b).

Because EPA has failed to meet these fundamental legal prerequisites for proposing and finalizing section 111(d) emission guidelines for CO_2 emissions, the Proposed Guidelines are unlawful and must be withdrawn.

VI. Definition of "Affected EGU"

As discussed in Section V above, these Proposed Guidelines are unlawful because, among other reasons, the scope of entities that EPA has proposed to regulate under section 111(d) is significantly broader than the corresponding category of new sources that EPA has proposed to regulate under section 111(b). The facilities that would be subject to emission standards in state plans under the Proposed Guidelines are any "affected EGU," along with any other "affected entity." *See, e.g.*, *id.* at 34,955-56, Proposed 40 C.F.R. § 60.5820 (defining "affected entity" and "emission standard"). The disconnect in coverage between these Proposed Guidelines and EPA's January 2014 NSPS Proposal is further confirmed by EPA's apparent confusion over even what sources should be considered "affected EGUs" under these different rules. Even if EPA were to adopt final emission guidelines under section 111(d) in which the "designated facility" is limited to "affected EGUs" as defined in the Proposed Guidelines, such

ED_000419-0005756

emission guidelines would still be unlawful because that definition is broader than the scope of new sources covered by the January 2014 NSPS Proposal.

Specifically, the Agency has proposed to include as "affected EGUs" several types of Subpart Da units (i.e., coal- and oil/gas-fired boilers and IGCC units) that would be excluded under the applicability criteria in the January 2014 NSPS Proposal. If EPA adopts final emission guidelines, it must define "affected EGUs" to be consistent with the applicability criteria in its January 2014 NSPS Proposal. The category of existing sources subject to emission guidelines under section 111(d) cannot be broader than the corresponding category of new sources subject to standards of performance under section 111(b).

In addition, as discussed in Section VI.B below, UARG notes that language in EPA's proposals for new, modified, and reconstructed EGUs has introduced uncertainty as to which of two approaches the Agency will take to define those sources under the section 111(b) standards of performance (although EPA says the scope of EGUs that would be subject to numerical emission limits under section 111(b) would not differ under either approach). *See* 79 Fed. Reg. at 1461; Memorandum from EPA, Office of Air Quality Planning and Standards ("OAQPS") to EGU NSPS Docket, "Amended Regulatory Text (Broad Applicability)" (June 2014), Docket ID No. EPA-HQ-OAR-2013-0603-0047 ("Broad Applicability Text"). This uncertainty has extended to the scope of regulation under the Proposed Guidelines. Because the same new, modified, and reconstructed EGUs would be subject to emission standards under either approach, defining the source category in the manner outlined in the Broad Applicability Text would not in fact, as EPA has suggested, expand the scope of existing EGUs that could be eligible for regulation under section 111(d). Each of the two scopes would trigger identical section 111(d) coverage for EGUs.

ED_000419-0005757

A. EPA's Definition of "Affected EGU" in the Proposed Guidelines Must Retain the Exclusions for Subpart Da Units That Were Proposed for New Subpart Da Units.

In its January 2014 proposed GHG NSPS for new EGUs, EPA proposed to define the source category of Subpart Da units for the purpose of regulating CO_2 emissions to include any electric utility steam generating unit (i.e., a boiler or IGCC unit) that meets certain applicability criteria. 79 Fed. Reg. at 1459. Among these criteria, the proposed NSPS would apply to a boiler or IGCC unit only if it (1) "combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years," and (2) actually "supplies more than one-third of its potential electric output and more than 219,000 MWh net-electric output to a utility power distribution system for sale on an annual basis."[11] *Id.* at 1502, Proposed 40 C.F.R. § 60.46Da(a). The former applicability requirement is known as the "low fossil use criterion," and the latter is known as the "one-third sales criterion." 79 Fed. Reg. at 1459.

In this rulemaking, EPA proposes to eliminate both of these criteria for Subpart Da units in its proposed definition of "affected EGUs," effectively expanding its definition of those sources beyond the applicability criteria in its January 2014 NSPS Proposal. 79 Fed. Reg. at 34,954, Proposed 40 C.F.R. § 60.5795(b)(1). Although the preamble to the Proposed Guidelines purports to tie the definition of "affected EGU" to the applicability criteria in the January 2014 NSPS Proposal for new EGUs, EPA's proposed definition would in fact eliminate the low fossil use criterion and the one-third sales criterion. *See* 79 Fed. Reg. at 34,854 (stating that emission guidelines would apply to existing sources that "in all other respects would meet the applicability

---

[11] Because EPA incorporated substantially the same applicability criteria for electric utility steam generating units in both its Subpart Da and Subpart TTTT approaches in the January 2014 NSPS Proposal, UARG's comments in this section apply equally to whichever approach the Agency adopts in that rulemaking.

ED_000419-0005758

criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs" and that "[t]he rationale for this proposal concerning applicability is the same as that for the January 8, 2014 proposal"). EPA has not provided any legal or technical rationale for altering the scope of what Subpart Da units qualify as "affected EGUs" in this rulemaking, and for that reason alone, its proposal to eliminate the one-third sales criterion and the low fossil use criterion is invalid. *See* CAA § 307(d).

Further, if EPA revises these Proposed Guidelines to define the "designated facility" as "affected EGUs," it cannot eliminate the one-third sales criterion and the low fossil use criterion from the definition of "affected EGUs" because doing so would expand the scope of the Agency's Proposed Guidelines under section 111(d) beyond the source category that EPA defined in its January 2014 NSPS Proposal for new units. Under the CAA, state plans may only impose obligations on an existing source "to which a standard of performance under this section would apply if such existing source were a new source." CAA § 111(d)(1). Existing boilers that actually sell less than one-third of their potential electric output to the grid or that combust fossil fuel for less than 10 percent of their heat input over a 3-year period would not be subject to the standards of performance set forth in the January 2014 NSPS Proposal if they were new, and therefore cannot legally be subject to emission guidelines under section 111(d). EPA cannot define a source category differently for new, modified, and existing sources. If EPA adopts final emission guidelines, it should define "affected EGUs" to be consistent with the definitions in the January 2014 NSPS Proposal.

B. The "Broad Applicability" Approach to the Proposed NSPS Would Not Support Regulating a Broader Universe of Sources Under the Proposed Guidelines.

Although the Agency does not acknowledge it in the Proposed Guidelines, EPA appears to be contemplating two different approaches to defining the category of sources that it proposes

to regulate in the NSPS rulemakings for GHG emissions from new, modified, and reconstructed EGUs. As a result, there is uncertainty as to precisely how any final NSPS would define the source category for regulation, although EPA suggests that the same sources would be subject to numerical emission limits under either approach. *See* 79 Fed. Reg. at 1461. As noted above, the docket for the proposed NSPS contains two versions of the regulatory text as it would be amended by those proposals—a "Proposed Applicability" version and a "Broad Applicability"/"Alternate Applicability" version. But because both approaches would ultimately subject the same new, modified, and reconstructed EGUs to emission standards, both approaches would place the same limits on which existing EGUs are eligible for regulation under section 111(d)—limits that EPA has exceeded in these Proposed Guidelines, as discussed in Sections V and VI.A above. The "Broad Applicability" approach would not in fact expand the scope of EGUs subject to the Proposed Guidelines beyond what would be covered under the "Proposed Applicability" approach.

The "Proposed Applicability" version of the NSPS contains the regulatory language that EPA has proposed to adopt governing new, modified, and reconstructed units under Subparts Da, KKKK, and TTTT. Memorandum from EPA, OAQPS to EGU NSPS Docket, "Amended Regulatory Text (Proposed Applicability)" (June 2014), Docket ID No. EPA-HQ-OAR-2013-0603-0044 ("Proposed Applicability Text"). That version applies to the source category of units as EPA proposed to regulate in the January 2014 NSPS Proposal and would exclude certain EGUs from the source category based on both design and operational characteristics. Under the Proposed Applicability Text, the category of boilers and IGCC units is defined as any electric utility steam generating unit that: (1) is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel; (2) was constructed for the purpose of supplying more than

ED_000419-0005760

one-third of its potential electric output capacity and more than 219,000 MWh as net-electric sales on an annual basis; (3) combusts fossil fuel for more than 10.0 percent of the heat input during any three consecutive calendar years; and (4) actually supplies one-third or more of its potential electric output and more than 219,000 MWh net-electric output to a utility power distribution system for sale on an annual basis. 40 C.F.R. § 60.40Da(a)(1) (defining affected facility); Proposed Applicability Text, Subpart Da § 60.46Da(a)(1). The category of stationary combustion turbines is defined in largely the same manner, with the exception that criteria 2 and 4 are determined on a three-year rolling average basis and with an additional fifth criterion that the turbine must combust over 90 percent natural gas on a heat input basis on a three-year rolling average basis. Proposed Applicability Text, Subpart KKKK § 60.4305(c).[12] Any source that does not satisfy all of the relevant applicability criteria does not fall within the regulated source category and cannot be subject to obligations under section 111.

By contrast, the "Broad Applicability" version would eliminate many of these applicability criteria and substantially broaden the source category. *See* Broad Applicability Text.[13] For boilers and IGCC units, that version would eliminate both the low fossil use criterion and—in the language of co-proposed Subpart TTTT—the one-third sales criterion, thus

---

[12] The proposed regulatory text in the January 2014 NSPS Proposal for new EGUs and the June 2014 proposal for modified and reconstructed EGUs contained several substantial inconsistencies between the language of Subparts Da and KKKK and the new co-proposed Subpart TTTT, despite EPA's stated desire that both approaches be "substantively the same." 79 Fed. Reg. at 1454 n.100. UARG commented on the inconsistent language in its comments on the January 2014 NSPS Proposal. UARG New Source Comments at 198. EPA must ensure that the language of proposed Subpart TTTT is substantively identical to the language of proposed Subparts Da and KKKK.

[13] The docket for EPA's January 2014 NSPS Proposal for new EGUs also contained a broader alternative to that proposal's applicability criteria. Memorandum from EPA, OAQPS to EGU NSPS Docket, "Alternate Applicability Approach" (Sept. 2013), Docket ID No. EPA-HQ-OAR-2013-0495-0062 ("Alternate Applicability Text"). Portions of the Broad Applicability Text addressing new EGUs differ from the Alternate Applicability Text.

ED_000419-0005761

expanding the source category to include non-fossil fuel boilers and low capacity factor boilers. *Compare* Proposed Applicability Text, Subpart Da § 60.46Da(a)(1)(ii), Subpart TTTT § 60.5509(a)(1), *with* Broad Applicability Text, Subpart Da § 60.46Da(a)(1)-(2), Subpart TTTT § 60.5509(a), 60.5580. Likewise, for all stationary combustion turbines, the Broad Applicability Text would eliminate *all* of the applicability criteria and expand the source category to include *every* stationary combustion turbine, including all simple cycle turbines, low capacity factor NGCC units, turbines that combust fuels other than natural gas, and turbines with design heat input less than 73 MW. *Compare* Proposed Applicability Text, Subpart KKKK § 60.4305(c), Subpart TTTT § 60.5509(a)(3), *with* Broad Applicability Text, Subpart KKKK § 60.4305(c), Subpart TTTT § 60.5509(a).

Instead of defining the source categories to exclude these units that EPA has proposed to find are not appropriate for regulation, under the Broad Applicability Text, the Agency would consider many of these previously excluded sources to technically be "subject to" a standard of performance that simply specifies "no emission standard." *See, e.g.*, Broad Applicability Text, Subpart TTTT, Tbl. 1. Although these units would not be required to comply with a numerical emission limit, they would be subject to monitoring, reporting, and recordkeeping requirements under the applicable NSPS. 79 Fed. Reg. at 1461 (discussing Alternate Applicability Text).

EPA makes no mention of the "Broad Applicability" approach in this rulemaking for existing EGUs, suggesting that EPA is no longer contemplating that approach for the proposed NSPS. In any event, EPA's choice between these alternative approaches will not affect the scope of what existing EGUs may be eligible for regulation under section 111(d). Under section 111(d), a state plan may establish standards of performance only for "any existing source . . . to which a standard of performance under [section 111] would apply if such existing source were a

ED_000419-0005762

new source." CAA § 111(d)(1). But the additional sources that the Broad Applicability Text would bring into the source category would be subject to "no emission standard." "No emission standard" is not a "standard of performance." Under the CAA, a "standard of performance" is defined as a "requirement of continuous emission reduction." *Id.* § 302(*l*). Further, for the purposes of section 111, a "standard of performance" means a "standard for emissions of air pollutants" reflecting the degree of emission limitation achievable by applying the BSER that has been adequately demonstrated. *Id.* §111(a)(1). Therefore, a source that is subject to "no emission standard" cannot be one "to which a standard of performance under [section 111] would apply." *Id.* § 111(d)(1).

VII. EPA Has Unlawfully Ignored the Federal Power Act's Division Between State and Federal Authority and Arbitrarily and Capriciously Ignored the Realities of Wholesale Electric Markets, Regional Transmission Grids, and Bulk Power System Reliability.

EPA's Proposed Guidelines violate the Federal Power Act ("FPA"), 16 U.S.C. §§ 791a *et seq.*, by seeking to regulate matters that Congress either preserved as the province of exclusive state regulation or specifically assigned to FERC. The Proposed Guidelines make scant mention of the FPA or FERC,[14] but as discussed below, multiple elements of the Proposed Guidelines would effectively result in EPA making energy policy decisions in areas that the FPA expressly leaves to state control. EPA would thus be wielding regulatory authority over energy resource development and planning that the FPA denies even to FERC. Other aspects of the proposed rule, including in particular proposed "Building Block 2," represent an unprecedented intrusion by EPA into areas that the FPA has made exclusively subject to FERC's jurisdiction. As a result, the Proposed Guidelines also violate section 310 of the CAA, which specifies that the Act

---

[14] *See, e.g.*, 79 Fed. Reg. at 34,834, 34,888 n.235, and 34,914. None of these references mention FERC's authority, or the limits on that authority, under the FPA.

ED_000419-0005763

"shall not be construed as superseding or limiting the authorities and responsibilities, under any other provision of law, of the Administrator or any other Federal officer, department, or agency." CAA § 310(a).

In addition, as discussed below, EPA's Proposed Guidelines are founded upon numerous fundamental factual errors that violate the "reasoned decision-making" requirement under the Administrative Procedure Act ("APA"). 5 U.S.C. § 706(2)(A); *see also Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). The Proposed Guidelines wrongly assume that various "technically feasible" but impracticable objectives can be achieved without serious harm to wholesale electric markets or to BPS reliability. EPA might have avoided these misunderstandings, and developed a more reasonable proposed rule, if it had seriously engaged with FERC. As discussed below, however, EPA has unreasonably excluded FERC from a substantive role in developing the Proposed Guidelines. It has irrationally deprived itself of the input of the federal agency that has real world expertise overseeing electricity markets, transmission grids, and electric reliability. The result is a proposal that has caused NERC and other independent expert entities to raise serious concerns that the Proposed Guidelines will jeopardize reliability.

In short, EPA's intrusion into regulatory spheres where it has no jurisdiction and no expertise has resulted in a proposal that will cause serious harm to wholesale electric markets and electric reliability if implemented, contrary to the requirements of reasoned decisionmaking and section 310(a) of the CAA.

ED_000419-0005764

A. The Proposed Guidelines Are Inconsistent With the FPA and Violate Section 310(a) of the CAA Because They Would Override the Division of Regulatory Authority Over the Generation, Transmission, Distribution, and Sale of Electric Energy Between the States and the Federal Government.

Part II of the FPA,[15] 16 U.S.C. §§ 824 *et seq.*, was enacted in 1935 and has been amended several times in the intervening years, most recently by the Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1277-1298, 119 Stat. 594, 978-86 (2005). For nearly eight decades, the FPA has established a bright line of demarcation between the federal and state roles in overseeing the generation, transmission, distribution, and sale of electric energy. That line of demarcation is straightforward and well understood.

Section 201(a) of the FPA states that "[f]ederal regulation . . . of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest. . . ." 16 U.S.C. § 824(a). That provision also expresses the congressional determination that federal regulation should "extend only to those matters which are not subject to regulation by the States." *Id.*; *see also Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205, 209 (1964).

Section 201(b) establishes FERC's exclusive jurisdiction "over all facilities for such transmission or sale of electric energy." 16 U.S.C. § 824(b).[16] It further affirms that states, not the federal government, have regulatory authority over "facilities used for the generation of

---

[15] Part I of the FPA, which was first enacted in 1920, addresses the licensing and oversight of hydroelectric facilities. It is not relevant to this proceeding.

[16] Section 201(f) of the FPA exempts state, municipal, and federal governmental entities, as well as most rural electric cooperatives, from FERC's jurisdiction under most provisions of the FPA. 16 U.S.C. § 824(f). Non-FERC-jurisdictional utilities that are not federal entities are instead generally subject to pervasive oversight by state, municipal, or other local bodies. Accordingly, to the extent that the proposed rule impacts the electric utility service by non-FERC-jurisdictional utilities it is invading the regulatory sphere that the FPA reserves for state and local regulation and not the sphere reserved for FERC. Thus, the Proposed Guidelines improperly invade local, state, and FERC jurisdictional spheres under the FPA.

ED_000419-0005765

electric energy"[17] as well as over electric distribution, retail sales, and intrastate transmission. *Id.*

The Proposed Guidelines would impermissibly inject EPA into the separate spheres that the FPA has assigned to the states and to FERC. Section VII.A.1 of these comments addresses the Proposed Guidelines' attempt to usurp states' control over regulatory matters that the FPA expressly leaves to them in violation of the Tenth Amendment. Section VII.A.2 summarizes FERC's relevant regulatory authority under the FPA and explains how EPA's Proposed Guidelines conflict with and impermissibly supersede and limit that authority, in violation of section 310(a) of the CAA. For both reasons, EPA should not adopt the Proposed Guidelines.

1. The Proposed Guidelines Unlawfully Usurp Authority Over the Generation of Electricity, Resource Planning, and Related Matters that the FPA and Tenth Amendment Reserve to the States.

The FPA draws clear lines between state and federal jurisdiction over electricity markets and generation facilities. *S. Cal. Edison*, 376 U.S. at 215 ("Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction . . . ."). The Supreme Court has noted that FERC itself "has recognized that the States retain significant control over local matters even when retail transmissions are unbundled" and referred to FERC's own acknowledgments of the limits on its jurisdiction in its landmark Order No. 888[18] to eliminate any uncertainty on this

---

[17] The FPA also gives FERC jurisdiction over certain specific generation-related matters, in addition to wholesale sales by generators, e.g., allegations involving manipulation of FERC-jurisdictional markets or compliance with FERC-approved reliability standards. As discussed below, however, "direct regulation" of generation and retail markets is reserved to the states.

[18] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub*

ED_000419-0005766

point. *New York v. FERC*, 535 U.S. 1, 24 (quoting Order No. 888 at 31,782, n.543 ("'Among other things, Congress left to the States authority to regulate generation and transmission siting'"), and n.544 ("'This Final Rule will not affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, including DSM [demand-side management]; authority over utility generation and resource portfolios; and authority to impose nonbypassable distribution or retail stranded cost charges.'") (2002)). The Supreme Court further observed that the FPA's "legislative history is replete with statements describing Congress' intent to preserve state jurisdiction over local facilities." *Id.* at 22.

The Supreme Court has also emphasized that federal regulation by agencies other than FERC may not invade the domain that the FPA has preserved for the states. In *Pacific Gas & Electric Co. v. State Energy Resources Conservation & Development Commission*, 461 U.S. 190, 194 (1983), the Court concluded that federal regulation of the safety of nuclear power plants did not override state authority over "the regulation of electricity production." The Supreme Court explained that states have "traditional authority over the need for additional generating capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like." *Id.* at 212. It noted that the only exception to state regulation of these activities was FERC's authority under the FPA over interstate wholesale sales and transmission by FERC-jurisdictional utilities. *Id.* at 205.

---

nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

ED_000419-0005767

Decisions of the U.S. Court of Appeals for the D.C. Circuit likewise confirm that federal regulation cannot directly or indirectly intrude into the sphere that the FPA reserves for state regulation. *See, e.g.*, *Elec. Power Supply Ass'n v. FERC,* 753 F.3d 216 (D.C. Cir. 2014) ("*EPSA*"). *EPSA* vacated FERC Order No. 745,[19] which established revised rules for compensating demand-side resources in FERC-jurisdictional markets, because demand reductions did not constitute wholesale sales of energy and "the Federal Power Act unambiguously restricts FERC from regulating the retail market . . . ." *Id.* at 224; *see also Duke Power Co. v. Fed. Power Comm'n*, 401 F.2d 930, 935 (D.C. Cir. 1968) (explaining that the "major emphasis" of the FPA "is upon federal regulation of those aspects of the industry which—for reasons either legal or practical—are beyond the pale of effective state supervision"); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (reiterating established principle that FERC may not "directly regulat[e]" electric generation).

Courts have also rejected attempts by FERC to use indirect means to regulate in areas that the FPA reserves to the states. *See, e.g.*, *EPSA*, 753 F.3d at 221 (quoting *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996)) (noting that "FERC cannot 'do indirectly what it could not do directly'"); *Richmond Power & Light v. FERC*, 574 F.2d 610, 620 (D.C. Cir. 1978).

FERC itself has expressly acknowledged the rights of states to encourage the development of particular generation resources as a legitimate policy interest that is within their jurisdiction under the FPA. *See, e.g.*, Order Accepting Proposed Tariff Revisions, Subject to

---

[19] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011), *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012).

ED_000419-0005768

Conditions, and Addressing Related Complaint, *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at 61,106 (Apr. 12, 2011) (a state may "act within its borders to ensure resource adequacy or to favor particular types of new generation"). FERC has recognized that state law does not intrude on federal jurisdiction to the extent that a state is directing the planning and resource decisions of electric utilities under its jurisdiction. *See* Order on Complaint and Petition for Declaratory Order and on Petition for Enforcement, *Midwest Power Sys., Inc.*, 78 FERC ¶ 61,067, at 61,246 (Jan. 29, 1997) (Iowa statute not preempted "to the extent that [it] require[s] [state utilities] . . . to purchase from certain types of generating facilities"); *see also* Order on Requests for Reconsideration, *S. Cal. Edison Co.*, 71 FERC ¶ 61,269 (June 2, 1995) (states have broad powers to direct the planning and resource decisions of utilities under their jurisdiction).

The FPA's preservation of state jurisdiction over generation, resource planning, and other matters is consistent with basic principles of federalism. It likewise comports with the Tenth Amendment to the United States Constitution, which declares that "[t]he powers not delegated to the United States by the Constitution, nor prohibited by it to the states, are reserved to the states respectively, or to the people." U.S. CONST. amend. X. Before Part II of the FPA was enacted in 1935, states pervasively regulated utilities within their borders based on their general police powers. The 1935 amendments to the FPA were adopted only after the Supreme Court held that states could not regulate interstate sales of electricity under the Commerce Clause. *Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 90 (1927). FERC was given authority over interstate transmission and interstate wholesale sales of electric energy solely to close this "*Attleboro* gap."

EPA's Proposed Guidelines ignore the careful division of responsibilities embodied in the FPA—and the constitutional underpinnings for this division—and attempt to claim state

ED_000419-0005769

authority over generation, resource planning, and other matters for EPA. As stated by FERC Commissioner Clark in recent Congressional testimony, the Proposed Guidelines "ha[ve] the potential to comprehensively reorder the jurisdictional relationship between the federal government and states as it relates to the regulation of public utilities and energy development" and "fundamentally change the very fabric of how the utility industry is regulated in the country." *FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges: Hearing Before the Subcomm. on Energy and Power of the H. Comm. on Energy & Commerce*, 113th Cong. 4, 7 (July 29, 2014) (written testimony of Tony Clark, Comm'r, FERC), *available at* http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid ("Clark Testimony") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). The Proposed Guidelines would "dramatically alter the[] traditional lines of authority by creating a new paradigm of oversight of net carbon emission from a state" and potentially result in states "ceding ultimate authority of the regulation of their state's public utilities and energy development to the EPA." *Id.* at 4, 5.

In enacting section 111(d) of the CAA, Congress could not possibly have intended to empower the EPA to take on such a monumental task. As the Supreme Court has recently stated, EPA cannot reasonably interpret a statute to authorize "an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization." *UARG v. EPA*, 134 S. Ct. at 2444. EPA can have no greater authority to address matters Congress has expressly reserved to state regulation than FERC has under the FPA. EPA should certainly have no more ability to "do indirectly what it could not do directly" than FERC would with respect to matters that the FPA left to the states. Similarly, the Tenth Amendment does not permit EPA to

ED_000419-0005770

displace sovereign state authority or "compel the States to enact or administer a federal regulatory program." *See, e.g.*, *New York v. United States,* 505 U.S. 144, 188 (1992).

Accordingly, the Proposed Guidelines violate both the FPA and the Tenth Amendment and must be withdrawn.

2. The Proposed Guidelines Usurp Regulatory Authority that the FPA Gives Exclusively to FERC.

The United States Supreme Court has repeatedly held that FERC's exclusive jurisdiction over interstate transmission is extraordinarily broad because of the integrated nature of the interstate transmission grid and the laws of physics. For example, in *New York v. FERC*, 535 U.S. 1 (2002), the Court endorsed an earlier ruling, *Federal Power Commission v. Florida Power & Light Co.*, 404 U.S. 453, 469 (1972), confirming FERC's exclusive jurisdiction over the Florida Power & Light Company's ("FPL") transmission facilities. As the Court recounted:

> [S]ince electric energy can be delivered virtually instantaneously when needed on a system at a speed of 186,000 miles per second, such energy can be and is transmitted to FPL when needed from out-of-state generators, and in turn can be and is transmitted from FPL to help meet out-of-state demands; . . . there is a cause and effect relationship in electric energy occurring throughout every generator and point on the FPL, Corp, Georgia, and Southern systems which constitutes interstate transmission of electric energy by, to, and from FPL.

New York v. FERC, 535 U.S. at 7 n.5 (internal quotation marks omitted).

FERC's jurisdiction over wholesale sales is comparably expansive. *See, e.g.*, *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 300 (1988)[20] ("The [FPA] long has been recognized as a comprehensive scheme of federal regulation of all wholesales of [energy] in

---

[20] *Schneidewind* dealt with the Natural Gas Act rather than the FPA. Because "the relevant provisions of the two statutes are in all material respects substantially identical," however, the Supreme Court has adopted an "established practice of citing interchangeably decisions interpreting the pertinent sections of the two statutes." *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (internal quotation marks omitted).

ED_000419-0005771

interstate commerce.") (internal quotation marks omitted); *Appalachian Power Co. v. Pub. Serv. Comm'n*, 812 F.2d 898, 902 (4th Cir. 1987) ("FERC's jurisdiction over interstate wholesale rates is exclusive . . . ."); *see also Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986) (quoting *S. Cal. Edison*, 376 U.S. at 215-16) ("Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction . . . . This was done in the [FPA] by making [FERC] jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.") (internal quotation marks omitted).

Congress has explicitly prohibited EPA from interfering with FERC's jurisdiction over these matters. Section 310(a) of the CAA specifies that the Act "shall not be construed as superseding or limiting the authorities and responsibilities, under any other provision of law, of the Administrator or any other Federal officer, department, or agency." As discussed in the following sections, the Proposed Guidelines unlawfully interfere with the authority and responsibility given to FERC by Congress in the FPA. For this reason, the Proposed Guidelines are unlawful and must be withdrawn.

a. The Proposed Guidelines Would Impermissibly Interfere With FERC's Exclusive Authority Under Sections 205 and 206 of the FPA To Regulate Interstate Transmission and Wholesale Sale of Electric Energy.

Sections 205 and 206 are the core FPA provisions that empower FERC to regulate both the interstate transmission and wholesale sale of electric energy. 16 U.S.C. §§ 824d, 824e. The Proposed Guidelines would intrude directly into this FERC-exclusive jurisdictional area in violation of section 310(a) of the CAA.

Under section 205(c), jurisdictional public utilities must file with FERC "all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the

ED_000419-0005772

classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services." 16 U.S.C. § 824d(c). Courts have affirmed that this filing requirement is to be read broadly to encompass all classifications, practices, and procedures that "significantly affect" the price or non-price terms and conditions of FERC-jurisdictional services. *See, e.g.*, *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) ("[T]here is an infinitude of practices affecting rates and service. The statutory directive must reasonably be read to require the recitation of only those practices that affect rates and service significantly . . . .") (emphasis omitted). Under section 205(a), FERC may only accept filed rates, rules, and practices if it determines that they are "just and reasonable." 16 U.S.C. § 824d(a).

Section 206 requires FERC to revise any filed "rate, charge, or classification," or "any rule, regulation, practice, or contract" affecting them, if it determines that they are "unjust, unreasonable, unduly discriminatory or preferential." *Id.* § 824e(a). In recent decades, FERC has generally relied on the interplay of competitive market forces, subject to its oversight, to ensure that wholesale prices for electric energy are "just and reasonable."

EPA's proposed Building Block 2 calls for "[r]educing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation." 79 Fed. Reg. at 34,836. The Proposed Guidelines assert that it would be technically feasible for states to use redispatch to achieve substantial emissions reductions. *Id.* at 34,862. They also posit that it would be technically feasible to increase the average utilization rates of NGCCs to seventy percent via redispatch. *Id.* at 34,863. EPA estimates the cost and economic impacts of achieving that NGCC utilization rate and concludes that they would be

ED_000419-0005773

reasonable. *Id.* ("We view these estimated costs as reasonable and therefore as supporting the use of a 70 percent utilization rate target . . . .").

Proposed Building Block 2 interferes with FERC's authority under sections 205 and 206 in several critical ways. First and foremost, the Proposed Guidelines directly invade FERC's core jurisdictional function by effectively determining that the price increases necessary to achieve a seventy percent NGCC utilization rate would be "just and reasonable." Under the precedents described above, this determination is unquestionably for FERC, not EPA, to make.

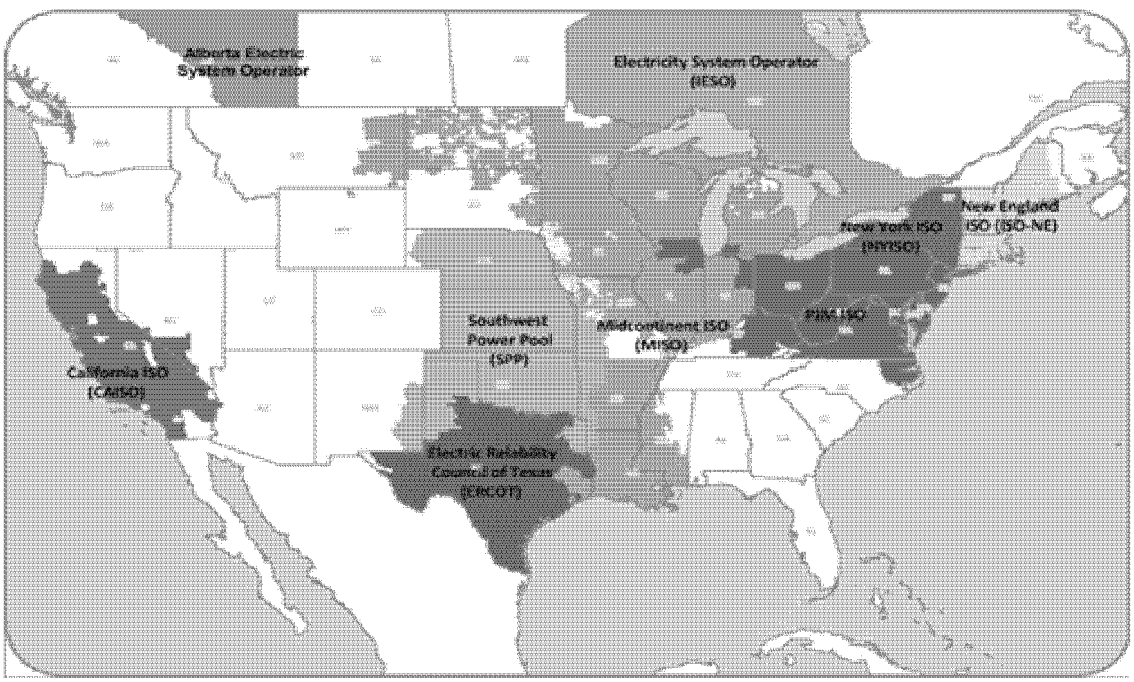
Building Block 2 would also require changes to the dispatch and redispatch rules applicable to EGUs. The Proposed Guidelines appear to acknowledge that dispatch and redispatch in an area encompassing nearly two-thirds of the load in the United States is conducted by ISOs and RTOs. *See, e.g.*, 79 Fed. Reg. at 34,888 ("On the regional level, ISO/RTOs control dispatch and are responsible for reliable operation of the [BPS]."). But EPA fails to consider the legal implications of the fact that ISOs and RTOs dispatch EGUs and other resources pursuant to voluminous and detailed rules filed with FERC under section 205. *See, e.g.*, FERC, *Security Constrained Economic Dispatch: Definition, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act As Added by Section 1298 of the Energy Policy Act of 2005* (July 31, 2006) (describing existing dispatch regimes, their emphasis on security-constrained economic dispatch, and the role of ISOs and RTOs in administering them), *available at* http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record); Section III of the ISO New England Inc. Transmission, Markets, and Services Tariff ("Market Rule 1") ("govern[ing] the operation of New England's wholesale

ED_000419-0005774

electricity markets and includes detailed information on pricing, scheduling, offering, bidding, settlement, and other procedures related to the purchase and sale of electricity"), *available at* http://www.iso-ne.com/participate/ rules-procedures/tariff/market-rule-1.

The map below depicts the territories subject to RTO dispatch. Of these, the "New England ISO" ("ISO-NE"), the "New York ISO" ("NYISO"), the "PJM ISO" ("PJM"), the "Midcontinent ISO" ("MISO"), the "Southwest Power Pool" ("SPP"), and the "California ISO" ("CAISO") are all FERC-jurisdictional RTOs. The Electric Reliability Council of Texas ("ERCOT") employs dispatch systems very similar to those used by other RTOs but is not subject to FERC regulation under section 205 given the physical separation of the ERCOT grid from the rest of North America.

Figure 1: Map of Territories Subject to RTO Dispatch



See http://www.ferc.gov/industries/electric/indus-act/rto.asp.

There is no question that dispatch rules must be filed under section 205 because it is well-established that they significantly affect FERC-jurisdictional rates and non-rate terms and

conditions of service. There is also no question that ISOs and RTOs must comply with the filed dispatch rules and are potentially subject to civil penalties for deviating from them under section 316A of the FPA. 16 U.S.C. § 825o-1.

FERC-approved RTO dispatch rules may be amended only by: (i) the RTOs, which must voluntarily submit amendments and persuade FERC to accept them under the standards of section 205; or (ii) by FERC, on its own initiative or in response to a third party complaint, under section 206. EPA and individual states have no authority to modify these dispatch rules. States also may not compel utilities, including ISOs and RTOs, to make involuntary section 205 filings. *See, e.g.*, *Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

In addition, EPA has ignored the fact that modifying redispatch rules to provide for the "environmental redispatch" contemplated by Building Block 2, *see* 79 Fed. Reg. at 34,863, would necessitate fundamental changes to existing ISO and RTO dispatch procedures that could conflict with FERC policies and with FERC's FPA authority. All ISOs and RTOs use a form of regional, security-constrained, bid-based economic dispatch. These regimes are often designed to co-optimize the dispatch of resources to produce the most efficient combination of energy and "ancillary services"[21] needed to satisfy all requirements at the lowest total cost. FERC has consistently favored the use of bid-based economic dispatch mechanisms for at least the last

---

[21] Section 1.2 of FERC's *pro forma* Open Access Transmission Tariff ("OATT") defines "ancillary services" as transmission or generation-related services "that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) ("FERC *pro forma* OATT"). In ISO and RTO regions, several ancillary services may be procured from suppliers that offer to sell them at prices determined by ISO and RTO dispatch algorithms.

ED_000419-0005776

decade. No ISO or RTO has rules or dispatch software algorithms that would implement environmental dispatch. Nor do they have rules or software that would enable them to target a seventy percent utilization rate for NGCCs within their own regions, let alone on an inter-regional or even a national level.

As FERC Commissioner Moeller has testified, "[s]imply put, the power plants with the lowest operating costs are called first to generate electricity—with various reliability requirements and other factors as part of the decision, depending on the structure of various markets." *FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges: Hearing Before the Subcomm. on Energy and Power of the H. Comm. on Energy & Commerce*, 113th Cong. 3 (July 29, 2014) (written testimony of Philip D. Moeller, Comm'r, FERC), *available at* http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid ("Moeller Testimony") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Switching to "environmental dispatch" would result in a system in which "units will be called to generate primarily based upon the emission profile of the unit." *Id.* Commissioner Moeller has also informed Congress that FERC-jurisdictional RTO markets "would need to be fundamentally altered and redesigned to implement EPA's proposal to accommodate environmental dispatch." *FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges: Hearing Before the Subcomm. on Energy and Power of the H. Comm. on Energy & Commerce*, 113th Cong. 3 (July 29, 2014) (Answers to Preliminary Questions for the FERC, Philip D. Moeller, Comm'r, FERC), *available at* http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-

ED_000419-0005777

epa%27s-proposed-clean-power-plan-and-other-grid ("Moeller Responses") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

It is, at best, disingenuous for the Proposed Guidelines to emphasize that ISOs and RTOs' existing economic dispatch rules have accommodated existing environmental rules on a plant-specific basis, e.g., by permitting sellers to incorporate environmental costs into their offers. 79 Fed. Reg. at 34,862. Revising dispatch rules to focus on NGCC utilization rates instead of economic dispatch would in fact be a radical transformation. *Id.*at 34,863. FERC Commissioner Clark has explained that:

> [T]he Commission has allowed RTOs to acknowledge the operating limits of certain plants. Also the Commission allows generators to recognize various governmentally imposed costs like taxes and cap-and-trade schemes, but this is simply a matter of allowing generators to bid-in costs that they have legally incurred. To go beyond that by changing the fundamental market dispatch algorithms in the ways some have suggested would be a major change, to say the least.

FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges: Hearing Before the Subcomm. on Energy and Power of the H. Comm. on Energy & Commerce, 113th Cong. 3 (July 29, 2014) (Answers to Preliminary Questions for the FERC, Tony Clark, Comm'r, FERC), *available at* http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid ("Clark Responses") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

Even if EPA's proposed overhaul of RTO dispatch mechanisms were technically feasible, which has not been established and which UARG does not concede, it could be approved only by FERC—not mandated by EPA or by states acting at EPA's behest. FERC, not EPA, would have to conclude that environmental dispatch is just, reasonable, and not unduly discriminatory. The

ED_000419-0005778

Proposed Guidelines' usurpation of these decisions from FERC interferes with the authority given to FERC by Congress in the FPA. As such, the Proposed Guidelines violate section 310(a) of the CAA, which expressly prohibits EPA from such interference with other federal agencies or federal laws.

The same legal considerations apply to FERC-jurisdictional public utilities that have not transferred control of their transmission facilities to an RTO, i.e., principally utilities in the southeastern and western states. These utilities provide transmission service under tariffs that are modeled closely on FERC's *pro forma* open-access transmission tariff ("OATT"). *See* FERC *pro forma* OATT (establishing the current version of the *pro forma* OATT used by most FERC-jurisdictional utilities that are not participating in RTOs). Non-RTO tariffs also include provisions governing redispatch of EGUs, and the curtailment of transmission customers, in certain situations. *See, e.g.*, *id.* §§ 13.3, 13.6, 15.4, 27, 30.5, and 33. Like RTO tariffs, non-RTO tariffs are filed with, and approved by FERC, and can be amended only by the filing utilities or by FERC—not EPA—under sections 205 or 206.

The Proposed Guidelines violate section 310(a) of the CAA because they interfere with FERC's exclusive authority under sections 205 and 206 of the FPA to regulate interstate transmission and wholesale sales of electric energy. As a result, the Proposed Guidelines are contrary to law, and EPA must withdraw them.

b. The Proposed Guidelines Conflict With Section 202(a) of the FPA and Impermissibly Intrude on FERC's Authority To Coordinate Regional Transmission.

Section 202(a) of the FPA authorizes FERC to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy" in order to assure "an abundant supply of electric energy" with "the greatest possible economy" and with regard to the "proper utilization and conservation of natural

resources." 16 U.S.C. § 824a. But it is "definitively" clear that such coordination must be voluntary and that FERC has no power to compel any particular "'technique of coordination.'" *Atl. City Elec. Co.*, 295 F.3d at 12 (quoting *Duke Power Co. v. Fed. Power Comm'n,* 401 F.2d 930, 943 (D.C. Cir. 1968)); *see also Cent. Iowa Power Coop. v. FERC*, 606 F.2d 1156, 1161 (D.C. Cir. 1979) (holding that the voluntariness requirement of section 202(a) prevented FERC from revising a proposed power-pooling agreement that "provide[d] a mechanism for coordinated daily operation of generation facilities" to create an even more "fully integrated electric system with central dispatch of generating units"). Thus, for example, FERC may not force utilities to form or join an RTO under section 202(a).

Recently, in *South Carolina Public Service Authority v. FERC*, 762 F.3d 41, 59 (D.C. Cir. 2014) (per curiam), the court held that FERC's mandatory transmission planning reforms under Order No. 1000 were lawful because section 202(a) only governed the "coordinated *operation* of existing transmission facilities, not to the planning of future facilities" and was "textually limited to coordination for purposes of generation, transmission and sale, all activities that require operating facilities." The decision thus affirmed that section 202(a) does not permit FERC to impose greater involuntary coordination involving existing facilities, such as operational EGUs.

The Proposed Guidelines intrude on FERC's section 202(a) jurisdiction by promoting the development of multi-state plans for the coordinated operation and dispatch of EGUs and by specifying rules to govern the development and evaluation of such plans. 79 Fed. Reg. at 34,851, 34,897. FERC has encouraged the voluntary formation of RTOs that dispatch EGUs within their regional boundaries. But the Proposed Guidelines call for greater regional coordination both through existing RTO structures and alternative multi-state arrangements. *Id.*

ED_000419-0005780

at 34,865 n.142, 34,867 (describing EPA's use of six regions for analytical purposes that were "informed by" but do not correspond to RTO boundaries), 34,888 (proposing that regional coordination be undertaken through non-RTO entities).

Although EPA professes that any additional regional coordination under the Proposed Guidelines would be voluntary, it appears that the rule would, as a practical matter, effectively require further coordination to address the integrated nature of the interstate grid and to reduce compliance costs. *See, e.g.*, MISO, *GHG Regulation Impact Analysis – Initial Study Results* at 3, 11, 14 (Sept. 17, 2014) (finding that compliance costs in the MISO footprint could be reduced by approximately $3 billion annually by taking a MISO-wide approach to reducing CO_2 emissions compared to making similar emission reductions on a "sub-regional" basis) ("Initial MISO Study Results"), *available at* https://www.misoenergy.org/WhatWeDo/EPARegulations/Pages/111(d).aspx (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). To the extent that the Proposed Guidelines would mandate new regional coordination, e.g., by effectively compelling the creation of multi-state dispatching arrangements in non-RTO regions, expanding the scope of existing RTO dispatch, or requiring RTOs to coordinate conflicting state plans, this would conflict with the voluntariness requirement of section 202(a) of the FPA, intrude into an area of FERC authority in violation of section 310(a) of the CAA, and constitute an unlawful EPA attempt to exercise even greater power over the coordination of transmission and sale of electricity than the FPA gives to FERC.

ED_000419-0005781

c. The Proposed Guidelines Unlawfully Intrude on FERC's Authority Under Section 215 of the FPA To Ensure Reliability of the BPS.

Section 215 of the FPA gives FERC the ultimate responsibility for the reliability of the BPS[22] by authorizing it to approve and enforce reliability standards developed by NERC and the various regional reliability entities. 16 U.S.C. § 824*o*. The Proposed Guidelines reference NERC, suggest that NERC and EPA have had some discussions about the Proposed Guidelines' potential reliability implications, 79 Fed. Reg. at 34,836, and "mention[] the concept of reliability more than a hundred times," Moeller Testimony at 6. But the Proposed Guidelines give no indication that EPA is prepared to defer to, or to even seriously account for, the extensive expertise that: (i) FERC has developed as the federal agency principally responsible for the reliability of the BPS; or (ii) NERC possesses as the independent body with the statutory responsibility under the FPA to "evaluate and improve the reliability of the BPS,"[23] and to develop and enforce reliability standards.

Commissioner Moeller has warned that "it's the details of calculating proper reserve margins and specific load pockets that matter from a reliability perspective." *Id.* He has urged EPA to include FERC in evaluating the reliability questions raised by the proposed rule, and in potentially, developing answers: "Just as the Commission does not have expertise in regulating air emissions, I would not expect the EPA to have expertise on the intricacies of electric markets and the reliability implications of transforming the electric generation sector." *Id.* at 7. NERC

---

[22] The statute defines the "bulk-power system" as "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability." 16 U.S.C. § 824*o*(a)(1).

[23] *See* NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at ii (Nov. 2014) ("Initial NERC Report") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

ED_000419-0005782

has also identified numerous concerns with EPA's Proposed Guidelines, which are discussed in detail in Section VII.B.4 below.

EPA's lack of expertise and knowledge in this area shows in the Proposed Guidelines. The Proposed Guidelines assume that electrons are fully fungible, when in reality the regional nature of transmission grids and the prevalence of transmission constraints seriously restrict the extent to which one EGU can be substituted for another. EPA has ignored technical requirements, e.g., the need for voltage support and other ancillary services, that complicate the integration of intermittent renewable resources, and practical limitations on the development of new transmission and pipeline infrastructure. It has also ignored the requirements of existing FERC-approved reliability standards and failed to consider how the obligation of RTOs, transmission-owning utilities, and EGUs to comply with them might conflict with the Proposed Guidelines' emission reduction goals.

Unless EPA reverses course, invites FERC and others with reliability expertise to the table, and modifies the Proposed Guidelines as necessary to reflect input from FERC, NERC, and other industry experts, the rule will result in conflicts between FERC-approved enforceable reliability standards and EPA requirements. By disregarding the reliability standards and by making its own reliability-related determinations, EPA is improperly supplanting FERC as the ultimate authority over the reliability of the BPS in contravention of section 215 of the FPA and section 310(a) of the CAA.

In sum, a federal agency may not assert authority over issues that Congress has exclusively reserved for another. *See, e.g.*, *Hunter v. FERC*, 711 F.3d 155, 156 (D.C. Cir. 2013) (rejecting FERC's attempts to regulate matters that the court believed were exclusively subject to the jurisdiction of the Commodity Futures Trading Commission). It is also clear that

ED_000419-0005783

"jurisdiction cannot arise from the absence of objection, or even from affirmative agreement" by a regulatory body, *see Columbia Gas Transmission Corp. v. FERC*, 404 F.3d 459, 463 (D.C. Cir. 2005), any more than it can be created by the consent of a private party. *See, e.g.*, *Weinberger v. Bentex Pharms., Inc.*, 412 U.S. 645, 652 (1973) ("Parties . . . cannot confer jurisdiction; only Congress can."); *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 398 (D.C. Cir. 2004); *Michigan v. EPA,* 268 F.3d 1075, 1081 (D.C. Cir. 2001) ("EPA is a federal agency—a creature of statute. It has no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress. 'It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress.' *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 . . . (1988). Thus, if there is no statute conferring authority, a federal agency has none."). These principles are embodied in the CAA. Section 310(a) makes clear that EPA cannot use the CAA as a vehicle to usurp the authority of another federal agency. This is precisely what EPA proposes to do, however, in the Proposed Guidelines. Because the Proposed Guidelines intrude on the exclusive authority given to FERC in sections 205, 206, 202(a), and 215 of the FPA, they are arbitrary and capricious and contrary to law. As a result, EPA must withdraw the Proposed Guidelines.

B. EPA Has Arbitrarily and Capriciously Ignored the Realities of the FERC-Regulated Wholesale Electric Markets and Bulk Power System.

EPA action must be overturned if it is "arbitrary, capricious, an abuse of discretion or otherwise not in accordance with law," or if it is "in excess of statutory jurisdiction, authority, or limitations . . . ." CAA § 307(d)(9)(A), (C). An agency action will be upheld if it "articulate[s] a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)). Agency factual findings will be upheld if

ED_000419-0005784

supported by substantial evidence. 16 U.S.C. § 825*l*(b). For the reasons set forth below, EPA's Proposed Guidelines do not represent the kind of "reasoned decision-making" that the CAA, the APA, and the courts require. The Proposed Guidelines therefore must not be adopted in their current form and should instead, be withdrawn, or, at a minimum, substantially revised to correct their many factual errors and faulty assumptions.

1. EPA Has Unreasonably Failed To Consult With FERC Regarding the Proposed Guidelines' Technical Feasibility and Impacts on Reliability and Markets.

EPA claims that the Proposed Guidelines were "substantially informed by the extensive input from states and a wide range of stakeholders . . . since the summer of 2013." 79 Fed. Reg. at 34,835; *see also id.* at 34,845-51. It is clear, however, from statements made by FERC's commissioners, including their sworn testimony before the House of Representatives' Committee on Energy and Commerce, Subcommittee on Energy and Power on July 29, 2014, that consultations with FERC have been extremely limited. It appears that only the office of FERC's Chairman had any contact with EPA and that those contacts were both limited and "private and paperless." Moeller Testimony at 7. No other Commissioners appear to have been involved in, or made aware of the details of, the limited FERC staff communications with EPA.

The Commissioners' testimony and responses to written questions also make it clear that FERC: (i) was not involved in preparing the Technical Support Document ("TSD") entitled "Resource Adequacy and Reliability Analysis," EPA-HQ-OAR-2013-0602-0368, that accompanied the Proposed Guidelines; (ii) has not conducted an independent study of the Proposed Guidelines' reliability impacts; and (iii) did not verify the feasibility of EPA's optimistic assumptions concerning the major new electric transmission and gas pipeline infrastructure development that must take place for the emission reductions contemplated by the Proposed Guidelines to be achieved (which are discussed separately below). To date, EPA has

ED_000419-0005785

also not accepted requests that FERC be given a formal role, along with NERC and other entities with reliability expertise, in discussing the reliability implications of the Proposed Guidelines. Moeller Testimony at 6 ("Going forward and at a minimum, I will reiterate my request for a formal role for the Commission with the EPA as it relates especially to the reliability implications of the proposal. Convening the appropriate reliability experts (including the Commission, and possibly the North American Electric Reliability Corporation, electric wholesale market operators, power generators, electricity consumers, along with input from the states) to examine the reliability implications is necessary to avoid additional unintended consequences.").

Commissioner Clark recently reiterated that EPA has not seriously engaged FERC on reliability issues. *See* John Sicliano, *FERC's Clark Urges States To Delay Climate Plans Until EPA Issues FIP Guide*, INSIDEEPA/CLIMATE (Nov. 5, 2014), *available at* http://insideepa climate.com/climate-daily-news/fercs-clark-urges-states-delay-climate-plans-until-epa-issues-fip-guide (subscription required) ("'I think there needs to be a much more transparent process in relation to how we're modeling reliability and how reliability is being taken into consideration. I recently read in the press clippings that an EPA official said "we are working closely with FERC on these reliability matters." And I read it, and I thought that's news to me.'").

Most recently, the Chairmen of the House Energy and Commerce Committee and the Subcommittee on Energy & Power and the Ranking Member of the Senate Energy & Natural Resources Committee wrote a letter to FERC Chairman Cheryl A. LaFleur that noted the evident lack of substantive outreach by EPA. The letter asked FERC to take action to "begin to mitigate EPA's failure to engage FERC and other relevant agencies . . . ." Letter from Fred Upton, The Hon. Chairman, House Energy & Commerce Comm., et al., to The Hon. Cheryl A. LaFleur,

ED_000419-0005786

Chairman, FERC at 4 (Nov. 24, 2014) ("November 24 Congressional Letter"), *available at* http://1.usa.gov/1xO4co5 (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

EPA's refusal to consider FERC's expertise regarding wholesale power markets, transmission operations, the real world impact of transmission constraints, and the BPS is inexplicable, arbitrary, and capricious. Article III courts frequently recognize and defer to FERC's expertise in these matters, *see, e.g.*, *S.C. Pub. Serv. Auth.*, 762 F.3d at 54-55 ("[I]n rate-related matters, the court's review of the Commission's determinations is particularly deferential because such matters are either fairly technical or 'involve policy judgments that lie at the core of the regulatory mission.'") (quoting *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009)). EPA's failure to show similar deference has resulted in a proposed rule that fundamentally misunderstands the technical realities of the modern utility sector and is therefore not the product of reasoned decisionmaking. This conclusion has been reinforced by NERC, as described in further detail below.

2. EPA's Erroneous Assumption that States Control the Dispatch of EGUs Is Likely to Result in Serious Distortions and Unintended Consequences.

As discussed above, proposed Building Block 2 wrongly assumes that states have "command-and-control" style authority over the redispatch of EGUs when a significant majority of EGU dispatch is in reality managed by FERC-jurisdictional RTOs. These comments have already explained how this error results in Building Block 2 violating the FPA. But the same oversight also makes the Proposed Guidelines arbitrary and capricious. EPA has not considered the practical difficulties—and potential for state-federal and inter-agency disputes—that pressing states to pursue environmental dispatch is likely to entail. As Commissioner Clark told Congress:

ED_000419-0005787

> [E]ven if all states in a region band together under the regional grid operator, any changes to the wholesale markets must necessarily be vetted and approved by FERC. The Commission would be charged with the awkward task of evaluating fundamental wholesale market design changes driven by environmental priorities approved by the EPA. Yet FERC is an economic and reliability regulator. Any decisions made by FERC must be rooted not in the Clean Air Act, but in our 'just and reasonable' and 'not unduly discriminatory or preferential' rate standard in the Federal Power Act. FERC's ability to alter or reject an RTO-proposed compliance mechanism would present a conflict with EPA's evaluation of the compliance plans. Absent Congress stepping in and clearly defining FERC authority and EPA authority, it is hard not to envision a future jurisdictional train wreck.

Clark Testimony at 7.

Similarly, if states do not coordinate their policies then "regional grid operators will be faced with an increasingly complex task of implementing multiple compliance mechanisms into what was once an efficiently-dispatched regional electric grid." *Id.* at 6. Commissioner Moeller has also explained that because electricity markets are actually "interstate in nature" that the Proposed Guidelines' "state-by-state approach results in an enforcement regime that would be awkward at best, and potentially very inefficient and expensive." Moeller Testimony at 2.

EPA's failure to consider these complications only serves to increase the likelihood that they will pose serious problems. EPA's approach does not represent the kind of "reasoned decision-making" that the APA requires.

3. EPA Underestimates the Challenges of Energy Infrastructure Development and the Impact of Transmission Constraints.

Although the Proposed Guidelines are based on the erroneous presumption that states can dictate how EGUs are dispatched, at times they recognize the interconnected, integrated, and multi-state nature of the actual transmission grid. For example, EPA states that "[t]he utility power sector is unique in that, unlike other sectors where the sources operate independently and on a local scale, power sources operate in a complex, interconnected grid system that typically is regional in scale." 79 Fed. Reg. at 34,844. EPA also suggests that "system operators typically

ED_000419-0005788

have flexibility to choose among multiple EGUs when selecting where to obtain the next MWh of generation needed" and that this results in electricity being highly "fungible." *Id.* at 34,880.

Similarly, the Proposed Guidelines assert that EPA has examined the "capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system" to accommodate a seventy percent utilization rate for NGCCs. *Id.* at 34,863. The Agency concludes that these systems would be capable of supporting the degree of increased NGCC utilization needed for states to achieve EPA's proposed goals because: (i) the pipeline system is already supporting national NGCC utilization rates of sixty percent or higher during peak hours; (ii) its proposed state goals are supposedly sufficiently flexible so that "even if isolated natural gas or electricity system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours;" and (iii) pipeline and transmission planners "have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity." *Id.* at 34,864.

Congressional testimony and other statements by multiple FERC commissioners (from both political parties) demonstrate that these assumptions are unrealistically simplistic, unreasonable, and incompatible with reasoned decisionmaking. Then-acting FERC Chairman LaFleur told Congress that "FERC staff emphasized that in light of EPA's proposal to rely on increased capacity factors for natural gas fired generation resources, gas pipeline adequacy should be considered from a regional perspective, not just a national perspective, due to existing constraints on the system." *FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges: Hearing Before the Subcomm. on Energy and Power of the H. Comm. on Energy & Commerce*, 113th Cong. 4 (July 29, 2014) (written

ED_000419-0005789

testimony of Cheryl A. LaFleur, Acting Chairman, FERC), *available at* http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

Commissioner Moeller stated that he was "skeptical of EPA's contention that the modeled [pipeline] capacity increases are feasible by 2020 . . . partly due to the fundamental manner in which the proposed rule would change the way that electricity is dispatched." Moeller Responses at 5. Moreover, expanding gas pipeline infrastructure has proven extremely difficult in recent years in certain regions that are widely understood to need more capacity, e.g., New England, which is particularly dependent on natural gas for heat and electricity generation during the winter. Commissioner Moeller explained that the fundamental problem has been finding ways to finance new construction when generators competing in RTO-administered electricity markets are reluctant to sign the long-term contracts that traditionally supported the financing of new pipelines before the markets were established. *Id.*; Moeller Testimony at 3-4. These financing difficulties are likely to be exacerbated by the Proposed Guidelines. *See* Moeller Testimony at 3-4.

With respect to electric transmission, the Proposed Guidelines pay scant attention to the regional nature of transmission grids, the significant limitations imposed by transmission constraints, and the reality that such constraints are hardly "isolated" as the Proposed Guidelines suggest. 79 Fed. Reg. at 34,864. As Commissioner Moeller informed Congress:

> As we have seen with the implementation of EPA's mercury rule (MATS), load pockets matter because the laws of physics trump written words. Although a specific generating plant may not contribute significant power to the grid, its other outputs such as voltage support or "inertia" qualities may contribute significantly to grid stability. Moreover, the details of how reserve margins are calculated can have a significant impact on the ability of excess capacity in one load pocket to

ED_000419-0005790

> transfer power to another load pocket that is short. These challenges can be addressed, but it takes engineering expertise, especially when designing optimal infrastructure improvements.

Moeller Testimony at 6.

In connection with Building Block 3, i.e., promoting greater deployment of intermittent renewable resources, EPA failed to consider transmission grid "integration issues" (e.g., voltage control, natural gas backup power, etc.) that would have to be addressed to accommodate the substantial influx of renewable resources that the Proposed Guidelines contemplate. *See id.* at 7. Commissioner Moeller noted that FERC had not been asked to, and had not, analyzed these significant implications. *See* Moeller Responses at 5. He also stated that he did not believe that FERC had "studied whether additional transmission lines would need to be built under the EPA Proposal to integrate more renewables, where the lines may be built, and how long it may take to site, permit, and build these lines" or estimated the cost of transmission necessary to supply increased renewable resources. *Id.* at 6.

4. EPA Relies on Assumptions that Independent Expert Analyses Demonstrate Are Faulty.

EPA's assumption that the Proposed Guidelines' emission reductions could be achieved on the contemplated timetable without significant negative impacts on electric reliability and reliability markets is contradicted by independent expert analyses. Most notably, NERC has issued an initial reliability review of EPA's Proposed Guidelines that has identified numerous serious concerns. *See* Initial NERC Report. As the Initial NERC Report explains, NERC is independent and impartial. The Initial NERC Report is a detailed review by the entity with the greatest collective expertise and experience regarding the reliability of the BPS in the United States. It is not intended to advocate a policy position on behalf of any entity or to promote any specific compliance approach. *Id.* at 1. But it does establish that "detailed and thorough analysis

ED_000419-0005791

will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability." *Id.* NERC is planning to conduct three more special assessments between now and December 2016 to evaluate more comprehensively the impact of EPA's Proposed Guidelines and of the state plans that will be submitted if the Proposed Guidelines are not withdrawn. *Id.* at 4.

The mere fact that NERC is already questioning the feasibility of the Proposed Guidelines ought to be enough to cause EPA to pause and reconsider them at a fundamental level. The specific flaws the Initial NERC Report identifies with each of the four proposed Building Blocks would make it irrational, arbitrary, and capricious for EPA to fail to do so.

With respect to Building Block 1, the Initial NERC Report acknowledges that improving the existing coal generation fleet's efficiency by six percent "may be difficult to achieve." *Id.* at 8. It explains that EPA calculated unit-specific heat rates using gross generation data from the CEMS, thereby ignoring "generation-reducing effects from post-combustion environmental controls . . . ." *Id.* EPA also used net-generation data, without considering the fact that these retrofits would reduce the net output and net heat rate efficiency of affected units. "Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as [MATS] and Section 316(b) of the Clean Water Act." *Id.* EPA also assumed that turbine overhauls would result in major heat rate improvements but "[r]egular turbine overhauls are generally not practical or economical" because they require units to be out of service for protracted periods. *Id.* The notion that there are significant efficiencies to be obtained through overhauls also ignores the reality that generation owners have strong incentives to operate at peak efficiency, including profit incentives in FERC-regulated wholesale power markets.

ED_000419-0005792

Moreover, the Initial NERC Report notes that EPA fails to account for factors that have "profound effects on the process efficiency of a coal-fired EGU," including:

> (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Id. (footnotes omitted).

The Initial NERC Report also explains how EPA failed to consider the interaction between Building Blocks 1 and 2. Assuming that Building Block 2 will cause coal units to cycle more often, resulting in lower capacity factors and higher heat rates, the heat rate improvements assumed by Building Block 1 are unlikely to be achievable. *Id.* Although EPA recognized capacity effects in its regression analysis, it did not evaluate the effects of lower capacity factors from dispatching natural gas generation before coal generation. *Id.*

With respect to Building Block 2 itself, the Initial NERC Report identifies "a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated." *Id.* at 9. First, NGCC units have traditionally been used for load following purposes, and while some are capable of operating at a high capacity factor, they are generally less well-suited to serve as baseload resources than coal generation. *Id.* Second, the Proposed Guidelines would accelerate an ongoing utility industry shift from coal- to gas-fired generation, threatening the fuel diversification that utilities traditionally rely on to help to preserve reliability. *Id.* Third, as the events of the winter 2014 "polar vortex" demonstrated, natural gas generation can face serious fuel availability issues during extended periods of cold weather. The Initial NERC Report expresses concern that over-reliance on natural gas generation will degrade utilities' ability to manage cold weather conditions and threaten reliability. *Id.* Fourth, Building Block

ED_000419-0005793

2's assumption that "the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure" is unrealistic. *Id.* at 10. There are "critical areas," including Arizona, Nevada, and New England that already face pipeline constraints, and those areas will need still more pipeline capacity to the extent that coal generation is replaced by natural gas generation. *Id.*; *see also* Section VII.B.3 (noting that FERC Commissioners have highlighted these same infrastructure issues).

With respect to Building Block 3, the Initial NERC Report identifies various flaws in the Proposed Guidelines' assumptions regarding the preservation of nuclear generation resources and the expansion of renewable energy. Initial NERC Report at 11-13. Among other issues, EPA's assumed "rapid growth in non-hydro renewable generation exceeds its own forecast" in the RIA of 356 TWh/year by 2030. *Id.* at 11. EPA also overlooked real world differences among state renewable portfolio standards that are contrary to EPA's assumptions. *Id.* at 12-13.

Furthermore, EPA completely failed to address the well-known grid reliability challenges, which have also been noted by FERC's Commissioners, *see* Section VII.B.3, associated with increased dependence on "variable" resources. Initial NERC Report at 13. Specifically:

> Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or [Essential Reliability Services], needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.
>
> A large penetration of [variable energy resources] will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher

> forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.

Id. (footnotes omitted). Thus, NERC makes it clear that increased dependence on renewables may seriously strain the utility industry's ability to provide or procure essential reliability services. *Id.* at 2.

With respect to Building Block 4, the Initial NERC Report notes that EPA has projected that energy efficiency will grow faster than electricity demand, an assumption with "complex" implications. Among other things, if EPA's aggressive rate of efficiency growth cannot be met, it will be necessary to adopt additional carbon reduction measures to meet the state targets, presumably through further reductions in fossil fuel generation that may not be achievable. *Id.* at 2, 14,16.

More generally, the Initial NERC Report indicates that, even if the Proposed Guidelines could be implemented, they will likely take longer to implement than EPA envisions.

> State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

Id. at 3-4.

NERC's 2014 Long-Term Reliability Assessment highlights the issues raised in the Initial NERC Report and emphasizes that environmental regulations, including specifically the Proposed Guidelines, are creating uncertainty and require assessment. NERC, 2014 Long-Term Reliability Assessment at 8-17 (Key Reliability Finding #2), *available at* http://www.nerc.com/

ED_000419-0005795

pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

The November 24 Congressional Letter asked FERC to hold a technical conference with participation by the Department of Energy, the National Association of Regulatory Utility Commissioners, and stakeholders to "examine the significant concerns, as identified by NERC's report, that EPA's Clean Power Plan presents for grid reliability." November 24 Congressional Letter at 3. That letter emphasized that "EPA lacks the mission and the expertise to determine what is necessary to maintain the reliability of the nation's electric grid. Indeed, Congress specifically established the *Electric Reliability Organization* for this very purpose." *Id.* at 2 (emphasis in original) (NERC is the FERC-approved "Electric Reliability Organization" under section 215 of the FPA).

Beyond NERC's concerns, the RTOs, which actually operate and plan for the future of the BPS and thus have enormous reliability expertise, have also raised concerns with the Proposed Guidelines. For example, on September 16, 2014, SPP informed Missouri regulators that it "anticipates that there will be significant reliability impacts as a result of compliance with [the Proposed Guidelines]." *Responsive Comments of the Southwest Power Pool, Inc., In the Matter of an Investigation of the Cost to Missouri's Electric Utilities Resulting from Compliance with Federal Environmental Regulations* at 3 (Sept. 16, 2014), Missouri Public Service Commission, File No. EW-2012-0065, Item No. 97, *available at* https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_ itemno_details.asp?caseno=EW-2012-0065&attach_id=2015006331 ("SPP Comments") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). SPP noted that addressing these reliability impacts would likely require transmission upgrades but that because transmission upgrades

normally require up to eight and a half years to be placed into service such solutions would likely not be feasible given the Proposed Guidelines' 2020 compliance deadline. *Id.* An October 2014 assessment of reliability impacts by SPP concluded that it was:

> clear that new generation and transmission expansion will be necessary to maintain reliability during summer peak conditions if EPA's projected generator retirements occur. Even the scenario that assumes optimal resource expansion using new natural gas-fired resources could be problematic during extreme winter load conditions with gas supply and delivery challenges.

SPP, *Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*, at 6 (Oct. 8, 2014), *available at* http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). In addition, "[m]ore comprehensive planning efforts with stakeholders and new tools/metrics will be required. Unprecedented coordination and cooperation beyond regional planning efforts will be necessary but may not be timely given significant challenges with interregional planning and necessary system expansion." *Id.*

Similarly, the MISO indicated that as much as an additional 14 gigawatts ("GW") of coal-fired generating capacity in the MISO footprint could be at-risk for retirement because of the Proposed Guidelines. Initial MISO Study Results at 13-14. This amount is beyond the 12,600 MW within MISO's area that is slated to retire by the end of 2016 to comply with MATS. ERCOT has also evaluated the potential implications of the Proposed Guidelines for grid reliability and the non-FERC jurisdictional wholesale electricity market in Texas. ERCOT's analyses indicated that:

> [I]mplementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid. ERCOT estimates that the proposed CO_2 emissions limitations will result in the retirement of between 3,300 MW and 8,700 MW of coal generation capacity, could result in transmission reliability issues due to the loss of generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable

ED_000419-0005797

> generation resources. The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region by up to 20% in 2020, without accounting for the costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT.

ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan* (Nov. 17, 2014), *available at* http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPower Plan.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). NYISO also noted that the Proposed Guidelines "present[] potentially serious reliability implications . . . ." NYISO, Comments of the New York Independent System Operator, Inc. on the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Dec. 1, 2014).

MISO has also expressed reliability concerns regarding the Proposed Guidelines. Specifically, MISO says that the Proposed Guidelines' interim goals "will force decisions that pit environmental compliance against electric reliability." Letter from John R. Bear, President and CEO, MISO, to The Hon. Gina McCarthy, Adm'r, EPA, at 4 (Nov. 25, 2014) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). To meet the interim goals, reductions in CO_2 emissions will need to begin in 2020, and MISO says "there will not be nearly enough time to plan for the replacement capacity, transmission upgrades, and natural gas delivery infrastructure that will be needed to maintain reliability and resource adequacy." *Id.* at 2.

More generally, RTOs have called on EPA to establish some form of "reliability safety valve" similar to the one-year compliance extension that is available to avoid retirement-related reliability impacts from the MATS compliance deadline. The Initial NERC Report states that

ED_000419-0005798

even if EPA were to do so, a "reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed . . . ." Initial NERC Report at 22.

5. EPA Has Not Accounted for the *EPSA* Decision's Potential Impact on Demand-Side Resources.

Building Block 4 assumes that states will be able to reduce "emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required." 79 Fed. Reg. at 34,836. The Proposed Guidelines focus on the role played by state-administered programs but appear to ignore the fact that demand-side resources have been active participants in RTO-administered markets, including especially RTO-administered capacity markets, for many years. The Proposed Guidelines likewise do not address the D.C. Circuit's decision in *EPSA*, which both vacated FERC Order No. 745 and arguably prohibits some demand-side resources from directly participating in FERC-jurisdictional markets, although it does not affect state-administered demand-response programs.[24]

It would not be consistent with reasoned decisionmaking for EPA to continue to simply assume that demand-side resources will play an expanded role in supporting emissions reductions given *EPSA's* potential implications. It might be that the change from FERC to state regulation of demand response will be beneficial in the long term, but EPA must recognize that demand response is likely entering a potential period of transition and uncertainty that makes the Building Block 4 assumptions unrealistic. *See* Mot. of FERC To Stay Issuance of Mandate at 11, *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014) (No. 11-1486) ("Whether the Opinion is read narrowly or broadly, its implementation will involve both setting new

---

[24] *EPSA* was decided less than a month before the Proposed Guidelines were published in the Federal Register.

ED_000419-0005799

prospective rules and unwinding demand response participation in certain wholesale markets—a task with significant market and financial implications that go far beyond the typical burdens of litigation . . . .").

6. EPA Inaccurately Describes RTO Capacity Markets and Overstates Their Potential To Advance the Proposed Guidelines' Goals.

Finally, the Proposed Guidelines suggest that:

> In most states where generation is no longer subject to price regulation, [RTOs] . . . ensure the adequacy of future generation supplies by administering auctions for forward capacity. In these auctions, owners of existing EGUs (with consideration of building blocks 1 and 2), developers of new EGUs including renewable generating capacity (building block 3), and developers of demand-side resources (building block 4) all compete to provide potential resources for meeting the projected demand for electricity services.

79 Fed. Reg. at 34,881 (footnote omitted). The Proposed Guidelines suggest that RTO capacity markets can serve as the functional equivalent of traditional state integrated resource planning mechanisms and that the BSER for CO_2 emissions should account for this. *Id.*

The Proposed Guidelines' description of RTO capacity markets is inaccurate because only two FERC-jurisdictional RTOs, ISO-NE and PJM, have what are generally considered to be "forward capacity markets." The NYISO is currently evaluating a possible move to a forward capacity market design but has concluded on two prior occasions that such a change was not needed in New York. *See, e.g.*, Written Statement of Emilie Nelson, Vice President – Market Operations, on Behalf of New York Independent System Operator, Inc., FERC Docket No. AD14-18-000 at 26-27 (Nov. 5, 2014) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Three FERC-jurisdictional RTOs, namely CAISO, MISO, and SPP, do not have any form of mandatory capacity markets. *See, e.g.*, Commission Staff Report, *Centralized Capacity Market Design Elements*, FERC Docket No. AD13-7-000 at 11-15 (Aug. 23, 2013) ("FERC Staff Report") (describing various RTO capacity market

ED_000419-0005800

designs), *available at* http://www.ferc.gov/CalendarFiles/20130826142258- Staff%20Paper.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). As noted above, the ability of demand-side resources to continue to participate in FERC-jurisdictional capacity markets is also in doubt in light of the *EPSA* decision.

Moreover, the Proposed Guidelines appear to overstate the potential of the capacity markets that actually exist in ISO-NE, the NYISO, and PJM to function as *de facto* approximations of traditional integrated resource planning systems. RTO capacity markets were not intended or designed to play such a role. Their principal purpose is to "ensure resource adequacy at just and reasonable rates through a market-based mechanism that is not unduly discriminatory or preferential as to the procurement of resources." FERC Staff Report at 2. FERC is considering a number of complex and controversial issues related to this goal, such as the types of payments to be made to different kinds of resources and the extent to which new resources should be subject to market power mitigation measures if they are deemed to be "uneconomic." *See, e.g.*, PJM Staff Proposal, *PJM Capacity Performance Proposal* (Aug. 20, 2014) (preliminary proposal to establish new categories of capacity products to address defects in existing PJM capacity market design), *available at* http://www.pjm.com/~/media/documents/reports/20140820-pjm-capacity-performance-proposal.ashx (included in UARG's separately filed Supplemental Materials for the Rulemaking Record); FERC, *Supplemental Notice of Technical Conference, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators,* FERC Docket No. AD13-7-000 (Aug. 23, 2013) (identifying and inviting comment on various capacity market design questions), *available at* http://www.ferc.gov/CalendarFiles/20130823115125-AD13-7-000TC1.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Consequently, EPA has unreasonably

ED_000419-0005801

overstated the potential for RTO-administered capacity markets to support the Proposed Guidelines' objectives.

VIII. If Lawful, The Proposed Guidelines Would Violate the Fifth Amendment Because Uncompensated Takings of Property Will Result.

As these comments explain, EPA's Proposed Guidelines are unlawful for numerous reasons. But assuming *arguendo* that the Proposed Guidelines were otherwise consistent with the CAA and other federal statutes (which they are not), they would nevertheless constitute an unconstitutional taking of property without just compensation. The Proposed Guidelines violate the CAA, the FPA, and are inconsistent with key court rulings. Nevertheless, for the sake of argument, UARG assumes EPA's Proposed Guidelines are authorized by statute and otherwise lawful for the purposes of this evaluation of whether the Proposed Guidelines, under those circumstances, would constitute a taking under the Fifth Amendment.

As EPA acknowledges, to meet the goals set forth in the Proposed Guidelines, numerous coal-fired EGUs throughout the country will need to be shut down. 79 Fed. Reg. at 34,933 (estimating retirement of 46-49 GW of coal-fired EGUs and 16 GW of oil/gas steam EGUs under EPA's Building Block Option 1, and retirement of 24-32 GW of coal-fired EGUs and 3-5 GW of oil/gas steam EGUs under its Option 2 approach); *see also* EPA, Goal Computation Technical Support Document (June 2014), Docket ID No. EPA-HQ-OAR-2013-0602-0460 ("Goal Computation TSD"); *id.* at App. 1, Docket ID No. EPA-HQ-OAR-2013-0602-0255. And for those coal-fired EGUs that do remain open, many will have their operations so severely curtailed that it will result in a partial taking.

The Fifth Amendment of the Constitution prohibits the taking of "private property . . . without just compensation." U.S. CONST. amend. V. The Supreme Court long ago extended the takings concept to regulation that goes too far: "The general rule . . . is that while property may

be regulated to a certain extent, if regulation goes too far it will be recognized as a taking." *Pa. Coal Co. v. Mahon*, 260 U.S. 393, 415 (1922). A total, or per se, taking occurs where regulations "completely deprive an owner of '*all* economically beneficial use' of her property." *Lingle v. Chevron U.S.A. Inc.*, 544 U.S. 528, 538 (2005) (emphasis in original) (quoting *Lucas v. S.C. Coastal Council*, 505 U.S. 1003, 1019 (1992)). Partial takings, like total takings, must be compensated under the Fifth Amendment. Courts evaluate partial takings claims by making "essentially ad hoc, factual inquiries" into three primary factors: (1) the character of the government action; (2) the economic impact of the regulation on the claimant; and (3) the extent to which the regulation interferes with distinct investment-backed expectations. *Penn Cent.*, 438 U.S. at 124.

The constitutional concept of "property" is broad enough to encompass the EGUs affected by the Proposed Guidelines, the generating capacity of those EGUs, and their remaining useful life (and corresponding future generating capacity). *See United States v. Gen. Motors Corp.*, 323 U.S. 373, 378 (1945) ("[Property] deals with what lawyers term the individual's 'interest' in the thing in question . . . . [T]he constitutional provision is addressed to every sort of interest the citizen may possess."); *see also Kaiser Aetna v. United States*, 444 U.S. 164, 179 (1979) (stating that the government must give just compensation for taking "sufficiently important" "*expectancies* embodied in the concept of 'property'") (emphasis added). Takings claims may be brought for the taking of real property, *see Lucas*, 505 U.S. at 1019, tangible property, *see Andrus v. Allard*, 444 U.S. 51, 65 (1979), and intangible property, *see Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1003-04 (1984). The EGUs at issue here are, themselves, obviously tangible property, their generating capacity is intangible property, and the remaining useful life (and associated future generating capacity) of the EGUs represent investment-based

ED_000419-0005803

expectations in the property, all of which are encompassed by the protections of the Fifth Amendment. The economic value of an EGU lies in the generation of electricity. Thus, eliminating or curtailing the generating capacity or remaining useful life of an EGU, as the Proposed Guidelines would do, directly interferes with an owner's primary "'interest' in the thing in question." *Gen. Motors Corp.*, 323 U.S. at 378. Accordingly, if the Proposed Guidelines are otherwise lawful—which they are not—their promulgation would require just compensation for all owners of EGUs that are forced to shut down or severely curtail operations because of EPA's regulatory action.

A. The Proposed Guidelines, if Lawful, Would Result in a Total Taking of Any EGU Forced To Shut Down To Ensure Compliance with the Guidelines.

EPA admits that the Proposed Guidelines will result in the forced retirement of coal- and oil-fired EGUs based on EPA-established state emission goals that can be met only by shifting generating capacity away from these EGUs to other sources of generation. 79 Fed. Reg. at 34,933; Goal Computation TSD, App. 1. If EPA were authorized to issue the Proposed Guidelines, the premature retirement of these EGUs would constitute a total taking because it would completely deprive the owners of these EGUs of all economically beneficial use of their property. *See Lingle*, 544 U.S. at 537. Because EGUs will be required to shut down to meet the state goals set forth in the Proposed Guidelines, the owner of the EGU would lose its capital investment in the EGU, the generating capacity of the EGU, and the remaining useful life of the EGU (and its associated future generating capacity).

Although the Supreme Court has permitted the government, without compensation, to restrict lawful property from being put to unlawful uses, *see Mugler v. Kansas*, 123 U.S. 623 (1887) (breweries banned under Prohibition Era law), or to restrict the use or sale of a previously legal product to the extent that it is nearly valueless, *see Andrus v. Allard*, 444 U.S. 51 (1979),

ED_000419-0005804

the Court has not allowed government appropriation of property without compensation where there is no showing that the property is a nuisance or creates an impending harm to others, *see Mugler*, 123 U.S. at 669 ("In the one case, a nuisance only is abated; in the other, unoffending property is taken away from an innocent owner."); *cf. Lucas*, 505 U.S. at 1030. There is no nuisance or impending harm here. Indeed, the EGUs that would be shut down under the Proposed Guidelines are heavily regulated facilities that operate subject to numerous permits, including Title V permits under the CAA. Moreover, which EGUs would shut down has no relationship to the features of or environmental controls in place at the EGUs themselves. In fact, older, less environmentally-controlled EGUs may continue to operate while newer EGUs with state-of-the-art environmental controls may shut down, simply by virtue of which state the EGU is located in and how much "excess" natural-gas fired, renewable, or other low carbon-emitting capacity the state possesses. In other words, factors that have nothing to do with the environmental characteristics of the EGUs themselves would determine which EGUs must shut down to comply with the rule. The shutting down of these EGUs under the Proposed Guidelines would result in a total loss of all economically beneficial use to their owners and thus constitute a total regulatory taking in the event that EPA's Proposed Guidelines were found otherwise to be lawful.

B. The Proposed Guidelines, if Lawful, Would Result in a Partial Regulatory Taking of Any EGU That Must Significantly Curtail its Operation or Remaining Useful Life To Ensure Compliance with the Proposed Guidelines' Emission Goals.

Under Building Blocks 2, 3, and 4 of the Proposed Guidelines, as reflected in the EPA state emission goals, many coal- and oil-fired EGUs that are not shut down entirely would experience serious curtailment of their operations as the Proposed Guidelines result in natural gas-fired generation being dispatched before coal- or oil-fired generation (Building Block 2),

ED_000419-0005805

increased use of renewable energy that will also be dispatched before coal- or oil-fired generation (Building Block 3), and the implementation of demand-side energy efficiency programs that are expected to result in less demand for electricity (Building Block 4). Although these actions would not rise to the level of a total taking under *Lucas*, partial takings claims may be brought under *Penn Central*, which established a set of factors that courts consider to determine whether a regulation results in a compensable partial taking: (1) the character of the government action; (2) the economic impact of the regulation on the claimant; and (3) the extent to which the regulation interferes with distinct investment-backed expectations. *Penn Cent.*, 438 U.S. at 124. The *Penn Central* factors are "designed to allow 'careful examination and weighing of all the relevant circumstances.'" *Tahoe-Sierra Pres. Council, Inc. v. Tahoe Reg'l Planning Agency*, 535 U.S. 302, 322 (2002) (quoting *Palazzolo v. Rhode Island,* 533 U.S. 606, 636 (2001) (O'Connor, J., concurring)). The factors focus "directly upon the severity of the burden that government imposes upon private property rights." *Lingle*, 544 U.S. at 539. As discussed below, analysis of these three factors demonstrates that the Proposed Guidelines, if otherwise lawful, would result in a partial taking for coal- and oil-fired EGUs that would be forced to significantly curtail their operations as a result of the Proposed Guidelines.

1. The Character of the Proposed Guidelines Weighs in Favor of a Takings Claim.

Under the Takings Clause of the Fifth Amendment, courts look not to the effectiveness of the regulation or legitimacy of the public purpose, but instead to the magnitude or character of the burden a particular regulation imposes upon private property rights and how that regulatory burden is distributed among property owners. *Lingle*, 544 U.S. at 541. A regulation causes a taking where it forces "'some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole.'" *Tahoe-Sierra*, 535 U.S. at 336 (quoting *Penn*

ED_000419-0005806

Cent., 438 U.S. at 123-24). Where a regulation has a severe or an "unduly harsh impact upon the owner's use of the property," it weighs in favor of a takings claim. *Penn Cent.*, 438 U.S. at 127; *see also Lingle*, 544 U.S. at 539. Likewise, where a government regulation is of an "extraordinary" character and destroys "'one of the most essential sticks in the bundle of rights that are commonly characterized as property,'" it weighs heavily toward a takings claim. *See, e.g.*, *Hodel v. Irving*, 481 U.S. 704, 716 (1987) (quoting *Kaiser Aetna*, 444 U.S. at 176).

For the owner of an EGU, one of the "most essential sticks" in the owner's bundle of property rights is the right to use the EGU for its lawful, economically beneficial, and only intended use: the generation of electricity. The Proposed Guidelines would require significant reductions in the operations of many coal- and oil-fired EGUs. In particular, reflecting EPA's Building Block 2, the EPA-required state emission goals would shift generation from coal-fired EGUs, which currently provide baseload generation, to NGCC units. Requiring severe curtailments in the operation of an EGU would prevent the owner of that property from realizing its sole purpose—the generation and sale of electricity.

Penn Central is instructive here. In *Penn Central*, which involved regulations affecting Grand Central Station in New York City, the Supreme Court found that regulations restricting the ability to build above the train terminal in historic Grand Central Station in New York City did not interfere with owner "Penn Central's primary expectation" because it did "not interfere in any way with the present uses of the Terminal . . . . [A]ppellants may continue to use the property precisely as it has been used for the past 65 years." 438 U.S. at 136. The Court further determined that the law "not only permit[ted] reasonable beneficial use of the landmark site but also afforded appellants opportunities further to enhance not only the Terminal site proper but also other properties" by permitting Penn Central to: (1) "profit from the Terminal but also to

obtain a 'reasonable return' on its investment," (2) expand into the air space as long as the new construction "would harmonize . . . with [the Terminal]"; and (3) to transfer its "pre-existing air rights . . . to at least eight parcels in the vicinity of the Terminal." *Id.* at 136-38.

By contrast, the Proposed Guidelines would prevent the use of EGUs in accordance with their intended purpose. The severe curtailment of operation of an EGU would prevent it from generating electricity, which is its sole purpose. The Proposed Guidelines would destroy the value of these sources by confiscating their generating capacity and preventing the owners of these EGUs from obtaining a reasonable return on their investment. Indeed, because many of the owners of these EGUs have obligations to provide electricity to their customers, the Proposed Guidelines would not only prevent the reasonable return on their investment but could require certain owners to build capacity to replace the severely curtailed operation of their existing coal-fired units or to purchase electricity from other electric generators on the open market to ensure that their customers' power remains on—even though the owner could provide such electricity to its customers from the affected EGUs if their operation was not restricted as a result of EPA's rule.

In sum, for those EGUs whose operation is severely restricted as a result of the Proposed Guidelines, EPA will have confiscated the "most essential sticks" in their bundle of property rights, assuming the Proposed Guidelines were otherwise lawful. The fact that these measures would be taken for the "public good" of reducing GHGs is of no relevance to the takings question. Owners of certain coal- and oil-fired EGUs should not be forced to bear this societal burden alone. Thus, the extraordinary character and severe impact of the Proposed Guidelines on those EGUs weigh heavily in favor of finding that a taking would occur if EPA were able to lawfully finalize its proposal.

ED_000419-0005808

2. The Proposed Guidelines Would Cause Severe Economic Impacts.

The second factor in the *Penn Central* analysis focuses on the economic impact of the regulation. 438 U.S. at 124. The inquiry is whether the regulation "impair[s] the value or use of [the] property" according to the owner's general use of its property. *PruneYard Shopping Ctr. v. Robins*, 447 U.S. 74, 83 (1980); *see also Penn Central*, 438 U.S. at 136-38. EPA admits that there would be significant economic impacts associated with the Proposed Guidelines. 79 Fed. Reg. at 34,935-36; EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants at ES-7 to ES-9 (June 2014), Docket ID No. EPA-HQ-OAR-2013-0602-0391 ("RIA"). For those coal- and oil-fired EGUs that would be forced to curtail their operations substantially, economic impacts would be severe. Those EGUs would no longer be able to run at the capacity at which they were constructed to run. This would result not only in the generation of less electricity—and thus fewer profits—but also higher operating costs and inability to recover investments that were made in anticipation of continued operations. Coal- and oil-fired EGUs are not designed to operate as peaking units, and the costs associated with doing so are significant. Failing to operate these units fully results in their needing to burn more fuel per MWh generated (which perversely results in greater CO_2 emissions). This "is not a case in which the Government is exercising its regulatory power in a manner that will cause an insubstantial devaluation of petitioners' private property," *Kaiser Aetna*, 444 U.S. at 180, but is instead a case where the government regulation would be "functionally equivalent" to a direct appropriation, *Lingle*, 544 U.S. at 539. Both the value and the use of these EGUs as electric generating facilities would be significantly impaired by the Proposed Guidelines, and their owners would lose significant control over the manner of operation of their sources. These

ED_000419-0005809

major economic impacts weigh heavily in favor of finding a taking assuming the Proposed Guidelines are otherwise lawful.

3. The Proposed Guidelines Would Significantly Interfere With Reasonable Investment-Backed Expectations.

The Proposed Guidelines would interfere significantly with the reasonable investment-backed expectations of the owners of those coal- and oil-fired EGUs whose operation will be significantly restricted. *See Penn Cent.*, 438 U.S. at 124 (establishing as a primary factor in a regulatory takings analysis the extent of interference with "distinct investment-backed expectations"); *see also Palazzolo*, 533 U.S. at 618 (adopting reasonableness requirement); *Ark. Game & Fish Comm'n v. United States*, 133 S. Ct. 511, 522 (2012) (adopting reasonableness requirement). Although the Supreme Court has indicated that the extent to which an industry is regulated plays a role in evaluating the reasonableness of investment-backed expectations, *see Monsanto*, 467 U.S. at 1008-09, this does not mean that prior regulation of an industry per se forecloses the reasonableness of investment-backed expectations, *cf. Palazzolo*, 533 U.S. at 633 ("Today's holding does not mean that the timing of the regulation's enactment relative to the acquisition of title is immaterial to the *Penn Central* analysis. Indeed, it would be just as much error to expunge this consideration from the takings inquiry as it would be to accord it exclusive significance.") (O'Connor, J., concurring); *see also Tahoe-Sierra*, 535 U.S. at 336 ("Accordingly, we have eschewed any set formula . . . . The outcome instead depends largely upon the particular circumstances in that case.") (internal quotation marks and citations omitted). As the Supreme Court has noted, whether a regulation has gone "'too far'" is instead "'a question of degree—and therefore cannot be disposed of by general propositions.'" *MacDonald v. Yolo Cnty.*, 477 U.S. 340, 348 (1986) (quoting *Pa. Coal*, 260 U.S. at 416). Thus, the appropriate question for a regulated industry like the electric generation industry is the degree to

ED_000419-0005810

which, when the affected sources were developed and constructed, the EGUs had a reasonable investment-backed expectation that they would be able to operate the source as the type of source it was designed to be and at a certain level of generating capacity in light of the existing regulatory climate, among other factors.

Although this determination will require an "essentially ad hoc, factual inquir[y]," *Penn Cent.*, 438 U.S. at 124, regarding how exactly the Proposed Guidelines would affect the EGU in question, the date that the investment decision was made for the EGU, and the laws and regulations existing at that time, the Proposed Guidelines, if valid, would lead to a number of strong takings claims by the owners of the coal- and oil-fired EGUs that are having their operations severely curtailed. The Proposed Guidelines would require drastic reductions in generating capacity for many sources. Despite the fact that EGUs are heavily regulated, their owners had no reason to expect that their operations would be curtailed as a result of section 111(d) of the CAA. First, most, if not all, of the investment decisions for these EGUs were likely made before the Supreme Court decided *Massachusetts v. EPA*, 549 U.S. 497 (2007), and held that GHGs could be regulated under the CAA. Prior to that time, EPA had not regulated GHGs under the Act and said it had no authority to do so. 68 Fed. Reg. 52,922, 52,925-29 (Sept. 8, 2003). Furthermore, all of the investment decisions were made well before EPA proposed to adopt its novel "building blocks" approach of determining BSER, which it set forth for the first time in the Proposed Guidelines. Nothing in EPA's prior rulemakings under section 111(d)—or indeed under section 111(b)—would give the owners of EGUs reason to anticipate that section 111(d) would be used to require reduced utilization of a source. In sum, the owners of those coal- and oil-fired EGUs that would have significant restrictions placed on the operation of those EGUs as a result of the Proposed Guidelines had no reason to expect at the time that the

ED_000419-0005811

investment decisions were made that this could occur. The owners instead constructed these EGUs with the reasonable investment-backed expectation that, although the sources would be subject to some regulation under the CAA and other statutes and regulations, the EGUs would operate for their remaining useful lives and at a certain level of generation and profitability.

In sum, the Proposed Guidelines would result in a total taking of those coal- and oil-fired EGUs that are required to shut down in order for the states in which they are located to meet the goals set forth in the Proposed Guidelines. And for those EGUs whose operation would be significantly curtailed as a result of the Proposed Guidelines, after examining the three *Penn Central* factors, it is clear that a partial taking would result. The impact of the Proposed Guidelines on these EGUs would be severe and that burden would be unfairly distributed by focusing exclusively on coal- and oil-fired EGUs. The Proposed Guidelines would also impose severe economic impacts on the owners of those EGUs and would significantly interfere with those owners' investment backed expectations. If EPA decides to proceed with the Proposed Guidelines and if those Guidelines could be lawfully promulgated, which for the many reasons presented in these comments they cannot, then EPA would have to justly compensate the owners of those EGUs that are forced to shut down or to restrict their operations significantly. Otherwise, the owners of these EGUs will be forced "'alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole.'" *Tahoe-Sierra*, 535 U.S. at 336 (quoting *Penn Cent.*, 438 U.S. at 123-24).

IX. EPA Usurps the Role of States and Treads Into Areas that Are Quintessentially Within the Purview of State Control in Violation of Section 111(d).

A. State Primacy Under Section 111(d) and EPA's Regulations Implementing Section 111(d)

EPA's authority under section 111(d) is narrowly tailored; Congress intended for section 111(d) regulation to employ the same cooperative federalism framework that exists in section

ED_000419-0005812

110 of the CAA, giving primacy to the states. *See* CAA § 111(d)(1) (EPA to establish "procedure similar to that provided by section [110]"). In contrast to the exclusive authority Congress gave to EPA to set *new source* performance standards, section 111(d) does not give EPA direct regulatory authority over *existing sources*. Instead, section 111(d) directs EPA to establish a "procedure" for states to submit plans establishing performance standards for existing sources. Section 111(d) gives the states broad discretion to develop such plans and to implement and enforce them based on specific state concerns and needs. EPA recognized this in 1975 when it promulgated the Subpart B regulations to interpret and implement section 111(d): "States will have *primary* responsibility for developing and enforcing control plans under section 111(d)." 40 Fed. Reg. at 53,343 (emphasis added). EPA's proposal to establish hard CO_2 emission intensity caps contravenes the language of the statute and that intent. 79 Fed. Reg. at 34,953, Proposed 40 C.F.R. § 60.5765; *id.* at 34,957-58, Proposed Subpart UUUU, Tbl. 1. EPA may require states to submit plans that contain performance standards for emissions of certain pollutants from designated facilities, but it does not have the authority to dictate the form and content of those performance standards.

In section 111(d), Congress directs EPA merely to "establish a *procedure* . . . under which each State shall submit to [EPA] a plan which . . . establishes standards of performance" for existing sources within the state. CAA § 111(d)(1) (emphasis added). EPA established this procedure in 1975 when it promulgated the Subpart B regulations, codified at 40 C.F.R. Part 60, Subpart B, §§ 60.20-60.29. Whereas section 111(d)(1) limits EPA's authority to setting up procedures, the states are given the authority and responsibility to establish the actual, substantive standards of performance. In contrast, section 111(d)(2)(A) authorizes EPA to set substantive standards of performance, but only in situations where a state has failed to submit an

ED_000419-0005813

acceptable plan. Congress carefully limited EPA's authority to establish substantive standards of performance for existing sources to those limited situations where a state fails to act. Thus, unlike the very different language in section 111(b) governing the standards of performance for new sources, section 111(d) gives EPA no direct regulatory authority over existing sources, and instead gives states broad discretion to develop such plans subject to a general requirement that the state's exercise of discretion be "satisfactory." CAA § 111(d)(2)(A).

The Act provides criteria for establishing whether a state plan is "satisfactory," including the definition of "standard of performance," and a direction that states shall be allowed to consider remaining useful life, "among other factors." *Id.* §§ 111(a)(1), 111(d)(1), (2). The Act leaves to the states substantial freedom as to the factors to be considered in formulating a state plan and how those factors are to be weighed, and it does not dictate any particular outcome for the state. States thus have significant discretion to adopt state plans that vary from EPA's emission guidelines, as long as they have considered relevant factors.

Congress envisioned the section 111(d) system to be like the state implementation plan system under section 110, under which as long as a state considers relevant factors, EPA may not second-guess the state's judgment. This conclusion is well-established in case law governing section 110 and arguably applies in this context as well, given the explicit connection Congress made between section 110 and section 111. Courts have noted that states, under section 110, are "given wide discretion in formulating" their plans. *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976). EPA's role is "confine[d] . . . to the ministerial function of reviewing [state plans] for consistency with the Act's requirements" and little more. *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012). The Fifth Circuit has also noted that:

> The great flexibility accorded the states under the Clean Air Act is further illustrated by the sharply contrasting, narrow role to be played by EPA. Quite

> simply, the Act provides that the Administrator shall approve the proposed plan if it has been adopted after public notice and hearing and if it meets [the] specified criteria.

Fla. Power & Light Co. v. Costle, 650 F.2d 579, 587 (5th Cir. 1981) (internal quotation marks omitted). Similarly, EPA has

> no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards of § 110(a)(2) . . . . Thus, so long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation.

Virginia v. EPA, 108 F.3d 1397, 1407-08 (D.C. Cir. 1997) (citing *Train v. NRDC*, 421 U.S. 60, 79 (1975)). EPA cannot disagree with a state plan merely because it would exercise its judgment differently. The Act is supposed to "leave[] it to the individual States to determine, in the first instance, the particular restrictions that will be imposed on particular emitters within their borders." *EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7, 12 (D.C. Cir. 2012). Anything in EPA's 1975 Subpart B rules that requires EPA "approval" must be read consistently with the CAA and case law indicating that as long as the state considers relevant factors, its plan must be deemed "satisfactory."

In the Proposed Guidelines, however, EPA interprets the statutory term "satisfactory" to mean that it has the authority to impose "binding" emission rates on each state. *See, e.g.*, 79 Fed. Reg. at 34,844, 34,892. This interpretation ignores the structure and context of section 111(d), which gives substantive authority to the states to establish the standards of performance in the first instance, and to consider whatever factors it wishes in applying those standards of performance. EPA instead has proposed to establish hard numeric standards of performance

ED_000419-0005815

(though it calls them "emission guidelines"[25] or "emission performance level[s]" rather than "standards of performance," EPA Legal Memorandum at 16-18, 29), and would apply them to states rather than to the sources.[26] Nothing in either the CAA or the Subpart B regulations empowers EPA to establish binding emissions performance obligations for states. Standards of performance are to be set *by states* and must apply to *sources*. EPA's statewide performance goals are emission limitations not authorized by the Act or the Subpart B regulations. EPA may not lawfully enlarge its authority in this way.

Under the CAA and the Subpart B regulations, EPA's responsibility under section 111(d) is to specify the BSER that limits the emissions of the pollutant in question from the source at hand. As discussed at length in Section III of these comments, EPA's establishment of BSER here is unlawful because it requires measures that occur beyond the source itself and over which the source has no control. But even EPA's application of the one Building Block that arguably falls within the scope of section 111 (Building Block 1) is flawed. Building Block 1 calls for heat rate improvements at coal-fired EGUs. Under the statute, EPA's determination of BSER for those units does not involve giving each state a rate that each unit must meet (either individually or collectively). Rather, EPA's determination of BSER in this instance might involve EPA identifying for consideration by the states a list of measures that could be made at a coal-fired

---

[25] EPA's Subpart B regulations define "emission guidelines" as emission limitations that apply to "designated facilities," not to the states in which those designated facilities are located. 40 C.F.R. § 60.21(e).

[26] As described in Section V of these comments, EPA may establish emission guidelines only for the same type of sources the Agency has regulated under section 111(b). CAA § 111(d)(1)(A); *Am. Elec. Power Co.*, 131 S. Ct. at 2537; *see also* 40 C.F.R. § 60.22(b)(5) ("The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of *designated facilities* . . . .") (emphasis added). The Court also confirmed that it is the *states* that "issue performance standards for stationary sources within their jurisdiction," not EPA that does so. *Am. Elec. Power*, 131 S. Ct. at 2537-38.

ED_000419-0005816

EGU to improve heat rate that EPA has determined to be BSER. States would then apply that BSER to each unit within the state to set the actual standard of performance for the EGU. And as the Act and the Subpart B regulations make clear, states could deviate from EPA's BSER determination based on things such as remaining useful life of the EGU or other factors such as the inability to do a certain improvement at a unit because, for instance, the cost would be excessive, the measure would be impossible to implement at that unit, or the measure had been done previously. This is how the partnership between EPA and the states should work under section 111(d). The Proposed Guidelines utterly fail in this regard.

If EPA finalizes the Proposed Guidelines, it will violate the Act, which requires section 111(d) performance standards to be state-led and promulgated, and to apply to existing fossil fuel-fired EGUs, the same sources to which EPA's section 111(b) standards apply. EPA has not given states the flexibility to set state performance standards—authority to which states are entitled under the statute. Moreover, EPA would force states to violate the terms of the Act by regulating sources that may not be regulated under a section 111(d) rule for existing fossil fuel-fired EGUs. *See, e.g.,* 79 Fed. Reg. at 34,853 ("EPA is proposing that states be authorized to submit state plans that do not impose legal responsibility on the affected EGUs for the entirety of the emission performance level, but instead, by adopting what this preamble refers to as a 'portfolio approach,' impose requirements on other affected entities (e.g., renewable energy and demand-side energy efficiency measures) that would reduce CO_2 emissions from the affected EGUs."). Although EPA asserts that it is giving states flexibility to adopt in their state plans whatever "building blocks" they see fit, *id.* at 34,859, in reality, because the standard of performance is an emission intensity cap applied to the state, rather than to existing facilities,

states in most cases must adopt emission limitations on facilities apart from fossil fuel-fired EGUs in order to meet the EPA-mandated, binding caps.

EPA's Subpart B rules generally require state emission standards to "be no less stringent than" the emission guidelines set forth by EPA. 40 C.F.R. § 60.24(c). When it first adopted its section 111(d) regulations, however, EPA took pains to emphasize that, in contrast to the "emission standards" that states adopt under their section 111(d) plans, emission guidelines are not "legally enforceable." 40 Fed. Reg. at 53,341 ("to emphasize that a legally enforceable standard is not intended, the term 'emission limitation' has been replaced with the term 'emission guideline'"); *see also* 40 C.F.R. § 60.21(f) (state-imposed "[e]mission standard means a legally enforceable regulation . . . ."). Thus, EPA cannot in the first instance prescribe to states a standard of performance, which it would do in the Proposed Guidelines. EPA stated in 1975 that emission guidelines "will not be requirements enforceable against any source. Like the national ambient air quality standards prescribed under section 109 and the items set forth in section 110(a)(2)(A)-(H), they will only be criteria for judging the adequacy of State plans." 40 Fed. Reg. at 53,343. Thus, the emission guidelines and BSER determinations that EPA publishes are supposed to be largely procedural and contain only nonbinding factors and descriptions of demonstrated systems for states to consider as the states set their own standards. They are not, as EPA has proposed, supposed to be "binding" emission rate limitations on states. 79 Fed. Reg. at 34,897 ("the state-specific goals will be binding emission guidelines"). What the Administrator determines to be BSER is merely one of the many factors states must consider in determining the level and form of any existing source performance standard as applied to a

specific EGU.[27] EPA's Section 111(d) guideline document is supposed to contain an "emission guideline" for designated facilities. 40 C.F.R. § 60.22(b)(5). EPA's Proposed Guidelines go beyond that mandate to propose binding emission limitations on entities that neither the Act nor the Subpart B regulations authorize EPA to regulate directly. Because states are not and cannot be regulated under section 111(b), emission limitations cannot be imposed on them under section 111(d).

Similarly, under the Subpart B rules, to which EPA claims to be adhering, 79 Fed. Reg. at 34,951, Proposed 40 C.F.R. § 60.5700 ("These emission guidelines are developed in accordance with section[] 111(d) of the Clean Air Act and subpart B of this part."), states have considerable flexibility to deviate from EPA's emission guidelines in adopting plans and emission standards.[28]

---

[27] As discussed above in Section III, the BSER is supposed to be reflected in state-established standards of performance that apply to "sources." In 1975, when it promulgated the Subpart B regulations, EPA interpreted section 111(d) being source-specific and technology-based. EPA stated that BSER is something that has been "adequately demonstrated *for designated facilities*." 40 Fed. Reg. at 53,340 (emphasis added). And it stated that it believed Congress "intended a technology-based approach" under section 111(d). *Id.* at 53,343. It emphasized that it viewed this interpretation as "legally correct in view of the language, statutory context, and legislative history of the provision." *Id.* But EPA has turned this long-established construct on its head by proposing to reflect the BSER in binding goals that apply to *states*. *See, e.g.*, RIA at ES-2 ("[T]his proposed rule contains state-specific goals that reflect the EPA's calculation of the emission reductions that a state can achieve through the application of BSER."); 79 Fed. Reg. at 34,892 ("[T]he interim and final [state] goals will be binding emission guidelines for state plans.").

[28] To the extent EPA is acting contrary to its own regulations, it is not entitled to deference in doing so. *Thomas Jefferson Univ. v. Shalala*, 512 U.S. 504, 512 (1994) (deference to agency's interpretation of its own regulation does not confer when it is "plainly erroneous or inconsistent with the regulation" or "alternative reading is compelled by the regulation's plain language or by other indications of the [Administrator's] intent at the time of the regulation's promulgation") (internal quotations omitted); *see also INS v. Cardoza-Fonseca*, 480 U.S. 421, 446 n.30 (1987) ("An agency interpretation of a relevant provision which conflicts with the agency's earlier interpretation is 'entitled to considerably less deference' than a consistently held agency view.") (quoting *Watt v. Alaska*, 451 U.S. 259, 273 (1981)); *Good Samaritan Hosp. v. Shalala*, 508 U.S. 402, 417 (1993) ("[T]he consistency of an agency's position is a factor in assessing the weight that position is due."). To the extent it is interpreting its Subpart B

ED_000419-0005819

For example, states may apply "less stringent emission standards or longer compliance schedules" to particular facilities or classes of facilities if the costs of adopting the standards suggested by the emission guidelines would be unreasonably costly, physically impossible, or for other reasons. 40 C.F.R. § 60.24(f)(1)-(3). States have significant discretion in designing their own plans and determining how individual sources or classes of sources may demonstrate compliance, including taking into account the "remaining useful life of the existing source." CAA § 111(d)(1). Applying these criteria, states may grant individual sources or types of sources longer periods of time to comply, or may apply less stringent standards than set forth in EPA's emission guidelines. EPA has also stated that "[s]tates will be free to vary from the levels of control represented by the emission guidelines . . . . In most if not all cases, the result is likely to be substantial variation in the degree of control required for particular sources, rather than identical standards for all sources." 40 Fed. Reg. at 53,343. Thus, states have flexibility to implement EPA guidelines as they deem "reasonable" where costs are determined to be "unreasonable," where they would be "physically impossible," or otherwise "unreasonable." EPA also made clear that "[s]tates will be free to set more lenient standards [than those set out in EPA's emission guidelines], subject to EPA review . . . in cases of economic hardship." *Id.*

Moreover, in accordance with its Subpart B rules, EPA must address in its guideline document sub-categories of "different sizes, types and classes" of existing sources where factors like "costs of control, physical limitations [or] geographical location" warrant the application of different guidelines. 40 C.F.R. § 60.22(b)(5). EPA has failed to do so here. The Agency

---

regulations in a way that conflicts with section 111(d), that interpretation is unlawful. A regulation—or interpretation thereof—that is "manifestly contrary to the statute" is not only unlawful, but is entitled to no deference. *United States v. Mead Corp.*, 533 U.S. 218, 227 (2001); *see also Chevron*, 467 U.S. at 844; *United States v. Morton*, 467 U.S. 822, 834 (1984); 5 U.S.C. § 706(2)(A), (D).

ED_000419-0005820

underscored as early as 1975 that "emission guidelines will reflect subcategorization within source categories where appropriate," and the guidelines "will in effect be tailored to what is reasonably achievable by particular classes of existing sources . . . ." 40 Fed. Reg. at 53,343. Because a standard of performance must be "adequately demonstrated" for each source, EPA has an obligation to establish highly subcategorized emission guidelines within a broad source category like existing fossil fuel-fired EGUs.

B. The "Flexibility" EPA Claims Exists in the Proposed Guidelines Is Illusory.

EPA has turned the flexibility embedded in section 111(d) on its head. In the Proposed Guidelines, EPA would set binding state emission reduction targets that cannot be adjusted by states once promulgated. This is the antithesis of state flexibility. EPA's aggressive assumptions in the Building Blocks further erode state flexibility and disregard the primacy that Congress explicitly gave to the states over EPA under section 111(d). The Proposed Guidelines, while frequently vague and incomplete, provide information on a broad range of issues related to state implementation. Generally, the Proposed Guidelines provide EPA's perspective on a particular detail of implementation and request comment on various, often more complex issues that do not appear to have been fully developed by the Agency. UARG's comments address many of these issues below. As a preliminary matter, however, the Proposed Guidelines' discussion of state implementation highlights two key flaws in the proposal: (1) the Proposed Guidelines' false claims of flexibility; and (2) their intrusion into areas of exclusive state jurisdiction.

EPA's Proposed Guidelines tout the "flexibility" the guidelines would provide to states. In reality, however, the proposed emission guidelines would dictate all key policy choices, including those that the CAA and EPA's Subpart B regulations expressly reserve to the states. The states, on the other hand, would be tasked with addressing issues over which EPA itself has

ED_000419-0005821

no authority and answering the unprecedented questions the Proposed Guidelines raise where EPA has apparently been unable to devise solutions.

The Proposed Guidelines lack flexibility because the state goals that are its centerpiece are set assuming significant emission reductions resulting from use of all four Building Blocks. EPA claims that states are free to disregard the policies represented by the Building Blocks when devising the elements of their plans. EPA states:

> We also note that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. If a state prefers not to attempt to achieve the level of performance estimated by the EPA for a particular building block, it can compensate through over-achievement in another one, or employ other compliance approaches not factored into the state-specific goal at all. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable/while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the goal computations, according to each state's needs and preferences.

79 Fed. Reg. at 34,926. Under EPA's reasoning, states could in fact implement none of the Building Block policies and instead create an entirely different program to control CO_2 emissions. This is a fantasy.

EPA claims that its "reasonable rather than maximum" approach to implementing the Building Blocks means that there is room for states to trade emission reductions among Building Block policies (and policies that were not included in the Building Blocks) to achieve each state's goal. But EPA's assumptions in modeling the Building Blocks were anything but reasonable. As explained in Section XIV, EPA has in fact made entirely unrealistic assumptions. The results of those analyses are inconsistent with the conclusions reached by the Arizona Department of Environmental Quality ("ADEQ"), NERC, SPP, the Kansas Corporation Commission ("KCC"), and other independent reviewers. For example, in initial comments filed with EPA, ADEQ presented an analysis supporting its finding that "Arizona has no flexibility to

ED_000419-0005822

shift from one Building Block to another to meet its rate-based goal under the program as proposed." Email from Steve Burr, Legal Support Section, Air Quality Div., ADEQ, to A-and R-Docket *et al.* at 1 (Aug. 22, 2014), Docket ID No. EPA-HQ-OAR-2013-0602-14064. Other states will face the same situation, as confirmed by UARG's assessment. Given these facts, there is no way for a state to meet its goal without adopting all four Building Blocks and implementing them largely in line with EPA's assumptions. Indeed, even more may actually be required for states to meet EPA's goals. EPA's approach to assessing each Building Block assumed that nothing would go wrong in the implementation of the Building Block policies. Accordingly, EPA's state goals leave no room to accommodate unexpected events that could disrupt generation from sources needed to ensure compliance with state goals. Yet disruption in generation from renewable sources and NGCC units will be unavoidable. Because the state goals ignore these realities, EPA cannot claim that its state goals reflect reasonable rather than maximum implementation of the Building Blocks. As a result, there is no true flexibility in the Proposed Guidelines.

Another reason the Proposed Guidelines would limit rather than enhance flexibility for states is that it would encroach on areas that fall under the exclusive jurisdiction of the states. Most—if not all—of the programs in Building Blocks 2, 3, and 4 are the quintessential purview of state electricity regulators—not state environmental agencies. These programs have been developed pursuant to well-established state sovereign powers over matters relating to electricity regulation, including determining the appropriate mix of generating resources within a state. EPA is barred by U.S. Supreme Court precedent from infringing upon a traditional state sovereign function unless Congress has adopted clear statutory language expressly authorizing the Agency to do so. *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947) (courts begin

preemption analysis "with the assumption that the historic police powers of the States were not to be superseded by [a federal law] unless that was the clear and manifest purpose of Congress"). Nothing in the CAA expressly authorizes EPA to regulate the generation of electricity or other such energy regulatory matters traditionally reserved to states. Indeed, as discussed in Section VII, the language of section 111(d) suggests the precise opposite. Further, as described in Section IV, given EPA's regulation of EGUs under MATS, EPA lacks authority to regulate EGUs under section 111(d) *at all*.

The Proposed Guidelines acknowledge that interference with the sphere of exclusive state jurisdiction is a considerable concern:

> [I]ncluding [renewable energy ("RE")] and demand-side [energy efficiency ("EE")] measures in state plans would render those measures federally enforceable and thereby extend federal presence into areas that, to date, largely have been the exclusive preserve of the state and, in particular, state public utility commissions and the electric utility companies they regulate."

79 Fed. Reg. at 34,902. EPA seeks comment on a proposal to remedy this situation by essentially creating a technical loophole. EPA suggests that it can avoid entanglement in areas over which the states are sovereign simply by not including things such as RE and EE in state plans, preventing such requirements from becoming federally enforceable, while states impose the requirements directly to allow compliance with what would be otherwise unachievable emission limits contained in state plans. *Id.* EPA does not address how elements necessary to ensure that state plans are implemented to achieve EPA's goals can be left out of those plans. EPA's proposed approach, moreover, would not prevent federal interference in these areas of traditional state primacy. It would require that states take action outside section 111(d) plans themselves but would nevertheless improperly compel state action.

ED_000419-0005824

EPA also proposes what it calls the "'state commitment approach.'" *Id.* The problems with that approach are even more glaring. Again, this approach would not make requirements for non-EGUs part of a federally enforceable state plan: "Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs." *Id.* This approach plainly does not avoid EPA interference in areas that are traditionally regulated only by the states. It merely seeks to avoid the appearance of such interference. Further, it fails to address how measures that are necessary to ensure achievement of a requirement under section 111(d) can be left out of a federally enforceable plan.

C. The Proposed Guidelines Conflict With State Laws and Fail To Take Account of Other CAA Requirements.

The Proposed Guidelines actually conflict with key state laws, including state constitutions. To override these laws, the CAA would have to provide clear authority, grounded in the Commerce Clause, for EPA to take such action. The Act provides no such authority. State laws that would interfere with the implementation of EPA's Proposed Guidelines are widespread. For instance, a September 9, 2014 letter from several governors identifies existing laws in Kansas, Kentucky, Louisiana, Missouri, and West Virginia that prohibit those states from regulating power plant emissions "by shifting pollution-control costs to other parts of the economy." Letter from Governors of Fifteen States to President Barack Obama at 1 n.3 (Sept. 9, 2014), *available at* http://governor.alabama.gov/ assets/2014/09/RGA-Letter-to-POTUS.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). In those states "[e]missions reductions must occur at the power plant source." *Id.*

ED_000419-0005825

Similarly, legislation is under consideration or has been adopted that conflicts with EPA's Proposed Guidelines. As reported in a June 9, 2014 article, at least nineteen states had introduced resolutions targeting the Proposed Guidelines, eleven states had introduced legislation, and six states had enacted bills as of that time. Nathanael Massey, *Some states push back against proposed EPA carbon rule*, CLIMATEWIRE, June 9, 2009, *available at* http://www.eenews.net/climatewire/stories/1060000921/search?keyword=Some+states+push+back+against+proposed+EPA+carbon+rule (subscription required). An August 2014 report identifies conflicting resolutions and legislation in 18 states. Raymond L. Gifford, *et al.*, *EPA's CO_2 Rule and 18 States' Resolutions and Legislation: EPA's Proposed CO_2 Rule Collides with Flexibility Asserted By States* at 3 (Aug. 2014), *available at* http://www.wbklaw.com/News/Articles__Publications/EPAs_CO2_Rule_and_18_States_Resolutions_and_Legislation__August_15_2014. Although the content of these laws and legislative proposals differ, many require state agencies to employ the full measure of state flexibility contemplated by the CAA, in contrast to the lack of discretion to implement section 111(d) requirements that EPA would dictate under its Proposed Guidelines. A law enacted by the Wyoming legislature, for instance, provides that EPA's emission guidelines must recognize state primacy in establishing carbon regulations. J.R. 6, 61st Leg., Gen. Sess., 2011 Wyo. Sess. Laws 559. Kentucky has also adopted legislation at odds with EPA's Proposed Guidelines. Signed by the governor on April 2, 2014, H.B. 388 limits BSER to "measures undertaken at each coal-fired electric generating unit" and precludes such measures from including fuel-switching, co-firing with other fuels, or limiting utilization. H.B. 388, 2014 Leg., Reg. Sess., 2014 Ky. Acts 18. Other states have longstanding laws, not enacted in reaction to the Proposed Guidelines, that will prevent the program EPA has proposed from being implemented. Arizona, for instance, enacted H.B. 2442

ED_000419-0005826

in 2010. ARIZ. REV. STAT. § 49-191. That statute prohibits any state agency from adopting or enforcing a state or regional program to regulate GHG emissions for the purposes of addressing changes in atmospheric temperature without express legislative authorization.

EPA has no authority to override these state laws due to the Supremacy Clause of the U.S. Constitution. U.S. CONST. art. VI, cl. 2. Wherever possible courts avoid determining that federal preemption of state law has occurred. *N.Y. State Conference of Blue Cross & Blue Shield Plans v. Travelers Ins. Co.*, 514 U.S. 645, 654-55 (1995); *Maryland v. Louisiana*, 451 U.S. 725, 746 (1981); *Napier v. Atl. Coast Line R. Co.*, 272 U.S. 605, 611 (1926). Furthermore, when a court examines whether preemption occurs, it looks first to the intent of Congress in passing the statute. *See, e.g.*, *Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88, 96 (1992). Here, EPA is acting pursuant to its authority under the Clean Air Act, which is a statute that regulates air emissions. But EPA's proposed action here would not directly regulate air emissions from municipal utilities and instead would regulate the amount and source of energy generation from utilities. Similarly, courts typically presume that "the historic police powers of the States were not to be superseded by [federal law] unless that was the clear and manifest purpose of Congress." *Rice*, 331 U.S. at 230; *see also Wisconsin Public Intervenor v. Mortier*, 501 U.S. 597, 605 (1991). As discussed in Section VII above, Congress intended for states to retain authority over energy generation and retail sales and for FERC to retain authority over interstate transmission of electricity. EPA cannot reasonably assert that Congress intended to grant EPA preemption authority over state constitutions and laws through the CAA to regulate energy production and transmission of municipal utilities.

In addition, little thought was given to how the Proposed Guidelines interact with other CAA rules. For example, Arizona will have to close all coal units to achieve its interim and final

ED_000419-0005827

targets under the Proposed Guidelines, but utilities in the state recently invested $500 million to comply with the Regional Haze Program. Furthermore, the Proposed Guidelines will require the ramping up of units located in nonattainment areas, which would violate NAAQS requirements. Section 111(d) explicitly requires that consideration of the remaining useful life of sources be considered when designing performance standards for existing sources. Contrary to that requirement, the Proposed Guidelines will lead to the stranding of assets if finalized, especially given its interaction with other CAA rules.

D. Selecting a Rate-Based or Mass-Based Goal

According to EPA, states decide the "emission performance level" to include in their plans, 79 Fed. Reg. at 34,900, but under the Proposed Guidelines, states are empowered only to select a rate-based or mass-based emission goal. EPA presents this choice as providing considerable "flexibility" for states. *See id.* at 34,897 ("[W]e are also proposing to provide states with the flexibility to translate the rate-based goals to mass-based goals."); *see also id.* at 34,908-09. It does not. EPA is merely affording states a choice between accepting an EPA-prescribed and inflexible rate-based state goal or translating that rate-based goal into an equivalent mass-based goal. *Id.* at 34,892 (translated mass-based goal must "achieve[] the same degree of emission limitation" as EPA's rate-based goal).

Under the Proposed Guidelines, states are invited to attempt to calculate a mass-based rate. *Id.* at 34,897. The preamble to the Proposed Guidelines states that: "[i]f the plan adopts a mass-based goal, the plan must include a description of the analytic process, tools, methods, and assumptions used to translate from the rate-based goal to the mass-based goal." *Id.* at 34,911. Similarly, section III of EPA's "Projecting EGU CO_2 Emission Performance in State Plans" TSD (June 2014), Docket ID No. EPA-HQ-OAR-2013-0602-0462 ("Projections TSD"), which was released with the Proposed Guidelines, purports to provide guidance to states on how to make

ED_000419-0005828

such a goal translation. That guidance, however, does little more than direct states to project the CO_2 emissions that would result from application of EPA's rate-based limit. These statements suggest that states have broad leeway to calculate mass-based goals. Proposed 40 C.F.R. § 60.5770 includes an additional requirement, however:

> The conversion must represent the tons of CO_2 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb CO_2/MWh rate equal to the rate-based goal for the state identified in Table 1 of [the Proposed Guidelines].

79 Fed. Reg. at 34,953, Proposed 40 C.F.R. § 60.5770. Although this roughly sketched methodology might produce rate-to-mass goal conversions that are equivalent, other approaches might prove better fits for some states, and EPA should provide states with flexibility to demonstrate that differing methods are appropriate, as the Agency suggests in the preamble language.

That other state approaches might be valid is seemingly confirmed by EPA's November 2014 TSD, entitled "Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents, Docket ID No. EPA-HQ-OAR-2013-0602-22187 ("Translation TSD"). Unlike the Proposed Guidelines, which require a protection of emissions "in the absence of emission standards contained in the plan," 79 Fed. Reg. at 34,953, Proposed 40 C.F.R. § 60.5770, i.e., in the absence of application of the Building Block, the Translation TSD directs states to adjust their 2012 emissions to "reflect[] the deployment of incremental building block three and four resources." Translation TSD at 5. The approaches contained in the proposed regulatory language of the Proposed Guidelines and the Translation TSD cannot be reconciled. Yet, EPA appears to believe that either approach could lead to accurate and satisfactory mass-based goals. EPA should therefore adopt the approach to mass-based goal conversion suggested

ED_000419-0005829

by the language in the preamble to the Proposed Guidelines: EPA should recognize state discretion to adopt different approaches to goal conversion provided states provide a reasonable explanation for the choices they have made.

UARG also notes that the Translation TSD includes an appendix presenting mass-based goals for each state calculated in accordance with the Translation TSD methodology. *Id.* at 9-16. UARG takes no position on the accuracy of the mass-based goals EPA has calculated. If accurate, however, EPA's mass-based goals confirm the exceptional stringency of the Proposed Guidelines. The results of EPA's conversions to mass-based standards and the impact they will have should demonstrate to the Agency how extreme its Proposed Guidelines are. Moreover, EPA should state expressly that the mass-based goals it has identified are not binding on states and do not establish a baseline or standard of reasonableness against which state calculations will be judged.

E. Types of State Plans

The Proposed Guidelines contemplate that states can develop "different types of state plans" to meet EPA's CO_2 emission goals. 79 Fed. Reg. at 34,901. As discussed in the Proposed Guidelines and EPA's "State Plan Considerations" TSD (June 2014), Docket ID No. EPA-HQ-OAR-2013-0602-0463 ("Plan TSD"), EPA has identified four plan types:

- Rate-based CO_2 emission limits applied to affected EGUs;
- Mass-based CO_2 emission limits applied to affected EGUs;
- A state-driven portfolio approach; and
- A utility-driven portfolio approach.

Plan TSD at 5; *see also* 79 Fed. Reg. at 34,901-02. The primary distinction between the EGU-driven and portfolio approach-driven plans is that the portfolio approach includes measures, such

as for RE and EE, that are legally enforceable against entities other than EGUs, including state agencies and nonprofit entities.

As an initial matter, and as EPA acknowledges, "section 111(d) gives states the primary responsibility for designing their own state plans for submission to the EPA." 79 Fed. Reg. at 34,901. States, accordingly, have broad discretion as to how they structure their plans. EPA, therefore, cannot disapprove a state plan that does not conform to the plan "types" it has identified.

In addition, although the Proposed Guidelines and the Plan TSD note some salient features of each plan type, neither provides a thorough assessment of those plan types or the questions and potential problems posed by their new and untested characteristics. For instance, EPA states that for plans that place all legal responsibility for compliance on EGUs, states can nevertheless rely on RE and EE to ensure that EGUs can meet their obligations. *Id.* EPA does not, however, explain how the availability of adequate RE and EE is to be ensured under such an approach, leaving states unsure of what it takes to obtain plan approval and leaving EGUs vulnerable to noncompliance. EPA suggests that states could force EGUs to invest in EE and RE, *id.* at 34,902, but does not grapple with whether or how states could impose such requirements or whether adequate RE and EE would be feasible to construct.

EPA's discussion of portfolio approaches is similarly ill-conceived. In the Plan TSD, EPA suggests that state agencies, public or private nonprofits, or electric distribution utilities could be assigned section 111(d)-related responsibilities. Plan TSD at 10. EPA does not, however, explain how any of this might be accomplished legally or practically, except to suggest that state legislatures might have to enact new laws. *Id.* at 14-18. EPA also suggests that the integrated resource planning ("IRP") process might be a vehicle for imposing portfolio approach-

ED_000419-0005831

type obligations, but does not explain what states that do not, or cannot, use the IRP process would be expected to do. *Id.* at 10-12.

The inadequacy of EPA's Proposed Guidelines is illustrated by the fundamental unanswered questions it raises with respect to current state programs, like the Regional Greenhouse Gas Initiative ("RGGI"), that EPA suggests could be a means by which states could comply with the Proposed Guidelines. *See* 79 Fed. Reg. at 34,901. RGGI is a mass-based cap-and-trade program that applies to CO_2 emissions from fossil fuel-fired EGUs and is carried out among nine northeastern states. The member states voluntarily undertook the RGGI program and designed its primary features through interstate working groups. Each state implements RGGI pursuant to state-specific legislation and regulations.

Despite the fact that RGGI has been in operation since 2008 and that its features are well known, EPA makes only vague assertions that RGGI might be a mechanism for compliance with section 111(d) requirements. This leaves many key questions unanswered and is not an approach that will encourage states to undertake the difficult process of negotiating multi-state plans and devising cap-and-trade programs. For instance, the state-by-state emission budgets for the RGGI states are known, as is the regional cap from the program. EPA has not explained, however, if the regional goal for the RGGI program is consistent with the Proposed Guidelines, how it might need to be altered if it is not consistent, or how states can ensure that other regional programs or additions to the RGGI program can achieve or maintain consistency with EPA's proposed goals.

The Proposed Guidelines also do not address a key component of the RGGI program: its investment of the proceeds from allowance auctions in energy efficiency and other measures to reduce demand as a mechanism for reducing CO_2 emissions. Would a program that simply includes investment requirements satisfy EPA's requirements for EE and other demand

ED_000419-0005832

reduction-related emissions reductions? Or would something more be required to make such emission reductions binding?

Further, in a number of instances, RGGI member states have diverted funds intended for investment in demand reduction measures to fill budget shortfalls. If a state legislature were to take similar action in the future, would the state be deemed to have violated its plan? Would EPA find a sole state in violation, or would that violation be attributed to the region? The Proposed Guidelines note that a number of these questions exist, but until EPA attempts to provide an answer to them, it cannot expect states to implement these policies, and it cannot claim to have provided adequate notice through its proposed rulemaking.

EPA also asks for comment on whether state plans can legally include measures such as RE and EE under a broad interpretation of "'standards of performance for [affected sources]'" or whether they could be included as "'implement[ing]' measures." *Id.* at 34,903. Although states may have the authority to enact laws or trading programs to impose RE and EE investment requirements on EGUs or to impose portfolio approach type measures pursuant to their own authorities, EPA fails to engage the question of whether it can require (or effectively require) states to include such measures in section 111(d) plans as a result of establishing emission goals that are so stringent as to be unachievable in the absence of such requirements. As discussed in Section XIII, not only are the goals EPA has proposed unlawful, but it would be unlawful for EPA to require the states to develop plans that are beyond the scope of section 111(d) and that command states to adopt new statutory and regulatory programs.

F. Timing for Plan Implementation and Achievement of State Emission Performance Goals

The Proposed Guidelines would create final state-specific goals to be met by 2030 and interim goals to be achieved on average over the 10-year period from 2020 to 2029. *Id.* at

ED_000419-0005833

34,904. EPA claims that this approach provides states with flexibility to design their programs and the trajectory of emission reductions. Again, this flexibility is an illusion. EPA itself acknowledges that states will have between 1.5 and 3.5 years from the expected deadlines for plan submittal before compliance actions must commence. *Id.* at 34,905. EPA insists this is not unreasonable because affected sources "will have knowledge of state requirements as they are adopted" and will therefore have more time to act. *Id.* The additional time EPA imagines is itself quite short, and it is unrealistic to expect sources to take costly actions before states finalize their plans and before EPA has reviewed and approved them, especially considering the uncharted territory the Proposed Guidelines force states to enter. Moreover, the emission goals EPA has set are too stringent and require such draconian actions to ensure compliance that many states will have no choice but to take significant action by 2020. For example, the State of Arkansas has concluded that the infrastructure that will be required to implement the Proposed Guidelines makes plan implementation "as early as 2017 to meet an interim goal in 2020 . . . far too soon and too abrupt to allow Arkansas utilities to meet the challenges of the proposed rule in a manner that is cost-effective for their ratepayers." Letter from Dustin McDaniel, Attorney General of the State of Arkansas to Avi S. Garbow, General Counsel, EPA at 2 (Aug. 4, 2014), *available at* https://static.ark.org/eeuploads/ag/EPA_letter.pdf ("Arkansas Letter") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). For that reason, Arkansas has requested that EPA eliminate the interim goal to allow for a less burdensome glide-path to compliance. *Id.* Indeed, it is nearly inconceivable that states could develop renewable energy, build out infrastructure, or even develop more traditional sources of generation to replace the sources that the Proposed Guidelines will force into retirement in time to meet the interim goals. The Congressional Research Service has even found that EPA's targets are "front

loaded," "with a disproportionate percentage of emission rate reductions required in the early years of the program (2020-2024)." Jonathan L. Ramseur, Cong. Research Serv., "EPA's Clean Power Plan Proposal: Are the Emission Rate Targets Front-Loaded?" at 1, CRS Insights IN10172 (Nov. 3, 2014), *available at* http://fas.org/sgp/crs/misc/IN10172.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). CRS finds, for example, that "90% of Arizona's total emission rate reductions occur between its 2012 baseline and its 2020 emission rate." *Id.* at 2. The Proposed Guidelines improperly tie states' hands and will wreak havoc on electricity markets in the near-term—EPA's assertions to the contrary notwithstanding. *See* Initial NERC Report at 17; SPP Comments at Attachment 1, slides 13-14. In the event that EPA decides to proceed with the Proposed Guidelines despite the myriad legal, technical, practical, and political issues that they present, EPA should, at the very least, eliminate the interim goals. EPA seems to suggest that it is at least considering this option in the NODA issued on October 30, 2014. *See* Section XV.

The Proposed Guidelines discuss a number of other issues related to timing of implementation measures. First, EPA proposes to require states to include achievement "demonstrations" for the interim and final goals in plan submittals. 79 Fed. Reg. at 34,904. The Plan TSD indicates that EPA believes such demonstrations will entail considerable efforts, including the use of utility-scale capacity expansion and dispatch planning models. Plan TSD at 28-31. The level of effort EPA apparently envisions requiring states to undertake is more extensive than can be justified under section 111(d)'s permissive "satisfactory" standard for state plans and likely to require far more work than can be completed in the time EPA proposes to allow for states to develop their plans. Indeed, states have three years to develop state implementation plans under section 110 of the CAA to implement the NAAQS, which is the

ED_000419-0005835

longest period of time EPA proposes to allow from the development of section 111(d) state plans. Yet states have no obligation to conduct this sort of modeling during the development of a state implementation plan. It is unreasonable for EPA to expect states to develop novel plans to implement a program that will transform the electric industry and the economy all while performing burdensome analysis that is not typically required to comply with environmental regulation.

In addition, EPA proposes that state plans must be either "self-correcting" or contain milestones, periodic checks, and corrective measures. 79 Fed. Reg. at 34,906-07. The Proposed Guidelines do not provide in-depth discussion of what EPA is considering, apart from the suggestion that corrective measures that are included in a state plan should be triggered by a ten percent deviation from projected performance, and corrective measures that would be included in a plan amendment to be submitted after such a deviation should be triggered by an eight percent deviation from projected performance. EPA is free to make these policy suggestions to the states, but nothing in section 111(d) authorizes the Agency to micromanage these policy choices.

EPA also requests comment on whether the consequences for failing to meet a state goal should include a requirement "to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal." *Id.* at 34,908. Attempting to impose emission reduction requirements more stringent than the application of BSER is inconsistent with the CAA. And again, the consequences of a failure to meet a state goal are policy decisions left to the states.

EPA also asks for comment on whether it should promulgate "a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110" in order to redress the failure of any state plan to achieve its emission goal. *Id.* Section 110 expressly authorizes EPA

ED_000419-0005836

to initiate a SIP call when the Administrator finds that a SIP is "substantially inadequate." CAA § 110(k)(5). There is no similar authority for section 111(d) plans.

Finally, EPA requests comment on its alternative state goals and compliance timing requirements. 79 Fed. Reg. at 34,909. Each of the flaws identified with respect to the primary proposal apply to the alternative.

G. State Plan Approvability Criteria and Components of Approvable Plans

The Proposed Guidelines include "four general plan approvability criteria, [and] twelve required components for a state plan to be approvable." *Id.* at 34,900. EPA notes that the approvability criteria and required components of a section 111(d) plan can differ from those required for a SIP under section 110. *Id.* at 34,909. EPA also states that compliance with the four criteria and the twelve components is required for a plan to meet the 111(d) "satisfactory" standard. *Id.* ("The EPA proposes to use the combination of these twelve plan components and four general criteria to determine whether a state's plan is 'satisfactory' under CAA section 111(d)(2)(A)."). EPA fails to recognize, however, that the "satisfactory" criterion under section 111(d) is far more permissive than the substantive requirements of section 110. The requirements of section 110, moreover, are themselves minimal. *See Train*, 421 U.S. at 79. Nevertheless, the four criteria and twelve components frequently appear to require more of states than submission of a "satisfactory" plan and arguably more than could be required pursuant to section 110. With the limitations on EPA's authority over section 111(d) plans in mind, the criteria and components are discussed below.

EPA's four proposed approvability criteria are: (1) Enforceable Measures; (2) Emission Performance; (3) Quantifiable and Verifiable Emission Performance; and (4) Reporting and Corrective Actions. 79 Fed. Reg. at 34,909. As to enforceability, EPA acknowledges "there may be challenges to practically enforcing against some such entities in the event of

ED_000419-0005837

noncompliance" resulting from the untested nature of its Proposed Guidelines. *Id.* And as explained in Section III.B, there are serious legal problems with the enforceability of EPA's Proposed Guidelines. Indeed, the Plan TSD also acknowledges the enforceability challenges presented by the Proposed Guidelines, and improperly suggests that it falls to states to resolve these questions. Plan TSD at 13-19. EPA cannot make enforceability a prerequisite to plan approval without first resolving these issues.

The second criterion for approvability is that the projected CO_2 emission performance by affected EGUs must be equivalent to, or better than, the required CO_2 emission performance level in the state plan. 79 Fed. Reg. at 34,910. As described above, however, this leaves states none of the authority section 111(d) provides to establish different performance standards for individual sources based on their individual characteristics and needs. Moreover, EPA appears to be contemplating highly involved demonstration requirements that are not consistent with what the Agency may impose under section 111(d) and that cannot realistically be performed in the time that would be permitted under the Proposed Guidelines.

The third criterion is that a state plan specify how the effects of each state plan measure will be quantified and verified. *Id.* Issues related to monitoring, reporting, and recordkeeping by EGUs are addressed in Section XVI of these comments. EPA also mentions quantification, monitoring, and verification of EE and RE measures. The Plan TSD in particular discusses a requirement that states include in their plans a separate "evaluation, measurement, and verification plan (EM&V plan)." Plan TSD at 36. To the extent EPA includes such a requirement in the final rule and to the extent it prepares guidance on EM&V plans, EPA must first provide adequate notice and opportunity to comment on such issues. It should, moreover, recognize that states have discretion over how to address these issues.

ED_000419-0005838

The final approvability criterion is that a plan contain provisions addressing annual reporting on plan performance and measures providing for corrective actions. As stated above, states have discretion to determine the manner in which they will address any shortfalls in their plans.

In addition to the four criteria, the Proposed Guidelines describe twelve components that EPA would require for a plan to be approvable. These components are:

1. Identification of affected entities;
2. Description of plan approach and geographic scope;
3. Identification of state emission performance level;
4. Demonstration that the plan is projected to achieve the emission performance level;
5. Identification of emissions standards;
6. Demonstration that each emissions standard is quantifiable, nonduplicative, permanent, verifiable, and enforceable;
7. Identification of monitoring, reporting, and recordkeeping requirements;
8. Description of state reporting;
9. Identification of milestones;
10. Identification of backstop measures;
11. Certification of hearing on state plan; and
12. Supporting material.

Id. at 34,852, 34,911-14. Many of the components EPA identifies are not, on their face, objectionable policies, such as identifying affected EGUs and other entities subject to the plan. Nevertheless, EPA should recognize that states have primary authority over the contents of their section 111(d) plans and that plans that do not contain these components or that adopt different

ED_000419-0005839

approaches may also satisfy the CAA's requirements. EPA cannot disapprove such plans merely because they might fail to include one or more of the components the Agency has created.

Furthermore, not all of the proposed components are unobjectionable. These components incorporate requirements already addressed in these comments: demonstration of projected performance, milestones, and corrective measures. The problems identified with these elements of the Proposed Guidelines are not remedied in any way by repackaging them as required plan components. The timeframe for developing and submitting state plans is inadequate to allow for the types of performance demonstrations EPA envisions, and EPA's milestone and corrective measure requirements would usurp state decisionmaking authority over the most minute details of a state plan. EPA can express its policy preferences for these measures, but it cannot, consistent with its limited authority under section 111(d), impose them as requirements for states.

H. Process and Timing for Submittal of State Plans

Unlike the specific contents and components of state plans, the CAA does empower EPA to establish "a procedure similar to that provided by section [110] . . . under which each State shall submit to the Administrator" a section 111(d) plan. CAA § 111(d)(1). EPA's proposed procedures, however, pose practicability concerns and, even in this area, EPA's Proposed Guidelines would overstep the Agency's legal authority.

The Proposed Guidelines' discussion of plan submittal and approval processes begins with an acknowledgement of the complexities posed by the Proposed Guidelines and state concerns over the time it will take to develop a plan. 79 Fed. Reg. at 34,915. EPA therefore proposes to require plan submission by June 30, 2016, longer than the nine months allowed for under the existing Subpart B rules. *Id.* Further, EPA proposes that states may seek an additional year if they are entering into single-state plans and may seek an additional two years if they seek

ED_000419-0005840

to join multi-state plans. *Id.* For the many reasons explained throughout these comments, EPA's Proposed Guidelines are unlawful. But even assuming for the sake of argument that they were lawful, states cannot develop plans fundamentally reconfiguring the electric generation industry and power supply market in the short time EPA proposes to provide. Indeed, the State of Arkansas has confirmed that, if the rule is finalized in June 2015, it "would then have to develop a state plan, seek any required legislation from the General Assembly and only then . . . submit the state plan to EPA for approval." Arkansas Letter at 2. The state concluded that the timeframe EPA has provided is not sufficient for the state to take those actions, noting that "the General Assembly will not even meet in regular session again to consider any necessary legislation until January of 2017, when the state is scheduled to meet some of the renewable goals." *Id.*

Further, EPA proposes to require states, in initial submissions, to justify any one-year or two-year deadline extension, and the Agency specifically asks for comments on whether there are justifications for extensions that EPA should reject. 79 Fed. Reg. at 34,915. EPA should take at face value states' good faith efforts to attempt to comply with EPA's exceedingly complicated and amorphous Proposed Guidelines and accept any state assertion that more time is needed to develop a plan unless there is clear evidence to the contrary. In addition, EPA proposes a number of required elements for initial plan submission, including a detailed roadmap to plan completion, before any deadline extension will be considered. *Id.* at 34,915-16. Placing additional burdens on states already struggling to meet extended deadlines is a waste of resources. Moreover, EPA should acknowledge that states have primary authority over plan contents and should defer to state judgments about what should properly be included in an initial

ED_000419-0005841

plan submittal, consistent with section 111(d)'s requirement that states need only submit plans that are "satisfactory."

With respect to the Agency's role in reviewing and approving state plans, EPA requests comment on whether it should authorize itself to use the hybrid approval mechanisms it has developed under section 110—the "partial approval/partial disapproval" and the "conditional approval." *Id.* at 34,916. Recognizing that disapprovals should be rare given EPA's limited review authority under section 111(d), EPA should make use of its section 110 hybrid approval mechanisms where use of such mechanisms will assist the states in implementing the section 111(d) program.

The Proposed Guidelines also briefly address modifications of state plans. *Id.* at 34,917. EPA states that such modifications may become necessary as implementation moves forward and that they will be permissible provided the revision "does not result in reducing the required emission performance for affected EGUs specified in the original approved plan." *Id.* EPA cites no authority and provides no justification for imposing this limitation. Provided a modified plan reflects consideration of relevant section 111(d) factors, it is "satisfactory," and the modification should be allowed.

Finally, EPA asks for comment on whether it should develop template plans. *Id.* If EPA is clear that states are not bound to use any template and that states that choose not to follow the template may nevertheless have approvable submissions, development of a template would be appropriate.

I. Key Considerations for States

The Proposed Guidelines' section on state implementation includes a subsection addressing what EPA calls "key considerations," which are issues that cover a wide variety of topics. Each of these key considerations is addressed below.

ED_000419-0005842

1. Affected Entities Other Than Affected EGUs

EPA notes that it wants to give states "broad discretion" to implement the section 111(d) program, including through the portfolio approach EPA has developed to reflect the Building Blocks it used to identify BSER. *Id.* at 34,917. EPA goes on to admit, however, that the program it has envisioned may prove "challenging to implement." *Id.* EPA suggests that it is a key state consideration, therefore, to figure if the program as imagined by the Agency could be workable. EPA has it backwards. In developing the Proposed Guidelines, EPA should have done the work necessary to determine if the program it has devised is practical. Under section 111(d), EPA cannot seek to impose stringent emission control requirements on states without knowing if the plans needed to implement those requirements can be developed. That is the antithesis of section 111's requirement that "performance standards" reflect levels of emission control that are "achievable" and "demonstrated."

2. Treatment of Existing State Programs

EPA states that it intends not to disadvantage states that have already adopted programs that reduce CO_2 emissions from EGUs. *Id.* at 34,918. With respect to early emission reductions (e.g., reductions from 2005 to 2012), EPA states that those actions are reflected in the 2012 baseline. EPA provides an example:

> For example, in such instances a significant shift to NGCC generation prior to 2012 may result in a lower potential for further re-dispatch to these units, as witnessed in the 2012 base period data. This would influence the calculated rate-based emission goal for the state, reducing the percentage improvement required relative to the base period CO_2 emission rate.

Id. at 34,918 n.291. Similarly, EPA says that states with established EE programs "would be closer to, or in some cases already achieving, the level of demand-side [EE] reflected in the state goals." *Id.* at 34,918. This approach does not give adequate credit for early action. Therefore,

ED_000419-0005843

as explained below, EPA should expand its proposed treatment of emission reductions from existing EE programs.

EPA proposes that existing programs that will result in future emission reductions can be used for purposes of complying with a plan. *Id.* EPA proposes that for any existing state requirements, a state may apply toward its required emission performance level the emission reductions that existing state programs achieve during a plan performance period as a result of actions taken *after* the date of this proposal. EPA further explains that "[t]his option would ensure that actions taken after proposal of the emission guidelines and prior to 2020 as a result of requirements in a state plan, could be recognized as contributing toward meeting a state's required emission performance level for affected EGUs." *Id.* EPA is also requesting comment on two alternatives. Under the first alternative, EPA would change the cutoff for the date by which actions to put EE into place may be taken. Specifically, EPA seeks comment on changing the action date from after the date of proposal to: (1) the start date of the initial plan performance period; (2) the date of promulgation of the emission guidelines; (3) the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for Building Blocks 1, 2, and 3, and the beginning of 2017 for Building Block 4, end-use energy efficiency); (4) the end of 2005; or (5) any other date. *Id.* Second, EPA requests comment on counting emission reductions that occur not only during a plan performance period but also during a specified date prior to the initial performance period, including (1) the date of promulgation of the final emission guidelines; (2) the date of proposal of the emission guidelines; (3) the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for Building Blocks 1, 2, and 3 and the beginning of 2017 for Building Block 4, end-use energy efficiency); (4) the end of 2005; or (5) any other date. *Id.* at 34,919. EPA

ED_000419-0005844

should expand the scope of the existing programs provisions of its Proposed Guidelines to give the broadest favorable treatment possible to EE actions taken to reduce CO_2 emissions regardless of whether those actions were taken prior to the proposal of the Proposed Guidelines. Many, if not most, of those actions taken to date have been pursued with the expectation that appropriate credit for early action would be reflected in any new legislation or regulation to address CO_2 emissions. Failure to provide adequate recognition for these actions will upset those expectations and will undoubtedly discourage future forward looking actions from being taken as a result.

EPA does not give adequate recognition or credit to states that have already undertaken significant measures to increase efficiency, retire coal-fired units, add new renewable or gas-fired capacity, or to otherwise reduce GHG emissions. For instance, Mississippi Power invested $600 million to upgrade pollution controls at Plant Daniel, and Entergy recently uprated what is now the country's largest single-unit power plant, Grand Gulf Nuclear Station. *See* Kristi E. Swartz, *EPA plan gives no credit for Southern states' strides, utility regulators say in Atlanta*, ENERGYWIRE (July 30, 2014), *available at* http://www.eenews.net/energywire/stories/1060003769/print (subscription required). Furthermore, the Tennessee Valley Authority ("TVA") has reduced its CO_2 emissions more than 17 percent below 2005 levels and aims to reduce them to 40 percent below 2005 levels by 2020, exceeding even EPA's targets. Kristi E. Swartz, *Regional carbon approach a 'difficult concept' for sprawling TVA*, ENERGYWIRE (Aug. 6, 2014), *available at* http://www.eenews.net/energywire/2014/08/06/stories/1060004112 (subscription required). TVA notes that a new nuclear plant it is building will not count toward its reduction targets in the Proposed Guidelines. *Id.* Similarly Duke Energy reduced CO_2 emissions 20 percent through 2013. Kristi E. Swartz, *Duke CEO emphasizes customer benefits*

ED_000419-0005845

in scrutiny of EPA power plant proposal, ENERGYWIRE (Aug. 8, 2014), *available at* http://www.eenews.net/energywire/stories/1060004240/print (subscription required). In another example, Georgia Power has been penalized for undertaking a nuclear power project whose operation is assumed in the state's baseline, even though the plant has not yet commenced operation. Jean Chemnick, *EPA rule not such a boon for nuclear after all – utilities*, GREENWIRE (Aug. 8, 2014), *available at* http://www.eenews.net/greenwire/stories/1060004265/print (subscription required).

Although EPA claims that "states with currently existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals," 79 Fed. Reg. at 34,839, this is not the case as such efforts have been put into the baseline, typically resulting in *more stringent* state targets. It is unfair for EPA to disadvantage companies and states that have acted to reduce emissions and not credit these measures toward compliance with state goals.

3. Incorporating RE and Demand-Side EE Measures Under a Rate-Based Approach

EPA asks for comment on what approaches should be permissible for crediting or adjusting CO_2 emission rates to take RE and EE into account. *Id.* at 34,919. EPA has no reason—or authority—to circumscribe the mechanisms that are available to states. These issues fall squarely within the purview of state authority under section 111(d) of the CAA.

4. Quantification, Monitoring, and Verification of RE and Demand-Side EE Measures

As described above, EPA is developing guidance on EM&V plan requirements for state plans and seeks comment on what that guidance should contain. *Id.* at 34,920. The Proposed Guidelines note that states and utilities have led the way in developing EM&V standards. *Id.* As such, this is again an area that is within the purview of the states and one in which EPA should

ED_000419-0005846

not interfere. EPA's guidance should provide states with assistance in how they might develop EM&V plans, but it should not attempt to impose EM&V requirements on the states or to burden and thereby discourage the use of EE and RE measures by imposing onerous monitoring and verification requirements.

5. Reporting and Recordkeeping for Affected Entities Implementing RE and Demand-Side EE Measures

EPA's Proposed Guidelines state that plans that incorporate RE and EE measures will require different reporting and recordkeeping requirements than those that would be applicable solely to affected EGUs. *Id.* at 34,921. EPA, therefore, seeks comment on what would constitute appropriate reporting and recordkeeping requirements for such entities. *Id.* EPA's Plan TSD does little more than summarize current efforts by states to address reporting and recordkeeping requirements used to implement existing state RE and EE programs. Plan TSD at 75-81. That TSD goes on to suggest, however, that the Agency might require more than the states' current programs contemplate. *Id.* at 82-83. There is no basis for that assertion.

EPA's state goals are based on a Building Block analysis of what states are currently achieving through their own RE and EE programs. It is unreasonable for EPA to rely on these programs for the purpose of developing state goals and, at the same time, to find those programs insufficiently reliable due to the robustness of their reporting and recordkeeping requirements. Moreover, EPA has not established that any additional reporting or recordkeeping requirements are, in fact, needed. EPA merely suggests that "supplemental reporting information . . . may be necessary" or that additional information "may also be valuable." *Id.* at 82. These vague assertions do not establish that such information is actually needed or valuable. EPA should instead defer to the states, as is appropriate under section 111(d), and refrain from attempting to circumscribe state discretion.

ED_000419-0005847

6. Treatment of Interstate Effects

The Proposed Guidelines recognize that the electricity market is interstate in nature and that EGUs in one state can provide electricity to customers in other states. 79 Fed. Reg. at 34,921. EPA further notes that state RE and EE programs frequently allow actions in other states, such as renewable generation across state lines, to satisfy intrastate program requirements. *Id.* The nature of this system creates enormous problems for EPA's proposal. EPA's proposed response to these problems is to adopt one set of rules for EE measures, a separate set of rules for RE measures, and yet another set of rules for multistate plans. *Id.* at 34,922. These simplistic rules, however, will not prevent serious, real-world problems from emerging and impacting states' abilities to comply with the Proposed Guidelines. Under the Proposed Guidelines, for instance, states would be able to take into account all RE measures implemented for purposes of compliance with a renewable portfolio standard ("RPS") regardless of whether the renewable energy is generated in-state or out-of-state. Although such an approach will benefit some states with RPS requirements, it could also significantly disadvantage states that have constructed renewable generation that happens to be consumed across state lines. With respect to EE measures, EPA would take the opposite approach, limiting credit for EE-related emission reductions to in-state activities only and ignoring the possibility that some states rely on out-of-state EE to satisfy their existing requirements. *Id.*

There is no simple solution that can remedy the inequities presented by these conflicting approaches to crediting RE- and EE-related emission reductions, and the simple fact that these problems are so inescapable demonstrates that EPA has strayed far beyond the bounds of its CAA authority. EPA's Proposed Guidelines will engender conflict among the states. EPA should recognize the seriousness of this issue and withdraw the Proposed Guidelines.

7. Projecting Emission Performance

ED_000419-0005848

As described above, EPA's Proposed Guidelines suggest the Agency is seeking to impose unnecessary burdens on states that the Agency is not authorized under section 111(d) to require. States should determine the manner in which they will evaluate the performance of their plans. At the very least, EPA must provide more time to states if it wants to encourage states to undertake the sort of detailed modeling and related work EPA appears to prefer.

8. Potential Emission Reduction Measures Not Used To Set Proposed Goals

According to EPA, "States may include measures in their plans beyond those that the EPA included in its determination of the BSER." *Id.* at 34,923. States should be free to include any measures they deem appropriate, consistent with the CAA, as part of their section 111(d) plans.

EPA requests comment on several additional issues in this section of the Proposed Guidelines. First, it recognizes the possibility of using new NGCC generation to replace higher emitting coal-fired EGUs. EPA asks how that new NGCC generation should be treated for purposes of demonstrating compliance with section 111(d) requirements:

> The agency requests comment on how emissions changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs. Specifically, considering the legal structure of CAA section 111(d), should the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a mass-based state plan (e.g., in a plan using a portfolio approach) also be considered?

Id. at 34,924. As an initial matter, as discussed in Section X, new NGCC units are outside the purview of section 111(d) as those units will be subject to the requirements of section 111(b). To the extent new NGCC generation can help offset requirements under section 111(d) plans, however, states should be given wide latitude to decide how to address new NGCC capacity for

ED_000419-0005849

purposes of calculating compliance. For example, to the extent newly constructed NGCC units displace higher-emitting generation, states that employ the rate-based approach under section 111(d) should be allowed to include the megawatts generated from these newly constructed units in the denominator for the state's rate. This approach would be similar to how the Proposed Guidelines treat renewable energy and new nuclear units. For states that use the mass-based approach under section 111(d), the emissions from newly constructed units should not be included in the program at all.

EPA also requests comment on allowing incremental emission reductions beyond what is required of new units under section 111(b) to count toward compliance with section 111(d). *Id.* For example, if a new NGCC plant were to install CCS, thereby exceeding the emission reductions required under section 111(b), those additional reductions could be credited toward the section 111(d) program. UARG supports this concept, and EPA should make clear that states are free to find other, similar incremental emission reductions that could also be applied toward compliance with the section 111(d) program.

Finally, EPA states that it is developing a framework for counting biomass-related emissions and notes that biomass can be carbon-neutral. *Id.* at 34,924-25. EPA should work to encourage the use of biomass and avoid unnecessarily burdening its use by seeking to impose unworkable and onerous verification (and similar) requirements.

9. Consideration of a Facility's "Remaining Useful Life" in Applying Standards of Performance

EPA's Proposed Guidelines include a discussion attempting to justify EPA's proposed decision to significantly curtail state discretion to consider remaining useful life and other factors in developing a state plan. *Id.* at 34,925-26. EPA first asserts that deviating from the Proposed Guidelines based on remaining useful life or other factors is simply unnecessary given the

ED_000419-0005850

flexibility EPA has designed into the Proposed Guidelines. *Id.* at 34,925. EPA argues instead that states can adjust requirements applicable to specific EGUs to accommodate their needs and make up for any adjustments to apply less stringent requirements to one EGU by making requirements for other EGUs (or other entities) more stringent. This argument assumes that there is enough room within each state's goal to make such accommodations. As discussed in these comments, the flexibility EPA's argument relies on does not exist. Indeed, it also assumes that EPA has itself adequately accounted for the remaining useful life of the facilities it seeks to regulate in setting the state goals. It has not.

Over the last several years, EPA has approved or directly imposed requirements on numerous facilities, forcing them to install expensive air pollution controls, such as scrubbers and SCR, to control visibility-impairing pollutants pursuant to the Regional Haze Program and to control hazardous air pollutants under the Agency's MATS requirements. In doing so, the Agency has frequently relied on 20 or 30-year remaining useful life estimates to support the imposition of these costly requirements. *See, e.g.*, 76 Fed. Reg. 52,388, 52,402 (Aug. 22, 2011). Yet, in many instances, compliance with the Proposed Guidelines will require the shutdown of coal-fired units in much shorter timeframes—in many cases by 2020. This is the case, for example, with respect to the Coronado Generating Station ("CGS") in Arizona. There, EPA imposed a requirement that CGS install SCR to control nitrogen oxides ("NOx") emissions by December 5, 2017. EPA based that requirement on a 20-year remaining useful life in determining best available retrofit technology ("BART"). *See* 77 Fed. Reg. 42,834, 42,864 (July 20, 2012). Now, however, EPA's own analysis supporting the Proposed Guidelines shows that the Agency expects all coal-fired generation in Arizona, including CGS, to shut down by 2020,

ED_000419-0005851

leaving CGS with hardly more than two years of remaining useful life. Goal Computation TSD, App. 1.

EPA similarly failed to take into account major pollution control projects that are mandated by MATS. Thus, as a practical matter, EPA's argument that deviation from the Proposed Guidelines based on remaining useful life or other factors is unnecessary is incorrect, and EPA's failure to account for its existing requirements would lead to massive and needless waste.

EPA's argument also depends on its assertion that it has authority under the CAA to place limits on state consideration of remaining useful life. It does not. EPA claims that its existing Subpart B regulations allow for state consideration of remaining useful life and other factors and deviation from EPA emission guidelines based on that consideration, but that EPA is free to take that right away from the states. 79 Fed. Reg. at 34,925 ("EPA has discretion to alter the extent to which states may authorize relaxations to standards of performance that would otherwise apply to a particular source or source category . . . ."). The source of state authority to consider remaining useful life in determining whether to adjust EPA's emission guideline is the CAA, not EPA regulations.[29] The Act states: "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." CAA § 111(d)(1) (emphasis added). This language provides EPA with no discretion to limit or prohibit states

---

[29] Moreover, even if the source of state authority to consider remaining useful life and other factors solely came from EPA's Subpart B regulations (which is not the case), EPA still must follow those regulations. If EPA wishes to change the Subpart B regulations, it must do so through notice and comment rulemaking. EPA has made clear that it is *not* proposing to revise its Subpart B regulations in this rulemaking. 79 Fed. Reg. at 34,844, 34,925 n.302.

ED_000419-0005852

from taking remaining useful life and other factors into account in applying a standard of performance to individual sources. It does not matter if EPA thinks this authority is unnecessary or if its rule might allow states an alternative that could approximate consideration of remaining useful life in some circumstances. The law grants states this right.

Finally, EPA argues that it can alter the state's authority to take remaining useful life into account and to deviate from or adjust EPA's emission guideline because the emission guideline the Agency has proposed differs so dramatically from the usual "presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category." 79 Fed. Reg. at 34,925. The fact that the Proposed Guidelines deviate so significantly from other section 111 standards speaks to the validity of the Proposed Guidelines themselves; it does not give EPA carte blanche to rewrite other provisions of the Act to better suit EPA's distorted rule.

J. Multi-State Plan Considerations

EPA's Proposed Guidelines address issues that will affect states that pursue multi-state plans for implementing section 111(d) requirements. Some of these issues are practical. For instance, the Proposed Guidelines assert that states participating in multi-state plans should submit a single plan signed by authorized officials from each participating state and that all required plan components must be included and address these requirements for the group as a whole. *Id.* at 34,911. EPA also requests comment on whether states should submit a single joint multi-state plan along with individual state plans addressing separately joint and state-specific plan elements. *Id.* EPA also asks for comment on whether each state participating in a multi-state plan should submit its own plan without submitting any joint plan. *Id.* EPA should allow states to proceed how they wish. Different processes will work more effectively for different parties, and EPA gains nothing by arbitrarily limiting state discretion.

ED_000419-0005853

The Proposed Guidelines also address joint demonstration of emission performance and propose that multi-state plans include a joint multi-state performance goal calculated based on each state's individual goal. *Id.* EPA seeks comment on two approaches for calculating the joint goal, described by EPA as follows:

> [1.] Under the first option, the weighted average emission rate goal for a group of participating states is computed using each state's emission rate goal from the emission guidelines and the quantity of electricity generation by affected EGUs in each of those states during the 2012 base year that the EPA used in calculating the state-specific goals. Different levels would be computed for the interim and final goals . . . .
>
> [2.] Under the second option, the weighted average emission rate goal for a group of participating states is computed using each state-specific emission rate goal and the quantity of projected electricity generation by affected EGUs in each state. The calculation would be performed for the 2020 through 2029 period to produce a multi-state interim goal, and for 2030 to produce a multi-state final goal.

Id. at 34,911-12. The results of either approach will differ depending of the mix of generation in each multi-state group. States should be free to decide among themselves which approach works best for their region and adopt either calculation method or any other calculation method they develop or deem appropriate. EPA does not have a basis in section 111(d) for limiting state discretion over this matter.

EPA also indicates that it would treat EE differently under multi-state plans than it would under single-state plans. For single-state plans, EPA proposes that "a state could take into account in its plan only those CO_2 emission reductions occurring (or projected to occur) in the state that result from demand-side EE measures implemented in the state." *Id.* at 34,922. For multi-state plans, however, EPA proposes to allow participating states "to distribute the CO_2 emission reductions among states in the multistate area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emissions reductions that result from demand-side EE measures implemented in those states." *Id.* Given the nature of multi-

ED_000419-0005854

state plans, attempting to limit EE in such plans based on origin would unnecessarily complicate implementation. Accordingly, EPA's proposed approach to allow states to determine how to distribute such EE-related emission reductions is appropriate.

UARG generally supports allowing states to enter into multi-state plans if they wish. As noted above, however, developing and finalizing multi-state plans in the timeframe allowed by EPA's Proposed Guidelines would be extremely challenging if not impossible. EPA should provide more time for the development of these plans and provide clear guidelines for multi-state plans. This should include a mechanism for trading between rate-based and mass-based programs.

X. EPA Cannot Require States To Regulate EGUs Simultaneously Under Sections 111(b) and 111(d) of the CAA.

EPA states that any EGU that becomes subject to a state plan under section 111(d) that subsequently undergoes a modification or a reconstruction must remain subject to the regulatory requirements of the state plan in addition to having to comply with EPA's requirements for modified and reconstructed EGUs under section 111(b). 79 Fed. Reg. at 34,962-63, 34,965, 34,969, 34,974-75, 34,987. UARG strongly disagrees with EPA's statement. The CAA does not allow EPA to regulate the same source as both an existing and new source. Although a state may have authority under section 116 of the CAA to impose additional regulatory requirements on a modified or reconstructed source as a matter of state law, EPA cannot *compel* states to regulate a given unit as both an existing and new source. As discussed below, under the plain language of the CAA, a source that is regulated under section 111(b) because it is a "new" source cannot simultaneously be subject to regulation under section 111(d) as an "existing" source under federal law, and vice versa.

ED_000419-0005855

In this rulemaking, EPA states that "a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard being promulgated under CAA section 111(b)." 79 Fed. Reg. at 34,903. Likewise, in its proposed standards for modified and reconstructed EGUs under section 111(b), EPA asserts that "existing sources that are subject to requirements under an approved CAA section 111(d) plan would remain subject to those requirements after undertaking a modification or reconstruction." 79 Fed. Reg. at 34,974. EPA claims that it can adopt this position because section 111 "is silent on whether requirements imposed under a CAA section 111(d) plan continue for a source that ceases to be an existing source because it modifies or reconstructs." 79 Fed. Reg. at 34,904. This is simply incorrect. Section 111 speaks clearly and directly to the issue.

The CAA states that "[t]he term 'new source' means any stationary source, the construction *or modification* of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2) (emphasis added). Section 111(a)(6) states that "[t]he term 'existing source' means any stationary source other than a new source." These definitions, by their own terms, are mutually exclusive.

Thus, under section 111, an existing source is one that has commenced construction before the publication of regulations (or proposed regulations) applicable to new sources of the same type. Such existing sources are subject to standards promulgated pursuant to section 111(d) of the Act. A new source can come into existence either through greenfield construction that commences after publication of proposed rules applicable to such new sources or through

ED_000419-0005856

commencing at such time a modification or reconstruction[30] of what would otherwise be an existing source. The critical fact here is that once a modification or reconstruction commences, the "existing" source ceases to exist and a "new" source takes its place. New sources are subject to regulation pursuant to section 111(b). Under the CAA's explicit terms, section 111(d) cannot apply to sources subject to section 111(b).

EPA has long codified this strict division between existing and new sources in binding legislative rules governing CAA programs. For instance, modified and reconstructed sources are regulated as new sources under the CAA's new source "maximum achievable control technology" program pursuant to section 112(g)(2). In finalizing NSPS for Subpart Da units in 1998, the Agency emphasized that the inclusion of modified sources in the definition of "new source" in section 111(a)(2) is a "clear statutory mandate." 63 Fed. Reg. at 49,448. EPA's newfound discovery of supposed statutory ambiguity cannot be reconciled with the Agency's longstanding implementation of the CAA.

Ignoring this clear statutory division, the Agency offers two policy reasons to justify some newly found statutory ambiguity and its proposal to subject new sources to both existing and new source regulatory requirements. First, EPA claims that modified or reconstructed units should remain subject to the existing source program because "[u]ncertainty about whether units would remain in the program could be very disruptive to the operation of the program." 79 Fed. Reg. at 34,904. Second, EPA argues that it should continue to apply the existing source program to modified and reconstructed sources because "potential discrepancies in the stringency of the

---

[30] A physical or operational change that increases the capacity of an existing source to emit may trigger a "modification" analysis. *See, e.g.*, 40 C.F.R. § 60.14. Replacement of components that involves investments exceeding 50 percent of the fixed capital costs of a comparable, entirely new facility triggers the reconstruction analysis. *See id.* § 60.15(d).

ED_000419-0005857

two programs" might "creat[e] incentives for sources to seek to avoid their obligations under a CAA section 111(d) plan by undertaking modifications." *Id.* Both of EPA's concerns would be resolved by withdrawing the proposed standards for modified and reconstructed EGUs. As discussed in Section II.A of the UARG Modified/Reconstructed Comments at 13-14, EPA has discretion not to impose NSPS for modified or reconstructed units and by choosing not to do so in this instance, it would avoid the concerns it has raised.

Moreover, even assuming that EPA's concerns are valid regarding disruption and uncertainty to the section 111(d) program over whether units would leave the program, this does not justify ignoring the plain language of the statute. State plans devised with the correct statutory interpretation in mind can include provisions to accommodate such changes. Indeed, EPA envisions many sources shutting down as a result of the Proposed Guidelines. RIA at 3-34, Tbl. 3-12. If state plans can accommodate units leaving the program through cessation of operations, there is no reason why they cannot accommodate the transition of modified or reconstructed units from the existing source program to the section 111(b) program for new sources. In addition, to the extent EPA has designed a section 111(d) program that cannot function while adhering to the requirements of section 111(a)(2) and section 111(a)(6), it is EPA's proposal, not the CAA, that must be revised. *See, e.g.*, *ASARCO*, 578 F.2d at 329 (where EPA is concerned about practical application of proposed rule, solution is to alter standard). Finally, although states can opt to impose additional requirements on modified and reconstructed EGUs as a matter of state law under section 116 of the Act, EPA cannot require the states to regulate a unit as both a new and existing source as this would violate the CAA.

It should also be noted that newly constructed EGUs that commence construction after January 8, 2014 (the date of publication of the proposed NSPS rule for new EGUs under section

111(b)) are outside of the section 111(d) program. To the extent these newly constructed EGUs displace higher-emitting generation units (such as an NGCC unit that replaces a coal-fired EGU), however, it would be permissible for a state that employs the rate-based approach under section 111(d) to allow the megawatt hours generated by these newly constructed units to be included in the denominator for a state's rate. This approach would be similar to how renewable energy and new nuclear units are treated in the Proposed Guidelines. For states that use the mass-based approach, the emissions from newly constructed units would not be included in the program at all.

With regard to EPA's concern that there could be an incentive for sources to modify or reconstruct "to avoid their obligations under a CAA section 111(d) plan," 79 Fed. Reg. at 34,904, for the reasons explained above, a source that undertakes modifications or undergoes reconstruction after the date of the proposal of the applicable NSPS *has no obligations under a section 111(d) plan* by operation of the CAA; it could only have such obligations as a matter of state law at the state's discretion. Further, to the extent EPA has proposed discrepancies in the new source and existing source programs that might create incentives the Agency dislikes, the solution is not rewriting the terms of the CAA. *See UARG v. EPA*, 134 S. Ct. at 2445 ("An agency has no power to 'tailor' legislation to bureaucratic policy goals by rewriting unambiguous statutory terms.").

Of course, the reason for this discrepancy is EPA's decision to propose a section 111(d) program that bears no relationship to the requirements of section 111 or to any section 111 standard EPA has previously written. *See, e.g.*, 61 Fed. Reg. 9905 (Mar. 12, 1996) (municipal solid waste landfills); 42 Fed. Reg. 55,796 (Oct. 18, 1977) (sulfuric acid production units). If

ED_000419-0005859

EPA were to write a section 111(d) standard that complied with the CAA, this discrepancy would disappear.

EPA's proposed interpretation of the CAA is inconsistent with the statutory text of sections 111(a)(2) and 111(a)(6) and is unsupported by rational policy considerations. EPA must, therefore, revise the Proposed Guidelines to conform to the CAA requirement that new sources subject to section 111(b) requirements (including modified and reconstructed sources) cannot also be required to comply with section 111(d) state plans under the CAA.

XI. New Source Review Issues

Building Block 1 of EPA's Proposed Guidelines consists of measures aimed to reduce CO_2 emissions from coal-fired EGUs by improving heat rate, which reduces the amount of fuel needed to produce the same amount of electricity. Heat rate improvements increase efficiency and "yield important benefits to affected sources by reducing their fuel costs." 79 Fed. Reg. at 34,859. In the Proposed Guidelines, EPA noted that "[s]everal studies have examined the opportunities to employ heat rate improvements" at coal-fired EGUs, and specifically cited a 2009 report by Sargent & Lundy as identifying "equipment upgrades . . . at a facility [that] could provide total heat rate improvements in a range of approximately 4 to 12 percent." *Id.* Likewise, EPA cites EPA's 2014 Technical Support Document (TSD) for GHG Abatement Measures, EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources, GHG Abatement Measures (Sept. 16, 2014) (clarified version), Docket ID No. EPA-HQ-OAR-2013-0602-17180 ("GHG Abatement Measures TSD"), which also lists upgrades that may be employed to reduce heat rate. *Id.* at 34,859 n.114.

The projects identified in the 2009 Sargent & Lundy report and the GHG Abatement Measures TSD include upgrades to the following components: soot blowers, boiler feed pumps,

ED_000419-0005860

economizers, turbines, boilers, air heaters, feedwater heaters, condensers, forced draft and induced draft fans, pulverizers, condensate pumps, flue gas conditioning systems, SCR systems, ash handling systems, neural network optimization systems, electrostatic precipitators, and system controls. *See* Sargent & Lundy LLC, Coal-Fired Power Plant Heat Rate Reductions at 2-1 to 5-4 (Jan. 22, 2009) (identifying projects), *available at* http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf; GHG Abatement Measures TSD at 2-1 to 2-16 (same). EPA further explained that "EGUs achieve heat rate improvements by . . . installing and using equipment upgrades . . . such as, extensive overhaul or upgrade of major equipment (turbine or boiler) or replacing existing components with improved versions." GHG Abatement Measures TSD at 2-16.

As EPA knows, however, every one of these upgrades has been targeted by EPA and citizen plaintiffs as triggering the NSR provisions of the CAA. Indeed, shortly after EPA launched its NSR enforcement initiative in 1999, EPA issued a formal applicability determination for a turbine upgrade at Detroit Edison's Monroe Plant called the Dense Pack project. In that determination, EPA cited that efficiency improvement as a major factor weighing against a finding that the project was routine maintenance, repair or replacement ("RMRR") and thus excluded from NSR permitting requirements:

> The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine .... It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity.

Letter from Francis X. Lyons, Reg'l Adm'r, EPA, to Henry Nickel, Hunton & Williams at 2, 3 (May 23, 2000) ("Detroit Edison Determination"), *available at* www.epa.gov/ttn/nsr/gen/

letterf3.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). EPA went on to assert:

> In general, a physical change in the nature of the Dense Pack project, which provides for the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels.

Id. at 4-5.

UARG has analyzed EPA notices of violation, citizen notices of intent to sue, and complaints available in the public record since EPA began its NSR enforcement initiative in 1999. Based on that analysis, UARG has identified *over 400* efficiency improvement projects targeted by EPA or citizens since 1999 as allegedly violating NSR. These projects are listed in Attachment A and are the same types of projects identified in the 2009 Sargent & Lundy report and GHG Abatement Measures TSD. Moreover, during that same period, EPA and citizens have targeted almost *600* other projects as violating NSR. These projects are listed in Attachment B and—like the projects cited by Sargent & Lundy and EPA—are also important to maintaining and improving the efficiency of coal-fired generating units. Indeed, these projects consist of "like-kind replacement of worn existing components," which EPA also identifies as essential to maintaining and improving the efficiency of coal-fired generating units. *See* GHG Abatement Measures TSD at 2-16.

EPA recognizes the potential NSR consequences of implementing Building Block 1, but states that it expects there will be "few" instances where "an NSR permit would be required." 79 Fed. Reg. at 34,928. UARG agrees that very few efficiency projects, if any, *should* trigger NSR. Efficiency improvements of the types identified in Attachments A and B constitute routine repair

ED_000419-0005862

and replacement of deteriorated components and do not trigger NSR. *See, e.g.*, *Nat'l Parks Conservation Ass'n v. TVA*, No. 3:01-CV-71, 2010 WL 1291335 (E.D. Tenn. Mar. 31, 2010) ("*NPCA*") (finding economizer and superheater replacements RMRR); *Pa. Dep't of Envtl. Prot. v. Allegheny Energy, Inc.*, No. 05-885, 2014 WL 494574 (W.D. Pa. Feb. 6, 2014) (finding superheater, lower slope panel, and reheater replacements RMRR). *But see United States v. Louisiana Generating, LLC,* No. 09-100, 2012 WL 4107129 (M.D. La. Sept. 19, 2012) (finding reheater replacements non-RMRR). Moreover, efficiency improvements of 1 to 6 percent are too small to significantly and identifiably change the dispatch of a unit in a large system, and in any event, such changes are minute with respect to the fluctuations in all other factors that can affect dispatch of a unit at any particular year.

But clearly these views are not shared by EPA's enforcement arm, as is evident from the Detroit Edison Determination and the hundreds of projects targeted in the enforcement initiative since then. Based on the history of EPA's NSR enforcement initiative, EPA's statement that there will be "few" instances in which Building Block 1 projects would trigger NSR rings hollow and is hardly reassuring to the utility industry. Over 20 years ago, EPA made similar statements regarding life extension projects amid concerns that EPA's determination that led to the Seventh Circuit's decision in *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901 (7th Cir. 1990) ("*WEPCo*"), would apply to such projects. At that time, EPA told industry that *WEPCo* would not "significantly affect power plant life extension projects." Letter from William G. Rosenberg, Assistant Adm'r for Air and Radiation, EPA, to The Hon. John D. Dingell, Chairman, Subcomm. on Oversight & Investigations, Comm. on Energy & Commerce, at 5-6 (June 19, 1991) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Moreover, in the preamble to the 1992 NSR reform rule, known as the WEPCo rule, EPA confirmed that

ED_000419-0005863

whether repair and replacement projects are judged routine would be determined with respect to industry practice. 57 Fed. Reg. 32,314, 32,326 (July 21, 1992). As EPA knows, however, many utilities relying on these and similar statements regarding repair and replacement projects were then targeted about a decade later for allegedly violating NSR for performing those very projects. *See, e.g.*, *United States v. Ala. Power Co.*, 681 F. Supp. 2d 1292, 1310 (N.D. Ala. 2008) (EPA "could not tell Congress it envisioned very few *future WEPCO*-type enforcement actions on the one hand, and then argue in subsequent enforcement actions that the utility industry was unreasonable in relying on those, or similar, EPA statements.").

Moreover, even if EPA believes there will be "few" instances where an NSR permit would be required, there is no suggestion that all states or citizens share that belief. Citizen plaintiffs have been just as active as EPA in litigating NSR suits over the past 15 years. Even when those citizen suits have lacked merit, they often delay the implementation of efficiency improvement projects, take several years to litigate, are very expensive, and drain scarce resources of the parties and courts.[31] The NSR citizen suits in *Allegheny Energy, Inc.*, 2014 WL 494574, and *NPCA*, 2010 WL 1291335, for example, each took approximately *nine years* to litigate at the district court level.[32] Both resulted in a complete dismissal of plaintiffs' claims.

---

[31] The same is often true for NSR enforcement actions. For example, in *United States v. Cinergy Corp.*, after more than a decade of litigation, a jury returned a verdict for EPA on only 4 of 14 projects, but even that limited success was reversed by the Seventh Circuit. 618 F. Supp. 2d 942 (S.D. Ind. 2009), *rev'd* 623 F.3d 455 (7th Cir. 2010). Likewise, EPA's enforcement actions against Duke Energy and Alabama Power are still pending after nearly *14 years* of litigation. *United States v. Duke Energy Corp.*, No. 00-1262 (M.D.N.C. filed Dec. 22, 2000); *United States v. Ala. Power Co.*, No. 01-152 (N.D. Ala. filed Jan. 12, 2011). Trial has not been scheduled in either case.

[32] Although New York, Maryland, and Connecticut appealed the district court's *Allegheny Energy* decision dismissing their citizen suit to the U.S. Court of Appeals for the Third Circuit, Pennsylvania and New Jersey chose not do so. The appeal is still pending.

ED_000419-0005864

For this reason as well, EPA's assurances provide no comfort to UARG's members, who are routinely targeted by citizens for alleged NSR violations relating to equipment upgrades.

This threat of litigation is compounded by the fact EPA maintains it can bring a suit alleging an NSR violation years after a project is undertaken and regardless of whether emissions in fact increase after the project. EPA's theory of liability under NSR has three fundamental tenets: (1) NSR enforcement can proceed on the basis of any repair or replacement project other than the most minor, repetitive maintenance; (2) for such repair and replacement projects, NSR enforcement can proceed on the basis of a projection alone (regardless of whether post-project actual emissions increase, much less increase as a result of the project), *see, e.g.*, *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 865 (S.D. Ohio 2003) (NSR enforcement can proceed on the basis of projection, even when post-project data are available (applying 1980 and 1992 rules)); *United States v. S. Ind. Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1022 & n.20 (S.D. Ind. 2003) (same (applying the 1980 rules)); and (3) even if a company performed a pre-project projection, EPA can always challenge that projection, *see, e.g.*, *United States v. DTE Energy Co.*, 711 F.3d 643, 650-52 (6th Cir. 2013) (rejecting EPA's theory). As a result, utilities implementing Building Block 1 that do *not* project an increase in emissions as a result of an equipment upgrade will face the ongoing threat of NSR litigation, years after their projects. In an enforcement action filed just last year, for example, EPA sued Oklahoma Gas & Electric Company ("OG&E") for allegedly violating NSR even though emissions since the projects have decreased. *United States v. OG&E*, No. 13-690 (W.D. Okla. filed July 8, 2013). And EPA brought these claims following the very same types of upgrades it is now recommending to implement Building Block 1—the replacement of economizers and turbine blades, and the addition of heat transfer surface in boilers. *See id.*, Compl. ¶ 42.

ED_000419-0005865

EPA's own recognition that "the NSR program has impeded or resulted in the cancellation of projects which would … improve … efficiency" confirms the need for regulatory certainty for utilities implementing Building Block 1. EPA, "New Source Review: Report to the President," at 1 (June 2002), *available at* http://www.epa.gov/NSR/documents/nsr_report_to_president.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Otherwise, EPA's Proposed Guidelines are destined to create the same uncertainty and encounter the same problems that have plagued the NSR program for the past 15 years. Rather than replow this ground, EPA should eliminate the threat of protracted NSR litigation and provide a clear statement that any upgrades necessary to implement Building Block 1 do not trigger NSR.

EPA failed to do so, however, instead waving generally in the direction of "flexibility" to suggest that the states themselves can provide the necessary relief from the efforts of EPA's enforcement arm and citizen groups for their sources as a part of their state plans under section 111(d). 79 Fed. Reg. at 34,928. EPA's first suggestion that states could somehow adjust statewide demand side measures and renewable energy requirements so as to counterbalance the supposed impact of unit-specific efficiency improvements on unit utilization is speculative at best. EPA's second suggestion of essentially imposing synthetic minor limits on all coal-fired sources (because, at least under the NSR enforcement initiative view of NSR, most, if not all, Building Block 1 projects likely trigger NSR) goes against the "flexibility" EPA touts in the Proposed Guidelines. Imposing such synthetic minor limits across the board would, for example, prevent a state plan from relying on the shutdown of smaller, less efficient units and increased utilization of larger, more efficient units.

ED_000419-0005866

In sum, at least Building Block 1 of EPA's Proposed Guidelines are based on measures that EPA's enforcement arm has declared illegal, as EPA has at least implicitly acknowledged. Because EPA's justification of the state emission goals relies on the ability of sources to implement efficiency improvement measures, and because EPA has failed to propose any credible regulatory provisions to otherwise address this issue, EPA has failed to demonstrate the achievability of its goals as required by section 111. *See, e.g.*, *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (a "standard . . . must be achievable" under section 111); *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980) (EPA bears the burden of explaining "how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated"). Similarly, EPA's failure to account for the potential cost of NSR—and NSR uncertainty—for Building Block 1 projects in the Proposed Guidelines is arbitrary and capricious. *See, e.g.*, *Star Enter. v. EPA*, 235 F.3d 139, 142 (3d Cir. 2000) (EPA must "tak[e] into account the cost of achieving [emission] reduction" under section 111 in setting standards) (internal quotation marks and citation omitted); *Pub. Citizen v. Fed. Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) ("an agency's rule normally is arbitrary and capricious if it entirely failed to consider . . . [a] statutorily mandated factor") (internal quotation marks and citations omitted).

XII. The Proposed Guidelines Are Not Justified by Their Purported Benefits When Those Benefits Are Characterized Properly.

If the benefits of the Proposed Guidelines are properly characterized—that is, without inappropriately claiming benefits from the U.S. Government's social cost of carbon ("SCC") estimates and the benefits of reducing pollutants that are regulated to protective levels by other rules—there are no benefits to weigh against the exorbitant costs. The Proposed Guidelines therefore cannot be justified and are thus unlawful. In fact, EPA never claims the Proposed

ED_000419-0005867

Guidelines will mitigate climate change, despite describing the issue of climate change at length as a purported rationale for the rule. While the Agency quantifies the estimated emission reductions that the Proposed Guidelines will achieve, it never makes the connection between those emission reductions and the resulting impact on climate change, raising questions about the purpose of the rule. A "standard of performance" for purposes of section 111 is defined as the degree of emission limitation achievable through the best, adequately demonstrated system of emission reduction, "*taking into account the cost* of achieving such reduction . . . ." CAA § 111(a)(1) (emphasis added). A section 111 standard that imposes greater costs than benefits is therefore unlawful. EPA's reliance on the SCC and public health benefits to claim benefits from the Proposed Guidelines is arbitrary and capricious. Any regulation whose costs outweigh its benefits is unlawful and is also ineffective and misguided. *See* CAA § 301(a) (authorizing EPA to adopt "such regulations as are necessary to carry out [its] functions under [the Act]"; regulations that yield no benefits cannot be "necessary").

A. Costs

EPA's estimate of the costs of the Proposed Guidelines appears to be significantly understated. As discussed elsewhere in these comments, EPA's Building Block assumptions are in most cases unrealistic and unachievable. Implementing the Building Blocks as designed will almost certainly cost more than EPA has estimated because of the Agency's unrealistic assumptions about achievability, discussed in Section XIV below.

EPA states that the purpose of the rule is to "continue progress already underway to lower the carbon intensity of power generation in the United States." 79 Fed. Reg. at 34,832. The Agency makes the case that climate change exists and is affecting the United States, *id.* at 34,841-43; RIA at 1-2, 4-1 to 4-6, but EPA does not even attempt to claim that the rule will have any impact on climate change. The preamble asserts that the Proposed Guidelines will reduce

ED_000419-0005868

CO_2 emissions, 79 Fed. Reg. at 34,931, and claims that emission reductions will be "meaningful," *see e.g., id.* at 34,878, but does not assert that those CO_2 emission reductions will actually accomplish anything in terms of climate change mitigation. The rule covers only a portion of the power generation sector in a single country—emissions representing less than 5 percent of global GHG emissions.[33] And the rule would reduce only a portion of the emissions of that sector. EPA estimates that the rule would result in a reduction in CO_2 emissions of about 555 million tons of CO_2 in 2030 for the Option 1 State Compliance Approach. RIA at 3-20, Tbl. 3-5. The IPCC has stated recently that 2010 global anthropogenic emissions of GHGs amounted to 49 gigatons (49 billion) tons per year. IPCC 2014 at 6. That is 1.13 percent of global emissions, assuming full compliance with the rule as proposed—not enough to significantly impact climate change. If the purported rationale of the Proposed Guidelines is to address climate change, but the rule would not in fact do hardly anything to mitigate climate change, EPA should either discard the rule entirely as being unfounded, or be more forthright about the real reasons for the rule.

EPA understates the Proposed Guidelines' likely disruption to the national economy, the negative impact on the reliability of the U.S. energy system, and the adverse impact to U.S. energy security. None of these impacts is easy to quantify. It is difficult to measure the multiplier effects of a wide-ranging regulatory effort that seeks to strand a significant portion of

---

[33] The U.S. State Department reports that 2010 U.S. power sector emissions were 2,342 Teragrams CO_2 equivalent. *See* U.S. Department of State, Projected Greenhouse Gas Emissions, at 82, Tbl. 5-5 (undated), *available at* http://www.state.gov/documents/organization/140007.pdf. That equates to 2.342 billion metric tons, or about 4.78 percent of global anthropogenic emissions in 2010. *See* IPCC, Climate Change 2014, Mitigation of Climate Change: Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, Summary for Policymakers, at 6 (2014), *available at* http://report.mitigation2014.org/spm/ipcc_wg3_ar5_summary-for-policymakers_approved.pdf ("IPCC 2014").

ED_000419-0005869

the country's existing electricity generating sector. In an attempt to look at some of these issues, NERA Economic Consulting recently conducted an extensive analysis of the projected impacts of the Proposed Guidelines on energy markets. *See* NERA Economic Consulting, Potential Energy Impacts of the EPA Proposed Clean Power Plan (Oct. 2014), *available at* http://www.nera.com/publications/archive/2014/potential-impacts-of-the-epa-clean-power-plan.html. NERA found that implementing EPA's Option 1, State Compliance Approach, with all four Building Blocks would cause 45 GW of coal-fired EGUs to retire, *id.* at S-6; cause coal-fired generation to decline 29 percent, with natural gas-fired generation increasing 5 percent, *id.*; and cause gas prices to increase 2 percent and electricity prices to increase 12 percent over the 2017-2031 period, *id.* NERA also found that the highest energy system costs from the Proposed Guidelines would stem from state energy efficiency programs which would cost about $560 billion in present value from 2017 through 2031. *Id.* at 21. NERA found that "total electricity-related costs . . . increase by an average of $34 billion per year from 2017 through 2031 across all sectors," with the largest of the increases going to residential and commercial consumers. *Id.* at 26.

NERA also examined the potential to implement EPA's Option 1 utilizing only Building Blocks 1 and 2, and found much more significant negative impacts, including a 71 percent decrease in coal-fired generation, a 55 percent increase in gas-fired generation, "169 GW of coal retirements, a 29% average increase in natural gas prices and a 17% increase in average delivered electricity prices." *Id.* at S-6, S-7. In this scenario, "the additional costs of providing electricity services would be about $335 billion," and "[t]he net result would be an increase in energy system costs by about $479 billion in present value terms over the period from 2017 through 2031." *Id.* at S-8.

ED_000419-0005870

NERA's attempt to quantify some of the broader effects of the Proposed Guidelines reveals that EPA has significantly underestimated the costs of the proposal, to say nothing of the disruption to the national economy or the effect on the reliability of the U.S. energy system or energy security. It must be stressed that NERA looked only at the impacts of the Proposed Guidelines to the energy system rather than to the macroeconomy at large. A full accounting of the costs of the Proposed Guidelines would examine the multiplier effects of these drastic increases to the energy system on other sectors of the economy, including manufacturing and services, and would almost certainly result in much higher estimated costs.

B. Social Cost of Carbon

EPA used SCC estimates "to analyze CO_2 climate impacts" of the Proposed Guidelines in monetary terms. 79 Fed. Reg. at 34,839 n.12. As a threshold matter, UARG repeats its strong objections to the U.S. government's development and use of SCC estimates to justify regulation. In response to the Office of Management and Budget's ("OMB") request for comments on the U.S. government's development of SCC values, UARG and others submitted extensive comments on the many legal, procedural, and other shortcomings associated with the development, derivation, and application of the SCC, and urged the U.S. government to discontinue the use of SCC values in the regulatory context. *See generally* Utility Air Regulatory Group, Comments to OMB on the Notice of Availability and Request for Comments on the Social Cost of Carbon Technical Support Document and Updates, 78 Fed. Reg. 70,586 (Nov. 26, 2013), (Feb. 26, 2014), Docket ID No. OMB-2013-0007-0091 ("UARG Comments to OMB"); Letter from Mary L. Frontczak, Sr. Vice President & Gen. Counsel-Americas, State Gov't Relations & Commc'ns, Peabody Energy, to Office of Information & Regulatory Affairs, OMB (Feb. 24, 2014), Docket ID No. OMB-2013-0007-0122. UARG's Comments to OMB included a study conducted by Dr. Anne E. Smith of NERA Economic Consulting cataloguing

the many uncertainties associated with the SCC. *See* Anne E. Smith, Ph.D., *Uncertainties in Estimating a Social Cost of Carbon Using Climate Change Integrated Assessment Models* (Feb. 26, 2014) ("NERA Social Cost of Carbon"). The UARG Comments to OMB, including Dr. Smith's study, are incorporated herein by reference and are included in the Supplemental Materials for the Rulemaking Record that UARG is filing with these comments. Among the issues UARG and Dr. Smith identified with the U.S. government's SCC estimates are that:

- They were derived in a nontransparent manner, without being subject to notice-and-comment rulemaking;
- The government's choice of inputs to the Integrated Assessment Models ("IAMs"), and the choice of IAMs themselves, that were used to derive the SCC estimates did not undergo peer review or public comment and are highly uncertain;
- There is no rational connection between the inputs and assumptions in the IAMs and the conclusions drawn from the results of the model runs;
- The IAMs and SCC cannot account for threshold effects or nonlinear changes that might be ascribed to additional emissions or emission reductions;
- The wide range of SCC values that the U.S. government developed is too broad to be useful, but still does not reflect the full range of uncertainty associated with measuring the impacts (both positive and negative) of climate change;
- There are serious questions regarding the usefulness of a single dollar amount to represent the asserted climate benefits of rulemakings, particularly given the severe limitations of climate science and the associated uncertainties with estimating the future costs and benefits of a regulation's impact on climate change;
- It is impossible to measure accurately the contribution of a regulation to climate change in isolation, as if one could realistically hold other emissions and change factors constant; and
- The IAMs do not recognize the possibility that we will adapt to climate change, or that a reduction in GHG emissions in the United States might result in an increase in GHG emissions elsewhere.

See generally UARG Comments to OMB.

The Electric Power Research Institute ("EPRI") also recently undertook a comprehensive review of the U.S. government's derivation of SCC values and found similar results, including

substantial inconsistencies and uncertainties among the three IAMs that detract from the government's "multi-model approach." *See generally* EPRI, *Understanding the Social Cost of Carbon: A Technical Assessment*, Report No. 3002004657 at xiv, 5-2 to 5-4, 7-1 (Oct. 2014), *available at* http://epri.co/3002004657. EPRI found that these inconsistencies "raise questions about the statistical comparability of the results, which, along with independence, is statistically required for averaging results as is currently done in the [U.S. government's] approach." *Id.* at xiv. EPRI suggested that the U.S. government's results therefore "may not be robust," and that they suggest "[e]xperimental design challenges" and suffer from "a lack of transparency." *Id.* at xv. Instead of continuing down the current path, EPRI recommends that the U.S. government undertake "a new framework" subject to external peer review to develop SCC estimates, which would improve transparency. *Id.*; *see also id.* at 7-4. EPRI also recommends that the U.S. government undertake "a fuller characterization and discussion of uncertainty and a subsequent analysis of robustness." *Id.* at xv.

For all these reasons, in particular the non-transparency and the uncertainties involved in the choice of IAMs and the choice of inputs to the IAMs, the lack of public and peer review of the process, and the resulting risk for gamesmanship, the U.S. government's deployment of SCC values is premature and should not be used in this rulemaking.

EPA improperly uses the SCC to justify the Proposed Guidelines. EPA estimates the monetized global climate benefits of Option 1 in 2030 to be $30 billion for the Regional Compliance Approach and $31 billion for the State Compliance Approach. 79 Fed. Reg. at 34,943-44, Tbl. 19. Two reasons in particular demonstrate why EPA should not use the SCC for regulatory analysis: (1) the SCC measures benefits on a global instead of domestic basis while costs are measured on only a domestic basis; and (2) EPA's use of discount rates is misleading.

ED_000419-0005873

First, the climate benefits figure of Table 19 reflects the purported *global* benefits of the Proposed Guidelines, even though the Guidelines would govern only domestic activities. This is inappropriate. Cost-benefit analysis for domestic policy should examine domestic costs and benefits. It is impossible to measure the contribution of a regulation to global climate change in isolation. One cannot know with any certainty how much reducing or continuing to emit a single ton of CO_2 will impact global climate change. Future global levels of GHG emissions must be factored into such an analysis, as must a firm sense of how marginal increases in emissions interact with the climate system (e.g., climate sensitivity). Moreover, it is inappropriate for the EPA to amass in its calculation climate benefits that largely will accrue outside the United States, when EPA has no jurisdiction to hold worldwide emissions constant, or to control the climate costs and benefits that may result outside of the United States. The U.S. government has estimated that a domestic SCC value represents about 7 to 23 percent of the global SCC value. Interagency Working Group on Social Cost of Carbon, United States Government, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 at 11 (Feb. 2010), *available at* http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf ("February 2010 TSD") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Thus, assuming such approaches were valid, which they are not, the $30 and $31 billion climate benefit estimates for the Proposed Guidelines, measured more properly on a domestic basis, are closer to the range of $2 billion to $7 billion, which is less than EPA's estimated compliance costs of that rule ($7.3 billion and $8.8 billion for the Regional and State Compliance Approaches for Option 1, respectively). 79 Fed. Reg. at 34,943-44, Tbl. 19.

ED_000419-0005874

Second, EPA presents climate benefits figures in the preamble of the Proposed Guidelines at only the 3 percent discount rate, rather than all four discount rates recommended by U.S. government TSDs on the SCC. February 2010 TSD at 1; Interagency Working Group on Social Cost of Carbon, United States Government, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 at 2 (May 2013, revised Nov. 2013) ("May 2013 TSD"), *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). EPA's RIA reveals that, using a 5 percent discount rate, the estimated *global* climate benefits of the Regional Compliance Approach to proposed Option 1 in 2030 are significantly lower—$9.3 billion. RIA at ES-18, Tbl. ES-6. Domestic climate benefits would be only $650 million to $2.1 billion (7% and 23% of $9.3 billion). Compared to EPA's estimated compliance costs for proposed Option 1 of $7.3 billion and $8.8 billion, it seems clear why EPA chose to omit the 5 percent discount rate figures in the preamble, even though it decided to include estimates at a 7 percent discount rate for air pollution health co-benefits, compliance costs, and net monetized benefits.

Had EPA used the 7 percent discount rate OMB recommends, even the global climate benefits of the Proposed Guidelines would almost certainly have been lower than the compliance costs.[34] And converting that global figure to a domestic figure would have reduced the estimate

---

[34] OMB, Circular A-4 Regulatory Analysis at 34 (Sept. 17, 2003), *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/omb/circulars/a004/a-4.pdf (citing OMB Circular A-94) ("For regulatory analysis, you should provide estimates of net benefits using both 3 percent and 7 percent. An example of this approach is EPA's analysis of its 1998 rule setting both effluent limits for wastewater discharges and air toxic emission limits for pulp and paper mills. In this analysis, EPA developed its present-value estimates using real discount

to de minimis levels. Even if one accepts EPA's SCC methodology, therefore, any thorough analysis of this issue would demonstrate that the benefits of EPA's Proposed Guidelines do not justify their costs.

In summary, the SCC values are speculative, selective, based on untested and inconsistent economic models, based on climate models that grossly over-predict, and are not tied to domestic policy and results. These issues in both the IAMs used to derive SCC values and the derivation and application of the SCC make SCC values far too speculative to be useful in trying to ascertain the real costs and benefits of the Proposed Guidelines. *See* UARG Comments to OMB at 4, 8-19; NERA Social Cost of Carbon at 9-29. In addition, because the SCC is currently the subject of an OMB rulemaking to consider these uncertainties and other issues with the SCC, EPA should at a minimum refrain from utilizing SCC values until OMB has finalized its rule on the use of SCC among federal agencies. Without the inflation provided by the SCC, its global measure of benefits, and EPA's use of low discount rates, the climate benefits of the Proposed Guidelines do not come close to their costs.

C. Public Health Benefits

EPA asserts that the Proposed Guidelines will lead to health co-benefits of at least $12 billion in 2020, 79 Fed. Reg. at 34,939, Tbl. 16 (based on EPA's Option 2, Regional Compliance scenario at a 7 percent discount rate); *see also* RIA at 4-31, Tbl. 4-13 (increasing to at least $23 billion in 2020); 79 Fed. Reg. at 34,937, Tbl. 14 (based on EPA's Option 1, Regional

---

rates of 3 and 7 percent applied to benefit and cost streams that extended forward for 30 years. You should present a similar analysis in your own work.") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). In the May 2013 TSD, the SCC for the year 2014 is calculated at $11 at a 5% discount rate, but at $56 for a 2.5% discount rate, a nearly five-fold difference with just a 2.5% decrease in discount rates. May 2013 TSD, App. A, Tbl. A1.

ED_000419-0005876

Compliance scenario at a 7 percent discount rate); RIA at 4-33, Tbl. 4-15. These estimates are complete fiction. Even if it were appropriate to use coincidental decreases in independently-regulated pollutants other than CO_2 to justify the Proposed Guidelines (which it is not), the Agency improperly credits the Proposed Guidelines for purported health benefits from reducing concentrations of fine particulate matter ("$PM_{2.5}$") and ozone ("O_3") *below* levels at which EPA has determined public health is protected. RIA at 4-15. Furthermore, the asserted benefits of the Proposed Guidelines include reductions in $PM_{2.5}$ and O_3 that are already required by existing regulatory programs. Such reductions simply cannot be attributed to the Proposed Guidelines.

$PM_{2.5}$ and O_3 are both regulated under the NAAQS program. 40 C.F.R. §§ 50.7, 50.10, 50.13, 50.15, 50.18. EPA sets NAAQS at the level "requisite to protect the public health." CAA § 109(b). NAAQS incorporate "an adequate margin of safety." *Id.* Thus, in establishing NAAQS for $PM_{2.5}$ and O_3, EPA has found that exposure to these pollutants does not endanger public health in areas where the NAAQS are attained.[35] These levels have been chosen after due consideration by the Clean Air Scientific Advisory Committee and EPA of the science. It is disingenuous for EPA to turn around and claim benefits from concentrations determined to be protective of public health, especially to justify a rule targeting a different pollutant.

EPA, however, goes even further to claim there are health benefits from reducing $PM_{2.5}$ and O_3 to levels *below* the NAAQS.[36] RIA at 4-15. Virtually all of the health benefits that EPA

---

[35] 78 Fed. Reg. 3086, 3164 (Jan. 15, 2013) ("The Administrator concludes that this suite of standards would be requisite to protect public health with an adequate margin of safety against health effects potentially associated with long- and short-term $PM_{2.5}$ exposures."); 73 Fed. Reg. 16,436, 16,483 ("[A] standard set at 0.075 [parts per million ("ppm")] would be sufficient to protect public health with an adequate margin of safety, and [EPA] does not believe that a lower standard is needed to provide this degree of protection.").

[36] NAAQS must be reviewed and revised, as appropriate, at least every five years. CAA § 109(d). In the event newer scientific information indicates significant health risks remain after

ED_000419-0005877

claims from the Proposed Guidelines would result from reduced exposure to $PM_{2.5}$.[37] In projecting the health benefits related to $PM_{2.5}$, EPA attributes benefits to the lowest modeled $PM_{2.5}$ levels, including levels well below the NAAQS.[38] RIA at ES-17. Because EPA's 2016 baseline modeling predicts that no more than five percent of the population will be exposed to $PM_{2.5}$ levels as high as the 12 $\mu g/m^3$ annual NAAQS,[39] a high percentage of the purported health benefits must come from exposures at levels below the NAAQS. Because, as discussed above, NAAQS are set at the level EPA has determined is protective of public health, it is improper to claim benefits below that level.

Many of the emission reductions—and any associated co-benefits—that EPA attributes to the Proposed Guidelines would occur even without them. Those purported co-benefits cannot

---

existing NAAQS are attained, EPA must revise those standards to address those risks. Thus, the NAAQS process will address even newly-recognized health risks. The Proposed Guidelines are not a necessary or appropriate tool for this purpose.

[37] For example, in Table 14, Summary of the Monetized Health Co-Benefits for the Proposed Standard Option 1 Regional Compliance Approach in the U.S., 79 Fed. Reg. at 34,937, the predicted health benefits due to reduced emissions of the O_3 precursor NOx range from $0.63 billion to $2.7 billion in 2020 (at a 3 percent discount rate) compared to total predicted $PM_{2.5}$ health benefits of $15.7 to $34.4 billion in 2020 (3 percent discount rate) (based on adding the benefits of reductions in emissions of the $PM_{2.5}$ precursors sulfur dioxide ("SO_2") ($12-26 billion), elemental and organic carbon ($0.75-1.7 billion), crustal matter ($0.77-1.7 billion), and NOx ($2.2-5.0 billion)). A similar preponderance of $PM_{2.5}$ co-benefits is reported in Tables 15 to 17. *Id.* at 34,938-40.

[38] A similar assumption was applied in estimating health co-benefits attributable to O_3. *See* RIA at ES-16.

[39] *See id.* at 4-46, Fig. 4-5 (illustrating graphically that only about 5 percent of the population is exposed to an annual mean $PM_{2.5}$ level of 12 $\mu g/m^3$ or greater in EPA's baseline modeling). Indeed, because (a) the baseline modeling used to generate Figure 4-5 did not reflect emission reductions anticipated from the MATS Rule that would drive baseline $PM_{2.5}$ concentrations still lower, *id.* at 4-43, n.100; (b) other analyses by EPA has shown attainment in 2020 nationwide except a few counties in California, *see infra* note 40 and accompanying text; and (c) states are required to deal with the residual non-attainment, *see* CAA § 110(a)(1), an even smaller percentage of the population than shown on the Figure would be expected to be exposed to concentrations above the NAAQS. In fact, exposures to 12 $\mu g/m^3$ could be zero.

ED_000419-0005878

therefore be properly attributed to the Proposed Guidelines. EPA projects that the vast majority of the country will attain the most stringent existing $PM_{2.5}$ and O_3 NAAQS by 2020, without the Proposed Guidelines.[40] States are required to develop plans to bring into attainment all areas determined to exceed the NAAQS, including those that EPA projects will not be in attainment in 2020. CAA § 110(a)(1). EPA acknowledges that it may be double-counting benefits. RIA at 4-15 (acknowledging the possibility that some of the estimated benefits of the Proposed Guidelines "may account for the same air quality improvements as estimated in the illustrative NAAQS RIAs").[41] In fact, the modeling that EPA performed using its IPM[42] to characterize the health co-benefits of the Proposed Guidelines failed to take into account air quality improvements

---

[40] *See* EPA, Projected Fine Particle Concentrations for Counties with Monitors in 2020 (Dec. 14, 2012) (projecting attainment of the $\mu g/m^3$ $PM_{2.5}$ NAAQS everywhere in 2020 except in a handful of counties in California), *available at* http://www.epa.gov/airquality/particlepollution/actions.html; EPA, Counties Projected to Violate the 2008 Ozone Standard in 2020 Using Air Quality Model Projections (Mar. 12, 2008) (projecting all but 28 counties will attain the 0.075 ppm O_3 NAAQS in 2020), *available at* http://www.epa.gov/airquality/ozonepollution/actions.html.

[41] EPA acknowledges that the benefits analyses for the section 111(d) proposal and for the $PM_{2.5}$ and O_3 NAAQS are both "illustrative," but indicates that it has greater confidence in the projected emission reductions for the Proposed Guidelines because they are focused on "one well-characterized sector (i.e., the EGU sector)." RIA at 4-15 to 4-16. The most recent RIAs for both the $PM_{2.5}$ and O_3 NAAQS, however, also assumed additional controls on EGUs in the modeled control strategy. *See* EPA, Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter at ES-7 (Dec. 2012), *available at* http://www.epa.gov/ttn/ecas/ria.html; EPA, Final Ozone NAAQS Regulatory Impact Analysis at 3-10 (Mar. 2008), *available at* http://www.epa.gov/airquality/ozonepollution/actions.html. Although states would, in the case of NAAQS, have the discretion to focus on another sector for implementation, the reality is that states will likely follow EPA's lead in focusing on controlling emissions from EGUs under a broad range of rules.

[42] According to EPA, the IPM is a "multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies." GHG Abatement Measures TSD at 3-20. IPM is able to project least-cost capacity expansion and electricity dispatch while also accounting for constraints due to fuel supply, transmission, dispatch, and reliability. *Id.*

ED_000419-0005879

associated with several rules for which specific implementation controls have yet to be specified.[43] Thus, it does not take into account many emission reductions from EGUs that have occurred and will occur from implementing the 2006 $PM_{2.5}$ NAAQS, 71 Fed. Reg. 61,144 (Oct. 17, 2006); the 2008 O_3 NAAQS, 73 Fed. Reg. 16,436 (Mar. 27, 2008); the 2010 NAAQS for SO_2, 75 Fed. Reg. 35,520 (June 22, 2010); and the 2013 $PM_{2.5}$ NAAQS, 78 Fed. Reg. 3086 (Jan. 15, 2013). These emission reductions will occur before the Proposed Guidelines are fully implemented. Thus, the NAAQS program and other existing rules—not the Proposed Guidelines—will redress any public health danger from $PM_{2.5}$ and O_3.

In short, EPA claims that the health co-benefits from the Proposed Guidelines are equal to or greater than the climate benefits. 79 Fed. Reg. at 34,840-41, Tbls. 1 & 2. Those co-benefits are, however, illusory. Most of them are attributable to exposures to pollutants at levels below those EPA has found protective of public health. Even those fictional benefits are largely due to emission reductions that will occur even in the absence of the Proposed Guidelines in order to address any residual pollutant levels above those found to be protective of public health. Thus, the health co-benefits of the Proposed Guidelines are essentially zero.

D. Summary

EPA underestimates the costs of the Proposed Guidelines by failing to account for the almost certain multiplier effects of the rule on the macroeconomy, as well as the disruption to, reliability of, and security of the U.S. energy system. Although the purported rationale for the Proposed Guidelines is based on climate change, EPA never makes the case that the proposed

---

[43] In the IPM modeling used by EPA to estimate the benefits attributable to the Proposed Guidelines, EPA accounted only for the MATS Rule and CAIR, both of which focus on EGUs and "other state and Federal regulations to the extent that they contain measures, permits, or other air-related limitations or requirements." RIA at 3-5.

ED_000419-0005880

rule would actually mitigate climate change, raising questions about the true purpose of the rule. Moreover, EPA improperly estimated the benefits of the rule by using SCC values, which are speculative, selective, based on untested and inconsistent economic models, based on climate models that grossly over-predict, and are not tied to domestic policy and results. EPA's use of health "co-benefits" to claim benefits from the Proposed Guidelines is improper given that NAAQS for those pollutants are already set at levels protective of public health. If the benefits of the Proposed Guidelines are properly characterized, there are no benefits to weigh against the costs of the rule. The Proposed Guidelines are therefore unjustified and unlawful.

XIII. EPA's Calculation of the State Goals Impermissibly Limits the States' Discretion and Is Error-Ridden.

A. Despite EPA's Claims, States Have Little to No Flexibility in Their Ability To Meet the State Goals Contained in the Proposed Guidelines.

In calculating the state goals, EPA applied all four Building Blocks to each state's 2012 electric generation to determine the extent to which the state could reduce its CO_2 emissions rate by 2030. 79 Fed. Reg. at 34,863. Although EPA's methodology in setting the goals is not transparent, in many cases it appears that EPA just assumes that each state can in fact feasibly implement all four Building Blocks, without having done the analysis itself and without having analyzed the effects of implementing all four Building Blocks at the same time, rather than in isolation. EPA says that if a state believes that one of the Building Blocks is technically infeasible or too costly, then it should alert EPA to this fact, implicitly acknowledging that the Agency adopted a one-size-fits-all approach without considering individual state characteristics. *Id.* at 34,893. But EPA also states that because it believes it is imposing "reasonable" levels of each Building Block ("rather than the maximum") that a state should be able to increase its use of another Building Block in such case to compensate for a lower or no use of another Building Block. *Id.* Notably, because the Agency has published only parsed IPM modeling results for the

ED_000419-0005881

year 2025 and not for 2030—the year for ultimate compliance with the proposed final and interim goals—EPA has not provided commenters with the data necessary to determine whether the selected Building Block implementation levels are actually feasible at a reasonable cost.

As discussed in Section III.A, section 111(d) provides that states are to develop performance standards for individual sources as part of state plans, after considering state and local factors and other factors particular to individual emitting units, including the remaining useful life of individual units. The Proposed Guidelines are unlawful because EPA proposes to establish emission goals that it says states have no authority to modify. *See* Section IX.A. Even if EPA had authority to establish emission standards for the states, because EPA has simply assumed each Building Block can be implemented fully without ascertaining whether that is in fact the case, the touted flexibility of the rule is illusory. *See* Initial NERC Report at 2, 22 (noting that Proposed Guidelines would require substantial fossil fuel-fired EGU retirements by 2020 and raise significant reliability concerns). In many cases, states cannot realistically implement one or more Building Blocks and do not have the flexibility to increase the stringency of other Building Blocks or measures to achieve their mandated goals.

The specific assumptions EPA makes in calculating state targets are also questionable. EPA assumes in the setting of state targets emissions from and capacity for existing units that do not currently exist, that have not yet been fully developed, and that may not ever be completed. In North Carolina, for example, EPA assumed the full operation in 2012 of two combined cycle units that were not in fact in operation. *See* James Marchetti, "Review of EPA's State-Specific CO_2 Emission Rate Goals: Building Blocks 2 and 3, at 11, Tbl. 6 (Nov. 2014) (Attachment C) ("Marchetti Report"). Duke Energy's Dan River NGCC plant started operating in December 2012. Another Duke Energy NGCC facility, Lee, started reporting data in January 2013 but both

the Lee and Dan River facilities were assumed by EPA in its North Carolina goal calculations to have been operating for all of 2012. These units should more appropriately be credited as "under construction" units rather than as part of the baseline of fully operational units. In addition, EPA identified 2,249 MW of new NGCC under construction capacity when in fact only 625 MW of NGCC was under construction. That was Duke Energy's Sutton NGCC plant that was under construction but not yet operational by the end of 2012. It began operation in late 2013. *Id.* at 15.

In calculating Tennessee's goal, EPA included TVA's Watts Bar Nuclear Unit 2, which is currently under construction. Tennessee cannot meet its state goal without this unit. Because of the many potential issues that could delay or otherwise negatively impact the startup and commissioning of nuclear units like this one, EPA should not include nuclear units under construction in the state goal assumptions. If the Agency continues to assume completion of nuclear units in state goals, then it should allow for an off-ramp or other adjustment if nuclear units are not completed or do not operate as expected.

South Dakota has only one NGCC plant, Basin Electric Power Cooperative's Deer Creek Station. That plant began operating late in 2012, running at about a 1 percent capacity factor. South Dakota also has only one coal-fired plant, Big Stone, owned by Otter Tail Power Company, Montana-Dakota Utility Resources Co., and NorthWestern Energy. The two South Dakota plants are located in different RTOs, however. Deer Creek will be in the SPP as of October 2015, and Big Stone is in MISO. Thus, for South Dakota at least, Building Block 2, or any form of redispatch, is not available, because these two plants have different owners with no contractual relationship, and they are committed and dispatched by two separate entities with unique commitment and dispatch processes. *Id.* at 18-19. Even if Building Block 2 were

feasible, it was also incorrect for EPA to assume Deer Creek was in operation for 2012; instead, EPA should have put that unit into the "under construction" category for purposes of calculating South Dakota's target. *Id.* at 11. Building Block 1 is also not an option for South Dakota because Big Stone is undergoing a $384 million upgrade to comply with BART Regional Haze Program requirements.[44] The new station service required by this upgrade—estimated to be as much as 8 MW out of 475 MW—will cancel out any heat rate improvements that the plant might achieve. J. Edward Cichanowicz & Michael C. Hein, "Evaluation of Heat Rate Improving Techniques for Coal-Fired Utility Boilers as a Response to Section 111(d) Mandates" at 2-7 (Oct. 13, 2014) (Attachment D) ("Cichanowicz Heat Rate Report").

In fact, as discussed at greater length in Section XIV.A below, the pollution control upgrades required by MATS and other rules are in many cases substantially *lowering* the operating efficiencies of existing units that are covered by the Proposal. *Id.*; *see also* Julie Wernau, *Illinois coal plant owners say they've done their part*, CHICAGO TRIBUNE (Aug. 19, 2014), *available at* http://www.chicagotribune.com/business/ct-carbon-rule-coal-0819-biz-20140819-story.html (quoting managing director of regulatory affairs at Dynegy as saying that the installation of scrubbers to lower sulfur dioxide emissions reduced plant efficiencies by 1.8 percent). Furthermore, in some cases, significant investments that have been recently made due to MATS and other rules will become stranded by the Proposed Guidelines if they are finalized. Under EPA's analysis, the Proposed Guidelines will result in the closure of all coal-fired power plants in Mississippi. TVA has the right to purchase all of the output of the 440 MW lignite-fired Red Hills Power Plant in Choctaw County, Mississippi, through a power purchase

---

[44] *See* Big Stone Plant Air Quality Control Systems, http://www.bigstoneplantaqcs.com/about-aqcs ("Big Stone AQCS").

ED_000419-0005884

agreement and has historically purchased most of the facility's output. The plant began operating in 2002. The plant is currently installing dry-sorbent injection in order to comply with MATS. If Red Hills is required to be shut down due to the Proposed Guidelines, the cost of this injection system would be stranded.

All of the examples above—describing several incorrect assumptions made by EPA in computing state goals—are not isolated and run counter to EPA's assertion that states have compliance flexibility. *See* Marchetti Report.

Finally, EPA appears to have neglected to account for the significant amount of electricity that is imported to the United States from Canada. The overwhelming majority of this power is generated by non-renewable sources, supply that helps to meet U.S. load at emission rates lower than that which would be achieved without the imports. *See* Canadian Electricity Association, Reducing GHG Emissions Under EPA's Section 111(d) Guidelines; Comments of the Canadian Electricity Association at 2-3 (Jan. 2014), Docket ID No. EPA-HQ-OAR-2013-0602-0007. Several U.S. states have formally recognized the significant role this imported power plays in reducing state electricity sector emissions. Vermont, Minnesota, Wisconsin, and Connecticut all credit Canadian imported hydropower for compliance in state renewable portfolio standards. *See id.* at 4.

If EPA fails to recognize the positive role imported Canadian power plays in the United States by allowing for such power to be used to meet state goals, the Agency runs the risk of instituting a non-tariff barrier or other trade distortion by disincentivizing the current free trade of electricity that occurs across the U.S.-Canada border. Under Chapter 9 of the North American Free Trade Agreement ("NAFTA"), technical regulations and standards must be structured to avoid serving as obstacles to trade. North American Free Trade Agreement, U.S.-Can.-Mex. art.

ED_000419-0005885

904(4), Dec. 17, 1992, 32 I.L.M. 289, 387 (1993) ("No Party may prepare, adopt, maintain or apply any standards-related measure with a view to or with the effect of creating an unnecessary obstacle to trade between the Parties."). For instance, if the final guidelines essentially mandate a significant ramp-up of natural gas-fired generation, without properly recognizing or crediting Canadian power imports, it is possible that zero-emitting generation from Canada will be displaced in favor of higher-emitting gas-fired generating in the U.S., thus resulting in higher emissions, lower imports from Canada, and greater difficulty for a state in complying with its state targets. If EPA finalizes the Proposed Guidelines, it must explicitly address the issue of Canadian imported power.

B. EPA Should Not Include Hypothetical Generation From Units that Are Under Construction When Implementing Building Block 2 in State Goal Calculations.

In calculating each state's goal, EPA assumes that NGCC units that were under construction in 2012 have available generating capacity that may be utilized to displace coal-fired generation under Building Block 2. Specifically, EPA assumes that each NGCC unit under construction will be completed and that it would operate at a 55 percent annual capacity factor under a "business as usual" scenario in the absence of the proposed emission guidelines. Goal Computation TSD at 12. This 55 percent annual capacity factor reflects EPA's calculation of the "average performance of NGCCs that came online in the past 5 years," although EPA did not provide any data analysis to support that calculation. *Id.* The Agency claims it "conservatively designated the generation associated with this 55% capacity factor as unavailable for redispatch to reduce CO_2 (i.e., not qualifying for building block 2), instead, reserving that amount of generation potential to meet other system needs presumed to have motivated the construction" of those units. *Id.* Accordingly, EPA assumes that an additional 15 percent of the under-

ED_000419-0005886

construction unit's nameplate capacity will remain available for redispatch, bringing the unit to an overall annual capacity factor of 70 percent.

EPA's approach is arbitrary and unreasonable. As a general matter, EGUs that commenced construction before January 8, 2014—even those that were "under construction" during the 2012 baseline year that EPA has proposed to use—would be considered "existing units" for the purposes of section 111(d) once completed, and thus could properly be subject to standards of performance contained in a state plan if they meet the relevant applicability criteria. *See* CAA § 111(a)(6). But EPA should not rely on generating capacity from "under construction" units when applying Building Block 2 to calculate the proposed state goals. EPA has no basis to assume what generating capacity will be available for redispatch from NGCC units that had no operating history during or prior to the 2012 baseline year. The average annual capacity factor of all recently completed NGCC units, *see* Goal Computation TSD at 12, is an inadequate predictor of the future generation performance of the individual units EPA includes in the state goals. Such an average does not account for the fact that some units are constructed for the purpose of supplying base load, while others are constructed as load-following units. Recent experience suggests that EPA's methodology grossly overestimates the generation capacity available from units that were under construction in 2012. For example, the Lee Combined Cycle unit in North Carolina (which EPA mischaracterized as "existing" in 2012 instead of under construction) operated at an 81 percent annual net capacity factor during 2013, its first year of commercial operation. Marchetti Report at 11. Tbl. 6. Yet EPA's methodology would require this unit to contribute an additional 15 percent of its nameplate capacity to displacing coal-fired generation, effectively pushing the Lee unit above a 96 percent capacity factor based on net capacity.

ED_000419-0005887

Given EPA's inability to provide a rational justification for predicting the hypothetical operating duty of units that were not operating in the baseline year of 2012, EPA should exclude "under construction" NGCC units from its application of Building Block 2 for the purposes of calculating state goals. Because these units are technically "existing sources" under section 111, however, they would remain subject to appropriate state plan requirements and would count towards compliance with a state's interim and final goals if they satisfy the relevant applicability criteria.

C. EPA Should Not Penalize States that Have Invested in Nuclear Generation by Including "At Risk" and Under-Construction Nuclear Capacity in State Goals.

Under Building Block 3, EPA also includes generation from nuclear units that are under construction and nuclear generation that the Agency considers to be "at risk" in calculating each state's goal. 79 Fed. Reg. at 34,870. EPA identified five "under construction" nuclear units in Georgia, South Carolina, and Tennessee that it claims will be completed at no "incremental cost," and that the Agency therefore believes "should be factored into the state goals for the respective states where these new units are located." *Id.* Likewise, EPA claims that states can "increase the amount of available nuclear capacity" by "preserv[ing] existing nuclear EGUs that might otherwise be retired." *Id.* EPA attempted to quantify this "at risk" nuclear capacity by citing an EIA report that projected nationwide nuclear capacity reductions of 5.7 GW due to "continued economic challenges." *Id.* at 34,871. The Agency distributed this amount among the states based on their existing nuclear capacity, "without making any judgment about the likelihood that any individual EGU will retire." *Id.*

EPA should not include generation from under construction or "at risk" nuclear capacity in the state goals. Although it appears that EPA's intent is to promote the construction and preservation of nuclear EGUs, incorporating these values into the state goals only penalizes

ED_000419-0005888

states that have already invested significantly in this low-emitting energy source, while doing nothing to promote nuclear capacity development in states that have not done so already. Marchetti Report at 37-38. The under construction nuclear units substantially lower the state goals for Georgia, South Carolina, and Tennessee by incorporating an assumed 17,392 gigawatt hours ("GWh") of generation into the goals for Georgia and South Carolina and 8,870 GWh for Tennessee. *Id.* at 38. Incorporating these under construction nuclear units does nothing to promote the completion of these EGUs—but as EPA recognizes, if unexpected circumstances prevent the units from being completed by 2020 as the Agency projects, it could make it impossible for those states to meet their goals. 79 Fed. Reg. at 34,870.

Likewise, EPA's inclusion of "at risk" nuclear capacity is arbitrary and serves only to penalize states with existing nuclear capacity. The Agency has made no attempt to evaluate whether *any* nuclear capacity is actually at risk of retirement in any state, instead extrapolating from generalized estimates of nationwide nuclear retirements. The result is that EPA overestimates the amount of nuclear capacity that is at risk (if any) in most, if not all, states. Marchetti Report at 37. And even if some nuclear capacity is at risk in a state (whether at the level EPA estimates or at some lower level), including this capacity in a state's goal does nothing to incentivize its preservation because states have no control over the primary factor threatening nuclear EGUs: federal license renewal. Thus, because states have little ability to promote nuclear capacity and can only be harmed by including under construction and "at risk" capacity in the goals, EPA's approach is simply a penalty and not an incentive. To the extent preserving and increasing nuclear capacity needs to be incentivized, that needs to be done by the relevant federal agency (the Nuclear Regulatory Commission) to the extent Congress has given that agency that authority. It cannot be done, however, by EPA through the CAA.

D. EPA's Goal Calculation Methodology Is Riddled With Errors.

Even if the Proposed Guidelines were lawful, which for all of the reasons discussed above they are not, EPA's approach to calculating each state's interim and final emission goals is fatally flawed. The Agency's goal calculation methodology contains numerous errors, inconsistencies, and oversights that substantially impact each state's goals. *See generally* Marchetti Report at 3-16. These errors do not affect just a handful of states: they undermine the proposed goals for every state in the nation. These basic and widespread errors demonstrate the fundamental inadequacy of the "analysis" EPA has performed to support this rulemaking. EPA must withdraw its Proposed Guidelines and, if the Agency so chooses, can re-propose a revised set of emission guidelines for public comment. EPA cannot simply finalize a new and different set of goals in this rulemaking. States and other interested parties, such as UARG, must have an opportunity to comment on any revised goals.

1. EPA Applies the Building Blocks to Non-Affected Units.

EPA's goal calculation methodology is defective because it applies the measures identified as BSER to sources that do not qualify as "affected EGUs" for the purposes of the Proposed Guidelines. In other words, the proposed state goals assume that state plans will constrain emissions from sources that EPA cannot lawfully regulate under section 111(d). This error affects the state goals because it overstates the number of sources that are available to implement the BSER building blocks—particularly Building Block 2, which is based on shifting generation from higher- to lower-emitting affected EGUs.

Under section 111(d), state plans may establish standards of performance only for "any existing source . . . to which a standard of performance under this section would apply if such existing source were a new source." CAA § 111(d)(1)(A)(ii). In this case, the Proposed Guidelines may be used only to establish standards of performance for existing EGUs that

ED_000419-0005890

otherwise meet the eligibility criteria for EPA's proposed NSPS for GHG emissions from new EGUs. *See* 79 Fed. Reg. at 1430. The NSPS for new EGUs applies to any stationary combustion turbine that, *inter alia*, has a base load rating greater than 73 MW (250 MMBtu/h) and was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh as net-electrical sales on a 3 year rolling average basis. *Id.* at 1506, Proposed 40 C.F.R. § 60.4305(c). Therefore, EPA's Proposed Guidelines may deal only with regulation of existing Subpart KKKK stationary combustion turbines that meet these same criteria. *See* CAA § 111(d); 40 C.F.R. § 60.21(b); Section V.

The preamble to the Proposed Guidelines suggests that EPA intended to follow these applicability criteria and exclude from the state goal calculations any unit that would not be subject to the Proposed Guidelines. *See* 79 Fed. Reg. at 34,895 n.260. It is clear from the supporting documentation for the Proposed Guidelines, however, that EPA disregarded these applicability criteria and applied the BSER building blocks to include ineligible Subpart KKKK units when determining each state's obligations. In particular, EPA made no effort to exclude from the Proposed Guidelines NGCC units that were not "constructed for the purpose of supplying, and suppl[y], one-third or more of [their] potential electric output and more than 219,000 MWh net-electric output to a utility distribution system." 79 Fed. Reg. at 1511, Proposed 40 C.F.R. § 60.5509(a)(1); 79 Fed. Reg. at 34,954, Proposed 40 C.F.R. § 60.5795(b)(2) (defining "affected EGUs" for purposes of Proposed Guidelines). Instead of using available data to determine which units met this one-third sales exclusion, the Agency pooled excluded units together with affected EGUs and applied the building blocks to them. Data available in the docket suggest that a substantial number of NGCC units used in EPA's goal calculation would qualify for this exclusion. For example, of the 464 plants that EPA examined to determine what

ED_000419-0005891

capacity factor is achievable for existing NGCC units, 162 had an annual plant-level capacity factor in 2012 that was less than 33 percent, with some plants operating as low as 0 percent. 2012 NGCC Plant Capacity Factor ("2012 NGCC Spreadsheet") Docket ID No. EPA-HQ-OAR-2013-0602-0250. Many of these plants, or individual units within these plants, would likely qualify for the one-third sales exclusion on a three-year rolling average. EPA can, and must, examine historical data for existing EGUs in order to determine which units would be exempt from regulation under the one-third sales exclusion before calculating each state's goal. This historical data is readily available to EPA. Indeed, shortly before the end of the comment period, EPA included generated data from 2010 and 2011 in the docket for this rulemaking, although it has not performed any analysis of these data to determine which existing EGUs would be exempt and how this would affect each state's goals.

Likewise, in calculating state goals, EPA should apply the measures identified as BSER to Subpart Da units only if they "combust[] fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years" and "suppl[y] more than one-third of [their] potential electric output and more than 219,000 MWh net-electric output to a utility power distribution system for sale on an annual basis." 79 Fed. Reg. at 1502, Proposed 40 C.F.R. § 60.46Da(a). The NSPS for new Subpart Da units applies only to sources that meet these (and several other) criteria. *Id.* EPA proposed to eliminate these applicability criteria in its proposed NSPS for modified and reconstructed EGUs and in its definition of "affected EGUs" for these Proposed Guidelines. *See* 79 Fed. Reg. at 34,954, Proposed 40 C.F.R. § 60.5795(b)(1); 79 Fed. Reg. at 34,979. As noted in Section VI and in UARG's comments on EPA's proposed GHG standards for modified and reconstructed EGUs, however, EPA cannot broaden the scope of the Proposed Guidelines to include units that, if they were newly constructed, would not be subject

to the proposed NSPS for new EGUs. UARG Modified/Reconstructed Comments at 69-76. Therefore, EPA must exclude such units from its goal calculation.

Excluding non-affected EGUs from the state goal calculation is critical because including these units in the 2012 generation and emission levels affects the stringency of the state goals as they will eventually be applied to affected EGUs. The state goals, as currently calculated, assume that some of the burden of achieving the goal will fall on EGUs that do not fit within the regulated source category. Because states cannot impose standards of performance on these units, the additional burden associated with these units will ultimately fall on affected EGUs that do meet EPA's applicability criteria. This is particularly important in implementing Building Block 2, where EPA's purported "system of emission reduction" requires transferring energy generation from coal- and oil/gas-fired steam EGUs to NGCC units with available generating capacity. Including NGCC units that meet the one-third sales exclusion in the goal calculation artificially inflates the amount of NGCC generating capacity that is available for redispatch, which thus inflates the amount by which coal-fired units must reduce generation under Building Block 2. Once this inflated redispatch is incorporated into a state's goal, affected NGCC units will be forced to operate at capacity factors significantly above 70 percent in order to accommodate the expected generation that states cannot require from non-affected EGUs. Paradoxically, including these units in the goal calculation also assumes that states can take measures to require NGCC units that formerly were exempt by virtue of the one-third sales exclusion to ramp up their utilization to 70 percent, effectively *forcing non-affected EGUs to become affected EGUs*.

This is plainly arbitrary and capricious. The proposed state goals are fundamentally flawed due to EPA's failure to apply its definition of BSER only to the source category subject

ED_000419-0005893

to regulation. Because this defect pervades EPA's entire methodology for calculating state emission goals, EPA must withdraw the Proposed Guidelines. If it so chooses, EPA can re-propose a corrected version of the guidelines and allow states and the regulated community to analyze and comment on the revised goals.

2. Errors Regarding 2012 Generation Data

As discussed in a report by UARG's consultant, James Marchetti, EPA's 2012 data regarding existing and under-construction EGUs contain numerous errors and invalid assumptions that affect its state goal calculations. Marchetti Report at 3-16. In particular, EPA has: (1) improperly used nameplate capacity to calculate generation available for redispatch from NGCC units; (2) double-counted some NGCC units as both existing and under-construction; (3) identified some under-construction NGCC capacity that does not appear to exist; and (4) improperly counted as "existing" some EGUs that retired or began operation in 2012 or shortly thereafter. Each of these is discussed below.

EPA improperly relied on nameplate capacity instead of more realistic measures of unit generating capacity, such as net capacity, in order to determine the level of existing NGCC capacity that the Agency considers to be available for redispatch to displace coal- and oil/gas-fired steam EGU generation. *Id.* at 3-5. Net capacity reflects the maximum output that generating equipment can supply to system load, and it is typically lower than nameplate capacity because it reflects capacity reductions due to electricity use for station service or auxiliary loads such as emission control technology. Further, net capacity for a unit may differ significantly between periods of peak summer and winter demand, reflecting the effects of ambient temperature and other factors on unit capacity. *See* "Net summer capacity" & "Net winter capacity," U.S. Energy Information Administration ("EIA") Glossary, http://www.eia.gov/tools/glossary/index.cfm?id=N. The difference between nameplate capacity and net

ED_000419-0005894

capacity can be substantial. For example, in Texas, the difference between the total nameplate capacity and summer net capacity of NGCC units in the state is roughly 5,000 MW. Marchetti Report at 4, Tbl. 1. Net capacity is a better indicator of the amount of NGCC capacity available for redispatch purposes because it reflects the amount of energy that these units will actually be able to supply to the power grid.

As discussed in the Marchetti Report, using nameplate capacity in the state goal calculations adds substantial levels of NGCC generation that are not actually available for redispatch in Building Block 2. For example, in Florida, the difference in available generation from 70 percent utilization of the actual summer net capacity of 23,784 MW versus the existing nameplate capacity of 29,485 MW is 35,054,309 MWh. *Id.* In order to support the levels of redispatch assumed in EPA's proposed state goals, NGCC units would have to operate at statewide average capacity factors in excess of 80 percent and above—much higher than the already-inflated utilization level of 70 percent that EPA assumes. For example, the *average* annual capacity factors would need to reach 87.0 percent in Florida, 84.2 percent in Arkansas, 81.1 percent in North Carolina, and 80.3 percent in Texas. *Id.* at 5, Tbl. 2. Because these values are statewide averages and many units cannot reach such high levels of utilization, many NGCC units would have to operate at even *higher* annual capacity factors.

Correcting for these inflated values to use net capacity would significantly increase the state emission goals. Yet in the Proposed Guidelines, EPA has failed even to acknowledge the implications of its use of nameplate capacity rather than other capacity measures, despite the fact that an accurate assessment of the existing NGCC capacity actually available for redispatch is essential to developing an achievable emission guideline using EPA's building blocks. EPA should use net capacity when analyzing and applying Building Block 2 in order to reflect more

ED_000419-0005895

accurately existing NGCC generating capacity and the level of NGCC utilization that would be necessary to compensate fully for displaced generation from other sources.

In addition, it appears that EPA has included some units' temporary supplemental generating capacity from the use of power augmentation modes, such as duct burners, in the existing NGCC capacity available for long-term redispatch. *Id.* at 6. Most NGCC units constructed since the early 2000s include duct burners. *Id.* Duct burners increase power throughput, but at the cost of substantially increasing heat rate and accelerating component wear. *Id.* Consequently, continual operation of duct burner capacity is not a feasible option for displacing coal-fired generation and should not be considered as part of a strategy to reduce CO_2 emissions. EPA must examine the NGCC capacity values used in its goal calculation and eliminate any duct burner capacity.

EPA's data also contain numerous errors in the Agency's treatment of certain existing and under-construction EGUs. *Id.* at 7-13. At least one NGCC unit—Ohio's Dresden Energy Facility—is double-counted as *both* existing and under-construction in 2012, meaning that a portion of its generation is redispatched twice in the goal calculation. The amounts of under-construction capacity listed for California, Colorado, Florida, Mississippi, and North Carolina are also questionable, and the fact that EPA is unable to identify any under-construction units in those states by name suggests that development of those units is too uncertain to rely on those units for redispatch.

Likewise, many of the EGUs that EPA has classified as "existing" for the purposes of redispatch under Building Block 2 did not commence commercial operation in 2012 at all. Marchetti Report at 8, Tbl. 3. As UARG's consultant notes, EPA incorrectly assumes that these units were available to provide generation throughout the year but operated at a zero percent

ED_000419-0005896

capacity factor, meaning that their entire capacity was available for redispatch under Building Block 2. *Id.* at 8. The Agency's faulty analysis added substantial amounts of NGCC generation to the state goal calculation for Alaska, California, Florida, Louisiana, and Utah—and as a result, inappropriately reduced generation from Subpart Da units in equal amounts. *Id.* at 7, 8, Tbl. 3. Similar mistakes are likely to have occurred for other states. These units should have been considered to be "under construction" and unavailable for redispatch in state goal calculation.[45]

EPA also errs in its treatment of "existing" units that either commenced commercial operation, were out of service, or retired in 2012. Units that commenced commercial operation or were out of service during 2012 may report artificially low capacity factors because they did not accumulate a full year of operating data by the end of that year. Conversely, units that retired in 2012 would appear to have capacity available for redispatch that will not actually be available to displace coal generation in the future.

For example, South Dakota's Deer Creek Station appears to have a 1 percent capacity factor based on nameplate capacity, but in fact did not begin commercial operation until August 2012. Goal Computation TSD, App. 7, Docket ID No. EPA-HQ-OAR-2013-0602-0256; Marchetti Report at 11, Tbl. 6. Similarly, the state goals for California, Colorado, Connecticut, Georgia, Idaho, Mississippi, North Carolina, Ohio, and Tennessee (and potentially others) all include artificially low 2012 generation levels from NGCC units that commenced operation during that year. *Id.* For nearly all of these units, the annual capacity factor increased significantly during the following full year of operation. For example, North Carolina's Dan River facility commenced operation in December 2012 and reported an annual capacity factor of

---

[45] As discussed in Section XIII.B, no generation from NGCC units that are under construction should be considered available for redispatch.

ED_000419-0005897

only 1 percent, but reported a 73.2 percent annual capacity factor the following year. *Id.* In addition, several units (including Washington's 322 MW Transalta Centralia Generation NGCC plant) were out of service for all or part of 2012, and their reported annual capacity factors may not reflect generation levels under normal conditions. *Id.* at 9, Tbl. 4. Units that came online or were out of service during 2012 should not be included in their states' goals so that EPA does not assign generation for redispatch from those units that is actually needed to meet generation obligations from those units that were not reflected in the partial year data.

Similarly, EPA should not include generation in its state goal calculations from NGCC units that retired in 2012 or are scheduled to retire in the near future. For example, EPA's goal calculation for Florida includes generation from the Hansel facility, which retired in October 2012, *compare* Goal Computation TSD, App. 7, *with* Marchetti Report at 9, Tbl. 4, and its goal calculation for New Jersey includes generation from the Gilbert facility, which is scheduled for retirement in 2015, *compare* Goal Computation TSD, App. 7, *with* 2012 NGCC Spreadsheet. Generation from these NGCC units will not be available for redispatch to displace lost generation from coal- and oil/gas-fired EGUs.

Two states provide illustrative examples of the serious errors in EPA's treatment of existing and under-construction NGCC units, as described in the Marchetti Report. For Florida, EPA's value for existing NGCC capacity incorrectly includes the 1,210 MW Cape Canaveral NGCC facility (which did not begin commercial operation until April 2013), Marchetti Report at 8, Tbl. 3, and the 122.4 MW Orlando Cogen facility (a compressed storage facility). It also includes the 55 MW Hansel NGCC facility, which retired in October 2012. *Id.* at 9, Tbl. 4. At the same time, EPA lists 1,157 MW of unspecified under-construction capacity. Correcting these errors would substantially increase Florida's state goals. Likewise, EPA's goal calculation

ED_000419-0005898

for North Carolina includes "existing" NGCC capacity from the 691.1 MW Dan River facility, which only commenced operation in the last month of 2012, and the 1068 MW Lee Combined Cycle Plant, which did not provide any generation to the grid until 2013. *Id.* at 11, Tbl. 6.

The Agency's widespread errors in its treatment of existing and under-construction NGCC units, and the effects of these errors on the state goals, cast doubt on the accuracy and reasonableness of EPA's entire goal calculation methodology. EPA must withdraw the Proposed Guidelines and correct its methodology to account for these errors.

3. EPA Assumes Unrealistic Emission Rates for NGCC Units and Subpart Da Units.

In calculating the state goals, EPA assumes that each state's coal-fired units will emit CO_2 at an average rate that is 6 percent lower than their average rate in 2012, and that NGCC units will emit CO_2 at an average rate that is the same as 2012, even after generation from those affected EGUs is redispatched under Building Block 2. This assumption is unreasonable and implausible. In practice, implementation of EPA's proposed BSER will increase the average CO_2 emission rate of coal-fired EGUs and may also increase the average emission rate of NGCC units.

For coal-fired EGUs, operation at low loads increases a unit's heat rate and thus its CO_2 emission rate. As discussed in the Cichanowicz Heat Rate Report and in Section XIV.A below, operating a unit at 50 percent load can negatively impact a unit's heat rate compared to full load by an amount greater than EPA claims units can improve heat rate through operating practices and equipment upgrades. Cichanowicz Heat Rate Report at 2-1, 2-6. EPA itself acknowledges that EGUs have higher heat rates (and thus a higher rate of CO_2 emissions) when operating as load following units and during periods of startup and shutdown. GHG Abatement Measures TSD at 2-5, 2-21. In the related NSPS rulemaking for reconstructed coal-fired EGUs, EPA

ED_000419-0005899

observed that subcritical units experience a 10 percent increase in heat rate when operating at 50 percent load. Memorandum from EPA OAQPS to EGU NSPS Docket, "Best System of Emissions Reduction (BSER) For Reconstructed Steam Generating Units and Integrated Gasification Combined Cycle (IGCC) Facilities" at 4 Fig. 2 (June 2014), Docket ID No. EPA-HQ-OAR-2013-0603-0046 ("2014 Reconstructed EGU TSD"). A primary component of EPA's proposed BSER in the Proposed Guidelines is to reduce utilization of coal-fired EGUs directly through redispatch to NGCC units under Building Block 2 and indirectly by increasing renewable energy and decreasing demand under Building Blocks 3 and 4. As a result, more coal-fired EGUs will convert from base load to load-following units and operate at lower loads, increasing their heat rates and counteracting any steps those units take to lower heat rate under Building Block 1. Therefore, each state's average CO_2 emission rate for coal-fired EGUs in the state goal calculations should be higher—not lower—than its 2012 level.

Similarly, it is unreasonable for EPA to assume without analysis that the average CO_2 emission rate for NGCC units in a state will be identical before and after application of the proposed BSER. Under Building Block 2, the Agency expects states to increase utilization of NGCC units to provide more base load generation. Depending on the design of these units, increased utilization may actually *increase* the overall fleet's average CO_2 emission rate. As EPA noted in its related NSPS rulemaking for modified and reconstructed Subpart KKKK units, some units "are designed to be highly efficient when operated as load-following units, but these design characteristics reduce the efficiency at base load." 79 Fed. Reg. at 34,980. Many of the NGCC units that have historically operated at lower capacity factors than EPA's target level of 70 percent may have done so because they operate more efficiently at those levels than when serving base load.

In order to develop a defensible goal calculation methodology, the Agency must use realistic CO_2 emission rates for affected EGUs that reflect the impact of all four building blocks on those units' operations and emission rates. The emission rates that EPA uses in the Proposed Guidelines are arbitrary.

XIV. EPA's Building Blocks

A. Building Block 1 Is Not Achievable.

EPA is proposing to find that overall heat rate improvements of 6 percent (or 4 percent under the alternate goals EPA solicits comment on) are achievable at existing coal-fired EGUs under Building Block 1. 79 Fed. Reg. at 34,861. EPA based its estimates of achievable heat rate improvements primarily on measures described in a 2009 report by Sargent & Lundy, along with the Agency's own limited analysis of historical generating data. *Id.* at 34,859; GHG Abatement Measures TSD. EPA's estimates are arbitrary and capricious, and they demonstrate the Agency's poor understanding of the nature, cost, and availability of heat rate improvement measures. EPA's "analysis" of historical data from coal-fired units fails to provide any support for its claim that heat rate improvements of 4 to 6 percent are achievable, and the Agency has failed to consider several critical factors that will make it impossible for affected EGUs to reach this goal individually or on average across any state.

As a threshold legal and regulatory issue, many of the operating practices and equipment upgrades that are the basis of the Agency's assertion that 4 to 6 percent heat rate improvements are achievable are not included in a Subpart Da affected facility. For this reason, EPA lacks authority to regulate such equipment under section 111(d). Subpart Da is the codification of the NSPS for electric utility steam generating units, and these pieces of complicated equipment, logically enough, generate steam. The "affected facility" is "each electric utility steam generating unit." 40 C.F.R. § 60.40Da. The steam turbines that extract thermal energy from

pressurized steam and are used to drive an electrical generator do not generate steam, and for 40 years EPA has never considered them to be part of the affected facility for purposes of section 111. In 1986, EPA had occasion to specify what other equipment is included in the Subpart Da affected facility. Memorandum from John B. Rasnic, Acting Dir., Stationary Source Compliance Div., EPA OAQPS, to James T. Wilburn, Chief, Air Compliance Div., EPA (Nov. 25, 1986) ("Rasnic Memorandum") (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Attachment C to the Rasnic Memorandum includes a drawing that literally draws a line around the boiler island. Equipment within the boiler island is the Subpart Da affected facility, while equipment beyond the boiler island is not. The following equipment is specifically beyond the purview of this rule: steam turbines, water purification equipment, water-supply systems, air cleaning and cooling apparatus, condensors, main exhaust and main steam piping, water screens, motors, and moisture separator for turbine steam. Rasnic Memorandum at 3. EPA's attempt to require improvements in these components' efficiency for Building Block 1 is contrary to law. The Supreme Court's recent caution regarding the Agency's attempts to pound square pegs into round holes in GHG regulation is on point. Any revision by policymakers of EPA's long-standing engineering and regulatory understanding of what equipment constitutes the "affected facility" under Subpart Da "should have alerted EPA that it had taken a wrong interpretive turn." *UARG v. EPA*, 134 S. Ct. at 2446.

Even if EPA had authority to regulate these pieces of equipment under section 111, its technical conclusions are misguided, flawed, and clearly erroneous. As discussed in the Cichanowicz Heat Rate Report, EPA does not account for the fact that the efficiency benefits associated with the measures identified in the 2009 Sargent & Lundy report are highly variable by unit, are not cumulative, and degrade over time. Cichanowicz Heat Rate Report at 3-1 to 3-2.

ED_000419-0005902

A recent report by the National Coal Council, a federal advisory committee to the U.S. Secretary of Energy, highlighted these basic facts, noting that "[t]he opportunity to apply these efficiency improvements across the existing fleet will vary significantly." National Coal Council, "Reliable & Resilient – The Value of Our Existing Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions" at 4 (May 2014) ("NCC Report"), *available at* http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Measures that may improve heat rate at an individual plant by as much as 1 percent may yield only negligible or nonexistent benefits at many others that have already implemented similar measures or that are otherwise operating in a highly efficient manner. *Id.* For example, the NCC Report estimates that the benefit of deploying variable speed drives to reduce auxiliary load may vary from 0.05 percent to 0.50 percent, depending on the state of a unit's existing drive motors. *Id.* at 65-66. Large benefits from steam turbine upgrades (the highest-payoff measure) are only possible for units that are already severely degraded; for most units, the available payoffs would lie at the low end of the possible range. *Id.* at 62; Cichanowicz Heat Rate Report at 3-6. Many of the available heat rate improvements for which the efficiency benefits outweigh the costs have already been implemented by EGU owners for economic reasons and would not yield substantial benefits if they were implemented again.

Likewise, many of the available actions to improve heat rate do not provide cumulative benefits and thus cannot be added together to estimate the potential efficiency gains at coal-fired EGUs. Cichanowicz Heat Rate Report at 4-4. In particular, measures that increase heat removal from the boiler, such as economizer modifications, improved air heater performance, and low

temperature heat recovery, do not provide additive efficiency benefits because any heat that is recovered by an individual project cannot be recovered a second time. NCC Report at 69.

In addition, to the extent that any measures to improve heat rate are available at a given unit, the long-term payoffs of many of these measures are significantly smaller than the immediate reduction in heat rate observed after implementation. *Id.* at 70. Upgraded components begin to incur wear as soon as they return to operation, and will need to be replaced themselves eventually in order to maintain the improved heat rate. For example, while a steam turbine upgrade may improve a unit's heat rate below its design level, gradual degradation of the turbine blades will reduce the magnitude of that improvement over time from the "new" state without periodic overhauls. Cichanowicz Heat Rate Report at 4-3 to 4-4. Field data indicate that the efficiency of a steam turbine retrofit may decline by 0.5 percentage points in the first 6 months, and by about 4 percentage points after 10 years. *Id.* at 4-4.

Accordingly, EPA cannot rely on the immediate, short-term payoff from efficiency improvements that will degrade over time as the foundation for an emission standard that a source must meet continuously into the foreseeable future. EPA's Environmental Appeals Board ("EAB") recently recognized as much in its order denying review of a PSD permit issued by Massachusetts to a new NGCC facility that accounted for efficiency degradation in setting the facility's GHG BACT limit. *In re Footprint Power Salem Harbor Development, LP*, PSD Appeal No. 14-02, slip op. at 14-15 (EAB Sept. 2, 2014), *available at* http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Filings%20By%20Appeal%20Number/9331677B331CFA1285257D4700716CDB?OpenDocument. Like coal-fired EGUs, the equipment in NGCC facilities can degrade over time and lose efficiency, leading to increased CO_2 emission rates. The EAB found that the BACT limit in the permit "appropriately accounted for the degradation of turbine

equipment over time that can lead to efficiency losses that directly impact greenhouse gas emissions." *Id.* at 15; *see also In re Pio Pico Energy Ctr.*, PSD Appeal Nos. 12-04 through 12-06, 2013 WL 4038622, at *49 (EAB Aug. 2, 2013) (upholding GHG BACT limit that accounted for "unrecoverable losses in efficiency over the life of the plant").

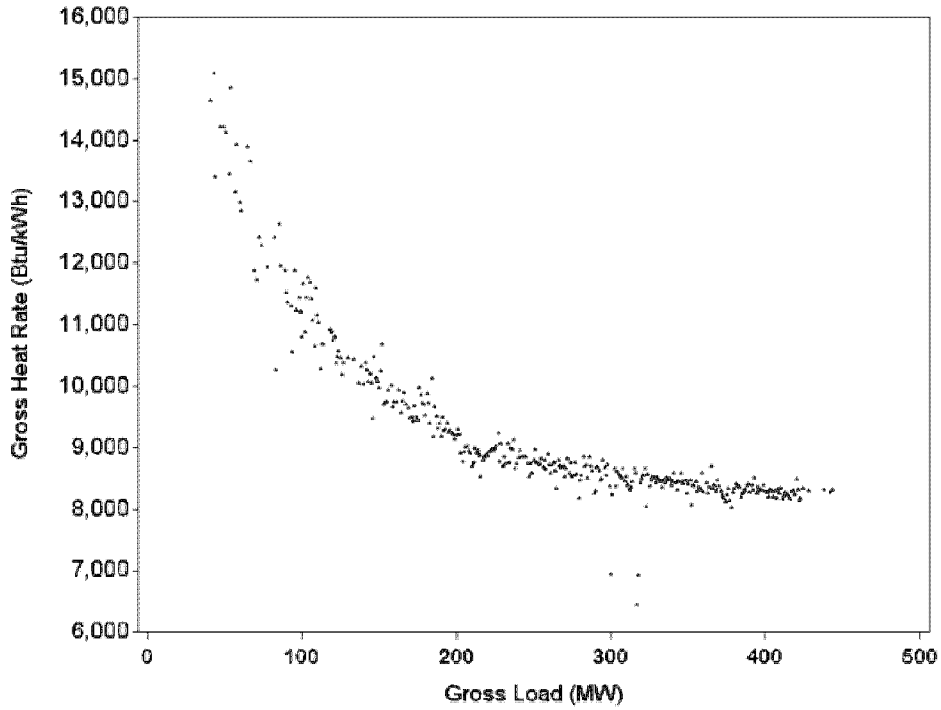
Numerous other analyses have noted the same issues regarding the practical limits on benefits from heat rate improvement measures. Notably, a new analysis by Sargent & Lundy (prepared in support of the National Rural Electric Cooperative Association's ("NRECA") comments on the Proposed Guidelines) is highly critical of the Agency's use of the 2009 Sargent & Lundy report to support the Proposed Guidelines. In the new analysis, Sargent & Lundy conclude that EPA greatly exaggerated the amount of heat rate improvements that can realistically be expected at coal-fired EGUs. *See* Sargent & Lundy LLC, "Coal Fired Power Plant Heat Rate Reduction – NRECA" (Nov. 21, 2014) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). This report emphasizes many of the same issues noted by UARG's consultants in the Cichanowicz Heat Rate Report, including the fact that actual benefits from many heat rate improvement methods are non-additive, temporal, and highly site-specific. Among other conclusions, the 2014 Sargent & Lundy analysis specifically disavows EPA's reliance on the earlier report, stating that "Sargent & Lundy's 2009 report does not conclude that any individual coal-fired EGU or any aggregation of coal-fired EGUs can achieve 6% heat rate improvement . . . or any broad target, as assumed by the EPA." *Id.* at C-1. Sargent & Lundy also note that the potential benefits cited in their 2009 report "were estimated at a conceptual level and were not based on detailed site-specific analyses." *Id.*

The conclusions reached by UARG's consultants in the Cichanowicz Heat Rate Report and the 2014 Sargent & Lundy report are further corroborated by similar analyses performed by

EPRI and by the National Coal Council. EPRI, "Range and Applicability of Heat Rate Improvements," at 5-1, 6-1 (Apr. 2014) (noting benefits are non-additive and not available at many units) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record); NCC Report at 69-70 (noting benefits are non-additive, site-specific, and may degrade over time).

In addition, in its Building Block 1 analysis, EPA ignores the ways in which EGUs' heat rates (and, thus, their CO_2 emissions) are negatively impacted by operating load and by auxiliary power requirements needed to run associated equipment and emission controls, despite paying lip service to these concepts elsewhere. *See, e.g.*, 2014 Reconstructed EGU TSD at 4. In particular, EPA has overlooked the negative impact on coal-fired EGU efficiency of EGUs' obligations under the remaining components of its proposed BSER and under other CAA programs. Under Building Block 2 of the Proposed Guidelines, EPA is requiring states to redispatch generation from coal-fired EGUs to NGCC units, which will result in more coal-fired EGUs being dispatched as load-following units rather than providing base load at high capacity factors. As EPA itself acknowledges, EGUs have higher heat rates when operating as load following units and during periods of startup and shutdown. GHG Abatement Measures TSD at 2-5, 2-21. Figure 2 below, which is analyzed in greater detail in the Cichanowicz Heat Rate Report, displays representative trends in 2012 heat rate data from Delaware's Indian River Generating Station Unit 4 at various capacity factors. Operating at its full load of 445.5 MW, Unit 4 achieves a heat rate of approximately 8,250 Btu/kWh, but at 50 percent load this heat rate decreases by about 9 percent to roughly 9,000 Btu/kWh. Efficiency decreases even more dramatically at lower capacity factors. *See* Cichanowicz Heat Rate Report at 2-3 to 2-6.

Figure 2: Gross Heat Rate for Indian River Unit 4 at Varying Loads



The Cichanowicz Heat Rate Report evaluated 28 coal-fired EGUs with recent flue gas desulfurization ("FGD") retrofits and found that operation at 50 percent load would increase unit heat rate by 7.4 percent (for subcritical boilers) and 4.3 percent (for supercritical boilers) on average compared to full load. *Id.* at 2-6. Thus, the changes in coal-fired EGU capacity factor required by Building Block 2 will most likely eliminate any gains in efficiency achieved through Building Block 1.

In addition, parasitic load at an EGU lowers net heat rate because it reduces the amount of gross plant generation that can be supplied to the grid. Auxiliary power loads are often needed to provide power to coal pulverizers, water pumps, and pollution control equipment, among other systems. NCC Report at 65, 70. As discussed in the Cichanowicz Heat Rate Report, retrofitting an existing coal-fired unit with SCR can increase auxiliary power

consumption by 1.5 percent, while adding FGD may increase auxiliary load by 1 to 2 percent depending on coal type. Cichanowicz Heat Rate Report at 2-7.

In assessing the achievability of Building Block 1, EPA has also failed to consider the fact that other provisions of the CAA will require existing coal-fired EGUs to install additional emission controls that will reduce those units' heat rates in ways that are not reflected in the 2012 generation data that is the basis for EPA's proposed state goals. This further reduces the potential gains in EGU efficiency. Many existing coal-fired EGUs will be required to install additional emission controls in order to comply with the 2012 MATS Rule, while others must install further retrofits in coming years to comply with regional haze requirements. For example, South Dakota's Big Stone Plant is currently undergoing a $384 million upgrade in order to comply with regional haze requirements that is estimated to consume as much as 8 MW of auxiliary power from the plant. *See* Big Stone AQCS. Likewise, as discussed in Section XI above, EPA and citizen plaintiffs have long targeted efficiency-improving measures like steam turbine upgrades in NSR enforcement suits alleging that such measures constitute "major modifications" triggering strict permitting requirements. To the extent that these groups can successfully argue that NSR requirements apply to Building Block 1 measures, NSR review could result in coal-fired EGUs having to install even more stringent emission controls, further increasing parasitic load. EGU owners typically perform the kinds of upgrades discussed in the 2009 Sargent & Lundy report in conjunction with emission control projects in order to minimize the resulting efficiency losses, but the heat rate improvements are generally outweighed by the new auxiliary load. Because EPA failed to consider the effect of looming emission control requirements on EGU heat rate, affected EGUs will be forced to overcome the energy penalties associated with these controls, and then achieve an *additional* 4 to 6 percent improvement in heat

ED_000419-0005908

rate on average in order to comply with the Proposed Guidelines. EPA is not only ignoring the CAA, but the laws of thermodynamics as well.

In addition to these fundamental oversights, EPA has failed to provide any reasonable analysis of whether its heat rate improvement targets are achievable. For several reasons, the "assessment of heat rate improvement potential" in the GHG Abatement Measures TSD does not support EPA's claim that state-wide heat rate improvements of 4 to 6 percent are achievable. *See* GHG Abatement Measures TSD at 2-30 to 2-34.

First, EPA's so-called "statistical analysis" of heat rate improvements available through "best practices" is fundamentally flawed and does not support EPA's chosen target of 4 percent. Indeed, it does not support *any* estimate of heat rate improvements at individual units or for the fleet as a whole. In particular, EPA's "model" assessing potential heat rate improvements via "best practices" is unfounded, arbitrary and capricious, and misleading. In this "model," EPA grouped hourly heat input data into "bins" representing ranges of load and ambient temperature, then performed crude calculations to reduce the variation among observations in each bin by arbitrary increments of 10, 20, 30, 40, and 50 percent. *Id.* at 2-30 to 2-31. The Agency used these adjusted values to calculate an adjusted heat rate for each unit, then compared the study population's average adjusted heat rate under each scenario to the population's actual average heat rate in order to determine the "improvement" under each scenario, with a roughly 30 percent reduction in each unit's variation corresponding to a 4.0 percent improvement in the overall study population's heat rate. *Id.* at 2-31. Accordingly, EPA "conservatively" proposed to find that a 4 percent improvement in heat rate is achievable by applying "best practices" of EGU operation because that level "is in the middle of the range of options" that EPA explored. *Id.* at 2-34.

ED_000419-0005909

As detailed in the attached report by UARG's consultants, this conclusion is arbitrary and totally unfounded. J. Edward Cichanowicz & Michael C. Hein, "Critique of EPA's Statistical Evaluation Defining Feasible Heat Rate Improvements," at 8-9 (Dec. 1, 2014) (Attachment E) ("Cichanowicz Statistical Critique"). Conspicuously absent from EPA's "analysis" is any discussion linking the 4 percent "best practices" estimate to any identifiable, technically feasible heat rate improvement measures. *See id.* at 9. At most, EPA's discussion shows that a 4 percent reduction in overall heat rate is *mathematically* feasible if sources can find a way to reduce variation in hourly heat input. The Agency makes no attempt to show whether the measures it identifies as "best practices" are *technically* capable of reducing heat input variation at individual units at all, let alone reducing variation to a sufficient degree to reach the target efficiency level. Indeed, as UARG's consultants note, if EPA had undertaken such an analysis it would have realized that the 9 "No Cost or Low Cost Options" the Agency identified as "best practices" are incapable of achieving such reductions as a technical matter. Each individually offers 0.1 to 0.35 percent improvement *at most*, and several of these options have benefits that are not additive. *Id.* at 10. Moreover, the 10, 20, 30, 40, and 50 percent reductions in heat input variation that EPA calculates at each unit do not represent varying implementation levels of "best practices" measures: they were apparently selected without any technical basis. Thus, EPA's decision to "conservatively" select a level of reduction that is "in the middle of the range of options" it arbitrarily chose is itself arbitrary.[46] GHG Abatement Measures TSD at 2-34.

---

[46] EPA states that its target of 4 percent heat rate improvements through "best practices" is equivalent to asking each unit to operate at its "best three-year moving average" heat rate. GHG Abatement Measures TSD at 2-34. This explanation also does not support the 4 percent "best practices" target. EPA does not discuss whether the difference between any unit's current heat rate and its best three-year moving average is due to operational factors within the unit's

ED_000419-0005910

Moreover, on a more fundamental level, EPA's analysis incorrectly assumes that the existence of variation in heat rate at individual units means there is "significant variation in the operation of EGUs" indicating that "significant potential for heat rate improvement is available through the application of best practices." *Id.* at 2-30. In fact, heat rate variability at individual units is driven by the design, duty cycle, fuel type, size, cooling conditions, and location of each unit, and it cannot be ameliorated by changes in operating practices. Cichanowicz Statistical Critique at 5-8. EPA did not assess differences in variability based on these factors or control for these factors in its achievability analysis. Rather, the Agency's assessment was based on a simplistic and deeply flawed regression analysis of hourly unit capacity factor and ambient temperature on gross heat rate and on the Agency's observations regarding "residual" heat rate variation not accounted for by this regression. *Id.* at 3. The report by UARG's consultants shows that much of the "unexplained" heat rate variability that EPA assumed could be reduced by implementing best practices actually reflects the impact on heat rate of differences in individual units' age, capacity factor, fuel type, boiler design, and cooling conditions, *id.* at 6-8, and that EPA's regression itself is flawed because its results defy known technical relationships between heat rate, operating duty, and ambient temperature, *id.* at 3-6.

In any event, many of the "best practices" that EPA identifies in the TSD are not operating practices at all, but instead involve replacing or upgrading physical components of the EGU or related power plant equipment. *See* GHG Abatement Measures TSD at 2-33, Tbl. 2-13 (listing "No-Cost and Low-Cost Options" EPA equates with "best practices"). These actions have no discernible connection to variability in a unit's heat rate. Although EPA quantifies the

---

control, or whether it would be achievable for a unit to consistently achieve a heat rate equivalent to its best three-year moving average using "best practices."

potential benefits of these measures in terms of reduced heat rate variability, the Agency presents no evidence that the "best practices" measures actually have the effect of reducing heat rate variability (as opposed to improving a unit's average heat rate while maintaining a similar range of variation in individual observations).

Second, EPA's assessment of available heat rate improvements through "equipment upgrades" is similarly arbitrary. EPA set this component of the target by identifying the four most costly heat rate improvement methods listed in the 2009 Sargent & Lundy report based on average estimated $/kW costs, then simply adding together the average estimated Btu/kWh improvements for each. *Id.* at 2-33. Based on this calculation, EPA concluded that the four specified equipment upgrades could provide a 4 percent heat rate improvement if all were applied on an EGU that has not already made them, but "conservatively" reduced the target to 2 percent because "some units may have applied at least some of the upgrades." *Id.* at 2-34, 2-35; 79 Fed. Reg. at 34,860 ("We therefore propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity just described remains.").

As discussed above, not only does this methodology include turbine and other upgrades that are beyond the scope of section 111, it erroneously assumes that the heat rate improvements from these upgrades are cumulative and that they provide consistent long-term benefits. In reality, the combined payoff from these four upgrades will be less than the sum of each measure's payoff would be when applied alone to an EGU, and these heat rate benefits will begin to degrade immediately once the unit returns to service. Also, EPA's reliance on the average Btu/kWh improvement of each measure is flawed because the potential payoff of each upgrade is highly unit-specific and is skewed towards lower values. *See* NCC Report at 71

ED_000419-0005912

("The benefits and cost are highly variable and depend on the specifics of any one site."). For example, the NCC Report notes that large gains from turbine overhauls are possible only for "units that are *severely degraded*," and potential benefits from variable frequency drives depend heavily on existing equipment. *Id.* at 62, 65-66 (emphasis added). Moreover, one of the measures EPA identifies—acid dew point control—is not broadly available and has not even been proven for most of the generating fleet. Cichanowicz Statistical Critique at 10 (discussing achievability of 2 percent heat rate improvement through "equipment upgrades").

In addition, EPA's attempt to account for individual characteristics by "conservatively estimat[ing]" a potential improvement of 2 percent instead of 4 percent is arbitrary and unreasonable. GHG Abatement Measures TSD at 2-35. Reducing the already-inflated target by half without further analysis is not "conservative," it is merely guesswork. The actual potential for efficiency improvements via equipment upgrades is likely much lower, given that "[m]any of these measures have been already applied on units in the existing inventory." NCC Report at 71; Cichanowicz Statistical Critique at 10. EPA cannot require affected EGUs to duplicate emission reductions they have achieved using measures they have already taken. Therefore, EPA must assess what efficiency upgrades have already been implemented by affected coal-fired EGUs in order to determine what level of additional heat rate improvements is achievable. The Agency has simply failed to adequately prepare the necessary background information for this rule. Likewise, EPA must also assess other factors that will determine what level of heat rate improvements is achievable for individual coal-fired EGUs across the source category as a whole, such as whether the upgrades are compatible with the design and hardware present at a unit and whether the upgrades may present operational reliability issues at a particular unit. *See* NCC Report at 71.

Finally, the individual EGUs to which EPA points as examples provide no support for the Agency's claim that Building Block 1 is achievable. EPA relies heavily on its analysis of historical CEMS-derived gross heat rate data from "16 EGUs that reported a single year-to-year heat rate improvement of 3-8%." GHG Abatement Measures TSD at 2-32; *see also* "GHG Abatement Measures Units with Heat Rate Changes," Docket ID No. EPA-HQ-OAR-2013-0602-0236 (listing the 16 identified units). According to EPA, significant year-to-year improvements at all other units in the study population were due to "changes in capacity factor, reporting method, or other events." GHG Abatement Measures TSD at 2-32. For two of the sixteen units, the Agency claims to have identified "equipment upgrades" that EPA speculates are "responsible for 2-3% heat rate improvement" based on estimates contained in the 2009 Sargent & Lundy report, while concluding that unspecified equipment upgrades were "the most likely cause of some of the observed heat rate improvements" at the remaining fourteen units. *Id.*

EPA apparently never contacted the owners of these units to determine what factors were responsible for the apparent reductions. UARG's consultants, however, contacted the owners of the sixteen units EPA singled out in the TSD in order to determine the cause of these reported year-to-year heat rate improvements. J. Edward Cichanowicz & Michael C. Hein, "Critique of EPA's Use of Reference Units To Select Heat Rate Reduction Targets" (Nov. 25, 2014) ("Cichanowicz Reference Unit Report") (Attachment F). Based on discussions with the owners of these units, in virtually every case the EPA-calculated heat rate improvement was due to a change in stack flow monitor calibration or other unrelated sources of normal variability in CEMS measurements and were not the result of purposeful efforts to improve unit efficiency. *Id.* at 1; Ralph L. Roberson, "Real Heat Rate Improvement or Measurement

Variability/Uncertainty" at 8 (Nov. 25, 2014) ("Roberson Report") (Attachment G). Figure 3 below summarizes the reported causes of observed CEMS-derived heat rate improvements at each of the sixteen units.

Figure 3: Causes of EPA-Calculated Heat Rate Improvements at 16 EPA Reference Units

Owner	Unit Name	Cause of Apparent Heat Rate Improvement
AES	Petersburg 1	Gross heat rate reduction by ~3% in 2003 due to steam turbine "dense-pack" retrofit. Other reductions due to CEMS changes. Net heat rate increases 2-3% prior to 2004 due to SCR retrofit and operating variables.
City of Springfield MO	Southwest 1	Almost all gross heat rate reductions appear to be due to unrelated variability in CEMS measurements. Steam turbine dense-pack derived a 2% reduction in the year following retrofit.
Duke Energy	Gibson 1	Unrelated CEMS measurement changes noted with retrofit of FGD and dedicated stack. Net heat rate based on coal use exceeds CEMS-derived values by 5-10%. The CEMS gross heat rate data lower than unit design basis.
Dynegy	Newton 1	Dynegy evaluating data.
Georgia Power	Gorgas 1	Georgia Power states most changes in reported gross heat rate are due to the variability and relative accuracy associated with using CEMS-based heat input data.
CLECO/ Lafayette Utilities System	Rodemacher 2/ Brame Energy Center	All reported gross heat rate reductions due to unrelated variability in CEMS measurements. Modest decrease in net heat rate (~2%) noted over 11 years but not due to targeted actions.
NV Energy	North Valmy	All reported gross heat rate reductions due to unrelated variability in CEMS measurements.
Nebraska Public Power	Sheldon 1	Gross heat rate when calculated using plant monitoring equipment increases over the reporting period. A reported gross heat rate reduction of 10% in 2006 is due to CEMS recalibration.

Owner	Unit Name	Cause of Apparent Heat Rate Improvement
Pacificorp	Dave Johnston 2	All changes CEMS-related; most due to calibration of stack gas temperature probe in 2005 and 2007. 24 month rolling average of net heat rate increases ~3%.
Pacificorp	Dave Johnston 4	Steam turbine upgrade in 2009. Replacement in 2011 of: legacy FGD with dry FGD; new stack; rebuilt boiler. CEMS location changed. The reported gross heat rate reduction of 10% is due to unrelated variability in CEMS measurements. Net heat rate lower ~1% vs. 2009.
Pacificorp	Jim Bridger 3	All reported reductions due to unrelated variability in CEMS measurements; notably, replacement of the stack flow monitor in 2005. 24 month rolling average of net heat rate decreased by 1.7% due to changes in operation.
TVA	Colbert 1-3	EPA conclusions regarding unit gross heat rate are compromised as heat input data is reported from common stack CEMS and apportioned by load, based on assumed identical heat rate. Yearly differences in unit operating conditions influence results. Any actual changes in reported gross heat rate are largely due to coal blend.
Wisconsin Public Service	Weston 3	Heat rate varies between 11,000 and 9,000 Btu/kWh over four years. All reductions in reported heat rate due to unrelated variability in CEMS measurements.
Xcel	Allan King 1	Refurbishment: boiler cyclones and heat exchangers; coal handling, steam turbine internals; cooling tower. Replaced legacy FGD and ESP with dry FGD and fabric filter; also SCR. Net heat rate actually increases vs. 2003 due to higher station load for environmental controls.

In other words, the reported heat rate improvements do not reflect actual changes in unit efficiency or reductions in unit CO_2 emission rates. The owners of eleven units report that all changes are due to unrelated variability in the CEMS-based measurements. Cichanowicz Reference Unit Report at 1. Some units did report significant initial heat rate improvements

from equipment upgrades, such as upgrading the steam turbine, but these improvements were generally more than offset by increases in net heat rate due to the retrofit of environmental controls. *Id.*

Indeed, the only conclusion that EPA's analysis of the 16 reference units supports is that CEMS-derived gross heat rate data contain too much unrelated normal variability to reliably quantify relatively small changes in unit heat rate, particularly when averaged over a year. *Id.* at 2. This conclusion is underscored in the attached report from UARG's consultant, which details numerous reasons why CEMS data reported under Part 75 are inappropriate for the purpose to which EPA applies them in these Proposed Guidelines, despite Part 75's stringent quality assurance criteria. Roberson Report at 3-8. Rather than reflecting actual changes in unit heat rate, variation in these values may reflect changes in flow monitor calibration, calibration reference methods, bias adjustment factors, stack diameter measurement, or monitoring technology, and physical changes in the flue gas handling system. *See generally id.* In addition, where units share a common stack, EPA's data handling procedures permit the owner to apportion the observed data between those units based on load—effectively assuming that those units' heat rates are equal. *Id.* at 5-6. EPA has failed even to acknowledge, let alone account for, these sources of variability in CEMS-derived gross heat rate data.

In sum, EPA has failed to satisfy its obligation to demonstrate that its proposed Building Block 1 target of 4 to 6 percent improvement in heat rate for coal-fired EGUs statewide is achievable "under the range of relevant conditions which may affect the emissions to be regulated." *Nat'l Lime Ass'n v. EPA*, 627 F.2d at 433. The Agency failed to consider important factors affecting the achievability of its proposed targets, including operating load, auxiliary power consumption, source-specific variability in available upgrades and associated benefits, and

the non-additive and temporal nature of some heat rate improvements. EPA's analysis of historical data from coal-fired EGUs is deeply flawed and does not support the Agency's claims.

B. Building Block 2 Is Not Achievable.

EPA is proposing to find that it is achievable for affected EGUs in each state to shift generation from existing coal- and oil/gas-fired steam EGUs to existing NGCC units until those NGCC units reach a statewide maximum capacity factor of 70 percent (or 65 percent under the alternate goals EPA solicits comment on). 79 Fed. Reg. at 34,864-66. EPA bases this conclusion on its observation that of 464 NGCC plants it identified with generation data in 2012, 10 percent had a capacity factor of 70 percent or greater. GHG Abatement Measures TSD at 3-8 to 3-9. Using a different set of data, EPA also observed that some units are capable of operating at greater than 70 percent capacity factor on a seasonal basis, with 16 percent and 19 percent of units operating at or above that level in the 2012 winter and summer seasons, respectively. 79 Fed. Reg. at 34,863. Relying on this data, EPA "assumed that 70% was a reasonable fleet-wide ceiling for each state" on an annual average basis. GHG Abatement Measures TSD at 3-9.

This conclusion is not supported by EPA's analysis, which fails to demonstrate that the 70 percent target for Building Block 2 redispatch is achievable by affected EGUs in the source category. In addition to the data errors described in Section XIII above, which misstate the amount of NGCC generation available for redispatch in each state, EPA's Building Block 2 analysis is insufficient because it fails to account for factors limiting the ability of EGU owners to increase utilization of their NGCC units. For example, some units are unable to increase generation to any level approaching 70 percent due to technical limitations, permit limits, or gas and transmission infrastructure constraints. Other NGCC units will not be able to generate sufficient amounts above 70 percent to make up for these lower-utilization units.

ED_000419-0005918

EPA's assumption that each state's entire fleet of existing NGCC units can match the operational level of its top 10 percent of units is unsupported and arbitrary. EPA did not undertake any assessment of the differences between high- and low-capacity factor NGCC units that may have led a small subset of those units to operate above a 70 percent capacity factor in 2012. The Agency acknowledged that units operating above 70 percent on an annual basis were "largely dispatched to provide base load power," and that units operating above 70 percent on a seasonal basis typically "were idled or operated at lower capacity factors" during periods of lower demand. *Id.* But EPA did not examine whether the NGCC units providing base load power have different characteristics from the other existing NGCC units that are expected to provide generation for redispatch, or whether units that were idled during periods of relatively low demand did so because of economic, technical, or regulatory constraints on their operations. Instead, EPA assumed that all NGCC units are identical. This is plainly unreasonable. In order to demonstrate that a standard is achievable, EPA must "establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard." *Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981). This determination cannot be based on "mere speculation or conjecture." *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (per curiam). EPA has failed to establish that the 10 percent of existing NGCC units operating at 70 percent capacity factor or higher are representative of the remainder of NGCC units in the source category. Indeed, many of these high-utilization units are likely *not* representative of the source category, given that EPA excluded a number of them from its calculations of each state's existing NGCC capacity in the Goal Computation TSD. *Compare* 2012 NGCC Spreadsheet (including, *inter alia*, Martinez Refining units in assessment of achievable NGCC capacity factor); *with* Goal

Computation TSD, App. 7 (excluding, *inter alia*, Martinez Refining units from California's existing NGCC capacity).

In reality, many existing NGCC units face constraints that will prevent them from increasing their utilization to a 70 percent capacity factor. Some units may be located in areas that are designated as in non-attainment for a NAAQS, and as a result would likely have operating permits imposing mass limits on carbon monoxide ("CO") or NOx emissions that would effectively establish a cap on those units' operations. Marchetti Report at 26. EPA is currently considering whether to revise the primary NAAQS for ozone to a more stringent level, which could lead to additional restrictions on EGUs operating in certain areas and would further limit states' ability to increase generation from NGCC units. *See* EPA, Proposed Rule: National Ambient Air Quality Standards for Ozone (Nov. 25, 2014) (pre-publication version), *available at* http://www.epa.gov/airquality/ozonepollution/pdfs/20141125proposal.pdf. In addition, some units were financed, designed, and maintained for the specific purpose of operating in cycling duty rather than as base load. Many of these units would not be able to achieve the target utilization rate without significant upgrades and testing to ensure that they are technically capable of operating near full load on a continuous annual basis. In any event, their permitted emission limits may not allow them to operate at a 70 percent capacity factor. For example, the Jackson Power Facility in Jackson, Michigan currently operates under a Title V permit containing enforceable restrictions sufficient to limit operation to well under a 70 percent capacity factor—likely 50 percent or less. Marchetti Report at 23. The Oswald and Fitzhugh NGCC facilities in Arkansas faces similar constraints. *Id.* at 24.

Other units were specifically designed and permitted to provide dedicated backup generation for intermittent sources of renewable energy, such as wind and solar. *See id.* at 36.

ED_000419-0005920

For these units, a significant portion of their capacity would need to be preserved for reliability purposes, limiting the capacity available for redispatch to displace coal-fired generation and serve base load. Further, for many existing NGCC units there is simply insufficient pipeline, gas availability, or transmission infrastructure to permit operating year-round at a 70 percent capacity factor. *Id.* at 19-23. These infrastructure limitations are exacerbated by the fact that the proposed state goals are calculated assuming that states will fully implement Building Block 2 by 2020, giving states and utilities only a few years or less in which to expand gas and transmission infrastructure as needed to reach the target level. As discussed below, such rapid expansion is impossible.

EPA does not even acknowledge, let alone adequately address, the constraints preventing existing EGUs from operating at a 70 percent or higher capacity factor. EPA completely ignores potential technical or permit limits on NGCC unit operation and dismisses infrastructure concerns. The Agency's primary response—that the allowance for "emission rate averaging across multiple units and across time" within a state in the proposed emission guidelines will compensate for such constraints—does not demonstrate that a 70 percent overall capacity factor is achievable. GHG Abatement Measures TSD at 3-15. EPA makes no attempt to determine whether each state will have a sufficient number of existing NGCC units that are able to generate sufficient electricity above a 70 percent capacity factor to make up for units that are not able to approach this level. As a result, the Agency's reliance on "averaging flexibility" is "mere speculation or conjecture." *See Lignite Energy Council*, 198 F.3d at 934.

EPA also points to historic trends in an attempt to justify its assumption that sufficient infrastructure already exists to support Building Block 2. For example, the Agency notes that NGCC generation increased by 22 percent between 2011 and 2012, supposedly demonstrating

ED_000419-0005921

that existing natural gas infrastructure can accommodate rapid increases in existing NGCC utilization. GHG Abatement Measures TSD at 3-9 to 3-10. But EPA fails to note that even after this expansion—which was largely a function of historically low natural gas prices in 2012 due to the widespread development of hydraulic fracturing technology—over half of the existing NGCC units that EPA examined still operated at a capacity factor below 50 percent, presumably due to the kinds of constraints that EPA attempts to wish away. *See* 2012 NGCC Spreadsheet. EPA also points out that nationwide NGCC generation increased by approximately 81 percent between 2005 and 2012 (compared to the estimated 47 percent increase by 2020 that would be required in order to implement Building Block 2), while failing to acknowledge that this figure includes new NGCC units that were constructed from 2005 to 2012 and does not simply reflect increased utilization of existing units, which is the centerpiece of the Building Block 2 approach. GHG Abatement Measures TSD at 3-11.

In addition, EPA relies on trends in hourly capacity factor to claim that a 70 percent annual capacity factor is an achievable goal. According to the Agency, the nationwide NGCC capacity factor during peak hours of the day averages 11 percentage points higher than the overall annual average, suggesting that the current system is able to support national average capacity factors "in the mid to high 50's for NGCC for peak" (i.e., 11 percentage points higher than the 2012 national average capacity factor of 45.8 percent).[47] *Id.* at 3-15 to 3-16. EPA does

---

[47] EPA is confused concerning its entire justification for Building Block 2. The Agency cites different values for this analysis in the preamble than in the GHG Abatement Measures TSD. In the preamble, EPA claims that national average capacity factors are "60 percent or higher" during peak hours, and that these values are "15 to 20 percentage points above their average utilization rates." 79 Fed. Reg. at 34,863. In contrast, EPA states in the GHG Abatement Measures TSD that national average capacity factors are "approximately 50%" during peak hours, and that these values are "approximately 11% above the average capacity factor." GHG Abatement Measures TSD at 3-15. EPA does not explain this discrepancy, but

ED_000419-0005922

not explain, however, why it believes it is reasonable to expect that the current system can accommodate an additional 10-15 percentage points in order to reach a 70 percent average capacity factor over all hours of the day.

The viability of EPA's Proposed Guidelines depends on the increased availability of both natural gas and renewable energy. *See* 79 Fed. Reg. at 34,864; RIA at ES-24, 3-26 (implying that new natural gas generating capacity will increase 20 to 22 percent by 2020 to replace retiring coal-fired capacity under Option 1, and stating that new natural gas generating capacity will increase 9 percent relative to the base case in 2020 under Option 2). Most significant new renewable capacity will be constructed far from load centers because of the unique siting needs and sensitivities of large-scale wind and solar projects. Ramping up both renewable energy and natural gas will require significant infrastructure improvements, most notably, more transmission lines and natural gas pipelines. Initial NERC Report at 2. Both of these forms of infrastructure require many layers of permitting and years of regulatory approvals, often at federal, state, and local levels. EPA is unrealistic in assuming that this infrastructure will be in place by 2020 for states to begin implementing all four Building Blocks.

A large number of permits, consultations, and approvals are needed from multiple government bodies to get a new transmission line permitted and constructed. The timeline for a transmission project depends on completion of planning studies and technical analysis, real estate availability (negotiating rights-of-way or exercising eminent domain authority), procurement of long lead time equipment, environmental permitting requirements, public opposition, regulatory approval, and opportunities for tie in outages. A relatively simple project

---

the values in the TSD appear to match the EIA sources EPA cites in both the preamble and the TSD, so this analysis assumes that the values in the TSD govern.

ED_000419-0005923

that will not traverse an environmentally sensitive area, require the exercise of eminent domain, or involve significant public opposition will take up to three years prior to construction. More complicated projects that will traverse federal lands, environmentally sensitive areas, or will generate public opposition may take as much as 10 years to complete.

Among the many permits that may be required for a new transmission line are the following: an Environmental Assessment or Environmental Impact Statement (required under *both* federal and state law in some cases), if the project involves significant state or federal government action of any kind; a Section 404 permit from the Army Corps of Engineers if dredge or fill material will be placed in "waters of the United States"; Section 7 consultation with the U.S. Fish and Wildlife Service under the Endangered Species Act if the project has the potential to impact threatened or endangered species; a Special Use Authorization under the National Forest Management Act if the project will traverse federal lands managed by the U.S. Forest Service; a right-of-way grant under the Federal Land Policy and Management Act from the U.S. Department of Interior Bureau of Land Management ("BLM") if the project traverses federal lands managed by BLM; a state water quality permit (if required by a state water quality statute); fish, game, and other wildlife related permits, if the project will divert natural flow of water bodies or otherwise affect fish and game; Section 106 National Historic Preservation Act consultation if the project might impact cultural or historic resources; a right-of-way lease agreement; and an air quality permit if disturbed acreage will exceed certain thresholds. *See* California Public Utilities Commission, Federal, State, and Local Permitting Processes Likely to be Required for Electric Transmission Projects (June 2009), http://www.cpuc.ca.gov/NR/rdonlyres/D896C1EA-BD35-4BC8-83C8-D332BAE959BF/0/GenericTransmissionLine

ED_000419-0005924

Permit.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

The Utah Office of Energy Development has estimated that a typical schedule for siting, permitting, and constructing a new transmission line in that state could take up to seven years, assuming the line is at least 100 miles long, crosses federal lands, and requires a federal environmental impact statement. *See* Utah Office of Energy Development, Guide to Permitting Electric Transmission Lines in Utah, at iii, Fig. ES-1 (Aug. 2013), *available at* http://energy.utah.gov/download/reports/PermittingGuide_Final%20080913%20(cd%20ver).pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).
In Colorado, siting transmission lines can take even longer because local governments (counties and municipalities) have jurisdiction over the siting of transmission lines and each may impose different permit or other authorization requirements and conditions.

As just one example of the time that may be required to carry out a transmission line project, in Arizona—a state that is likely to require significant amounts of new transmission infrastructure, given that the state's proposed goal assumes that all coal-fired generation is eliminated by 2020—the Morgan to Sun Valley Transmission Line Project is expected to take 8 to 9 years from its conception in 2007 to final approval, before the design phase even begins. *See* APS, "Current siting projects," *available at* https://www.aps.com/en/ourcompany/generation transmission/transmissionfacilitysiting/Pages/current-siting-projects.aspx. The project will extend 38 miles and hold a 500 kilovolt transmission line and a 230 kilovolt line, crossing roughly 9 miles of federal public lands. The State of Arizona has diligently carried out its functions in the regulatory process: the process simply involves numerous steps, such as siting and public participation, that require a significant amount of time to complete. In addition,

ED_000419-0005925

because the project will cross federal land (a common requirement for Western projects), it was required to undergo analysis under the National Environmental Policy Act ("NEPA"), which took 4 years and culminated in an environmental impact statement analyzing the potential impacts of the entire project and a record of decision approving the project utility's corridors and necessary right-of-way. *See* BLM, "APS Sun Valley to Morgan 500/230kV Transmission Line Project Record of Decision," (Jan. 2014), *available at* http://www.blm.gov/style/medialib/blm/az/pdfs/energy/aps.Par.38965.File.dat/ROD.pdf. The project's owner anticipates that the project will receive final approval and a notice to proceed from the state in 1 to 2 years. Design and construction of the project will not begin until it receives a notice to proceed.

Moreover, although significant gains have been made in the past several years in locating new sources of natural gas, little has been done to improve the infrastructure needed to connect this new gas to power plants. The Interstate Natural Gas Association of America ("INGAA") predicts that the natural gas industry will need to construct 2,000 miles *per year* for the next twenty years of new gas transmission mainlines and laterals to meet demand. *See* The INGAA Foundation, Inc., Jobs & Economic Benefits of Midstream Infrastructure Development: US Economic Impacts Through 2035, at ES-1 (Feb. 15, 2012), *available at* http://www.ingaa.org/File.aspx?id=17744 (included in UARG's separately filed Supplemental Materials for the Rulemaking Record); *see also* The INGAA Foundation, Inc., North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, at 38 (Mar. 18, 2014), *available at* http://www.ingaa.org/Foundation/Foundation-Reports/2035Report.aspx (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). INGAA and other industry groups also stated recently that more than 338,000 miles of pipeline will need to constructed between 2014 and 2035. *See* Comments of American Petroleum Institute,

ED_000419-0005926

Association of Oil Pipe Lines, International Association of Geophysical Contractors, Interstate Natural Gas Association of America, Utility Air Regulatory Group, and Utility Water Act Group on Three Endangered Species Act Critical Habitat Proposals of the U.S. Fish and Wildlife Service and the National Marine Fisheries Service Published on May 12, 2014, at 5 (Oct. 9, 2014), *available at* http://www.ingaa.org/File.aspx?id=22680 (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). For perspective, there were about 306,000 miles of gas pipeline in use in the United States at the end of 2008. *See* EIA, "Estimated Natural Gas Pipeline Mileage in the Lower 48 States, Close of 2008," *available at* http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ mileage.html.

EPA has not adequately addressed in the record these significant barriers that exist to ramping up the use of natural gas and renewables in the electricity generating sector by 2020 and 2030. In order to meet EPA's interim goals between 2020 and 2030, this capacity realistically needs to be in place by 2020. EPA has not demonstrated how the sector will be able to ramp up natural gas and renewable capacity in time to meet the deadlines in the Proposed Guidelines given the many years needed to plan, permit, and build the infrastructure to support these forms of generation. This lack of demonstration and record support is an additional factor rendering the rule arbitrary and capricious.

The Agency suggests that pipeline infrastructure will have sufficient time to expand if necessary to accommodate Building Block 2 because the Proposed Guidelines "provide[] for flexible implementation that will permit efficient scheduling of infrastructure upgrades as needed." GHG Abatement Measures TSD at 3-16. Presumably, EPA is suggesting that states may delay full implementation of Building Block 2 because compliance with the proposed state interim goals is based on average emissions from 2020 to 2029. The "flexible implementation"

ED_000419-0005927

timeline EPA claims to have provided states is largely illusory, however, particularly with respect to Building Block 2. For most states, redispatch under Building Block 2 accounts for the most significant emission reductions of any building block, and EPA calculated the proposed state goals with the assumption that Building Blocks 1 and 2 would be fully implemented by 2020. 79 Fed. Reg. at 34,905-06; *see* Goal Computation TSD at 18 (noting that in calculating state goals, only "the RE and EE assumptions change for each year from 2020 through 2029"). Delaying full implementation of Building Block 2 in order to allow for necessary infrastructure development would significantly increase a state's emissions in early years of the 2020 to 2029 compliance period, forcing the state to achieve more drastic emission reductions in later years in order to comply with the interim goal on average. Thus, most states will need to implement necessary infrastructure improvements to accommodate Building Block 2 by 2020 or very soon thereafter. This timeline is likely infeasible, given that gas pipeline projects often require a decade to complete, in part because the timeline for environmental permitting can be lengthy.

In addition, by focusing its achievability analysis for Building Block 2 on annual capacity factors, EPA has failed to consider the effect of widespread redispatch to NGCC on states' ability to meet demand during periods of peak load. During peak demand, many utilities are already operating all of their available generating capacity to the fullest extent, including NGCC and coal-fired units, while also purchasing power from merchant generators. Marchetti Report at 24-26. But in several states, the limits on coal utilization that follow from redispatch to existing NGCC will eliminate or severely limit coal-fired units as an option for meeting peak demand. In Arizona and other states, the interim and final goals are based on eliminating coal-fired generation from the state's generation mix completely. Without access to this coal-fired capacity, utilities would be forced to purchase substantial additional amounts of electricity from

ED_000419-0005928

NGCC merchant generators on the short-term market. *Id.* at 25. Yet many of these merchant generators already operate at or near full capacity during periods of peak demand, and in any event, their capacity may be committed to serve load in neighboring states under other long- or short-term agreements. *Id.* Therefore, utilities cannot rely on merchant generation to meet long-term demand requirements during peak summer months in lieu of generation from existing coal-fired units. *Id.* at 25-26.

EPA's Building Block 2 is also based on the faulty premise that generation from any NGCC unit located within a state may be redirected by a utility or state within the state's borders to offset reduced generation from coal-fired units elsewhere in the state. In many cases, this is simply not true. In most states, electric generation is dispatched by an RTO or ISO, which calls up generation from EGUs within its system such that the lowest cost generating sources are dispatched first. *See id.* at 16-19. Thus, as an initial matter, neither a utility nor any state agency controls the relative dispatch of coal-fired EGUs and NGCC units in most states. In addition, the areas covered by RTO and ISO systems typically do not coincide with state borders. In most cases, an ISO's footprint includes generating units in several states, and some states are divided between multiple ISOs. As a result, it is common for EGUs within a state to be dispatched based on direction from different managing authorities, and for EGUs to serve load outside of the states in which they are located. There may be limited interconnection between the different dispatch systems in a state, and EGUs in one part of a state may lack the cross-state transmission rights needed to serve load in a different part of the state.

One straightforward example may be found in South Dakota, which contains only one coal-fired unit (Big Stone, operating in the MISO) and one NGCC unit (Deer Creek, soon to join the SPP). *Id.* at 18-19. Because these units operate in different ISOs, they do not share a

ED_000419-0005929

common dispatch signal, and reduced generation from Big Stone will not necessarily be replaced by increasing generation from Deer Creek. In addition, each of these units was designed, sited, and permitted to serve the needs of their utilities' respective customer bases, not those of other utilities. Thus, even though these units are located in the same state, each utility owns firm transmission rights from its unit to its own retail load—and not to the other utility's customers. *Id.* at 19. The issue becomes even more complicated in states with a more complex generation mix—for example, Texas contains at least three separate RTOs (the ERCOT, SPP, and MISO), with the majority of its NGCC generating capacity concentrated in just one (the ERCOT). *See* FERC, Market Oversight, Regional Transmission Organizations, http://www.ferc.gov/market-oversight/mktelectric/overview/elec-ovr-rto-map.pdf.

Even where electricity dispatch is governed by individual utilities and not by an ISO or RTO, similar limitations on in-state redispatch arise where a state is served by multiple utilities or where a utility spans multiple states. For example, TVA generates power from fossil fuels in 4 states and distributes power to Tennessee and portions of 6 other states. It also buys and sells some power from neighboring systems and optimizes the dispatch of generating assets and operation of transmission infrastructure as a system (not necessarily within individual states) to maintain reliability and minimize cost. Three of TVA's five NGCC units are located in Mississippi, but all of its coal-fired units are located outside of Mississippi (TVA does purchase power through a power purchase agreement from the Red Hills coal-fired unit in Mississippi). Increasing the capacity factor of TVA's Mississippi NGCC plants would have minimal effect on coal-fired generation in Mississippi: virtually all of the generation displaced would be from TVA's coal-fired units in other TVA states.

ED_000419-0005930

In sum, EPA has failed to demonstrate that its Building Block 2 target of redispatching generation from existing coal- and oil/gas-fired steam EGUs to existing NGCC units up to an overall NGCC capacity factor of 70 percent is achievable. The Agency failed to assess whether the subset of NGCC units currently operating at 70 percent capacity factor represents the remainder of existing NGCC units, and it did not properly address economic, technical, regulatory, or infrastructure constraints preventing some units from operating at the target level. Above all else, Building Block 2 demonstrates that EPA fundamentally miscomprehends how energy is generated and distributed in the United States.

C. The Renewable Energy Component of Building Block 3 Is Not Achievable.

EPA proposes to find that it is achievable for states to increase in-state generation from renewable energy sources to an amount that is based on application of a regional annual growth factor to the state's 2012 renewable energy generation, gradually approaching a maximum regional renewable energy generation target. 79 Fed. Reg. at 34,867. EPA expects states to begin taking measures to increase renewable energy generation in 2017, three years before the beginning of the compliance period. *Id.* The regional maximum renewable energy target for each state is based on the average 2020 primary RPS goal of states within each region that have RPS goals. *Id.*

The renewable energy generation goals that EPA has calculated for each state are unachievable. EPA's methodology for determining these goals is fatally flawed because it arbitrarily ties each state's goal to the RPS goals of other states, which often do not require as much renewable energy generation as they appear to and reflect each state's unique mix of renewable energy potential. Marchetti Report at 31-34. For example, EPA relied on state RPS goals that are based on capacity rather than generation, despite claiming that it excluded such goals. *See* GHG Abatement Measures TSD at 4-9 n.108; Marchetti Report at 32 (noting Kansas

RPS is capacity-based). EPA's renewable energy generation targets for some states are unreasonably aggressive and do not take into account factors affecting the actual renewable energy growth potential in each state. Even EPA's IPM modeling results indicate that predicted renewable energy generation by the end of the compliance period will not come close to the renewable energy targets EPA used in its goal calculation. Accordingly, EPA must withdraw the Proposed Guidelines and reduce its renewable energy generation targets to more realistic levels.

1. EPA's Method for Calculating the Renewable Energy Targets for Building Block 3 Is Flawed.

EPA's approach to determining regional renewable energy generation targets is flawed in several respects. First, it is arbitrary for EPA to assume that each state is capable of achieving similar levels of renewable energy generation as its neighboring states. The Agency acknowledges that state RPS goals reflect "policy objectives including both feasibility and costs" and not merely renewable energy potential. 79 Fed. Reg. at 34,866. These policy objectives may vary wildly from state to state within individual regions. Moreover, renewable energy potential is highly state-specific and depends on each state's natural resources (e.g. insolation, availability of wind energy, biomass resources, etc.), existing transmission infrastructure, and current renewable energy development. The proposed "regional" approach is simply based on NERC regions and does not reflect similarities between states based on renewable energy potential.

EPA's failure to account for the precise nature of existing state RPS goals leads to unreasonable results. For example, the renewable energy target for the South Central region[48] is based entirely on Kansas's 2020 RPS target of 20 percent renewable energy capacity. *See*

---

[48] The South Central region includes the states of Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, and Texas. GHG Abatement Measures TSD at 4-15.

ED_000419-0005932

generally Kansas Renewable Energy Standards Act, KAN. STAT. ANN. §§ 66-1256 through 66-1262. Because actual generation is significantly less than capacity, a 20 percent target based on capacity would not come close to approximating a 20 percent generation-based renewable energy target. Moreover, in adopting its RPS, Kansas was building upon its experience with 24.2 percent average annual growth in wind from 2008 to 2012. *See* Marchetti Report at 32. No other states in the South Central region have a generation-based RPS; the Texas RPS is also capacity-based. Thus, EPA erroneously imputed a renewable energy generation-based target to the entire region that does not exist in any state in the South Central region.

EPA also failed to account for factors limiting certain renewable generation in particular states—factors that would prevent certain states from meeting their goals. In Arkansas, industrial combined heat and power ("CHP") facilities burning wood or wood-derived fuels made up over 95 percent of the state's renewable energy generation and only grew at a 1.6 percent average annual rate from 2008 to 2012. *Id.* Arkansas cannot reasonably quadruple this growth rate, as it would be required to do to meet its renewable energy target. Similarly, Kentucky has very low wind and solar generation potential. *See* EIA, Kentucky Profile Analysis (Dec. 18, 2013), *available at* http://www.eia.gov/state/analysis.cfm?sid=KY.

Likewise, the renewable energy target for the entire Southeast region[49] is based solely on North Carolina's 2020 RPS goal of 10 percent and assumes a renewable energy growth rate of 13 percent per year for each state. But in Georgia and Alabama, industrial CHP sources burning wood or wood-derived products (such as pulp and paper mills) constitute over 90 percent of each state's renewable energy generation. Marchetti Report at 34. Between 2008 and 2012, these

---

[49] The Southeast region includes Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee. GHG Abatement Measures TSD at 4-15.

ED_000419-0005933

industrial CHP sources grew at an annual rate of only 2.1 percent in Georgia and actually *declined* by 5.1 percent annually in Alabama. These sources have little potential for growth, so in order for Georgia to achieve its state renewable energy target, other renewable energy sources would need to increase by *over 44 percent per year*. Accordingly, EPA's approach is inherently defective because it does not account for these state-specific limits on achievable renewable energy potential.

Second, EPA's analysis of state RPS goals is oversimplified and reflects EPA's limited understanding of these goals. Some state RPS goals are voluntary, while others establish requirements only for large, investor-owned electric utilities or apply less stringent "secondary" or "tertiary" RPS goals to smaller utilities, municipal utilities, or cooperative utilities. *See* GHG Abatement Measures TSD at 4-10. But EPA applies the more stringent primary RPS goals to all in-state generation and treats all goals as mandatory, artificially leading to more aggressive renewable energy generation targets. Many state RPS goals include hydroelectric power generation, but EPA does not include existing hydroelectric power towards compliance with its Proposed Guidelines. Marchetti Report at 33. For example, New York counts hydroelectric power towards its 29 percent RPS target, and this source accounted for 83 percent of the state's renewable generation in 2012. *Id.* Including this component of the RPS in the Building Block 3 goals without allowing states to rely on existing hydropower for compliance will substantially increase the amount of new renewables required in each state, even in states that have already reached their own RPS goals.

Moreover, some state RPS goals allow utilities to comply through mechanisms other than actually developing in-state renewable energy generation. For example, as described in the Marchetti Report at 31-32, North Carolina's RPS goal allows utilities to meet 25 percent of their

requirements by reducing energy consumption through energy efficiency measures, and another 25 percent of their requirements by purchasing renewable energy certificates from out-of-state facilities. Thus, the 10 percent RPS target EPA assumed for North Carolina effectively requires in-state renewable energy generation to reach only 5 percent by 2020. Because North Carolina's RPS alone sets the regional target for the entire Southeast region, EPA's target is roughly 100 percent too high for eight states. This is not a minor error. North Carolina and other states have built cost-control mechanisms into their RPS goals in order to reduce the requirements for utilities if compliance becomes too burdensome. *Id.* EPA did not account for any of these flexible compliance mechanisms when dictating regional renewable energy generation targets.

Third, EPA's methodology is flawed because it requires states to begin increasing renewable energy generation by 2017, three years before the compliance period begins for the Proposed Guidelines. To put this timeline in perspective, initial state plan submissions are not due to EPA until June 30, 2016, and EPA is allowing itself until June 30, 2017, to take final action approving or disapproving these plans. 79 Fed. Reg. at 34,915-16. Thus, EPA's proposed rule would require states to begin implementing their plans before they have even received the Agency's approval. The disconnect is even greater in light of the fact that states may delay plan submission until June 30, 2017 (for various reasons), or June 30, 2018 (for multi-state plans), pushing final EPA approval of these plans to mid-2018 or -2019. *Id.* at 34,915. In addition, building new renewable energy generation capacity requires several years to allow for planning, obtaining funding, seeking regulatory approval, and construction. Increasing Renewable Energy capacity will also require new transmission infrastructure, which can require 8-10 years to complete, as described in Section XIV.B above. In effect, states would have needed to begin efforts to implement Building Block 3 several years ago. This is plainly unreasonable.

ED_000419-0005935

Due to these issues, EPA's proposed renewable energy generation goals are drastically higher than the states can achieve within EPA's proposed timeline. Comparing present-day estimates of the expected baseline renewable energy growth to the renewable energy totals EPA applies in Building Block 3 reveals just how unreasonable, arbitrary, and capricious the Agency's estimates of potential renewable energy generation are. The Marchetti Report compares estimated renewable energy generation under Building Block 3 assumptions in the EIA's *Annual Energy Outlook (AEO) 2013* baseline analysis, and in EPA's IPM runs projecting the results of state-focused implementation of the Proposed Guidelines (State Option 1). Marchetti Report at 28-30, Tbl. 13 & Fig. 2. Under Building Block 3, EPA proposes to find that states can increase nationwide renewable energy generation from 217,868 GWh in 2012 to 522,723 GWh in 2029, with an annual growth rate from 2020 to 2029 of roughly 7.1 percent. *Id.* at 28. In stark contrast, the EIA projects that under the status quo, nationwide renewable energy generation will reach only 385,433 GWh in 2029, with an annual growth rate of only 1.5 percent from 2020 to 2029. *Id.* at 29, Tbl. 13. EPA's own "Base Case" modeling predicts even less renewable energy growth under status quo conditions, with only about 350,000 GWh in 2029 and an annual growth rate of 1.7 percent. RIA at 3-27. Although states may have some available measures at their disposal that could lead to *some* incremental increase in renewable energy generation from the status quo over this timeframe, expecting the nation as a whole to *nearly quintuple* its annual growth rate for renewables and increase its expected renewable energy generation by more than one third over projected levels is simply unreasonable.

This same pattern holds true for individual states. The Marchetti Report also contrasts EPA's estimated renewable energy generation under Building Block 3 for Georgia and Alabama

with a comparable baseline regional estimate from the EIA's *AEO 2013*.[50] Marchetti Report at 30-31 & Tbl. 14, Fig. 3. Under Building Block 3, EPA expects Georgia and Alabama together to increase renewable energy generation from 6,055 GWh in 2012 to 26,523 GWh in 2029, for an annual growth factor from 2020 to 2029 of 11.4 percent. But EIA's baseline projection forecasts renewable energy generation of only 18,700 GWh in 2029, for an annual growth factor of 2.0 percent. EPA cannot establish that increases of this magnitude are achievable—particularly because, as discussed in the next section, the Agency has failed to provide any parsed analysis of its IPM model runs for 2030 that would allow states to assess the impact of these required increases. Indeed, EPA has provided data for only 4 of the 25 IPM model runs that it performed as support for the Proposed Guidelines.

Finally, in addition to the regional RPS-based approach to developing Building Block 3 goals that EPA used to calculate and justify its Proposed Guidelines, EPA also solicits comment on an "alternative approach" to quantifying achievable renewable energy generation. 79 Fed. Reg. at 34,869-70; Alternative RE Approach Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602-0458 ("Alternative RE Approach TSD"). EPA has not applied this alternative renewable energy approach to calculate an alternative set of proposed state CO_2 emission goals, and therefore it cannot promulgate final state CO_2 emission goals based on this alternative renewable energy approach without first issuing a supplemental proposal publishing such alternative state goals for comment. UARG reserves the right to comment more extensively on the alternative renewable energy approach in any supplemental proposal that EPA would publish.

---

[50] The *AEO 2013* SERC Reliability Corporation – Southeastern includes most of Alabama and Georgia, plus a small section of eastern Mississippi and the Florida panhandle.

UARG notes, however, that the alternative approach to quantifying state renewable energy potential is also arbitrary and unreasonable. The alternative approach would set each state's renewable energy generation target at the lesser of two calculated values. The first calculation is based on a National Renewable Energy Laboratory ("NREL") GIS-based study estimating state renewable energy technical potential by technology type (solar, wind, etc.). EPA would: (1) identify each state's technology-specific renewable energy potential for each technology; (2) determine each state's current "development rate" for each type of technology based on 2012 generation data; (3) establish a "benchmark rate" of development for each technology type based on the top 16 states; (4) apply this benchmark rate uniformly to states for each technology type to develop target generation levels for each technology; and finally (5) add the state's target generation level for each technology type to determine the state's overall renewable energy generation target. Alternative RE Approach TSD at 1-2. The second calculation is based on the results of IPM runs that assume the cost of new renewable builds of each renewable energy technology type is reduced by "the avoided cost of other actions that could be taken instead to reduce power sector CO_2." *Id.* at 2.

Neither calculation provides a reasonable method to determine achievable renewable energy generation targets for states. The approach that relies on the NREL GIS-based study would arbitrarily apply a set of uniform benchmark development rates to all states across the country without considering whether the states used to set the benchmark rates for each technology type are representative of the rest of the country. EPA would not consider factors that may lead some states to develop specific renewable energy technologies more than others. In addition, this approach adds estimated renewable energy potential across various technology types, even though the NREL study warns (and EPA acknowledges) that these estimates *cannot*

ED_000419-0005938

be added together because they may double count available land for use by multiple renewable energy technologies. *See id.* at 2 (estimates "may overstate electricity production potential because a given site cannot produce RE simultaneously from multiple technology types"); Anthony Lopez, *et al.*, NREL, U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis, at 2 (July 2012), *available at* http://www.nrel.gov/gis/re_potential.html ("the same land area may be the basis for estimates of multiple technologies"). Likewise, the IPM-based approach is arbitrary because EPA does not provide any justification for its assumptions regarding reduced costs for new renewable energy generation.

2. EPA Has Not Provided All of the Data Needed To Evaluate the Proposed Guidelines in Violation of Section 307(d)(3) of the CAA.

EPA must provide the basis and purpose for the Proposed Guidelines under section 307(d)(3) of the CAA. The basis and purpose must include "a summary of . . . the factual data on which the proposed rule is based; . . . the methodology used in obtaining the data and in analyzing the data; and . . . the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3). EPA's failure to include the data for 21 of its modeling runs has affected UARG's ability to comment meaningfully on the Proposed Guidelines. In response to a request from UARG under the Freedom of Information Act, EPA responded that it had not parsed the 21 modeling runs, which is why those data are not included in the docket. Letter from Karen Orehowsky, Deputy Dir., Clean Air Markets Div., EPA to Craig S. Harrison, Hunton & Williams LLP (Aug. 12, 2014) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Without such parsed data, however, EPA cannot have conducted a reasonable inquiry into the achievability of Building Block 3. This is an egregious failure to comply with section 307(d)(3), and will render any final rule unlawful. EPA is "play[ing] hunt the peanut with technical information, hiding or disguising the information that it

ED_000419-0005939

employs," and is "treat[ing] what should be a genuine interchange as mere bureaucratic sport." *Conn. Light & Power Co. v. Nuclear Regulatory Comm'n,* 673 F.2d 525, 530 (D.C. Cir. 1982).

The four parsed IPM runs that are available demonstrate that the Agency's Building Block 3 targets are far too costly and do not represent realistic estimates of the potential renewable energy generation available to achieve the Proposed Guidelines. EPA performed IPM modeling runs to assess how states would comply with the Proposed Guidelines under both state-focused and region-focused compliance approaches. Thus, the results of these IPM runs constitute EPA's estimate of representative scenarios in which the power sector is operating in compliance with the Proposed Guidelines at the least cost possible, within the constraints EPA imposes on the model.

IPM model runs predict that actual renewable energy generation growth will meet only a small fraction of EPA's target under the least-cost approach to compliance with the Proposed Guidelines. IPM predicts that under both the state-focused and region-focused compliance approaches, renewable energy generation will reach only 356,063 GWh by 2029, and will grow at an annual rate of 1.1 percent from 2020 to 2029, far short of EPA's target of 522,723 GWh by 2029. Marchetti Report at 29, Tbl. 13. This level of generation is only 1.7 percent greater than the renewable energy generation that EPA predicts in 2029 under its own Base Case analysis, and is *actually 7.6 percent lower* than the EIA predicts will occur in 2029 *in the absence of any emission guidelines. See id.*; RIA at 3-27. EPA's own analysis severely undermines the Agency's prediction of the level of increased renewable energy generation that is achievable, and demonstrates that the Agency has failed to accurately consider factors such as cost and feasibility. The IPM results suggest that rapid growth in renewable energy generation is so costly that states are able to achieve only negligible incremental increases in renewable energy

generation above the status quo (at best), and they must instead rely more heavily on other components of EPA's selected BSER in order to comply with the Proposed Guidelines. This, in turn, will increase the cost of those other Building Blocks in ways that EPA has failed to analyze in the Proposed Guidelines.

EPA must withdraw the Proposed Guidelines because they impose arbitrary, capricious, and unachievable renewable energy generation targets.

D. EPA Correctly Excluded Natural Gas Conversion and Co-Firing From Its Proposed BSER Determination.

EPA states that it "does not propose to consider [natural gas conversion or co-firing at coal-fired utility boilers] part of the best system of emission reduction adequately demonstrated for existing EGUs." 79 Fed. Reg. at 34,875. This conclusion is due largely to the high costs of implementing such a conversion. However, EPA "solicit[s] comment on whether natural gas co-firing or conversion should be part of the BSER." *Id.* at 34,876.

UARG agrees that natural gas conversion and co-firing are not BSER for coal-fired EGUs and should not be included in the Proposed Guidelines. Although sources should have the option to voluntarily use these measures to comply with CO_2 emission standards, natural gas conversion and co-firing are extremely costly and are appropriate only for certain EGUs based on site-specific factors. *See* Lowell L. Smith, "Overview of Natural Gas Conversion Options To Meet Emission Requirements on Coal-Fired Electric Generating Units" (Nov. 2014) ("Smith Report") (Attachment H).

XV. Issues Raised by EPA's October 30, 2014 Notice of Data Availability

Late in this rulemaking process EPA issued a "notice of data availability" ("NODA"), 79 Fed. Reg. 64,543-53 (Oct. 30, 2014). For the most part, NODA is a misnomer; it contains

ED_000419-0005941

virtually no discussion of any relevant new "data,"[51] but instead is described as a means to "provid[e] additional information on several topics raised by stakeholders." *Id.* at 64,543. The NODA identifies three topics that the Agency says have been raised either in public or private meetings with certain unnamed stakeholders: (1) "the emission reduction compliance trajectories created by the interim goal for 2020 to 2029"; (2) "certain aspects of the building block methodology"; and (3) "the way state-specific [CO_2] goals are calculated." *Id.* Although some of the stakeholders' suggestions regarding EPA's Proposed Guidelines might have profound effects on the requirements that states and regulated entities might have to meet in any final guidelines, the Agency has not budged on its December 1, 2014 deadline for comments on the Proposed Guidelines or on the NODA itself. *Id.* In any event, the NODA contains no EPA proposals or proposed regulatory language but rather is musings about different policies that the Agency might prefer. These seem more appropriate for an advance notice of proposed rulemaking rather than a NODA on the eve of a comment deadline. Most of the suggestions that are discussed in the NODA cannot be pursued without EPA undertaking additional analyses after which it could re-propose the rule for comment. *See* CAA § 307(d)(3).

A. General Issues

As UARG stated in a November 13, 2014 letter to the EPA Administrator, EPA should provide the public with more time to comment on the issues raised in the NODA.[52] Letter from Allison D. Wood, Hunton & Williams LLP, to Regina A. McCarthy, Adm'r, EPA at 2 (Nov. 13, 2014). Although the Agency has not proposed any *specific* changes to its original June 18, 2014

---

[51] By way of contrast, EPA released valuable data in its Translation TSD, which it noticed in 79 Fed. Reg. 67,406 (Nov. 13, 2014).

[52] EPA rejected this request. Letter from Janet McCabe, Acting Assistant Adm'r, EPA to Allison D. Wood, Hunton & Williams LLP (Nov. 18, 2014) (included in UARG's separately filed Supplemental Materials for the Rulemaking Record).

ED_000419-0005942

Proposed Guidelines, UARG members need additional time to prepare fully informed and well-considered comments on the issues that have been raised for the first time in the NODA. The October 30, 2014 Federal Register notice was published barely a month before the due date for comments. The Proposed Guidelines are extraordinarily complex and, as discussed below, the issues raised in the NODA on which EPA solicits comment are very broad, seem to contain some approaches that are either new or that contradict its previous positions, and ultimately obscure to the point of incoherence what approach EPA might ultimately take. Obscuring what action an agency might take late in a comment period does not provide adequate notice to the public, is not reasoned decisionmaking, and provides no grounds for EPA to assert that its unsupported policy musings are a logical outgrowth of the original proposal.

EPA acknowledges that the various alternative approaches the Agency is now contemplating in the NODA could fundamentally alter the proposed emission guidelines and lead to more stringent goals for all or some states. 79 Fed. Reg. at 64,544. EPA also recognizes that many issues in the NODA—and the four Building Blocks generally—"interact with each other." *Id.* Realistically there is no way to assess how stringent any state's goals will actually be until EPA provides greater certainty on its preferred approach. Because of this fundamental ambiguity, EPA cannot finalize any of the changes discussed in this NODA without issuing a supplemental proposal that clarifies the Agency's position, provides the basis and purpose for its approach pursuant to CAA section 307(d)(3), provides specific details of how each state would be affected, provides sufficient economic analysis of the changes, and provides proposed regulatory text. None of these things are present in the NODA.

UARG is pleased that EPA appears to recognize some of the legal flaws and irrational consequences inherent in the Proposed Guidelines. For example, EPA now appears to recognize

ED_000419-0005943

that the Proposed Guidelines do not consider the remaining useful lives of existing EGUs, despite the explicit statutory command to do so in section 111(d)(1)(B) of the CAA. *Id.*; *see also id.* at 64,549. The Agency has discovered that if finalized the Proposed Guidelines would create an enormous stranded asset problem with the required shutdown of many coal-fired EGUs that have recently been constructed or have recently received significant capital investment to comply with other EPA regulations, such as the MATS Rule and measures to reduce emissions of visibility-impairing pollutants. *Id.* at 64,546. EPA now concedes that its requirement for redispatch in Building Block 2 will in many situations distort regional electricity markets. *Id.* at 64,549. Finally, the Agency now seems to acknowledge that the Proposed Guidelines render illusory its oft-stated purpose of providing states with flexibility with respect to time and emission reduction strategies. *Id.* at 64,544. For all of these reasons and for the reasons stated elsewhere in these comments, EPA should withdraw the Proposed Guidelines, resolve the many problems that it has finally recognized, and propose a fundamentally different approach. EPA's scattershot efforts to date fail to satisfy the basic elements of notice and comment rulemaking. *See* CAA § 307(d)(3); 5 U.S.C. § 553.

B. Building Block 2 Issues: New NGCC and Co-Firing as Components of BSER

The NODA solicits comment "on ways that building block 2 could be expanded to include new NGCC units and natural gas co-firing in existing coal-fired boilers." 79 Fed. Reg. at 64,545. EPA's discussion suggests that BSER should be based on "the cost and feasibility of the total amount of natural gas used, as opposed to the extent to which the gas is used for particular types of generation (i.e., existing NGCC generation, new NGCC generation, or co-firing)." *Id.* at 64,549. EPA claims that requiring new NGCC and co-firing as part of the BSER would be "more consistent with historic NGCC deployment, better reflect growing geographic availability of natural gas supply, contribute to expanded generation fuel diversity in states that currently

have relatively little NGCC capacity, and offer more cost-effective emission reductions." *Id.* Under this new approach, raised for the first time in the NODA but not formally proposed, in addition to shifting generation from existing coal-fired units to existing NGCC units until the NGCC units reach a 70% capacity factor, Building Block 2 would also assume "some minimum value as a floor for the amount of generation shift for purposes of building block 2, whether that shift takes the form of redispatch from steam generation to existing NGCC units, re-dispatch to new NGCC units, or co-firing natural gas in existing coal-fired boilers." *Id.* at 64,550. The minimum floor for redispatch away from coal-fired units would be expressed as a percentage of the state's fossil steam generation. EPA specifically solicits comment on a minimum value of 12 percent (the shift observed by the lower quartile of states with some redispatch under the current Proposed Guidelines), but requests comment on a vast range of possibilities between 0 and 55 percent. *Id.*

This approach is both unlawful and unreasonable. As discussed in Section X, EPA has no authority to impose federally enforceable obligations on *new* sources (such as new NGCC units) under section 111(d). Nor does EPA have authority under section 111(d) to require the construction of any new source. By its explicit terms, section 111(d) (entitled "Standards of performance for existing sources; remaining useful life of source") applies only to existing sources, which the CAA defines to be mutually exclusive of new sources. A state plan "establishes standards for performance for any *existing source* . . . ." CAA § 111(d)(1)(A) (emphasis added). EPA erroneously suggests that constructing a new NGCC unit can be considered to be a "system of emission reduction" under section 111. *See* 79 Fed. Reg. at 64,550. As discussed in Section III, a "system of emission reduction" is limited to activities that can be implemented at the source itself. The approach EPA discusses would require owners to

ED_000419-0005945

go beyond the source itself and construct an entirely new source to replace it. EPA's glib claim that a source owner "may invest in new NGCC units," *id.*, does not mean that replacing an affected EGU's generation with generation from a new facility can be required under CAA section 111.

Moreover, EPA's suggestion that natural gas co-firing at existing boilers can be designated as BSER, *id.*, is wrong both as a matter of fact and of rulemaking procedure. Co-firing has not been adequately demonstrated for the source category as a whole, and EPA has failed to provide any justification for any such determination as required by section 307(d)(3) of the CAA (EPA must provide the basis and purpose for the proposed guidelines). The fact that owners or operators of certain individual units have determined co-firing to be feasible and economic does not imply by any stretch of the imagination that co-firing is an adequately demonstrated system of emission reduction. EPA for decades has implemented section 111 such that any NSPS "establishes what every source can achieve, not the best that a source could do." Letter from Gary McCutchen, Chief, New Source Review Section, EPA OAQPS, to Richard E. Grusnick, Chief, Air Div., Ala. Dep't of Envtl. Mgmt. at 1 (July 28, 1987), *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/crucial.pdf (included in UARG's separately filed Supplemental Materials for the Rulemaking Record). Natural gas co-firing is far too expensive to qualify as BSER (or as a component of the combined BSER EPA is proposing) for coal-fired EGUs. EPA recognized this in the Proposed Guidelines when it specifically rejected co-firing and conversion as BSER. The Agency noted that that:

> [T]here are more cost effective opportunities for coal-fired utility boilers to reduce their CO_2 emissions than through natural gas conversion or co-firing. As a result, the EPA has not proposed at this time to include this option in the BSER and has not incorporated implementation of the option into the proposed state goals.

ED_000419-0005946

79 Fed. Reg. 34,875. EPA similarly rejected proposing natural gas co-firing as BSER for modified and reconstructed coal-fired EGUs. The Agency noted that:

> While conversion to or co-firing with natural gas in a utility boiler is a technically feasible option to reduce CO_2 emission rates, it is an inefficient way to generate electricity compared to use of an NGCC and the resultant CO_2 reductions are relatively expensive. The EPA found costs for natural gas co-firing to range from approximately \$83/ton to \$150/ton of CO_2 avoided. Even for cases where the natural gas could be co-fired without any capital investment or impact on the performance of the affected facility (e.g., an existing IGCC facility that already has a sufficient natural gas supply), the costs of CO_2 reduction would still be approximately \$75/ton of CO_2 avoided.

79 Fed. Reg. at 34,982 (citation omitted). Even at the low end of the range cited by the Agency these costs are clearly too high for an NSPS. Indeed, if EPA has determined that co-firing is inappropriate as BSER for modified and reconstructed Subpart Da units, which pursuant to section 111(a)(2) are deemed to be *new* units, it certainly cannot be deemed to be BSER for *existing* Subpart Da units.

Some environmental groups and states have asked EPA to include in its consideration of the costs with regard to BSER "some benefits associated with the co-firing of natural gas with coal" such as "reduc[ing] emissions of nitrogen oxides (NOx); sulfur dioxide (SO_2); particulate matter; and hazardous air pollutants, including mercury." 79 Fed. Reg. at 64,550. As discussed in Section XII.C., EPA's purported co-benefits cannot be attributed to the Proposed Guidelines, and in any event are inappropriate in its making a BSER determination.

Finally, EPA solicits comment "on other factors or variables that might affect the decision to use natural gas in co-firing at a particular unit (e.g., type, age, or size of a boiler), as well as factors that could limit the amount of co-firing that could be done." *Id.* There are technical challenges in converting a coal-fired boiler to burn natural gas, whether to co-fire both coal and natural gas through separate burners, dual fuel fire both coal and gas in the same burner,

fire either coal or gas, or fire only natural gas. These technical issues must be evaluated on a case-by-case basis, taking into consideration the remaining anticipated useful life of the unit. Potential necessary alterations can concern the following: (1) initial boiler design; (2) burner design; (3) gas piping; (4) burner management; and (5) boiler and combustion controls. Smith Report at 2. Depending upon the specific boiler design, changes to a coal-only designed boiler to accommodate natural gas firing may include alterations to the following: (1) convective pass (superheat, reheat, attemperation, etc.); (2) fuel supply system; (3) control system; (4) burners; and (5) emission control systems. *Id.* at 4. With respect to the availability of natural gas, the following must be considered: (1) proximity of a major gas pipeline; (2) capacity of the source pipeline; (3) regional breakdown between residential and industrial natural gas use; (4) long-term natural gas supply availability; (5) potential for interruptible natural gas supply; and (6) costs and benefits of alternative emission reduction methods. *Id.* If EPA wishes to pursue the possibility of including natural gas co-firing at existing boilers as BSER, it must undertake a thorough engineering and cost evaluation, as required by section 307(d)(3) of the CAA, and allow UARG a sufficient period of time to evaluate and comment on those studies.

C. Issues Regarding an Alternative "Glide Path" to Compliance

EPA's NODA seems to recognize for the first time that the Proposed Guidelines' interim goals (to be met on average from 2020 to 2029) deny states the implementation flexibility and safeguards for reliability that the CAA requires. This result is the opposite of what EPA states it intended to preserve in the Proposed Guidelines. *See* 79 Fed. Reg. at 64,545. The Agency claims that its intent in proposing to require compliance with an interim goal is to "provide states with a reasonable glide path to compliance with their final goals by 2030." *Id.* at 64,548. Yet EPA fails to explain why interim goals are necessary to achieve the Proposed Guidelines' ultimate goal. For the reasons discussed in Sections XIII and XIV of these comments, EPA

ED_000419-0005948

should eliminate entirely any interim goals for states. Such requirements can severely limit a state's flexibility and ability to respond to reliability concerns, which EPA disingenuously claims is an overriding goal of the Proposed Guidelines.

This NODA is the first time that EPA has discussed the use of a "glide path" for states to comply with the 2030 final goals, and the Agency has neither formally nor informally defined that term. The Agency, however, often uses the phrase "glide path" in other CAA contexts. For example, "glide path" is commonly employed with respect to the "reasonable progress goals" in state implementation plans addressing regional haze requirements. *See* 40 C.F.R. § 51.308(d)(1). In the regional haze context, the states, rather than EPA, play the primary role in determining whether their own glide path toward attaining natural visibility conditions may deviate from a uniform rate of improvement, based on considerations of "costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources." *Id.* § 51.308(d)(1)(i)(A). UARG believes that if any final emission guidelines were to include interim goals, that they should be flexible and allow states to comply using a reasonable glide path. Each state should have the authority to define its own glide path using criteria such as costs, energy impacts, and the remaining useful life of affected sources. Final guidelines that allowed such a glide path would be a logical outgrowth of the Agency's June 2014 Proposed Guidelines.

Regarding Building Block 2, EPA suggests ways to reduce the negative consequences of requiring an interim goal: (1) allowing credit for early CO_2 emission reductions; and (2) phasing in Building Block 2 over time rather than assuming full redispatch by 2020. 79 Fed. Reg. at 64,545. If EPA does not abandon interim goals, UARG urges the Agency to adopt both of these changes in the final guidelines. First, UARG supports providing full credit for early actions that

ED_000419-0005949

result in reduced CO_2 emissions before the compliance period begins in 2020. This relaxation from the proposed approach alone, however, will not significantly alleviate the negative consequences of EPA's proposed interim goals. The timeline between final state plan approval (which, for many states, may not occur until mid-2018 or later) and 2020 is far too short for states to implement significant action to encourage implementation of early emission-reducing measures that would counteract the Agency's stringent interim goal requirements. EPA should provide for redispatch under Building Block 2 to be phased in, rather than be fully implemented by 2020. As EPA now appears to recognize, requiring full redispatch by 2020 makes it impossible for some states to meet the interim goal because of "technical, engineering, and infrastructure limitations." *Id.* at 64,546. One consequence of EPA not phasing in redispatch would be the required shutdown of many coal-fired units that "have recently been constructed" or "have received significant capital investment (e.g., in the form of pollution control retrofits)." *Id.* Full redispatch by 2020 is simply unachievable and bad public policy.

EPA should allow the states to determine how quickly Building Block 2 may be phased in. The Agency suggests that an appropriate phase-in schedule could be based on "whether, and to what extent, any additional infrastructure improvements (e.g., natural gas pipeline expansion or transmission improvements) are needed to support more use of existing natural gas-fired generation," or on avoiding stranded investments considering the "book life" of generating assets. *Id.* at 64,548-49. States are in a much better position than EPA to assess these factors and determine an appropriate phase-in schedule. EPA gives no indication as to how it would go about assessing these factors and developing a phase-in schedule on its own for the states.

UARG is pleased that EPA seems to have discovered that section 111(d)(1) requires EPA to "take into consideration, among other factors, the remaining useful life of the existing source

ED_000419-0005950

to which [a] standard applies." CAA § 111(d)(1). UARG strongly objects, however, to the Agency's apparent suggestion that book life is an appropriate means of implementing this statutory mandate. Book life is an accounting and ratemaking concept that concerns depreciation. It does not describe the end of useful life of an asset, which should be determined on a case-by-case basis. Moreover, the statutory mandate to consider the remaining useful life by implication includes the discretion to exempt such sources from regulation.

UARG also supports altering the Proposed Guidelines to provide for the gradual phase-in of heat rate improvements under Building Block 1. 79 Fed. Reg. at 64,548. Efficiency improvement measures require significant time and investment to implement, including planning, contracting with vendors to perform this work, and scheduling outages in which it can be performed. Under the Proposed Guidelines, every coal-fired EGU that is not retired would be expected to implement these measures by 2020. This would place an enormous strain on the energy grid as numerous units go down for outages at once in order to implement these measures by 2020. Units would be reluctant to begin this work before a final state plan is approved, which in many states may not occur before mid-2018 (and in states with multi-state agreements may not occur before mid-2019). NERC just issued a report that emphasizes that EPA's Proposed Guidelines pose a serious obstacle to the reliable supply of electricity in this nation. Initial NERC Report at 9-10, 22. NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. Among its findings in its Executive Summary are that under EPA's Proposed Guidelines: (1) essential reliability services may be strained; and (2) more time for implementation may be needed to accommodate reliability enhancements. *Id.* at 2-3; *see also* Section VII.B.4 (discussing Initial NERC Report).

ED_000419-0005951

D. Regionalized Approach to Building Blocks 2 and 3

EPA solicits comment on a third "regionalized" approach to RE in Building Block 3. The Agency's new approach was not included in the June 14 Proposed Guidelines and is not actually proposed in the NODA. Under a "regionalized" approach, EPA would "adjust[] each state's RE target based on the RE potential available across a multi-state region in which the state is located" rather than attempting to determine what level of renewable energy could be generated within the state itself. 79 Fed. Reg. at 64,551. This approach would "group states into regions; aggregate RE generation potential across states within each region; and then reapportion the aggregate identified RE generation to individual states according to criteria that assume regional RE development in which parties in multiple states participate, regardless of the specific state where the generation occurs." *Id.* EPA believes this approach would "better align RE targets with the proposal to allow the use of certain out-of-state renewables for compliance." *Id.*

Similarly, EPA solicits comment on using a regional approach to redispatch under Building Block 2 that would include requiring redispatch across state lines. Again, EPA does not actually propose this approach and merely seeks comment on an approach whereby "regional availability of NGCC generation would be considered rather than just in-state availability of NGCC generation in setting building block 2 targets." *Id.* at 64,550. Under this approach, the levels of required generation shift under Building Block 2 could be determined in at least three different ways—using six regions whose borders are informed by NERC regions, RTOs, or some alternative regional structure. *Id.* at 64,551. The Agency explains that using regional approaches could "mitigate the concerns expressed" by certain unnamed stakeholders "that building block 2 has little or no effect on certain states with large amounts of coal-fired generation and limited excess NGCC capacity." *Id.*

ED_000419-0005952

As noted, EPA has neither proposed any of the regional approaches on which it requests comment nor has it provided sufficient information such as technical analyses that UARG needs to allow it to comment in a meaningful way. The Agency provides no direction on how states might be grouped into regions, instead listing four significantly different options and also soliciting comment on "some other approach." *Id.* EPA does not specify how the aggregate RE generation potential across states within each region might be calculated. The Agency does not specify what criteria would be used to reapportion aggregate RE generation into state goals, instead asking commenters for direction on "a simple state-specific quantitative characteristic that reflects interstate patterns to develop RE potential at reasonable cost across a region." *Id.* And EPA does not specify what components of a state's RE targets would be "regionalized" under this approach. *Id.* at 64,551.

The questions posed in the NODA reveal the incomplete nature of the entire Proposed Guidelines. EPA asks a long series of questions concerning many different approaches, the permutations and combinations of which are staggering in number. The Agency seems to try to shift the burden of justifying its Proposed Guidelines to the regulated community. EPA's musings and requests for thoughts on a variety of different approaches essentially show that the Agency has little if any idea how its Proposed Guidelines might work. The Agency's failure to complete the necessary background work suggests that a more appropriate course of action at this time would have been to issue an advance notice of proposed rulemaking designed to elicit information to use in formulating a proposal, rather than to propose an approach that is both poorly-conceived and has not been fully analyzed by the Agency and then issue a NODA designed to elicit information. The process EPA has employed here is backwards.

ED_000419-0005953

Although UARG appreciates the Agency's interest in obtaining information necessary to develop a sound proposal, the myriad questions posed in the NODA confirm that EPA has failed to collect the data and perform the technical analyses needed to identify and analyze the impacts of the Proposed Guidelines. Most of EPA's questions with regard to various regionalized approaches cannot be answered without detailed analyses of emissions and other data that the Agency should have undertaken and placed in the docket as part of its basis and purpose of the Proposed Guidelines. CAA § 307(d)(3). In this regard, the APA defines a rule as a statement of "future effect" designed to "prescribe law or policy." 5 U.S.C. § 551(4). Because a rule is intended to prescribe the legal standards that govern the future conduct of regulated parties, a proposed rule must be more than a vague set of criteria for future applications with a series of questions regarding how the Agency might formulate a final rule. *See Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983) ("Agency notice must describe the range of alternatives being considered with reasonable specificity" to allow for adequate public comment and "better-informed agency decisionmaking"; unspecified, general notice is inadequate.). The Agency's Proposed Guidelines are entirely inadequate in this regard, and thus EPA should terminate this proceeding until it has had time to gather and analyze the data needed to formulate a proper proposed rule.

E. Goal-Setting Methodology

EPA's NODA solicits comment on whether EPA should alter its goal computation methodology in order to reduce generation more drastically from existing fossil fuel-fired EGUs. The Agency neither proposes this change in the NODA nor did it propose such an approach in the June 2014 Proposed Guidelines. Instead, the Proposed Guidelines implement Building Block 2 redispatch from coal to natural gas by "subtract[ing] 1 MWh of fossil steam generation and corresponding emissions from the 2012 baseline levels for every 1 MWh of incremental NGCC

ED_000419-0005954

generation." 79 Fed. Reg. at 64,552. This leaves the total level of overall generation in a state unchanged after implementation of Building Block 2. By way of contrast, the formula for Building Blocks 3 and 4 "incremental RE and EE to 2012 baseline generation levels . . . but does not reduce the 2012 baseline levels of fossil generation . . . by that incremental RE and EE, or remove the corresponding emissions." *Id.* EPA now solicits comment on an alternative approach in which "incremental RE and EE explicitly replaces generation from fossil fuel-fired sources in the goal calculation." *Id.* According to EPA, this approach would "reflect the full potential, under the BSER, for incremental RE and EE to replace fossil steam generation." *Id.*

EPA forthrightly recognizes that adopting this alternative approach would necessarily "increase the collective stringency of the state goals" and subsequently increase the costs of the Proposed Guidelines. *Id.* at 64,553. UARG agrees that if EPA were to adopt this alternative goal computation approach it would necessarily reduce (i.e., make more stringent) states' final and interim goals across the board, significantly increasing the costs of the Proposed Guidelines. This approach would further reduce the share of a state's generation that could come from existing fossil fuel-fired EGUs, and in states where that generation would already be significantly reduced due to other components of the Proposed Guidelines, the alternative approach could eliminate coal-fired generation altogether—just as Building Block 2 would already eliminate coal-fired generation in several states.

UARG opposes this approach for three reasons. First, as discussed in Section III.B, EPA has no authority to establish a standard of performance under section 111 based on reduced utilization (or retirement) of a source. Second, if EPA wishes to pursue such a dramatic change in its Proposed Guidelines, it must undertake a thorough evaluation of costs and other implications, as required by section 307(d)(3) of the CAA, and allow UARG a sufficient period

ED_000419-0005955

of time to evaluate and comment on those studies. UARG suspects there will be significant costs, including additional stranded assets, as well as additional threats to the reliable supply of electricity. It cannot intelligently and meaningfully evaluate these issues, however, without the additional analyses that EPA has failed to undertake. Third, beyond the likely very high additional costs, this alternative approach is nonsensical as a method to achieve EPA's apparent overarching goal of reducing generation from all fossil fuel-fired EGUs because it would have the counterintuitive effect of *encouraging* the construction of additional *new* fossil fuel-fired EGUs relative to EPA's June 2014 Proposed Guidelines. According to EPA, the rationale for its proposed goal computation approach (which adds incremental RE and EE to the goal formula without simultaneously reducing fossil generation) was that the additional RE and EE would replace expected generation increases from fossil sources that otherwise occur after 2012. *Id.* at 64,552. In other words, RE and EE would be used to meet future generation needs, while leaving the existing fossil EGUs to continue serving existing (i.e., pre-2012) load demand. The alternative approach on which comment is requested in the NODA would require that incremental RE and EE be used first to satisfy existing (i.e., pre-2012) demand by displacing generation from existing fossil EGUs. *Id.* If the incremental RE and EE spurred by the Proposed Guidelines is dedicated to meeting historical demand, any post-2012 increases in demand will need to be met by other sources. Because the proposed goals for RE and EE under Building Blocks 3 and 4 are already extremely aggressive, the most likely source for additional future generation is new fossil fuel-fired EGUs. Therefore, one likely outcome of the alternative approach discussed in the NODA would be to encourage the use of new fossil generation to satisfy future demand rather than RE—a policy outcome that seems to be at odds with EPA's overall goals.

ED_000419-0005956

XVI. Monitoring, Recordkeeping, and Reporting Requirements for EGUs

EPA proposes to require that state plans include monitoring provisions for EGUs that are no less stringent than those in its Proposed Guidelines at Subpart UUUU § 60.5805. According to EPA, monitoring under Part 75 and reporting to EPA's ECMPS would generally satisfy those requirements, with only a few exceptions. 79 Fed. Reg. 34,913.

Part 75 requires monitoring and reporting of CO_2 mass emissions (in tons per hour or tons per day) and hourly gross unit load from fuel combustion (in gross megawatt electrical or "MWge"). Although Part 75 does not specify a method for measuring unit load, EGUs routinely measure gross load with a watt meter (or meters). For CO_2 mass emissions, Part 75 provides four options.[53] First, any EGU may use a CO_2 CEMS and a stack flow monitoring system. For that option the CO_2 CEMS consists of a CO_2 concentration monitor and an automated data acquisition and handling system ("DAHS"). 40 C.F.R. §§ 72.2, 75.10(a)(3)(i), 75.13(a). Second, any EGU may use a CO_2 CEMS and a stack flow monitoring system, where the CO_2 CEMS consists of an oxygen ("O_2") concentration monitor and a DAHS. *Id.* §§ 75.10(a)(3)(iii), 75.13(a). EGUs that use an O_2 concentration monitor convert O_2 concentration to CO_2 concentration using fuel factors ("F-factor")[54] provided in Part 75, Appendix F § 3.3.5. *Id.* § 75.13(c) and pt. 75, App. F § 4.4.1. Appendix F, Table 1 provides F- and Fc-factors for most

---

[53] These methods also are described in detail in EPA's Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases at 5-9 (Jan. 30, 2009), Docket ID No. EPA-HQ-OAR-2008-0508-0004 ("EPA GHG MRR TSD").

[54] F-factors represent the ratio of gas volume to the calorific value of the fuel combusted. Identical F-Factors are used to calculate emission rates in all NSPS affecting EGUs. *See* 40 C.F.R. pt. 60, App. A-7, Method 19. An Fc-factor specifically represents the volume of CO_2 generated.

ED_000419-0005957

commonly used fuels, but also allows calculation of a site-specific F- or Fc-factor in the event one is not provided for a specific fuel. *Id.* pt. 75, App. F §§ 3.3.5., 3.3.6.

For options one and two, the CO_2 (in ppm or percent) and the volumetric stack flow (in standard cubic feet per hour) are used, along with a constant (or "K-factor") for CO_2 and, if CO_2 or O_2 concentration is measured on a dry basis, an hourly average stack moisture value (in percent H_2O) to determine hourly CO_2 mass emissions in tons per hour. *Id.* §§ 4.1 and 4.2. According to EPA, in 2006, eighty-five percent (85%) of total CO_2 mass emissions reported under Part 75 were reported using one of these two methods. EPA GHG MRR TSD at 6, Tbl. 4. That constitutes thirty-three percent (33%) of the total number of units reporting under Part 75. *Id.*

Third, any EGU that combusts only fossil fuel may determine CO_2 mass emissions based on the measured carbon content of the fuel and the procedures in Appendix G to estimate CO_2 in tons per day. 40 C.F.R. §§ 75.10(a)(3)(ii), 75.13(b). Under that procedure, carbon content based on analysis of a fuel sample collected at the specified period (e.g., per shipment or delivery for oil and gas delivered in lots, monthly for natural gas, and daily for other gases) and fuel feed rates using a fuel flow meter (for oil and gas) are used to determine CO_2 mass emissions in tons per day.[55] *Id.* pt. 75, App. G § 2.1. EGUs using wet FGD systems or a fluidized bed boiler must calculate and include CO_2 from sorbent. *Id.* § 75.13(b) and pt. 75, App. G § 3. According to EPA, in 2006, only one percent (1%) of CO_2 mass emissions reported under Part 75 was reported

---

[55] Coal-fired EGUs also are allowed to use this option under Part 75 using weekly coal sampling and company records of the amount of coal combusted. If this option were chosen, the EGU could adjust the estimated CO_2 for carbon retained in ash. 40 C.F.R. § 75.13(b) and pt. 75, App. G § 2.2. However, no Part 75 coal-fired EGU has opted to use this method. EPA, Plain English Guide to the Part 75 Rule at 13 (June 2009), *available at* http://www.epa.gov/airmarkets/emissions/docs/plain_english_guide_par75_final_rule.pdf ("Part 75 Plain English Guide").

ED_000419-0005958

using this method. EPA GHG MRR TSD at 6, Tbl. 4. That constitutes five percent (5%) of the total number of units reporting under Part 75. *Id.*

Fourth, any EGU that meets the definition of gas-fired or oil-fired[56] may determine CO_2 mass emissions using hourly heat input and the same F-factors referenced above (for EGUs using an O_2 concentration monitor). 40 C.F.R. pt. 75, App. G § 2.3. Heat input is determined using fuel feed rate and the gross calorific value of the fuel determined under Part 75, Appendix D with a certified fuel flow meter and fuel sampling and analysis, respectively. 40 C.F.R. § 75.13(b), pt. 75, App. G, Equation G-4, and App. F § 5. According to EPA, in 2006, fourteen percent (14%) of total CO_2 mass emissions reported under Part 75 were reported using this method. EPA GHG MRR TSD at 6, Tbl. 4. That constitutes fifty-nine percent (59%) of the total number of units reporting under Part 75. This Appendix G method is the most frequently used method for Part 75 gas- and oil-fired EGUs. Part 75 Plain English Guide at 13.

Although the CO_2 mass emission values reported under Part 75 are not used to determine compliance with any requirement under the Acid Rain Program ("ARP"), all the data used to calculate CO_2 mass emissions (except measured carbon and *daily* fuel use) also are used to calculate compliance with one or more emission limits under the ARP, and under other NSPS applicable to EGUs. Accordingly, EPA already has determined that the data are of sufficient quality for compliance calculations like those proposed in this rulemaking. States participating in the RGGI[57] trading program also rely on these Part 75 methods to determine compliance with that program's CO_2 mass emissions allowance holding requirement (although some states have

---

[56] Gas-fired and oil-fired EGUs do not include EGUs that combust coal, or solid or liquid coal-derived fuel, but do include EGUs that combust coal-derived gaseous fuel. 40 C.F.R. § 72.2.

[57] RGGI is a mandatory state CO_2 cap and trade program covering nine northeastern and mid-Atlantic States.

ED_000419-0005959

opted not to allow use of the Part 75 option for calculating *daily* CO_2 mass emissions under Appendix G § 2.1). Part 75 Plain English Guide at 12.

EPA's Proposed Guidelines generally recognize the adequacy of Part 75 data by proposing that states allow use of two of the four options allowed under Part 75, and by requiring compliance with Part 75 monitoring plan and quality assurance and quality control ("QA/QC") requirements. Based in part on this similarity, EPA's proposed information collection request ("ICR") assumes "no new information collection burden" beyond what already is required under Part 75 and the GHG Reporting Rule at 40 C.F.R. Part 98, at least for the first three years following final rule promulgation. EPA, Supporting Statement, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (40 CFR Part 60, Subpart UUUU) at 3 (May 2014), Docket ID No. EPA-HQ-OAR-2013-0602-0438 ("Proposed Existing Source ICR Supporting Statement"). EPA appropriately proposes not to allow use of Part 75 bias-adjusted data. Proposed Subpart UUUU § 60.5805(a)(2)(iv). However, in some instances, EPA proposes to require that states impose new requirements, some of which could increase burden and stringency beyond existing requirements once state plans are implemented. 79 Fed. Reg. at 34,913-14.

UARG supports EPA's proposal that states rely on Part 75 monitoring procedures, without bias adjustment,[58] but objects to the proposed elimination of one of those options and imposition of additional requirements for existing units. EPA has provided no justification for requiring states to impose on EGUs monitoring that is different from, let alone more stringent

---

[58] The bias adjustment factor is a one-way (positive) adjustment that was justified based on the ARP's status as a market-based program. In recognition of that fact, Part 75 does not require bias-adjustment of diluent or flow data used to calculate CO_2 mass emissions, and EPA has never required use of Part 75 bias-adjusted data to determine compliance under an NSPS. *See, e.g.,* 40 C.F.R. § 60.49Da(c)(2), (d), (m). This rule should be no different.

ED_000419-0005960

than, Part 75. UARG also objects to the Agency's failure to make clear that use of Part 75 missing data substitution procedures is not appropriate in compliance calculations.[59]

A. Proposed CO_2 Monitoring Methods

1. The CEMS Option

EPA proposes that states require existing EGUs that combust solid fuel (and to allow other existing EGUs) to monitor CO_2 mass emissions using a CO_2 concentration monitor, flow monitor, and (if applicable) a moisture monitoring system in accordance with Part 75. Proposed Subpart UUUU § 60.5805(a)(2)(i). As an alternative, EPA proposes to allow EGUs that combust only liquid or gaseous fuel to determine CO_2 mass emissions under the provision in Part 75, Appendix G § 2.3 that uses heat input determined under Part 75, Appendix D and a carbon-based F-factor to determine CO_2 mass emissions. *Id.* at § 60.5805(a)(3). UARG supports these options, but believes that EPA has unreasonably eliminated several other Part 75 options.

UARG does not oppose requiring solid fuel-fired EGUs, or allowing other EGUs, to use CEMS. Part 75 and Subpart Da already require solid fuel-fired units to use CEMS to determine compliance with other requirements. However, UARG does not understand why EPA has specifically required use of a CO_2 CEMS (and not allowed use of an O_2 CEMS to obtain CO_2) at an EGU that *does not* use carbon separation.[60] Both existing NSPS applicable to EGUs—

---

[59] In the proposed GHG NSPS for new, modified and reconstructed sources under CAA § 111(b) EPA made clear that Part 75 missing data substitution procedures cannot be used. *See, e.g.,* 79 Fed. Reg. 1430 (Jan. 8, 2014), Proposed Subpart TTTT § 5540(a)(1), Subpart Da § 60.46Da(g)(1)(i), Subpart KKKK § 60.4374(a)(1); Memorandum from EPA OAQPS to EGU NSPS Docket (EPA-HQ-OAR-2013-0603), "Amended Regulatory Text (Proposed Applicability)" (June 2014), Docket ID No. EPA-HQ-OAR-2013-0603-0044. UARG assumes that the failure to prohibit use of substitute data was an oversight.

[60] An O_2 CEMS cannot be used to obtain accurate CO_2 measurement at the stack of an EGU that employs carbon separation because the calculation to convert O_2 measured at the stack to CO_2 relies on the use of F-factors. *See, e.g.,* 40 C.F.R. pt. 75, App. F § 4.4. Any equation that

ED_000419-0005961

Subparts Da and KKKK—allow use of either a CO_2 concentration monitor or an O_2 concentration monitor as the diluent monitor to calculate emissions in lbs per MMBtu. And, Part 75 explicitly allows use of an O_2 concentration monitor to measure CO_2 concentration to obtain CO_2 mass emissions. There is no valid reason not to allow both types of monitoring systems under this rule as well. Although most coal-fired EGUs opt to use CO_2 concentration monitors,[61] there are valid reasons an EGU (particularly a gas- or oil- fired EGU) might prefer an O_2 monitor. Oxygen analyzers generally cost less, are more stable, and are less affected by interferences (e.g., H_2O and CO) that can impact CO_2 measurements. EPA could easily add an option for use of an O_2 monitor simply by adding a reference to § 75.10(a)(3)(iii) in Proposed Subpart UUUU § 60.5805(a)(2).

UARG also is concerned that the proposed language requiring EGUs that measure CO_2 concentration on a dry basis to "install, certify, operate, maintain, and calibrate a continuous moisture monitoring system" under § 75.11(b), Proposed Subpart UUUU § 60.5805(a)(2)(i), could be interpreted as eliminating the option in § 75.11(b)(1) to use appropriate default moisture values rather than installing and calibrating a monitoring device. The Part 75 default moisture values for coal and wood were derived from the Agency's own evaluation of data in a 1999 rulemaking in which the Agency determined that they were sufficiently conservative to ensure no under-reporting. 64 Fed. Reg. 28,564, 28,567, 28,568, 28,590 (May 26, 1999). EPA

---

uses an F-factor will not provide accurate measurements downstream of any device that removes CO_2 from the gas stream. However, UARG does not expect any existing EGU to employ carbon sequestration.

[61] Dilution-based CO_2 concentration monitors are the monitoring system of choice for coal-fired EGUs because they measure on a wet-basis. Dilution systems are often the only reasonable choice for EGUs with wet FGD because they eliminate plugging and other issues associated with corrosive flue gas conditions. Dilution systems cannot measure O_2 because the dilution air contains O_2.

ED_000419-0005962

approved the default moisture value for natural gas (boilers only) in 2008 based on data submitted to EPA. 73 Fed. Reg. 4312, 4315, 4342 (Jan. 24, 2008). UARG can think of no reason why EPA would eliminate this option for existing units, and hopes that the reference to installing and calibrating systems was not intended to eliminate use of the default values.

If the Agency has a reason for eliminating the O_2 monitoring and moisture default value options for either coal-fired EGUs or liquid and gas-fired EGUs, EPA must issue a rulemaking proposal identifying that reason so that UARG can comment on the Agency's rationale. Because existing EGUs still will need to comply with the ARP, eliminating these options in state plans effectively eliminates them in Part 75.

For EGUs using CEMS, EPA proposes a new requirement to measure the dimensions of each stack or duct at the flow monitor and reference method sampling location using a laser device at "three or more distinct locations and average the results." Proposed Subpart UUUU § 60.5805(a)(2)(iii). UARG objects to this provision. A requirement for a one-time measurement to establish stack diameter and area at one location using a laser device would not be unreasonable, if EPA had established that such devices are more accurate than other measurement methods and are not overly burdensome. EPA's rulemaking record, however, contains no evidence that existing methods are not sufficiently accurate, and no evidence that laser devices would provide significantly more accurate results. As a result, it appears that the requirement imposes additional cost and burden with no corresponding benefit. UARG also has concerns that measurements taken with a laser device while a unit is operating may be adversely affected by stack flow. If EPA has evidence to support this proposed requirement, EPA should provide it. In addition, the proposal to require a measurement at three "distinct" locations is not reasonable and may not be possible on some stacks. Measurement at three "distinct" locations

ED_000419-0005963

presumably would require three ports none of which are directly across from each other. Common configurations depending on stack diameter are to have two ports 90 degrees apart or four ports 90 degrees degree apart—neither of which provides three distinct locations. In other words, most plants will have at most two distinct locations. EPA must remove the requirement.

2. The Heat Input and Fuel Factor Option

UARG agrees with EPA's proposal to allow liquid and gaseous fuel-fired EGUs to use the Appendix G in lieu of CEMS. Requiring use of stack flow or diluent monitors on such EGUs would result in unnecessary additional construction, equipment, and implementation costs, and less accurate measurements of CO_2 mass emissions.[62] UARG also agrees with the proposal to allow, but not require, the use of site-specific F-factors under equation G-4. Proposed Subpart UUUU § 60.5805(a)(3)(ii). Appendix F provides F-factors for most commonly used fuels and includes a procedure for annual determination of a site-specific F-factor for fuels that are not listed, or if a source wants to develop its own F-factor. However, the variability in commonly used fuels is not sufficient to warrant determination of a site-specific F-factor for *all* fuels. To the extent there is small variability, it also is unlikely that variability would be captured in an annual determination. EPA has relied on F-factors identical to those in Part 75, Appendix F in

---

[62] Existing liquid and gas-fired EGUs use Appendix D to comply with the ARP requirements to monitor and report hourly heat input and SO_2 mass, and the Subpart KKKK requirement to monitor NOx in lb/MWh. EPA previously considered and rejected the idea of requiring such units to install stack flow monitoring systems in lieu of using Appendix D. 66 Fed. Reg. 18,546 (Apr. 10, 2001). The Appendix D procedure, which relies on a calibrated fuel flow meter, provides a more direct, and more accurate, measurement for such EGUs, because fuel flow meters can meet tighter performance specifications than stack flow monitors, and they are not subject to the same interferences that can bias measurement. Requiring use of a diluent CEMS at gas- and oil-fired combustion turbines also would be unjustified. The combined potential errors associated with CEMS stack monitoring, including allowed variability in Protocol 1 calibration gases, calibration error, and relative accuracy, are greater than the error associated with the mass balance options available under Part 75.

ED_000419-0005964

NSPS compliance determinations since the mid-1970s. Requiring development of a site-specific F-factor for commonly used fuels would be a waste of time and resources. However, the option to develop such factors is necessary to account for the fact that EPA may not have developed a default factor for some fuels.

3. Monitoring of CO_2 Mass Emissions From Integrated Equipment

EPA proposes to define "steam generating unit" and "stationary combustion turbine" to include "any integrated equipment that provides electricity or useful thermal output" to the affected facility or auxiliary equipment.[63] Proposed Subpart UUUU § 60.5820. When EPA proposed to include "integrated combustion turbines and fuel cells" in the definition of a post-May 3, 2011 steam generating unit in Subpart Da, EPA recognized that emissions from that equipment likely would not be exhausted through the primary boiler stack and, because the emissions would be relatively small, suggested that they be estimated rather than monitored. 76 Fed. Reg. 24,976, 25,070 (May 3, 2011). The Agency also acknowledged that there likely were no such devices currently being used, but suggested that it hoped to promote their use. *Id.* UARG's comments on that definition focused on its lack of clarity and usefulness, given the improbability that such equipment would be used in the near term.

Although UARG continues to believe that there are few real world applications for such equipment, at least at fossil-fuel-fired utility boilers, UARG agrees that if such equipment were used, continuous monitoring likely would not be warranted. Such integrated equipment either

---

[63] Such integrated equipment could be interpreted to include a fuel reformer that produces hydrogen to power a fuel cell or combustion turbine, a start-up boiler that enables cold start of a large power generation steam generator, a small industrial boiler that fires continuously to generate steam to warm the heat recovery steam generator ("HRSG") of NGCC units, or a combustion turbine that preheats boiler feedwater for a HRSG or provides auxiliary steam for the stripping tower of a CCS.

ED_000419-0005965

has very few emissions, or operates very infrequently. UARG also believes that given the uncertainty about their use, the Agency should not spend resources specifying monitoring requirements in the rule. As a result, UARG suggests that EPA encourage states to include a provision allowing submission and approval of a petition for exemption of emissions that are *de minimis* from the compliance calculation, or for an alternative means of accounting for any resulting emissions (e.g., a mass balance calculation or engineering estimate) from any integrated equipment that are not otherwise required to be monitored under an NSPS or otherwise accounted for in the primary equipment's monitoring (e.g., by venting the emissions into a stack with CEMS).

B. Monitoring and Reporting of Electric Output

Output-based standards require the monitoring of generation. To determine compliance with the proposed output-based standards, EPA proposes to require installation of a sufficient number of watt meters to measure "net electric output" from the facility, as well as specifying special provisions for CHP facilities and process steam applications. Proposed Subpart UUUU § 60.5805(a)(4). For the first time, EPA also proposes to require that these measurements be made "using 0.2 class electricity metering instrumentation and calibration procedures as specified under [American National Standards Institute ("ANSI")] Standards No. C12.20." *Id.*

EGUs already are required to record and report hourly gross unit load from fuel combustion (in MWge) under Part 75. 40 C.F.R. §§ 72.2 (defining "unit load"), 75.57(b)(3) (requiring recording of hourly gross unit load), 75.64(a)(2) (requiring reporting of recorded values).[64] As a result, all existing EGUs already measure and record gross MWs for all

---

[64] Although Part 75 does not specify a method for measuring generation, Subparts Da and KKKK require EGUs complying with an output-based standard to install, calibrate, operate, and record data from a watt meter. *See* 40 C.F.R. §§ 60.49Da(k)(1), 60.4335(b)(3). Combined cycle

ED_000419-0005966

generation. In order to facilitate reporting under state plans, EPA proposes that affected EGUs also "could report hourly net electric generation under [Part 75] via ECMPS." Technical Support Document: Part 75 Monitoring and Reporting Considerations at 6, Docket ID No. EPA-HQ-OAR-2013-0602-0461 ("Part 75 GHG Guideline TSD").[65] It is not clear whether EPA is proposing that Part 75 be revised to simply provide a mechanism for such reporting in the event a state chooses to require or allow it, or whether EPA is suggesting that sources reporting under Part 75 be required to report net electric generation. UARG would oppose the latter requirement. EPA has no authority under section 111(d) to require reporting of net generation or output under Part 75.

UARG also is concerned that EPA has overlooked important details regarding how generation already is being reported. EPA has made clear in its ECMPS Reporting Instructions for Emissions,[66] the value reported under Part 75 represents an hourly rate and not the total load for the hour. As a result, for hours of partial operation, the value already reported under Part 75 will not represent the actual output for that hour. *See* ECMPS Emissions Reporting Instructions § 2.4. Similarly, units on common stacks report the weighted sum of the hourly unit loads for all units that exhaust through the stack. In addition, reported steam load for an hour is reported at the measured temperature and pressure (i.e., is not corrected to ISO conditions). *Id.* EPA's Proposed Guidelines, on the other hand, require calculation and use of actual electrical output for

---

combustion turbines with HRSGs that do not have a duct burner are not required under Part 75 to report generation from the HRSG, but may do so voluntarily (and most do). *See* EPA, Part 75 Emissions Monitoring Policy Manual at Q. 17.2 n.1 (2013) ("Part 75 Policy Manual") (advising EGUs to report total generation if required to monitor total MW under other applicable regulations), *available at* http://www.epa.gov/airmarkets/emissions/monitoring.html.

[65] To implement such a scheme, CHP units also would need to report useful thermal output via ECMPS.

[66] *Available at* http://ecmps.camdsupport.com/learn_docs.shtml (released June 12, 2013).

ED_000419-0005967

each hour and useful thermal energy relative to standard ambient temperature and pressure conditions.

If EPA intends sources to include partial unit operating hours in state compliance calculations, the values already being reported under Part 75 would need some adjustment for use in compliance calculations. EPA suggests as much with respect to output in its proposal to require that EGUs with common stacks or multiple stacks monitor "stack operating time." Proposed Subpart UUUU § 60.5805(5), (6). As a result, EPA should clarify whether it intends that partial hours be included in state calculations. And, if EPA anticipates that states rely on data reported to ECMPS, EPA must address the discrepancies.

With respect to the proposed requirement to comply with the ANSI 2010 C12.20 standard for electricity meters, EPA has not provided justification for that proposal in this rulemaking. In a TSD included in the docket, EPA says only that the requirement "would ensure a level playing field regarding the minimum acceptable accuracy of equipment … while minimizing any additional burden of upgrading equipment used to measure net generation." Part 75 GHG Guideline TSD at 4. However, EPA has not provided any information to suggest that all EGUs are not already using meters of acceptable accuracy or that requiring compliance with the ANSI standard would not impose additional burdens or require the upgrading of equipment. EPA has never before found it necessary to impose such requirements because EGUs already have sufficient incentives to ensure that the electricity they generate and use is accurately measured.

Compliance with that proposed requirement would be burdensome. Although some EGUs may have meters that comply with all or parts of the ANSI standard, some do not and the cost of replacing such meters is not insignificant. Moreover, the ANSI standard itself is extraordinarily detailed and not at all suited to a regulatory program under which penalties could

be sought for a failure to comply. UARG notes that EPA has not provided a copy of the standard in the docket, or even discussed the content of the standard in any meaningful way. In short, UARG believes the only entity that would significantly benefit from requiring compliance with the cited ANSI standard is ANSI itself, which charges a significant sum for access to the standard and restricts the networking and transferring of the purchased file to another person or computer.[67]

With respect to the monitoring of net electric output, EPA's proposal appears to be based on an assumption that net output would be determined using existing equipment and simple apportionment schemes. Part 75 GHG Guideline TSD at 3 ("EPA understands that the equipment needed to convert gross generation to net generation on an hourly basis exists at all EGUs."). UARG agrees that if the monitoring of net electric output is required, EPA must allow EGUs to use existing equipment and methods for metering station service, and to apportion common station service to individual units using unit generation. *Id.* at 3-5. As EPA is well aware, measurement of unit-specific net output can be complicated by the difficulty in measuring auxiliary energy consumption of numerous plant-specific devices. Most plants do not have the internal electrical distribution system designed to distribute and measure internal usage on a unit basis. If EPA were to require replacement of existing equipment or to impose more stringent standards on existing equipment, EPA would need to revise its proposal to estimate and solicit input on the additional costs and burdens of such metering.

---

[67] *See* ANSI eStandards Store, http://webstore.ansi.org/FindStandards.aspx?SearchString=C12.20&SearchOption=0&PageNum=0&SearchTermsArray=null%7cC12.20%7cnull.

ED_000419-0005969

C. Monitoring and Reporting of Useful Thermal Output

EPA proposes to define net energy output as net electric or mechanical output, plus 75 percent of any useful thermal output. Proposed Subpart UUUU § 60.5820. Steam is the most common type of useful thermal output and is commonly measured using a flow meter, a temperature sensor, and a pressure sensor. Part 75 GHG Guideline TSD at 6. For CHP units, EPA proposes to require the continuous monitoring of useful thermal output from CHP systems, Proposed Subpart UUUU § 60.5805(a)(4), and assumes that a CHP unit that sells its output already would be using such equipment, Part 75 GHG Guideline TSD at 6. However, EPA solicits comment on whether EPA should specify "best practices" for measurement of useful thermal energy and quality assurance protocols to ensure consistent and accurate reporting, "while minimizing additional burden." *Id.*

UARG does not believe that it would be appropriate for EPA to specify which technologies to use or to impose requirements for periodic QA. As an initial matter, UARG questions EPA's focus on the accuracy of useful thermal output measurements given the Agency's uncertainty regarding the amount of credit that should be provided for whatever is measured. As noted above, although EPA has proposed to allow credit for 75 percent of measured useful thermal output, it also has solicited comment on providing credit for as little as two-thirds and as much as 100 percent. 79 Fed. Reg. at 34,914. Wherever EPA comes out on that issue from a policy perspective, any accuracy gains that might be achieved from imposing additional requirements surely would be lost in the noise of the calculations and assumptions used to justify the arrived upon percent credit. *See, e.g.,* Memorandum to Docket, Credit for Thermal Output at Combined Heat and Power (CHP) Facilities, Docket ID No. EPA-HQ-OAR-2013-0495-0070.

ED_000419-0005970

Regardless of the amount of credit provided for the measured thermal output, each EGU should be allowed to select the technologies that best suit its needs under the circumstances, and to determine the best mechanism to ensure an appropriate level of accuracy. Certain technologies (like ultrasonic flowmeters and coriolis meters) typically are not used for steam measurements due to the high temperature applications and costs, and it would not be appropriate for EPA to attempt to impose their use. Although some manufacturer's may claim that their more complex and costly equipment provides greater accuracy than the widely used differential pressure type flow meters, those benefits often are not realized when the meters are used in real world plant applications. Different types of meters, instruments, and calculation methods also provide varying levels of accuracy depending on the steam conditions, which can vary from source to source. For example, some steam is supplied, and therefore metered, at conditions that are barely superheated or barely at the saturation temperature. Moreover, some equipment simply would not benefit from any periodic QA. For example, thermocouples and resistance temperature detectors either work or fail completely. Because removing such sensors for calibration may be difficult, and even dangerous in high pressure processes, there is no benefit to removing them until they fail and have to be replaced.

Manufacturers' recommendation also are not universally appropriate for ongoing maintenance or QA, and are not appropriate for use in rules because they vary from vendor to vendor and can change over time. UARG cannot comment on the reasonableness of requirements, procedures, or specifications EPA cannot reasonably identify. ASME Performance Test Codes also are not appropriate for ongoing QA because they were designed for performance testing, not long term performance. Although most flow meters probably would meet the ASME measurement of fluid flow in closed conduits ("MFC") standards generally,

UARG does not believe EPA has justified imposition of such standards in this context, and any requirement for their use would have to refer simply to the standard series as a whole in order to ensure that the entire range of flow meter types and conditions used at existing plants would be covered.

D. Monitoring Plan and QA/QC Testing

EPA proposes to require preparation of a site-specific monitoring plan consistent with 40 C.F.R. § 75.53(g) and (h) and that "each monitoring system . . . meet the applicable certification and quality assurance procedures in § 75.20 … and Appendices B and D to part 75." Proposed Subpart UUUU § 60.5805(a)(1), (2)(ii). EPA also says that it is considering requiring that the Part 75 monitoring plan include "the reporting of equipment used to measure net electric output (and net energy output for CHP units) in an EGU's monitoring plan under [Part 75]." Part 75 GHG Guideline TSD at 7. EPA also is considering requiring the reporting of the results of any new QA/QC test on equipment used to measure net electric or energy output to ECMPS. *Id.* Again, it is not clear whether EPA is proposing that Part 75 be revised to simply provide a mechanism for such reporting in the event a state chooses to require or allow it, or whether EPA is suggesting that all source reporting under Part 75 be required to report this information.

UARG does not oppose a requirement for preparation of a monitoring plan for systems to measure and record CO_2 mass emissions, or submission of that plan to ECMPS. The Part 72 "designated representative" ("DR") for modified and reconstructed EGUs already will have to develop and submit such plans under Part 75 that include that information. UARG also supports reliance on Part 75 QA/QC. However, UARG does not believe that there is any benefit to including equipment used to measure electric and energy output in the Part 75 monitoring plan or to requiring additional QA/QC for that equipment. EGUs already have sufficient incentives to ensure that their equipment for measuring output is accurate, and EPA has not provided any

information to suggest that additional quality assurance is warranted. UARG also believes that any increase in accuracy would be dwarfed by other sources of allowed error in the overall measurements that cannot be eliminated. On the other hand, the resources necessary to track such equipment, to purchase and install new equipment if necessary to meet new accuracy standards, and to perform such testing would be significant.

UARG also does not understand EPA's proposed reference to compliance with Part 75, Appendix D for units using CEMS. Proposed Subpart UUUU § 60.5805(a)(1), (2)(ii). Under Part 75, CEMS certification requirements are in Appendix A, and ongoing QA/QC requirements are in Appendix B. Appendix D is the procedure for calculating heat input and mass emissions of SO_2 for units without CEMS. EPA should replace the reference to Appendices B and D with "Appendices A and B."

E. Use of Specific Methods for Flow RATAs and Baseline Adjustments Following a Change in Method

EPA proposes to require that if an EGU chooses to use Method 2 to perform the required relative accuracy test audit ("RATA") on a flow monitoring system, the EGU must use a calibrated Type-S pitot tube (rather that the default Type-S pitot). Proposed Subpart UUUU § 60.5805(a)(2)(v). UARG does not oppose such a requirement. However, EPA also solicits comment on requiring use of what it calls "the most accurate RATA reference method for specific stack configurations" when performing tests on stack gas flow monitors, and use of a "computation[al] adjustment" when an EGU changes RATA reference methods. 79 Fed. Reg. at 34,913-14.

Approved methods for flow RATAs under Part 75 include Methods 2F, 2G, 2H, and conditional test method ("CTM") 041. Method 2F uses a three dimensional ("3-D") probe to determine yaw angle, pitch angle, axial velocity, and volumetric stack flow. Method 2F was

ED_000419-0005973

developed to eliminate high bias of stack flow measurements in stacks with cyclonic flow. Method 2H and CTM-041 provide procedures for adjusting stack flow measurements to correct for velocity decay near a stack or duct wall that is not present in the measurements taken elsewhere in the stack.[68] In the Part 75 GHG Guideline TDS at 7-8, EPA expresses concerns that allowing sources to use these alternative methods (and in particular allowing EGUs to change methods over time) could lead to inconsistencies between emissions or heat input values.[69] To avoid this result, EPA solicits comment on whether it should require use of the more accurate methods, and whether it should develop adjustment factors for normalizing data when an EGU opts to use a different reference method to calibrate its stack flow monitor during a RATA. *Id.*; 79 Fed. Reg. at 34,913-14.

Although EPA must allow use of Methods 2F and 2H (or CTM-041), EPA should not require either one. First, not all EGUs will obtain more accurate measurements using these methods. EGUs with axial flow and smooth stack liners may not experience any improvement in flow measurements from those methods, which are designed to correct for non-axial flow and wall effects caused by friction. Although the methods can provide more accurate (and lower) stack flow measurements for other EGUs, they also impose additional burdens. Any EGU concerned about overestimation of measured flow due to cyclonic flow conditions, or wall effects, can opt to use the methods. There is no basis to require their use. EPA also should allow

---

[68] Methods 2F and 2H, which address stacks and round ducts, are codified at 40 C.F.R. Part 60, Appendix A-1 and A-2, respectively. CTM-041 addresses wall effects in square ducts. Although EPA has proposed to revise Method 2H to reflect the CTM-041 procedure for square ducts, 74 Fed. Reg. 42,819 (Aug. 25, 2009), EPA has not yet finalized it.

[69] In Section XIV.A, UARG discusses how changes in the manner of calibrating flow monitoring systems and other sources of variability in heat input measurements can result in changes in reported heat rate that EPA erroneously concluded were the result of purposeful efforts to improve unit efficiency.

ED_000419-0005974

use of Method 2G. Method 2G uses a 2-dimensional probe to measure yaw angle (but not pitch) and near-axial velocity. Method 2G also can provide more accurate (i.e., lower) flow measurements than Method 2 under some conditions. 40 C.F.R. pt. 60, App. A-2. Method 2G is often performed using an auto-probe, which can reduce testing time. Part 75 allows use of Methods 2, 2F, 2G, 2H, and CTM-041. *Id.* pt. 75, App. A § 6.5.10.[70] EGUs should be allowed to choose which version of the flow method is best for the particular application and should not be required to perform 3-D testing where it is not needed.

Regarding EPA's suggestion that it develop "adjustment factors" that would be applied if an EGU changed flow methods, EPA has not provided sufficient information for UARG to comment on the reasonableness of such a requirement. EPA's example – that a unit that transitions from Method 2 to Method 2H when performing flow RATAs would apply a "percentage reduction of baseline data" – is unclear. Part 75 GHG Guideline TDS at 7-8. Specifically, it is not clear what data EPA is suggesting would be altered – the baseline data used in setting the state goal or data used to determine compliance under an approved state plan. EPA's suggestion that data would be "reduced" by some percentage suggests that EPA's reference is to baseline data. But would that require recalculation of the state goal every time an EGU changed flow RATA methods? The altering of data collected under Part 75 could have serious consequences and UARG certainly would object to use of such altered data for any other program. EPA also does not provide a timeframe for this requirement. If EPA is suggesting that the compliance data – not baseline data – be altered, there would be no adjustment needed for data collected prior to implementation of the state plan, or for changes in methods made before

---

[70] Currently, to use CTM-041, EGUs must submit a one-time written request to EPA. *See* EPA, Rectangular Duct Wall Effects, http://www.epa.gov/airmarkets/emissions/rect-wall-ducts.html.

ED_000419-0005975

2012. Finally, EPA has not provided any information to inform how it might calculate an adjustment factor. Since the impact of a change in flow methods would be site specific, EPA presumably would have to require a comparison of flow data collected with the CEMS before and after the RATA. But that is hardly a concept that is sufficiently developed to allow for meaningful content.

In short, the two sentences of vague conceptual language in the TSD is not sufficient to inform commenters of the scope or impact of EPA's proposal. If EPA intends to pursue such a requirement, EPA must issue a rulemaking proposal that fully explains what kind of adjustment EPA is proposing and specifically how the percentage value would be determined.

F. EGU Recordkeeping Requirement

EPA proposes to require that EGUs maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record, and that those records be kept "on site" for at least 2 years. Proposed Subpart UUUU § 60.5805(b).

UARG opposes the proposed 10 year record retention period for all of the supporting information, unless EPA can show a special need as required under the Paperwork Reduction Act regulations. 5 C.F.R. § 1320.5(d)(2)(iv).[71] To the extent EPA or a state intends to audit the accuracy of a certified report by reference to supporting information, EPA should do so within a reasonable period of time (e.g., 3 years). Absent an audit, the data have little or no usefulness. Part 75 has a 3-year record retention requirement, and EPA has not provided any information to suggest that has been inadequate. 40 C.F.R. § 75.57(a). Given EPA's proposed reliance on Part 75 monitoring, compliance with Part 75 recordkeeping should be sufficient for approval of a state plan.

---

[71] UARG could find no such justification in EPA's Proposed ICR Supporting Statement.

ED_000419-0005976

UARG also opposes the proposed on-site requirement if it means that retention of electronic records that can be accessed "on site" (even if they are physically located offsite) would not be sufficient. Many of the records to be retained are recorded only in electronic form and, depending upon the facility's management practices, may be retained at a central location in order to facilitate backups and other services. As long as the facility can access the information on site, there is no reason for it to be physically located there.

XVII. Objection to Promulgation of Rules Not Proposed

NSPS rulemakings are subject to section 307(d) of the CAA. CAA § 307(d)(1)(C). Among other requirements, the rulemaking proposal must "be accompanied by a statement of its basis and purpose," that includes: "(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule." *Id.* § 307(d)(3). Further, all of those required "data, information, and documents" must be "included in the docket on the date of publication of the proposed rule." *Id.* Section 307(d) also establishes requirements for final rules. Among other things, the promulgated rule must be accompanied by (1) a statement of basis and purpose like that required for the proposed rule, (2) an explanation of the reasons for any major changes in the promulgated rule, and (3) a response to each of the significant comments submitted during the comment period. *Id.* § 307(d)(6)(A), (B). These requirements are fundamental to both reasoned decision making and judicial review. *Small Refiner*, 705 F.2d at 519 (the fundamental purpose of section 307(d)(3) is to require that "EPA…give a detailed explanation of its reasoning at the 'proposed rule' stage" of the rulemaking process); *Home Box Office, Inc. v. FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977) (per curiam) (without a response to significant comment, the "opportunity to comment is meaningless").

Consistent with these key principles, UARG objects to promulgation of any final rule the content of which UARG could not reasonably have anticipated based on the proposed rule, and to any failure by the Agency to adequately respond to UARG's comments. In particular, UARG notes the absence from this rulemaking docket of 21 of the 25 IPM modeling runs that EPA performed. EPA relied on these modeling runs in establishing the Proposed Guidelines, and their absence from the rulemaking docket has prevented meaningful comment on the Proposed Guidelines, in violation of section 307(d) of the CAA.

ED_000419-0005978

Frank P. Prager
Vice President
Policy & Strategy

1800 Larimer St., Suite 1200
Denver, CO 80202
Phone: **303 294-2108**
Frank.prager@xcelenergy.com

December 1, 2014

EPA Docket Center (EPA/DC)
U.S. Environmental Protection Agency
Mail Code 28221T
1200 Pennsylvania Avenue, NW.
Washington, DC, 20460

Attention Docket ID No. EPA-HQ-OAR-2013-0602

Re: Proposed Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources; Electric Utility Generating Units

Dear Sir or Madam:

Xcel Energy Inc. is pleased to submit the following comments on EPA's proposed Clean Power Plan.

In our comments, we describe Xcel Energy's environmental leadership and emission reduction strategy and how that strategy should serve as a model for state compliance plans under the proposed rule. We also discuss the failure of EPA to recognize state clean energy leadership actions (such as those that have driven our emission reduction programs) in the design of the Clean Power Plan and suggest some narrow changes to the proposal that would help provide adequate credit for clean energy leadership. Finally, we discuss our broader legal and policy concerns with the rule, as well as some specific additional concerns with the rule design.

Xcel Energy appreciates EPA's consideration of these comments and its unprecedented effort to take feedback on the proposed Clean Power Plan. We look forward to working with the Agency, our states and other stakeholders to develop workable, cost-effective climate policy.

Please contact me at 303-294-2108 or Jack Ihle, Xcel Energy's director of Environmental Policy at 303-294-2262 if you have any questions about the issues addressed in these comments.

Sincerely

Frank P. Prager
Vice President, Policy and Strategy
Xcel Energy Inc.

cc: Jack Ihle, Xcel Energy

Table of Contents

Table of Contents 2
I. Executive Summary 3
II. Xcel Energy's Clean Energy Leadership Story 6
III. The Proposed Clean Power Plan does not Recognize Early Action Taken by Leading States 9
IV. Simple Changes to the Clean Power Plan Would Help Recognize State Clean Energy Leadership 12
V. The Clean Power Plan Has Significant Legal and Policy Shortcomings 26
VI. EPA Should Not Adopt a Renewable Potential Approach Under Block 3 38
VII. EPA Should Address Other Issues with the Proposed Rule 43

ED_000419-0005980

I. Executive Summary

Xcel Energy is a public utility holding company headquartered in Minneapolis, Minnesota. We serve approximately 3.4 million electric customers and 1.9 million natural gas customers in the eight states of Colorado, Minnesota, Texas, New Mexico, Wisconsin, North Dakota, South Dakota, and Michigan. The company has been the nation's number one utility wind provider for a decade. We have some of the nation's leading clean energy programs and, through programs like our Metro Emissions Reduction Program in Minnesota and the Colorado Clean Air-Clean Jobs Act, have been on the cutting edge of coal plant retirement and fleet modernization efforts.

We describe our clean energy strategy in detail in Section II below. Because of our clean energy leadership efforts, Xcel Energy is on track to reduce its carbon dioxide emissions by 31% by 2020, ten years before the target established by the Obama Administration in the Clean Power Plan. We are proud of this achievement, but we are equally proud of the fact that we have been able to achieve this result while maintaining reasonably-priced, reliable electric service to our customers.

We believe that our approach to clean energy, created in collaboration with our customers, state policy-makers, the environmental community and other stakeholders, should serve as a model for EPA's efforts to regulate CO_2 under Section 111(d) of the Clean Air Act. We also believe it is critical that EPA's rule recognize the billions of dollars that we and our customers have invested and continue to invest in clean energy and early emission reductions.

For this reason, we are pleased that EPA recognizes the importance of state leadership and flexibility in the development of the Clean Power Plan. However, the company shares the

ED_000419-0005981

concerns of our states that the proposal would ignore – and in fact punish – clean energy leadership. As set forth in Section III of the comments that follow, the proposed rule sets more stringent targets for states that, prior to the 2012 baseline year, retired coal plants, invested in renewable energy ("RE"), and implemented customer energy efficiency programs.

Fortunately, there are several simple, targeted changes to the rule that can improve the proposal's treatment of early action. In particular, as discussed in detail in Section IV of these comments, the final rule should:

- Recognize the retirement of coal plants occurring prior to the 2012 baseline;
- Account for the effect of renewable energy on the dispatch of natural gas combined cycle plants;
- Grant states the flexibility to establish their own emission reduction glide paths for the 2020 to 2030 time period;
- Allow leading renewable states to bank renewable energy for use in meeting their 2030 compliance obligations; and
- Fix technical problems in the rule that harm clean energy leaders.

These narrowly designed changes would help address the failure of the proposal to recognize early action. EPA could incorporate these changes into the proposed rule without significantly affecting national emissions outcomes or altering the fundamental structure of the rule.

As our environmental leadership record demonstrates, we share with EPA the goal of producing a workable, cost-effective and legally defensible strategy to address greenhouse gases. The targeted changes we propose in these comments would help move the rule in the right direction.

ED_000419-0005982

However, we are concerned that, beyond the issues addressed in our targeted proposals, the Clean Power Plan has more fundamental legal and policy flaws that could undercut the purpose of the rule and stand in the way of creating a viable greenhouse gas emission reduction program. As discussed in Section V of these comments, the proposed rule would stretch Section 111(d) to the breaking point. Contrary to Section 111(d), the rule would regulate electrons and the electric system rather than emission sources. Relying on this little used provision of the Clean Air Act, EPA would assume unprecedented power to oversee the nation's energy infrastructure, a task that it is neither legally nor institutionally prepared to undertake. Moreover, the proposal is constructed on four clean energy "Building Blocks" that are in many respects arbitrary and infeasible. At the same time, as indicated in the comments of NERC, SPP and the other reliability regions, the rule has implications for the reliability of the electric system, especially at the onset of the interim target period in 2020.

We discuss these concerns in detail below. In Section VI and VII, we also provide feedback to EPA regarding various aspects of the rule, including among other things, the inappropriateness of a "potential" approach to setting state RE targets. We hope that the comments below will provide EPA with information that will improve the rule and help enhance the success of EPA's carbon reduction program.

ED_000419-0005983

II. Xcel Energy's Clean Energy Leadership Story

Xcel Energy is a major U.S. electricity and natural gas company with regulated operations in eight Western and Midwestern states (Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, Colorado, Texas and New Mexico). We provide a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers. Xcel Energy's generating units are capable of producing over 17,000 megawatts ("MW") of electricity, using a variety of fuel sources including coal, natural gas, oil, nuclear, renewables and hydropower.

For the past decade, Xcel Energy has pursued a clean energy strategy that reflects the desire of our customers and the communities we serve to protect the environment, reduce risk and promote clean energy, all while maintaining reliable service at an affordable price. Our clean energy strategy serves as an example of how states and utilities can work together to significantly reduce emissions at the lowest cost to customers.

Through our clean energy strategy, Xcel Energy is on track to achieve EPA's overall emission reduction target of 30 percent by 2030 from 2005 levels; in fact, we are on track to reach those levels by 2020. Equally important, these improvements have occurred at prices that have kept energy affordable for customers and in a manner that has maintained reliable utility service.

We have worked proactively with states to develop comprehensive emission reduction programs to modernize an aging fleet of generating plants. Under these programs, we continue to retire, convert and refurbish coal-fueled units to reduce emissions and prepare for more stringent

ED_000419-0005984

environmental requirements. From 2005 to 2018, we will have retired or converted seven coal plants capable of producing 2,240 megawatts, about 25% percent of our coal fleet's capacity.

With the state of Minnesota, we implemented the Metro Emissions Reduction Project, a $1.3 billion effort completed in 2009 that significantly reduced emissions from three Twin-Cities area plants while increasing electricity output by about 300 megawatts. Similarly, pursuant to Colorado's Clean Air-Clean Jobs Act adopted in 2010, we are implementing a $1.1 billion plan to retire six aging coal units in the state and replace them with a new, highly efficient natural gas plant. In addition, we are converting a seventh coal unit to natural gas and upgrading three remaining coal units with state-of-the-art emission controls.

All of Xcel Energy's operating states have renewable standards or objectives, including Colorado and Minnesota, which have some of the most aggressive renewable portfolio standards in the country. We acted early to meet, and in some areas exceed, these standards. We now manage more than 5,000 megawatts of wind energy, more than any other U.S. utility, and by the end of 2015 we expect to have 7,000 megawatts of wind on our system. For a decade, we have been ranked the country's No. 1 utility wind power provider and are also ranked among the top-ten U.S. utilities for solar power, with 320 megawatts of solar capacity on our system.

Through our energy efficiency programs, customers also play an important role in our clean energy strategy. With support from our states and customers, we have built one of the largest energy saving portfolios in the country. Xcel Energy currently offers more than 90 programs to help customers manage electricity consumption and more than 45 programs to manage natural gas. Last year our customers saved nearly 985 gigawatt hours of electricity and 1.5 million dekatherms of natural gas, enough electricity to power about 121,000 homes and natural gas to

ED_000419-0005985

fuel 17,000 homes annually. We estimate our customers have saved enough electricity to avoid building about 16 power plants since 1992.

ED_000419-0005986

III. The Proposed Clean Power Plan does not Recognize Early Action Taken by Leading States

In this proposal, EPA faced a task unique in the history of regulation under the Clean Air Act. Despite the flaws we see in the rule design (discussed below), we believe that some important aspects of the proposed Clean Power Plan are consistent with our own experience in creating workable and cost-effective clean energy programs. Above all, we support the flexibility EPA intends to provide to states in drafting their 111(d) implementation plans and identifying the most appropriate mix of strategies to comply with the rule. The Agency appropriately defers to the states to design plans that meet the Agency's goals. Only states truly understand their own energy systems, and EPA has appropriately given states broad latitude to use all the tools available to them to reduce emissions.

Unfortunately, even within this flexible framework, the proposed rule fails in one important aspect: it would provide very little credit to existing state clean energy programs. It ignores the billions of dollars invested in clean energy by leading states throughout the nation. In fact, the proposal would give an easier compliance path to states that resisted clean energy in the past. Even worse, the Clean Power Plan actually punishes states that are clean energy leaders.

The Clean Power Plan fails to recognize early action in several different ways. First and foremost, it sets a 2012 baseline for the calculation of future emission reductions. By doing so, it ignores the emission reductions achieved from 2005 to 2012. In Minnesota, our Xcel Energy affiliate spent $4 billion between 2005 and 2012 to reduce emissions by 21%. Almost all of those dollars and the associated reductions were swept away by the proposed rule.

ED_000419-0005987

However, the proposed rule does more than just ignore pre-2012 emission reductions. It penalizes clean energy leadership. For example, in Minnesota between 2007 and 2009, we retired two aging coal plants and replaced them with natural gas combined cycle facilities. As discussed in more detail below, the decision to do so actually resulted in a more stringent Clean Power Plan target for the state of Minnesota. Moreover, the proposed rule punishes states that have led the way in RE policy. Block 3 establishes renewable targets based on the regional average of renewable portfolio standards (RPS). Thus, states unknowingly increased the stringency of their Clean Power Plan emission targets by passing RPS laws that ironically were designed to help address the states' contribution to global greenhouse gas emissions. Even within an individual region, Block 3 also imposes a lesser standard for states that have low levels of existing

How the Clean Power Plan Punishes Early Action in Minnesota: The Numbers

Had Minnesota not been a clean energy leader:

1. Minnesota would have a lower regional RE generation target. Without Minnesota's RPS, the regional RE generation target for the North Central region would have been 11.5% rather than 15%.

2. Minnesota would have a lower state RE generation level. Minnesota's final renewable target in 2029 would have been only 5.3% of 2012 total generation, rather than 15%.

3. Minnesota would receive a less stringent target under Block 2. With no renewables, we estimate that Minnesota would have had a natural gas combined cycle capacity factor of 39% in 2012, rather than the actual capacity factor of 24%. Moreover, if Minnesota had not completed the coal to gas conversions under MERP, the NGCC capacity to redispatch would have been 2,116 MW, rather than 2,768 MW. For both reasons, Block 2 would have had much less impact and the state's goal would be much less stringent.

We estimate that, without clean energy leadership, Minnesota's final goal would have been **1,233 lb/MWh** instead of 873 lb/MWh.

Assumptions:

- *In step 1, the revised regional RE target was calculated based on the average of remaining RPS targets in North Central region states.*
- *In step 2, Minnesota's 2012 RE generation was assumed equal to the lowest RE generation in the North Central region. We assumed the North Central region growth factor remains at 6%.*
- *In step 3, we have not accounted for the fact that absent the MERP coal retirements, Minnesota would also have had a higher 2012 fossil emission rate before application of any of the Blocks. Accounting for this would make the state's goal less stringent than the 1,233 lb/MWh estimated here.*

ED_000419-0005988

renewables. The RE target in those states may never get close to the renewable generation of their neighbors. Renewable leaders, who already have taken advantage of the most cost-effective RE opportunities, are expected to do more than the states who delayed action and still have more low hanging fruit in RE.[1]

Further, the interaction of the building blocks exacerbates the adverse impact of the rule on leading RE states. Many states with high levels of RE generation used their natural gas combined cycle plants ("NGCCs") to balance intermittent RE. As a result, the capacity factors of NGCCs in 2012 were lower than they would have been absent RE leadership, and the NGCCs have more "headroom" below the 70% capacity factor target in Block 2. When EPA applies the Block 2 redispatch modeling to these NGCCs, the resulting emission reductions are greater, and the states consequently have more stringent state goals. This too penalizes early action in RE.

The proposed rule's failure to recognize early action is bad policy on every level:

- It tells states that they are better off fighting EPA rather than leading the way to cleaner energy.
- It tells companies that the value of a proactive clean energy strategy may be swept away by future regulation.
- It tells customers that they will pay twice if they commit early to clean energy leadership.

[1] Similarly, under Block 4, states and utilities that have taken a leading role in offering energy efficiency programs well before the proposed rule should be given a fair opportunity to take credit for these early actions. EPA seems to agree with this statement based on sections VIII.F.2.d of the proposed rule and on page 5-34 of the *GHG Abatement Measures* TSD. This is the only reasonable policy for customers and utilities that have taken a leading role in establishing the energy efficiency industry.

ED_000419-0005989

- It tells the public that the most beneficial emission reductions – those that have already occurred – are environmentally irrelevant.

ED_000419-0005990

IV. Simple Changes to the Clean Power Plan Would Help Recognize State Clean Energy Leadership

As discussed in more detail in Section V below, Xcel Energy has significant concerns about the proposed rule. These concerns go to both legal and policy choices implied by the rule, and they reflect serious flaws in the rule design that, if not corrected in the final rule, could undercut the viability of the Clean Power Plan.

However, despite the importance of the issues discussed in Section V, EPA need not discard the entire structure of the rule to address the narrower issue of its failure to provide credit for early action. A few simple changes to the Clean Power Plan will help credit early emission reductions without significantly altering the structure or environmental benefits of the rule. We have already provided these proposed changes to EPA in the form of a presentation provided to the Agency on August 28, 2014. A copy of that presentation is attached to these comments as Exhibit A. A detailed discussion of our proposed changes is set forth below.

The simplest approach to recognizing early reductions, considering EPA's stated goal of a 30% reduction from 2005 levels by 2030, would be to use a more flexible baseline that would directly credit emissions reductions since 2005. In fact, EPA has suggested in its recent Notice of Data Availability ("NODA") that an earlier baseline year may be appropriate under the rule (79 Fed. Reg. at 64,553). Although the NODA implies that EPA is considering a baseline only as far back as 2010, a more appropriate baseline is the EPA reference year of 2005.

ED_000419-0005991

If EPA does not adopt an earlier baseline year, however, the more targeted changes described below provide some credit for early reductions without changing the basic structure of the Proposed Rule.[2]

A. Exempt NGCC plants built to replace coal plants from Block 2

In the last few years, Xcel Energy and other utilities have retired coal plants and replaced them with NGCC facilities at the same site, achieving the emission reductions and clean energy goals that the Clean Power Plan seeks. The NGCC capacity associated with any such retirement and replacement projects prior to the release of the Proposed Rule should receive an exemption from the target-setting redispatch methodology under Block 2. For example, between 2007 and 2009, Xcel Energy's Minnesota affiliate Northern States Power Company retired 652MW of coal units at the High Bridge and Riverside plant sites and replaced them on-site with 1,080MW of NGCC. According to our research, this change would have minimal impact on the rule's outcomes as only a handful of examples of onsite NGCC-for-coal replacement projects exist: In Wisconsin, five coal units at Port Washington, totaling 320 MW, were replaced with 1,150 MW of natural gas combined cycle capacity in 2005-2008. In North Carolina, 522MW of coal units at two plants were replaced with 2,185MW of natural gas combined cycle in the 2012-2013 timeframe. Similar examples exist in Tennessee.

As seen in these cases, the utilities proactively replaced high carbon intensity generation with lower carbon intensity resources, directly lowering carbon emissions and in some cases increasing flexibility to better manage variable renewable generation. The

[2] Even if EPA does not adopt all of these targeted changes, Xcel Energy is committed to continue to work with EPA and other stakeholders to find approaches that can ensure adequate credit for clean energy leadership.

ED_000419-0005992

retirement/replacement projects would count toward compliance if they had occurred after 2012. Despite the fact that they occurred prior to EPA's baseline year, they should be exempt from Block 2.

This exemption would provide value for those companies and states that took proactive steps to shift to a lower carbon resource prior to the proposal's baseline year. While some of these projects also increased the overall capacity of the fleet, we propose that only the amount of NGCC capacity that replaced previously operating coal plants (i.e. 652MW in the case of Minnesota) should be exempt from the 2012 NGCC capacity assumed able to redispatch in Block 2. Providing this exemption only to on-site, coal-to-NGCC replacements and to the capacity of coal retired (not necessarily the full capacity of NGCC installed) will provide appropriate credit to the handful of states and companies who conducted these projects, without significantly changing the overall reductions achieved nationally under Block 2.

B. Correct the renewable/NGCC offset penalty in the rule

As EPA is aware, NGCCs are an important resource for balancing high levels of intermittent RE. In fact, because of the flexibility and dispatch characteristics of NGCCs, wind often tends to displace NGCC generation. Studies by MISO, ERCOT and NREL demonstrate that a significant portion of wind generation displaces NGCC generation - from 32.6% in the MISO region up to 83% in the West and 87% in ERCOT. An internal analysis conducted by Xcel Energy using historical data from four representative months showed that wind displaces NGCC about 39% of the time on the system of Xcel Energy's Colorado affiliate, Public Service of Colorado (PSCo).

ED_000419-0005993

These wind/NGCC "displacement factors" demonstrate that NGCCs in states with high wind penetration have a lower capacity factor due directly to the operation of wind generation in those states and their utility systems. Therefore, the 2012 baseline NGCC capacity factors used in EPA's Block 2 methodology were lower in states with significant RE than they would have been absent these pre-2012 RE investments. Because the amount of NGCC generation assumed to displace coal and oil/gas steam generation depends on the difference between actual 2012 capacity factors and the 70% capacity factor target, this leads to more stringent Block 2 calculations and emissions targets in states with high renewables. A reasonable national estimate of the wind/NGCC displacement factor is 50% based on the studies cited above. Assuming a wind/NGCC displacement factor of 50%, we have re-calculated the 2012 baseline NGCC capacity factors for the states we serve that have NGCCs. We see significant changes in capacity factors in these cases, as shown in Table 1.

Table 1. NGCC capacity factors under 50% wind/NGCC displacement assumption.

State	EPA's 2012 NGCC Capacity Factor	"But for wind" NGCC Capacity Factor (50% displacement factor)
Colorado	30%	41%
Minnesota	24%	39%
Texas	45%	50%
Wisconsin	39%	42%
New Mexico	39%	48%
Michigan	42%	43%

EPA should consider the impact of high levels of wind penetration and recalculate the baseline NGCC capacity factors for each state. The calculations would still be based on 2012 generation data, but the baseline NGCC generation would be adjusted by the method we suggest here to account for what NGCCs in each state would have generated were it not for high levels of RE

ED_000419-0005994

penetration. In this way, the EPA could provide credit to states that have both been RE leaders and built high-efficiency NGCCs.

C. Grant states the authority to build a credible interim target pathway

As EPA has heard from many parties, the Proposed Rule's interim targets present a significant challenge for overall cost, economic disruption, stranded assets, and potentially electric system reliability. The interim targets are based on the assumption that Blocks 1 and 2 can be fully implemented in 2020, which for many states is not realistic. Even under its current, very aggressive schedule, EPA will likely approve most state plans by 2017 to 2019 at the earliest, yet the plans will likely require states and utilities to undertake permitting changes, investments in new gas and transmission infrastructure, procurement of significantly greater amounts of firm gas supply, and other actions that will take several years to implement. Moreover for some states – including Minnesota, North Dakota and South Dakota – Block 3 is also fully phased in by 2020, giving no gradual ramp-in. For these and other reasons, NERC and several reliability regions (entities primarily responsible for ensuring electric system reliability) have studied the Clean Power Plan and found that stringent interim targets would likely have an adverse impact on reliability.[3]

In addition, states with clean energy leadership histories have received more stringent final targets, and therefore more stringent interim targets. We note that the three states in which Xcel

---

[3] See for example:

- North American Electric Reliability Corporation, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan.* November 2014.
- Southwest Power Pool, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan.* October 2014.
- Midcontinent Independent System Operator, *Comments to EPA on Proposed Clean Power Plan.* November 2014.

ED_000419-0005995

Energy owns coal plants, Minnesota, Texas, and Colorado, have much more stringent final targets – 41%, 38% and 35% below EPA's 2012 adjusted emission rate respectively – than the national average rate reduction of 19%. The interim targets in turn are strongly related to the final targets. Minnesota, Texas and Colorado's interim targets are 38%, 34%, and 32% below their 2012 baselines. These required reductions to interim targets are dramatic, and in some cases unworkable.

While it is true that the interim targets incorporate flexibility by allowing a ten-year averaging period, the flexibility is in reality quite limited. Under the proposal, emissions in the early years cannot be much above the interim target value, or the later interim years would actually have to be well below the final target, effectively creating an interim target that is more stringent than the final target. In addition, there are not many significant, cost-effective CO_2 reduction opportunities outside the four Blocks that comprise BSER. In some states, the only viable way to achieve the interim targets may be premature retirement of much or all coal capacity, which will have implications for cost, stranded assets, and reliability.

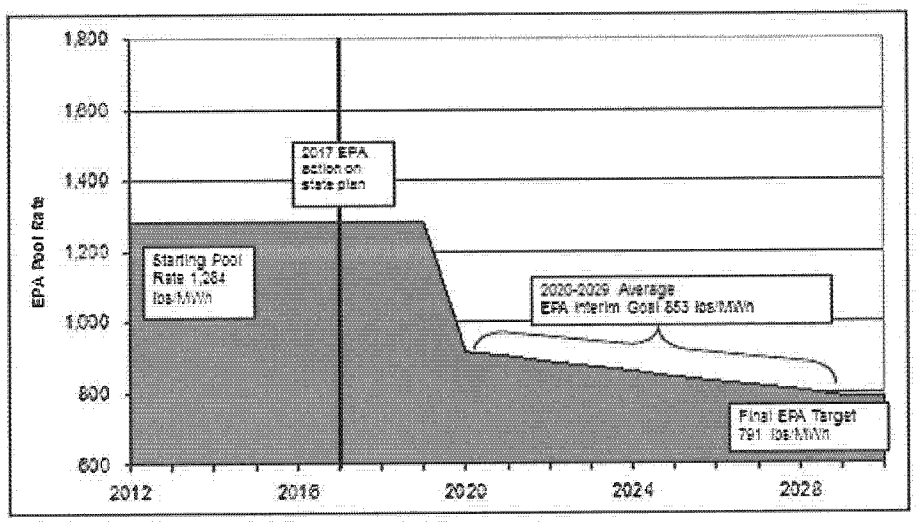
It is true that ongoing emissions reduction efforts prior to 2020 will reduce emissions rates and reduce the gap between 2012 rates and the interim targets. In fact, Xcel Energy has one of the most robust ongoing emissions reduction trends in the U.S. by, for example, adding 40% additional wind capacity from 2014 to 2016 on top of our nation-leading wind portfolio. However, our current plans are not nearly enough to achieve the interim targets.

Our Southwestern Public Service system in Texas vividly illustrates the significant timing problem with the interim targets. The in-state Texas 111(d) equivalent emissions rate of our Southwestern Public Service (SPS) operating subsidiary is currently about 1,780 lb CO_2/MWh.

ED_000419-0005996

While we are adding 450 MW of additional wind energy in Texas by the end of 2015 and also shifting dispatch to newer, more efficient natural gas units, by 2020 our emissions rate will be 1,670 lb/MWh, nowhere close to the Texas interim target of 853 lb/MWh. In fact, achieving that 853 lb/MWh rate, or anything close to it, is all but impossible for our SPS system in Texas in the few years before 2020. This challenge is compounded by the very short timeline between a final EPA-approved state compliance plan (or federal plan) in 2017-2019 and the first binding target year of 2020.

Figure 1. Texas CO_2 emission reductions required under Clean Power Plan.



To fix this interim target problem, Xcel Energy supports the proposal of the Coalition for Innovative Climate Solutions (CICS). Put simply, the CICS proposal would grant states the authority to build a credible interim target pathway to the final 2030 target levels. This option would replace the proposed interim target structure, which is not rooted in any requirement of the statutory language of Section 111(d).

ED_000419-0005997

Under the CICS proposal, states would build a credible, workable, enforceable glide path to their final target based on existing or new state policies, programs, and procedures covering the power sector. The state would propose this glide path to EPA as part of their state compliance plan. States would rely on existing policies such as integrated resource planning, renewable portfolio standards, efficiency programs, plant retirement plans, nuclear uprate programs, and any other credible programs that reduce emissions and are state-enforceable.

EPA would have the ability to accept or reject the plans based on the credibility of the proposal, but would not have the authority to mandate specific interim target levels, as long as the final target level is reached. Please see the comments of the Coalition for Innovative Climate Solutions for more details.

EPA would secure many benefits to U.S. electricity consumers by deferring to the states and allowing greater interim target flexibility. First and foremost, reliability of the U.S. power sector would be maintained, as states would not be scrambling to meet an arbitrary and too-short deadline. Second, costs would be much better managed under this approach, as states could account for stranded costs better, and utilities would be able to optimize the timing of their emissions reductions. This may allow, for instance, more time to invest in new RE rather than a potentially more expensive gas re-dispatch compliance pathway. Third, if states had greater discretion over their states' interim glide paths, they may be better positioned to contemplate regional cooperation in their state compliance plans.

Moreover, states and utilities often exceed the goals of environmental regulations, so greater interim target flexibility should not be assumed to carry with it a loss of environmental benefits. As but one example, Xcel Energy is now far beyond its renewable standard requirements in

ED_000419-0005998

several states. Those state renewable standards allowed us the flexibility to buy RE when the time is right, and we have done so. Given the right tools, including flexibility, states can drive tremendous environmental outcomes.

We appreciate EPA's acknowledgement in the October 30 NODA (79 Fed. Reg. at 64,543) of the challenges created by the stringent interim targets, and efforts towards creating a smoother and less disruptive "glide path." This is moving in the right direction. While we urge EPA to consider the CICS proposal of allowing states to create an enforceable glide path, if EPA does instead establish a federally enforceable glide path – e.g. by ramping in Blocks 1 and 2 as suggested in the NODA – it is critically important for EPA to design this glide path to address the reliability concerns identified in these comments and by NERC and RTOs.

D. Establish a bank for RE to recognize early action and ease planning in later years

We have pointed out elsewhere in these comments that leading RE states have received more stringent, more expensive state emissions mandates under the Proposed Rule. The proposed structure tends to punish states that have passed renewable standards, built RE, and used NGCC plants to integrate RE.

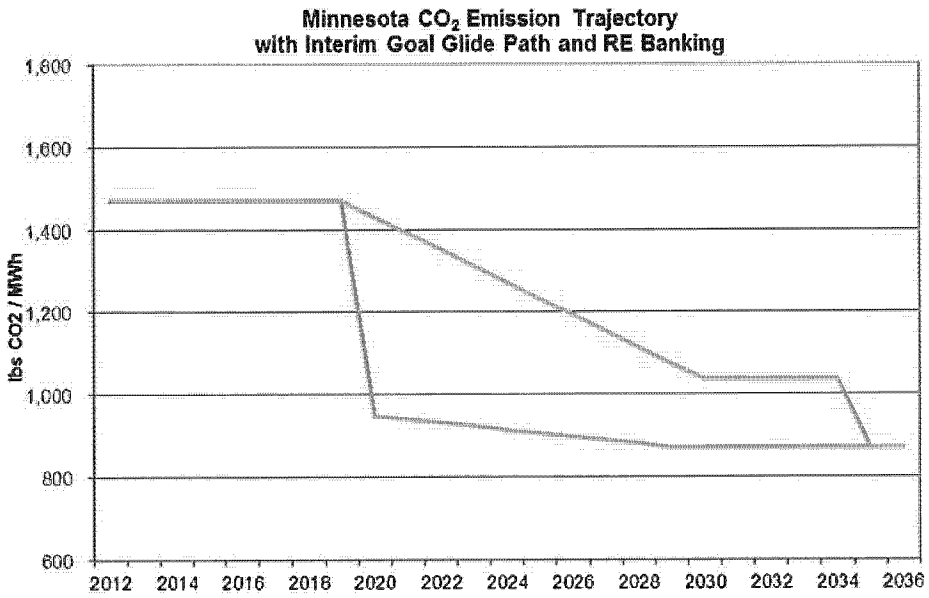
To fix this problem, while working within the basic parameters of EPA's proposal, we propose a banking concept to credit early and ongoing RE development. The design set forth in these comments is only one among several possible designs for RE banking. Under our concept, EPA would first set a floor for banking eligibility of 1.5 times the national average renewable generation in 2012. The national average in 2012 was 5.6%, so this floor would be 8.4%. Only states that had renewable generation above that level would qualify for banking. These states

ED_000419-0005999

would be allowed to bank all renewable generation that is above the 2012 leadership floor percentage for the years of 2017-2019.

States would be able to realize the value of the bank in later years of the program. We propose that, working in conjunction with the state-determined interim target period concept discussed above, states would have the option to "spend" their bank in the form of adding the banked renewable MWh into the denominator of their final targets from 2030-2034. After the bank is depleted, or by 2035, states would then be required to achieve the final target established in the Clean Power Plan. Thus, banking rewards renewable leadership by deferring investments in the last increment of emissions reductions necessary to meet the final goal, but states would ultimately still be required to meet the same final goal.[4]

Figure 2: Interim Target Fix and RE Bank Working Together to Create More Workable Targets for Leading Clean Energy States.



[4] However, if EPA does not allow states to propose their own glide path to the 2030 target, banking becomes still more important as a means to alleviate some of the cost and other impacts of the interim targets.

ED_000419-0006000

The renewable banking concept offers many benefits. First, it would restore the message to states that early action on renewables will not be ignored. In fact, it would do so in a way that explicitly recognizes that the early reductions made by RE long before 2020 have real value under the program. Second, it would more fairly treat the utility customers who have funded proactive RE development. Third, the banking concept would create a new incentive for implementation of new renewables prior to 2020. This may be critical for ongoing renewable development, especially if the current set of federal tax subsidies for solar and wind is not renewed.

Banking accomplishes these objectives while maintaining the same total carbon loading to the atmosphere as required under the proposed rule; it provides relief only to the extent that equivalent reductions occurred prior to the commencement of the program. It recognizes early reduction actions taken long before the proposed rule would become binding. Finally, the general concept of early reduction banking, and renewable banking in particular, enjoys the support of a broad set of stakeholders across the utility industry, environmental advocates, and renewable trade groups, and is raised by EPA as an alternative in the proposed rule (79 Fed. Reg. at 34918-19).

E. Technical fixes

1. Baseline Data Issues

The single year of baseline data used by the EPA for the goal calculations does not consistently reflect the actual operational and technical realities faced by system operators. Many states see discrepancies in their operations in 2012 that directly impact their goal calculation and their

ED_000419-0006001

ability to meet the targets. For example, the largest coal unit in Minnesota, the 900 MW Sherco 3, did not run at all in 2012 due to a major equipment failure in 2011. This anomaly skews the state's 2012 emissions baseline downward and makes Minnesota's emissions goals more stringent. The EPA can solve this issue by adding back into the 2012 fossil rate a proxy (e.g. 2010 emissions and generation) for how Sherco would have operated in 2012. This would increase Minnesota's goal by 83 lb/MWh. In the alternative, we support EPA's suggestion in the NODA to adopt a multi-year baseline or allow states to choose baseline year(s) (79 Fed. Reg. at 64,553).

2. NGCC Capacity Ratings

The data that EPA used for Building Block 2 NGCC redispatch overstates available operational capacity, further penalizing states with significant amounts of NGCC capacity. In the goal calculation, EPA used NGCC nameplate capacity, which does not reflect actual deliverable capacity to the grid, because it does not take into account capacity lost due to high altitude, power consumed onsite to run the plant, and other real-world factors. EPA overstates the NGCC capacity available for redispatch by an average of 13% across the country, and up to 25% in our states. Fortunately, a more accurate capacity rating is available to EPA: the average of the summer and winter net dependable capacity provides a more reliable estimate of the available capacity. This net dependable data is publicly available from the EIA website (http://www.eia.gov/electricity/data/eia860/index.html). Generating units also report net dependable capacity data to the North America Electric Reliability Corporation (NERC) to support its work to develop and implement reliability standards. If EPA continues to use the Block 2 component in the final rule, it should use the average of the summer and winter net dependable capacity.

ED_000419-0006002

3. NGCC Unit Configuration Issues

EPA should correct errors in its unit-level data for NGCCs used for both existing and new constructed units. The NGCC data set has several inaccuracies for units in our system or states: For our Brush unit in Colorado, the Brush 1-3 "GT2" unit was erroneously included while the Bush 4 "GT4" and "GT5" units erroneously excluded. The net result is an increase in NGCC capacity of 25MW.

In Minnesota, EPA used a nameplate capacity for Mankato Energy Center of 530MW, reflecting a planned configuration of two combustion turbines (CTs) and one steam turbine. However, the second CT is planned for 2018 and does not yet exist. Because the second CT does not exist, and the heat recovery steam turbine (HRST) was oversized in anticipation of the second CT, the available nameplate capacity in 2012 for Mankato was actually 375MW, made up of the 295MW from the single CT and 80MW of additional power from the HRST, rather than 530 MW. Further, the net summer dependable capacity recorded by the EIA would bring down the capacity to 300MW. Thus, EPA has overstated the capacity of the Mankato Energy Center by 230 MW.

EPA should clarify the units included as "under construction" for Colorado. The data indicates that there is 200MW of new NGCC considered "under construction" in Colorado in 2013; however, we have not seen this new construction in any resource plans for major Colorado actors. We believe this may be a duplicate entry (inclusion as both existing and "under construction") for the Pueblo Airport facility with 200MW built and online in 2012.

4. NGCC Air Permit Restrictions

In re-dispatching the NGCC fleet to 70%, the EPA also ignores the fact that many NGCC units have air permit limits that legally restrict them from running at these high levels. In Colorado, for example, our Brush 1-3 unit is limited by its air permits to 37% annual capacity factor, Brush 4 is limited to only 18% annual capacity factor, and Arapahoe at 30% annual capacity factor. Further information on these technical fixes can be found in Section VII.

The anomalies in the baseline year, overstatement of the available NGCC capacity, conflicting air permit restrictions, and configuration errors skew the resulting emissions targets, and tend to hurt leading states with a large NGCC fleet.

ED_000419-0006004

V. The Clean Power Plan Has Significant Legal and Policy Shortcomings

Above, we propose a series of targeted "fixes" to the rule that would help address what we see as its biggest flaw: its failure to credit early action. However, the proposed Clean Power Plan has significant, fundamental legal and policy shortcomings. By failing to address these shortcomings, EPA risks the failure of the entire Section 111(d) program and the credibility of its climate strategy. We encourage EPA to address the shortcomings discussed in this section.

A. The Proposed Existing Source Standard for GHG Emissions from Power Plants Violates the Requirements of Section 111 of the Clean Air Act

EPA's proposed identification of the Best System of Emission Reduction ("BSER") for existing power plants is not permissible under the legal standards that apply to Section 111 rulemaking under the CAA. Xcel Energy agrees with the detailed analyses of this issue contained in the comments filed by the CICS, the Edison Electric Institute (EEI) and the Class of '85, and incorporates them by reference into these comments.

At the most fundamental level, EPA lacks authority to establish standards that apply to activities beyond the "stationary source." Section 111 defines an "existing source" as "any stationary source other than a new source."[5] In turn, "stationary source" means "any building, structure, facility or installation which emits or may emit any air pollutant."[6] EPA's proposal seeks to define a "source" as the entire interconnected electric grid of the United States, including the devices that the grid powers. In so doing, EPA proposes to assert authority over non-emitting activities such as end user energy efficiency and RE generation (Blocks 3 and 4). This approach is not consistent with the reach of Section 111.

---

[5] CAA Section 111(a)(6).
[6] *Id.* At 111(a)(3).

ED_000419-0006005

EPA's proposal is also illegally asymmetric with how EPA proposes to regulate new sources in this source category under Section 111(b). EPA's proposal seeks to regulate far more activities than those proposed to be regulated under Section 111(b), when regulation under Section 111(d) is only authorized for sources that would be regulated under Section 111(b) "if such existing source were a new source."[7] Since the existence of a standard for new sources is one of the requirements for EPA's authority to adopt standards for existing sources, the proposed broader sweep of EPA's proposal exceeds EPA's authority.

In seeking to regulate the electric grid, EPA is proposing to exercise the broadest possible authority through one of the most little-used, narrow provisions of the CAA. In a recent opinion evaluating EPA's GHG New Source Review rules, the Supreme Court cautioned EPA about statutory interpretations that "would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization. … We expect Congress to speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.'"[8]

In addition to proposing regulation of activities beyond its statutory authority to regulate "existing sources," EPA's proposal also goes well beyond its statutory authority to identify a "standard of performance." The BSER must be both "adequately demonstrated" and the emissions limitation "achievable." In its legal memorandum in support of the proposal, EPA announces that the term "system" in the phrase "best system of emission reduction" is limitless: "the 'system of emission reduction' may include anything that reduces emissions … including measures that replace production of generation at the affected source and thereby reduce

[7] *Id.* At 111(d)(1)(ii).
[8] *UARG v EPA*, 134 S. Ct. 2427, 2444 (2014).

ED_000419-0006006

emissions..."[9] This proposal thus asserts, uniquely in the history of Section 111, authority not only to determine what controls or work practices a source must employ to reduce its emissions, but to decide whether and how much a source can operate at all. In order to achieve this result, EPA contravenes the CAA by including in the BSER requirement activities that are not subject to regulation under the CAA (Blocks 2, 3 and 4).

EPA cannot cure the internal inconsistencies in its proposed BSER by stating that even if the BSER and state goals are not achievable by application of the four building blocks, EPA will not change the BSER because there may be other things that can be done to reduce emissions.[10] In making this argument, EPA turns the NSPS program on its head. Section 111 requires EPA to determine controls that are adequately demonstrated and emission limitations that are achievable. This means that a source needs to be able to install the designated system and be able to use it to meet the resulting emission limitation. Because the emission limitation is representative of what BSER can achieve, sources have always been free to select alternate controls that meet the BSER limit. It is contrary to the CAA, however, for EPA to select an unachievable BSER.

States, not EPA, must consider the specific circumstances of their existing sources to derive the lb/MWh goal for their state. By proposing to establish state goals that states will not be allowed to change through their state plans, EPA disregards the critical distinction between existing and new sources. The group of existing sources were sited and constructed at different times, reflect different boiler technologies, have differing existing control systems, have been operated and maintained in different ways and have different remaining useful lives. New sources are built after an NSPS takes effect, and the source can be designed and built to comply with a known

---

[9] Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, at 52 (2014). See also 79 Fed. Reg. at 34885, hereafter "Legal Memorandum.".
[10] See for example 79 Fed. Reg. at 34875, 34891, 34902; 34925 on the CAA provision allowing states to consider remaining useful life of sources; etc.

ED_000419-0006007

standard. This is precisely why Section 111(d) focuses on state planning and allows states to consider remaining useful lives and other factors in determining what emission reductions to require of various sources.[11] EPA must let states develop the standards of performance applicable to their sources, considering cost, nonair quality health and environmental impacts, energy requirements, and, among other factors, the remaining useful life of the sources.

EPA cannot bolster its proposed BSER with an extra-statutory assertion that it can choose a technology or technologies in order to achieve "meaningful" or "appropriate" reductions.[12] The amount of reductions that may be achievable is unrelated to a determination that a technology has been adequately demonstrated. EPA must set an emission limit at the level that is achievable by demonstrated technology, not a limit that would result in GHG reductions that EPA deems "appropriate."

B. EPA should not abuse its authority under Section 111(d) to become a national energy regulator.

Under the proposed Clean Power Plan, EPA has entered into energy policy decisions that are beyond both its CAA authority and its expertise. Among other things, the Clean Power Plan implies that EPA has the authority to oversee state decisions regarding power plant dispatch, RE development and energy efficiency. These decisions have traditionally been left to state regulators (or to the market) for good reason: State public utilities commissions are uniquely situated to make decisions regarding the electricity policies within a state. PUCs are subject to the authority of and constraints imposed by the state legislatures and are accountable to the

---

[11] *See* CAA Section 111(d)(1), referring to state plans and to the factors states may consider in making their plans. In contrast, CAA Section 111(b) requires EPA to directly promulgate national standards for new sources.

[12] *See* Legal Memorandum at 39, incorporating by reference EPA's legal analysis of BSER requirements from the January 2014 proposal related to a 111(b) GHG standard for power plants.

ED_000419-0006008

legislature and the people of the state for the wisdom of their decisions. EPA, whether acting from a distant office in Washington or a regional office, has no such accountability.

The Clean Power Plan implies that EPA will (1) judge resource planning decisions made by state public utilities commissions; (2) enforce those decisions once a plan is approved; and (3) impose its own resource planning decisions if it finds the state decisions unsatisfactory. In the final rule, the Agency should recognize that it lacks the expertise and authority to do any of these things and, consistent with Section 111(d), should clearly limit its authority to the control of emissions.

As Section 111(d) makes clear, states have broad latitude to design their own emission control plans, and should be encouraged to do so. EPA should not second guess those decisions nor attempt to enforce them. EPA's oversight of state processes should ensure that state processes contain appropriate procedural protection and consider substantive environmental and energy policy criteria, but it should not substitute its judgment for that of the state.[13]

C. The Proposed Clean Power Plan Rests on "Building Blocks" That Are Unachievable and Arbitrary.

Despite its admirable commitment to flexibility, the Clean Power Plan cannot establish emission targets for any state based on policies or programs that would be unachievable if they were directly enforceable. Many aspects of the Blocks are not technically and economically feasible, either on an individual basis or when interactions among the building blocks have been adequately considered. In addition to our comments below, we join the comments of CICS, EEI,

[13] In fact, Section 111(d) requires that states prepare plans to develop BSER for their systems. Among the factors states may consider are cost, nonair quality health and environmental impacts, energy requirements, and, among other factors, the remaining useful life of the sources (*see* CAA Section 111(a)(1) and 111(d)(1)(B)). If, after appropriate consideration of these factors, a state concludes that it cannot meet EPA's emission rate goal, Section 111(d) implies that EPA must defer to this decision.

ED_000419-0006009

Class of 85 and the Electric Power Research Institute (EPRI) regarding concerns about the feasibility of the different building blocks.

1. Block 1

EPA proposes a Block 1 heat rate improvement target of six percent for every major U.S. coal plant. However, the ability of a plant owner or operator to improve the efficiency of a given unit is entirely dependent on unit-specific factors such as unit age, equipment condition, prior efficiency projects, current emissions controls and other factors.

EPA has also derived incorrect conclusions from the continuous emission monitoring system ("CEMS") data to support its Block 1 target. The CEMS data is limited in its usefulness in determining whether heat rates did or did not improve; for instance annualized CEMS data does not adjust for startups, shutdowns, degradations in heat rates following projects, cycling of coal plants to follow load or renewables, or other factors. But most glaringly, the CEMS data expresses heat rate in gross terms rather than net terms, meaning that CEMS data ignores increases in "house power" needed to run environmental controls. Partially due to this use of gross CEMS data, EPA incorrectly concludes that the heat rate of our A.S. King Plant in Minnesota has improved.[14] While we did undertake a number of heat rate improvements at A.S. King during a plant rehabilitation project from 2004-2007, we also added a number of power-consuming environmental controls such as a scrubber, SCR, and a baghouse. Our own net-basis testing shows that A.S. King's heat rate was 4.7% worse, not better, due to these changes to the plant. Put simply, A.S. King is now a far cleaner plant, but its heat rate is slightly worse. In

[14] A.S. King was one of sixteen coal EGUs that EPA cited as evidence of significant year-to-year efficiency improvements.

ED_000419-0006010

setting the Block 1 target, EPA should properly account for true net-basis heat rates, and should also factor in the widespread adoption of environmental controls taking place nationwide.

Moreover, yet again, the proposed rule punishes utilities that have taken early action to improve heat rates. Where heat improvement measures have been taken, such as at our A.S. King station, and for a new unit such as our company's Comanche Unit 3 which came online in 2010, significant additional improvements may not be possible. Credit for those improvements is swept away by the 2012 base year, and Block 1 applies a potentially unrealistic burden to newer plants and plants where improvements have been made.

EPA's approach to Block 1 assumes one level of heat rate improvement is universally achievable across all U.S. coal plans, and ignores the wide variations in the potential for efficiency improvements. A better approach is to allow states to set their own targets based on unit-specific information that accounts for differences in achievable heat rate improvements.

2. Block 2

As discussed in Section III above, Building Block 2 creates significant penalties for early action. In addition to this concern, by assuming that each NGCC unit in the nation can achieve a 70% capacity factor, Block 2's essence is arbitrary and capricious. Block 2 ignores the manner in which the utility industry, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) make dispatch decisions.

In the utility industry, dispatch decisions are made based on two factors: reliability and cost. The system operator orders coal, gas and nuclear units to run first if they are necessary to assure

ED_000419-0006011

a reliable electric system. Many coal units provide voltage support to enable the transmission system to deliver electricity; other coal units must operate to enable the system to meet load in the event of sudden system changes, such as an unexpected outage of another fossil unit or the loss of a renewable resource (e.g. when the wind stops blowing). Yet, the Block 2 redispatch plan assumes that any coal unit, even those required for reliability, may back down when NGCCs increase their capacity factor.

Moreover, some NGCCs cannot achieve the Block 2 goals. Many NGCCs have air permit limits that restrict them from operating up to a 70% capacity factor. For example, as discussed above, one of our Colorado NGCC plants (Brush 1-3) is limited by its air permits to 37% annual capacity factor. Other units lack the gas infrastructure or firm gas supply[15] necessary to support a 70% capacity factor or were never designed to run at that level. EPA should not presume that all NGCC units in any given state can achieve the Block 2 targets.

Block 2 also ignores the manner in which dispatch decisions are made in the utility industry. EPA has arbitrarily chosen 70% as the redispatch target for NGCCs. Dispatch is not an arbitrary construct; where not demanded by reliability, dispatch decisions are made based on economics. The system operator will always dispatch the lowest marginal cost units first, and move up the "stack" to the higher cost units as customer demand increases.

Because the economics of unit dispatch vary dramatically from utility system to utility system, Block 2 would impose arbitrarily different cost of compliance on the different states.[16] Indeed, a

---

[15] For example, where gas pipelines supply electric generation only in summer, since they must serve heating needs in winter.

[16] In fact, in many parts of the country, dispatch decisions are not under the authority of state agencies or even incumbent utilities. Pursuant to FERC regulation, many states belong to RTOs or ISOs and have

ED_000419-0006012

mere glance at the different state targets shows the arbitrary impact of Block 2. Consider two similar, adjacent states: North and South Dakota. Despite the fact that they are in the same region of the country, North Dakota and South Dakota have very different targets. North Dakota is required to achieve an 11% reduction to 1,783 lb/MWh, while South Dakota must labor to achieve a 35% reduction to 741 lb/MWh. The primary reason for this difference is EPA's decision to use the arbitrary redispatch methodology to address NGCCs; North Dakota has none, while South Dakota has a single NGCC that was under construction in 2012 and thus had a very low capacity factor. With a difference in targets of more than 1,000 lb/MWh, the two states will face completely different compliance economics.

3. Block 3

Block 3 is flawed in two significant respects: it is beyond EPA's authority, and it fails to account for RE leadership. These shortcomings are discussed in detail elsewhere in these comments, especially in Sections III, V and VI.

4. Block 4

Xcel Energy has an extensive, lengthy (30+ years) and successful history of offering customers a broad choice of opportunities to reduce their energy consumption through energy efficiency and demand side management (DSM) programs. Our leadership gives us an experienced viewpoint on the proposed energy efficiency targets and associated policies included in Block 4 of the proposed rule, and our positions are backed by other technical experts. Based on our experience,

---

turned their dispatch decisions over to these interstate bodies. These states could not order a redispatch of their plants even if they wanted to do so.

ED_000419-0006013

and in agreement with the detailed analyses filed by EPRI and EEI, Block 4 inappropriately assumes high rates of sustainable energy savings.

In Block 4, EPA assumes a national "best practice" target of 1.5% incremental annual energy savings. No state has seen utility program savings of this magnitude over the time period that EPA has estimated for this proposed rule. EPRI also indicates that the 1.5% target is higher than that identified in their study, "U.S. Energy Efficiency Potential Through 2025," where EPRI estimates that cost-effective economic potential for energy efficiency is 0.9% of retail sales.[17] The EPRI estimate even includes a broader set of measures which occur outside traditional utility or state-run energy efficiency programs, such as state energy building codes and more efficient federal and state appliance and equipment standards, while EPA's Block 4 methodology drove a higher target without these measures.

EPA's assumption that high rates of cost-effective energy efficiency development can continue through 2030 and beyond is optimistic. In a recent docket before the Colorado Public Utilities Commission to establish energy efficiency goals, Xcel Energy affiliate Public Service Company of Colorado presented a third-party potential study –the same study that EPA referenced in its GHG Abatement Measures TSD, Table 1- "Summary of Recent (20110-2014) Electric Energy Efficiency Potential Studies". Our potential study did not look out past 2020, and only one of the roughly dozen potential studies noted did. We do not believe that establishing a 1.5% is acceptable when little analysis was done much beyond the 2020 period. Furthermore, our study showed a one-third reduction in cost effective achievable energy efficiency potential from the years 2013 through 2020, again indicating that large potential may not be sustainable over time.

---

[17] Electric Power Research Institute. April 2014. *U.S. Energy Efficiency Potential Through 2035*. Available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477.

ED_000419-0006014

Our experience in Minnesota, where we have attained a savings rate among the highest of investor-owned utilities across the nation, similarly shows that achieving high rates of energy efficiency development over time will be increasingly difficult. Energy efficiency potential is a delicate balance of technological development, increasing energy codes and standards, and customer preferences. Based on our experience, we believe that these three variables are unlikely to move in a predictable and favorable fashion over such an extended time period. Like EEI and EPRI, we believe that EPA did not properly account for the lower energy efficiency potential that occurs with tightening building codes and appliance and equipment standards. States would be challenged to reach long-term Block 4 targets and sustain these annual energy savings levels indefinitely after 2017.

In a recent example, the roughly 30 percent increase in lighting standards due to the Energy Independence and Security Act of 2007 stimulated a dramatic short-term rise in new energy savings that has already peaked. Since the standard lighting efficiency baseline is now increased by 30%, there is less potential for lighting programs in energy efficiency programs; over half of our energy efficiency savings is associated with lighting programs. In addition, the potential for lighting-related savings is likely to decline further as newer lighting technologies will deliver lower savings on an individual bulb basis as the baseline becomes more efficient. In short, in states that have historically led on energy efficiency, the low-hanging fruit is already picked.

The Company appreciates EPA's recognition that the utility and DSM industries have built significant capacity to evaluate the certainty of energy savings realized through existing DSM programs. This acknowledgment emphasizes that prior investments in DSM will provide continued benefits to early actors and also gives assurance that rigorous evaluation, measurement, and verification (EM&V) practices established and implemented in partnership

with state commissions may need only minor modifications to meet EPA's guidelines. The Company urges EPA to take a flexible approach to EM&V. EPA should allow each state, especially those with established EM&V protocols, to tailor a plan that meets the needs of their unique stakeholders with the least disruption to existing policies and procedures. EPA has stressed the need for strict EM&V protocols but also acknowledges that newer programs may not have the established protocols desired. New programs are needed to meet aggressive DSM goals, and EPA should rely on the experience of the states to determine whether EM&V protocols are acceptable. The Company also strongly supports the states' option to use gross savings for compliance purposes, since all energy savings, whether influenced by state policies, utilities or local trade allies result in emission reductions.

ED_000419-0006016

VI. EPA Should Not Adopt a Renewable Potential Approach Under Block 3

In the Alternative RE Approach Technical Support Document, EPA has proposed an alternative approach, based on theoretical renewable potential, to develop RE targets under Building Block 3. EPA also suggests a "Regionalized RE Approach" concept in the October 30, 2014 Notice of Data Availability (79 Fed. Reg. at 64,543). As these comments discuss in other sections, EPA has at best questionable authority to apply renewable targets to states under the limited statutory authorities of Section 111(d). If EPA includes Block 3 in the rule, however, it should not adopt the proposed alternative described in the TSD because the approach (1) increases the disparity of state targets; (2) punishes states that have taken early actions to reduce emissions; (3) reduces the flexibility offered to states under the rule; and (4) is arbitrary. If EPA uses any other form of an alternative approach, it should avoid increasing the disparity between states under Block 3 or in the state emissions reduction targets.

The proposed alternative approach to Block 3 in the TSD would increase the disparity of targets between states. Under the rule as proposed, the emissions reductions targets already range from 11% to 72% from 2012 to 2030, a major issue that creates unfairness between states and may stymie regional compliance cooperation. The proposed alternative approach would exacerbate this issue by creating patently unfair and even unreachable levels of renewable generation in some states, such as New Mexico at 72% and South Dakota at 159%. Table 2 below shows how the proposed alternative approach would increase unfairness and disparity among states.

ED_000419-0006017

Table 2: RE Generation Under Building Block 3: The Renewable Potential Approach Greatly Increases Disparity Between States

Renewable Generation Requirement in 2030 as a Percentage of 2012 Total Generation Under Building Block 3	Proposed Regional RPS-based Approach	Renewable Technical and Market Potential Approach
Lowest State Requirement	2%	0%
Highest State Requirement	25%	159%

The proposed alternative approach would also further punish states that have been leaders in RE development. By enacting policies and working with their utilities to implement renewables at levels far above the national average, these states have shown the nation that RE is a viable and significant pathway to reduce carbon dioxide emissions. In fact, the single most significant factor in Xcel Energy's expected 31% reduction in CO_2 emissions between 2005 and 2020 is the RE that we source from seven different states. EPA should not punish the states leading national renewable development by further increasing the stringency of their reduction targets.

ED_000419-0006018

Table 3: Leading Renewable States That Would Be Punished Under the Alternative Renewable Approach to Building Block 3.
(Note: The 2012 RE generation for the states below is at least double the national average of 5.6% in 2012)

State	2012 Renewable Generation Percentage	Proposed Emissions Reduction Target (2012-2030)	Emissions Reduction Target under Renewable Technical and Market Potential Approach (2012-2030)
Colorado	12%	35%	42%
Minnesota	18%	41%	52%
New Mexico	11%	34%	54%
North Dakota	15%	11%	29%
South Dakota	24%	35%	84%

The proposed alternative renewable approach is also arbitrary. For many states, the proposed approach arbitrarily uses a carbon price to set the targeted amounts of renewable generation. EPA cross-analyzed the technical potential by state with an economically modeled assessment (IPM modeling) of likely renewable development if renewable costs were reduced by $30/MWh, which EPA claims is equivalent to an estimated $40 per ton of CO_2 emissions reduction. In fact, in the majority of states, EPA's alternative approach used this carbon price rather than the technical potential to set the Block 3 requirement.[18] Nowhere else in the Building Block structure of the proposed rule does EPA differentiate a state's emission reduction requirements based on a carbon price. For example, Block 2 requires a 70% capacity factor for NGCCs in every state regardless of what carbon price may be implied by that requirement. EPA should not arbitrarily

[18] In the alternative calculations, the binding result was more often the IPM economic runs than the technical potential. For solar, the technical potential figure was only used in 13 states; for wind, technical potential was used for 18 states; for geothermal, only 6 states.

ED_000419-0006019

apply a carbon price in Building Block 3 while holding the state requirements in the other building blocks constant regardless of their cost implications.

In other states, the targets were set by theoretical potential and not limited by the economic modeling step. In these states, EPA's approach is arbitrary because it is based on natural resource availability. This differs markedly from the other Blocks. EPA did not estimate re-dispatch potential under Block 2 based on available natural gas resources in a state, did not estimate potential nuclear growth under Block 3 based on uranium reserves, and did not estimate efficiency potential under Block 4 based on a state's natural resources available to build LED light bulbs or high-efficiency air conditioners.

The proposed alternative approach, by dramatically increasing the levels of renewable generation assumed in setting the state goals, could also effectively eliminate a key compliance flexibility mechanism in our states. Since, as described elsewhere in these comments, Xcel Energy and many other industry stakeholders believe that the other three building blocks significantly overestimate what is feasible and adequately demonstrated for coal plant heat rate improvement, NGCC utilization and energy efficiency, the ability to generate more RE than EPA assumed in Block 3 is a key flexibility mechanism to compensate for the infeasibility of the other three building blocks. If EPA increases the RE requirements in Block 3, making state goals more stringent, those states will have less flexibility to comply cost-effectively with the rule.

EPA raises in the NODA the possibility of a third approach to RE in Block 3, termed a "regionalized approach." This appears to be a technical potential-based approach in which RE technical potential would be evaluated at the regional level (based on the same regions EPA uses in the Proposed Rule, or other regions to be determined). EPA would then apportion to states the

overall RE target thus derived, based on *pro rata* share of 2012 regional electric sales or *pro rata* share of 2012 generation. EPA suggests this approach might help address the discrepancy in the Proposed Rule "between setting targets based on in-state renewable assets or resources while allowing other states that import renewable energy to count certain amounts of that generation toward their compliance" (79 Fed. Reg. at 64,545). EPA provides no numerical results, either on the new RE targets for regions or states or on the effect this third approach would have on states' interim and final targets. Xcel Energy cannot support this approach without further information, and we suspect it would create many of the same problems – arbitrary target setting, more stringent targets for our states, and punishment of renewable energy leaders – as the RE Alternative Approach EPA published along with the Proposed Rule.

EPA should not pursue the proposed renewable potential described in the TSD in the final rule. EPA's proposed approach based on state RPS targets is a better pathway. The flaws in the RPS approach, such as inadequately rewarding early action, can be largely resolved by the rule changes we propose in these comments. If EPA uses any other form of an alternative approach, it should in any case not increase the disparity between states under Block 3 or in the state emissions reduction targets.

ED_000419-0006021

VII. EPA Should Address Other Issues with the Proposed Rule

A. Interstate RE Issues

For goal-setting purposes, EPA's formula applies the regional RE growth factor to 2012 generation from all RE facilities physically located in a state, regardless whether some of this generation serves load in other states (GHG Abatement Measures TSD, chapter 3). However, for compliance purposes, EPA suggests that "consistent with existing state RPS policies, a state could take into account all of the CO_2 emission reductions from RE measures implemented by the state, whether they occur in the state or in other states. This proposed approach for RE acknowledges the existence of RE certificates (RECs) that allow for interstate trading of RE attributes and the fact that a given state's RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with that state's RPS." (79 Fed. Reg. at 34,922). EPA states elsewhere that approvable 111(d) state plans must be non-duplicative, i.e. the emission reduction benefits of the same measure may not be counted in more than one state's plan.

Xcel Energy's position is that the state whose customers are paying for RE should receive compliance credit for that RE in its 111(d) plan. We urge EPA to take an approach for goal-setting that is consistent with the above principle, to avoid conflicts between states. While we do not disagree that RECs can be a useful tracking mechanism, the ownership of RECs should not take precedence over the fundamental principle that the state whose customers are paying for RE should receive compliance credit. In the event that the customers who paid for the energy did not acquire or no longer hold ownership of RECs, those who paid for the energy should receive compliance credit.

ED_000419-0006022

B. Nuclear Issues

EPA assumes 5.8% of the installed nuclear capacity in a state is "at risk" and could be preserved from retirement by this rule. As a result, EPA includes in the denominator of state goals the generation of that "at risk" portion, operated at an assumed 90% capacity factor. This makes the state goal more stringent for any state with existing nuclear capacity. If these nuclear units continue to operate, presumably a state may include generation from the "at risk" portion in its compliance demonstration after 2020 – though the proposed rule does not make this explicit.

Xcel Energy currently owns and operates 1,664 MW of carbon-free, baseload nuclear generation in Minnesota. Our nuclear units include Monticello (564 MW summer capacity, currently licensed to operate until September 2030), Prairie Island Unit 1 (550 MW summer capacity, licensed to operate until August 2033), and Prairie Island Unit 2 (550 MW summer capacity, licensed to operate until October 2034). These units appear as 1,819 MW in the formula – an apparent overstatement by about 155 MW – and the "at-risk" portion (106 MW) of this adds 840 GWh to the denominator of Minnesota's goal (GHG Abatement Measures TSD at 4-35).[19]

As written, the rule may not recognize our recent power uprate at Monticello, is unclear on how to calculate compliance credit for preserved nuclear, and provides very little incentive to maintain these carbon-free baseload resources. We believe EPA should:

[19] The reasons for the discrepancy between 1,819 MW and 1,664 MW are unclear. Our calculation, based on the summer capacity of the three units, would indicate: 1,664 MW * 5.8% considered at-risk * 8,784 hours in 2012 * 90% capacity factor assumption = 763 GWh that should have gone in the MN state goal denominator, not 840 GWh. We advise EPA to remove the 5.8% "at risk" nuclear component from goal setting; but if EPA retains this element of the state goals, at minimum EPA should correct the technical error for Minnesota.

ED_000419-0006023

- Remove the 5.8% "at risk" nuclear component from goal setting, but allow compliance credit for new nuclear and nuclear uprates. The "at risk" percentage is arbitrary, not well supported, and simply creates a penalty for prior investments in nuclear.
- Make clear in the final rule that any power uprate after 2005, or at very least after the 2012 base year – not after date of proposal – is treated the same as "new" nuclear and receives compliance credit for its full generation, from the time the nuclear unit begins to operate at its uprated capacity. Nuclear uprates should be credited because they will displace generation and emissions from affected fossil EGUs -- EPA's goal.

Xcel Energy incorporates by reference the additional comments of EEI on ways EPA may appropriately credit nuclear generation in the rule.

C. Hydro Issues

The proposed rule did not include generation from existing hydro in the 2012 baseline used in Block 3, but allows state plans to give compliance credit to "incremental hydropower generation from existing facilities (or later built facilities)" (79 Fed. Reg. at 34867). Elsewhere, EPA proposes that any existing state requirement, program or measure implemented after date of proposal (June 18, 2014) can be counted for compliance, but only credited for its emission impacts starting at the beginning of the initial plan performance period (2020). EPA takes comment whether earlier or later dates should be considered, both for the first date when a measure is eligible for inclusion, and for when its emission impacts may begin to count toward compliance (79 Fed. Reg. at 34918-19).

ED_000419-0006024

The proposed approach suggests that if a utility adds incremental capacity to an existing dam, builds a new dam, or signs a new Power Purchase Agreement (PPA) for generation from a dam built after June 2014, those MWh could be included in the denominator of the state's compliance demonstration. EPA should credit such measures after 2005, or at minimum after the 2012 base year, rather than after the date of the proposal. Thus, we support EPA's alternative in which any such measure undertaken after the base year of 2012, or after 2005 should be eligible. Consistent with our advocacy of a renewable banking approach discussed in Section IV, we also support EPA's alternative in which the emissions impacts of any such measure could be counted and banked prior to 2020 – e.g, beginning in 2017.

We request that EPA clarify in the final rule that any qualifying hydro measure (incremental or new capacity) is eligible for compliance credit whether the dam in question is in or outside the United States. Xcel Energy's Minnesota affiliate contracts for power from Manitoba Hydro, and is considering whether to enter into new PPAs. If we enter into a new PPA with Manitoba Hydro, this will reduce our emissions from affected EGUs in the United States and should be creditable. EPA and the states should ensure that there is no double-counting of the same hydro capacity in more than one state's 111(d) plan, but as long as that condition is met, should make hydro in Canada eligible for compliance.

Finally, we request that EPA clarify in the final rule that new or incremental hydro is eligible for inclusion in a state's 111(d) plan even if large hydro is not defined as an eligible energy resource in the state's RPS. A state need not be asked to alter what is eligible for RPS compliance; any measure that reduces emissions from the affected EGUs should be eligible in 111(d) plans, regardless whether it is eligible for RPS compliance. Clarification on this point from EPA will give states greater clarity when they are drafting their 111(d) plans.

ED_000419-0006025

D. Other Requested Clarifications

1. Recognition of coal plant retirements between 2012 and 2020

EPA should not require states to make, for any plant retirements between 2012 and 2020, a demonstration of "additionality" showing these emission reductions would not have occurred in the absence of the CAA 111(d) program. The Preamble hints that EPA may require states to make such a showing, stating "… total emissions to the atmosphere would likely be greater under this approach [of allowing emission reductions prior to 2020 to be applied toward meeting the required level of emission performance in a state plan], unless the pre-2020 emission reductions that can be counted toward the state goal are limited to reductions that would not have occurred in the absence of the CAA section 111(d) program" (79 Fed. Reg. at 34,919). This hints that a unit retirement that serves any purpose in addition to carbon reduction – e.g. MATS compliance, other environmental regulations, or a fleet modernization program designed in collaboration with a state legislature – may be considered to "have occurred in the absence of the CAA section 111(d) program" and not be creditable for 111(d) compliance.

In achieving EPA's Clean Power Plan objective of reducing CO_2 emissions, it is *whether and when* unit retirements happen, not *why* they happen, that matters. Xcel Energy strenuously objects to any dissection of utilities' intent, or disqualification of unit retirements that serve multiple purposes. Utilities always make the costly and complex decision to retire a plant in consideration of multiple factors, and it is unnecessary and subjective to distinguish plant retirements motivated by future carbon regulation from those that would have "occurred anyway." For years, utilities have made such decisions under the expectation of future GHG

ED_000419-0006026

regulations, whether under a legislative or CAA framework. Utilities have also considered the MATS rule and other environmental regulations making continued operation more costly, lower gas prices, and other economic, regulatory, social and political pressures. The coal plant retirements Xcel Energy has carried out, both before 2012 and those planned between 2012 and 2020, are designed in part to reduce future carbon compliance costs for our customers and in part to meet other environmental regulatory obligations. It would be difficult to identify which plant retirements would have occurred, and which would not have occurred, in the absence of carbon regulation that has been expected for years, and now takes the form of a CAA section 111(d) program. Creating uncertainty whether a coal plant retirement prior to 2020 would receive compliance credit only creates the perverse incentive to delay retirements.

EPA should make clear that CO_2 emission reductions due to unit retirements after the 2012 base year may be applied toward goal achievement after 2020, and may be banked prior to 2020 beginning on the date of retirement, without requiring states or utilities to make any demonstration that the retirement would not have occurred in the absence of the CAA section 111(d) program. This should include retirements that, in addition to CO_2 reduction, achieve compliance with MATS or other regulations, as well as retirements that are carried out in fulfillment of state legislative program such as the Clean Air Clean Jobs Act in Colorado.[20] EPA should specify in the final rule how such retirements will be credited, under both rate-based plans and in the event that a state elects to convert its rate target to a mass budget.

2. Ambiguous and asymmetrical treatment of biogenic CO_2 emissions

[20] Which EPA praises in the preamble (79 Fed. Reg. at 34,834 and 34,849 and 34,881).

ED_000419-0006027

EPA should provide greater clarity and consistency in the treatment of biomass power. Currently biomass MWh are treated as carbon-neutral in calculating state goals (since all biomass MWh eligible for state renewable portfolio standards are included in the denominator, with no CO_2 emissions in the numerator); this makes the interim and final goals more stringent for any state with existing biomass plants. The treatment of biomass for compliance however is unclear. EPA's November 19 guidance memorandum on biogenic CO_2 emissions appears to support the treatment of waste-derived feedstocks and certain forest-derived feedstocks as "having minimal or no net atmospheric contributions of biogenic CO_2 emissions, or even reduc[ing] such impacts, when compared to the alternate fate of disposal."[21] This is a positive step, but implies that CO_2 emissions may be assigned to biomass facilities utilizing other feedstocks. In addition, the revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources*, on which the guidance memorandum is based, remains a draft document subject to revision.

This inconsistency creates a penalty for states with existing biomass plants, since their goal is more stringent because of these plants, but they may be required to assign CO_2 emissions to at least some types of biomass used for 111(d) compliance. This will act as a significant disincentive to biomass use, due to the complexity and uncertainty of the *Accounting Framework*. Instead, EPA should clarify that biomass power and biomass co-firing in fossil plants are considered carbon-neutral when used for goal achievement. We support EPA's suggestion that sustainably-derived forest feedstocks may be considered carbon-neutral, but note that in defining what constitutes sustainably-derived forest feedstocks, EPA should not substitute its judgment for that of the responsible state forestry agency charged with setting such standards. EPA's guidelines should also recognize the methane avoidance associated with waste-derived

[21] Memorandum, *Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources*. Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, to regional Air Division directors. November 19, 2014.

ED_000419-0006028

feedstocks, such as biogas and landfill gas, which can make such feedstocks better than carbon neutral.

3. Acceptability of out-of-sector GHG offsets in 111(d) plans

The proposed rule is unclear on the eligibility of out-of-sector GHG offsets for inclusion in states' 111(d) plans. Many states currently beginning to consider which measures to include in their plans are uncertain whether to use GHG offsets. EPA should clarify that states may use GHG offsets to achieve any emission reductions their state plan (e.g. under the "state portfolio" or "state commitment" approaches) does not assign to affected EGUs. GHG offsets are generally considered one of the most powerful cost-containment mechanisms available in existing cap-and-trade programs, and can deliver significant economic and environmental (wildlife habitat, water quality, etc.) co-benefits. Voluntary and regulatory offset programs have developed rigorous protocols and associated rules to ensure that GHG offsets represent real, additional, permanent, verifiable and enforceable reductions.

E. Preliminary Comments on October 30 Notice of Data Availability

As discussed above, on October 30, 2014, EPA published a NODA providing supplemental information and alternative policy designs addressing specific issues under the proposed Clean Power Plan. While we appreciate EPA's efforts to address some of the issues that have been raised by stakeholders since the proposal of the Clean Power Plan, the NODA includes very significant potential changes to the proposal and was released only one month before the comment deadline on this very significant and complex rule. Because of the complexity of the rule, numerical analysis is necessary to understand how the proposed changes might affect our

ED_000419-0006029

states and our customers. That analysis is lacking at this time. We therefore request that EPA provide more information and more time to comment on the implications of the NODA.

Nevertheless, we provide the following preliminary comments on the NODA:

- We appreciate EPA's constructive suggestions for comments on the proposal's treatment of early action and interim targets. These are the very issues that Xcel Energy has identified as concerns in these comments, and for which Xcel Energy has proposed constructive, workable changes that EPA can incorporate into its final rule. Our primary response to the NODA, and the proposed rule overall, is our set of proposed changes discussed in detail in Section IV of this document. Those changes would help improve early action credit and mitigate interim target concerns.
- EPA should not use any of the options discussed in the NODA to increase the disparity of targets among the states. Within the NODA, EPA discusses new methods by which state targets may be set differently than under the proposed rule. For instance, EPA discusses a broader set of options through which more natural gas might be incorporated into the U.S. utility system under Block 2, and also a "regionalized approach" to RE potential under Block 3. As we point out in Section III of these comments, our states' early action has in many cases resulted in state targets that are far more stringent than the national average, even as these states made considerable progress on reducing emissions before 2012. EPA should consider the implications for equity in state targets as it contemplates any changes to its target-setting methodology.
- The NODA proposes that EPA may modify Block 2 using a "holistic" set of options to increase natural gas generation in the power sector, such as new NGCCs and gas co-firing at coal plants, and a regional approach to NGCC redispatch potential. This

proposal is vague, and its implications are impossible to understand from the NODA itself. We are concerned that, depending on how it is implemented, this proposal could cause states with a diverse generation portfolio to end up with more stringent targets despite their effective clean energy leadership.

- As discussed in Section VI, a potential-based approach to renewable energy tends to increase disparity between state targets, punishes leading clean energy states, and is arbitrary. The NODA's discussion of a more regionalized approach to apply renewable technical potential to Block 3 leaves us with the same concerns.
- We oppose the revised methodology for Blocks 3 and 4 that assumes that renewables and energy efficiency will displace generation from coal and oil/gas steam. As the largest provider of wind energy in the country, managing the dispatch of three different wind-heavy utility systems every day, we believe this proposed assumption for EPA's target-setting is not supported by reality. In fact, as we discuss in Section IV of these comments, with supporting national and internal analyses, renewables tend to displace gas more often than not. Nationally, it is a reasonable estimate that wind energy displaces natural gas combined-cycle generation about 50% of the time, and wind displaces gas-fired combustion turbine plants in addition. While renewables displace some amount of coal-fired generation, this is true for a relatively small fraction of the total renewable MWh. EPA's current target-setting method, which essentially assumes that renewables displace generation at the system average emissions rate, is a reasonable approach. EPA should reject the assumption that renewables displace only coal or gas steam generation.
- As stated elsewhere in these comments, we:
    - support the "glide path" approach of phasing in Blocks 1 and 2 through increasing NGCC capacity factors as moving in right direction, but still believe that the best

approach is the CICS proposal of glide paths designed and proposed by states described in Section IV.

- support the alternative, stated in the original proposed rule and restated in NODA, of allowing crediting of "early" (2014-2020) reductions to compensate for higher emissions 2020-2029, i.e. banking. As discussed in Section IV, our own banking proposal centers on renewable energy leadership and the application of these banked credits to the final target years, but EPA's discussion of emissions reduction banking proposals is helpful toward crediting early action and mitigating interim target concerns.
- support the option to use a multi-year baseline as well as the option for states to choose any year(s) within this timeframe. Creating the option to look at more than one year, and earlier years, is helpful for baseline purposes. Looking further back to 2005 rather than 2010 would be more helpful still in more appropriately recognizing earlier emissions reductions.

F. Preliminary Comments on Rate to Mass Conversion Technical Support Document

Xcel Energy appreciates EPA providing an example of rate to mass conversion. It is useful to have an illustrative calculation, and we appreciate that EPA has noted this is not the only way states could create an approvable mass budget. The company supports allowing states the option to use a simple mass-based approach to developing their emission control plans. In some circumstances, a mass-based approach may allow states to avoid some of the implementation issues described elsewhere in these comments, including our concerns related to EPA's role in state energy planning and EM&V under an energy efficiency program.

ED_000419-0006032

However, it is challenging to digest a complex TSD released only 15 business days before comments are due. EPA should provide more time to review and comment on the proposed TSD. As a preliminary matter, any mass conversion approach should provide full credit to the same emission reduction initiatives that would help a state meet the rate-based target.

We support EPA's approach of providing a pathway rate to mass conversion, while also providing states the ability to suggest other reasonable methods to convert their rate-based targets to mass targets. The states may be able to develop and propose other reasonable, and possibly improved, methods to translate rate targets to mass targets. This option may alleviate preliminary concerns we have with the proposed translation method, such as the assumption that energy efficiency and renewables displace only existing generation, and the assumption that new NGCCs ought to receive tons under a mass cap based on their state's allowed emissions rate, regardless of whether that rate is 500 lb/MWH or 1500 lb/MWH. Also, as EPA correctly notes in the Projecting EGU CO_2 Emission Performance in State Plans TSD, projecting generation and emissions over time requires reliance on often uncertain projections of future energy and economic conditions, including energy consumption, fuel prices and economic growth. In the mass conversion, EPA should provide states periodic opportunities to revise their generation forecasts and mass budgets in light of changed circumstances. Furthermore, the method should allow states to employ the degree of modeling sophistication they choose based on local conditions and state resources.

Finally, we encourage EPA to also consider the concerns regarding the rate to mass conversion TSD presented in the EEI and CICS comments.

ED_000419-0006033

Exhibit A

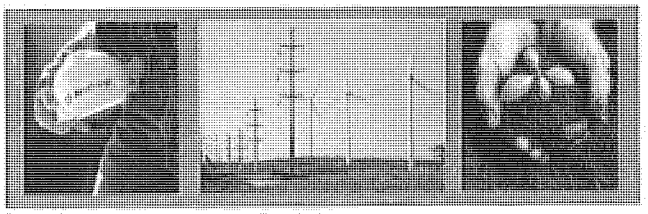
Recommended Changes to Section 111(d) Rule

Xcel Energy

August 28, 2014

ED_000419-0006034

Recommended Changes to Proposed 111(d) Rule



Xcel Energy Inc.
August 28, 2014

Problem with (and Solutions for) the Section 111(d) Rule

- Rule puts greater burden on states that are leaders in clean energy
  - Pre-2012 coal plant retirements
  - Renewable energy leadership
  - Interim targets
- Result:
  - Greater costs for leading states and utilities
  - Disincentive to pursue future clean energy leadership
- Simple, narrowly focused changes can help mitigate this burden without dramatically changing rule structure

2

Proposed Changes

1) Block 2: Exempt NGCCs built after 2005 to replace coal from the 70% capacity factor assumption
2) Block 2: Eliminate the Penalty for NGCC Generation Displaced by Renewables
3) Interim Targets: Increase Flexibility in Interim Goals
4) Block 3: Provide Early Action Credit for Renewables through Banking
5) Technical Corrections (e.g. Sherco 3, nameplate NGCC capacity, etc.)

Note: Changes Shown Individually Here are Cumulative

3

1. Block 2: Exempt NGCCs Built After 2005 to Replace Coal

- Problem: Proposed rule punishes pre-2012 state multi-pollutant emission reduction programs
  - Example: Minnesota's Metro Emission Reduction Program (MERP)
  - New CCs replaced coal, reducing CO_2 emissions
  - Because of Block 2 re-dispatch, MERP caused Minnesota to have a lower target
- Solution: Recalculate Block 2 excluding NGCC capacity that replaces coal retired under multi-pollutant programs
  - Exemption would apply to the lesser of the capacity of coal retired or the capacity of NGCC installed

4

1. Block 2: Exempt NGCCs Built After 2005 to Replace Coal

- MERP Example:
  - 652 MW High Bridge and Riverside coal plants replaced with 1,080 MW of NGCCs at same sites
  - Exempt 652 MW of this NGCC from Block 2 in Minnesota

	2030 Goal		
State	Proposed	Revised	Change
Minnesota	873	957	84

  - Other Affected States with Multi-Pollutant Retirement Programs:

	2030 Goal		
State	Proposed	Revised	Change
Georgia	740	843	103
North Carolina	992	1029	37
Tennessee	1163	1210	47
Wisconsin	1203	1230	27

5

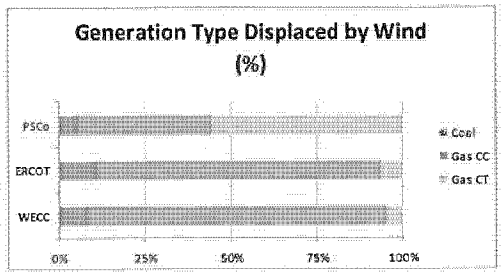
2. Block 2: Eliminate the Penalty for NGCC Generation Displaced by Renewables

- Problem: Intermittent renewable energy is predominantly balanced with NGCC generation
  - Wind generation drives down capacity factors of NGCCs
  - Block 2 creates more aggressive goals for states with renewables and NGCCs
  - Block 2 penalizes renewable energy leadership
- Solution:
  1. Estimate NGCC MWh displaced by wind in 2012 (roughly 50%)
  2. Add the displaced MWh to actual NGCC MWh in 2012; re-calculate capacity factor
  3. Re-calculate Block 2 with adjusted capacity factor

6

2. Block 2: Eliminate the Penalty for NGCC Generation Displaced by Renewables

Several studies in different regions indicate that 40 to 80% of energy produced by wind displaces NGCC generation



System	Study
Xcel Energy Colorado System (PSCo)	Xcel Energy Historical Analysis for 2013, based on four representative months
ERCOT	"Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements" March 2008
WECC	"The Western Wind and Solar Integration Study Phase 2, National Renewable Energy Laboratory", September 2013

7

2. Block 2: Eliminate the Penalty for NGCC Generation Displaced by Renewables

Changes in Emission Targets from Elimination of NGCC Generation Displacement Penalty (Using 50% Displacement)

		2030 Goal
MN	proposed	873
	revised	977
	change	*105*
CO	proposed	1108
	revised	1155
	change	*47*
TX	proposed	791
	revised	831
	change	*41*

8

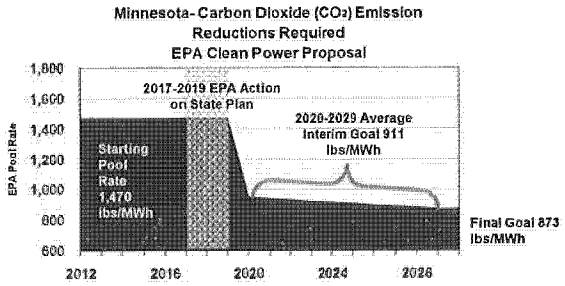
2. Block 2: Eliminate the Penalty for NGCC Generation Displaced by Renewables

	Change in Final Goal		
State	40% displacement Factor	50% displacement Factor	60% displacement factor
Colorado	38	47	56
Idaho	69	84	98
Iowa	84	102	119
Minnesota	85	105	124
New Mexico	37	46	55
Oklahoma	38	48	57
Oregon	35	43	50
South Dakota	233	279	322
Texas	33	41	48
Washington	38	46	55

9

3. Interim Targets: Increase Flexibility in Interim Goals

- Problem: EPA's interim goals would require most reductions by 2020
- Greater burden on clean energy leaders; "low hanging fruit" is gone
- Potential for premature retirements, stranded costs, reliability impacts



- Solution: Allow states to establish own interim glide path based on emission reduction plans
  - Assures credibility
  - Protects clean energy states from disruption
  - Enables other "fixes"

10

4. Block 3: Early Action Credit for Renewables Through Banking

- Problem: Leading renewable energy states have more stringent, more expensive mandates
  - More stringent mandates drive higher regional average target
  - Lagging states have lower starting point, have less stringent RE goal, and may never reach regional target
  - Cheapest renewables already built in leading states
- Solution: Create renewable energy bank to raise 2030 goal and allow more time for compliance with final state goal

4. Block 3: Early Action Credit for Renewables Through Banking

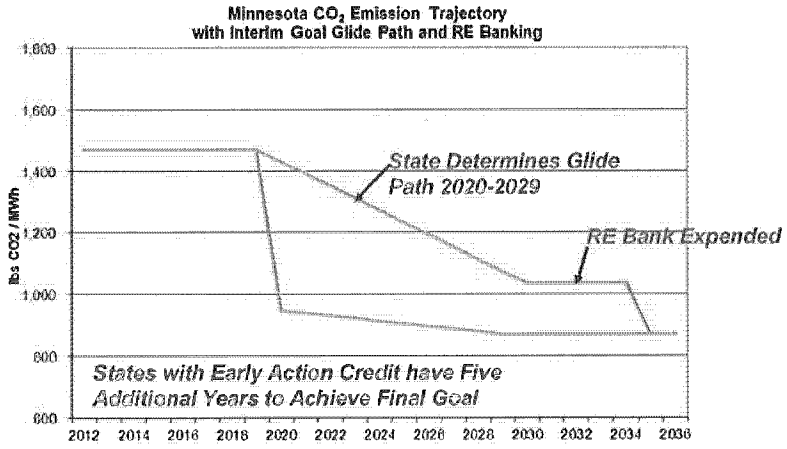
Potential Design:

- Only states with 2012 RE percentage above 1.5 x the national average are allowed to bank
- Bank = (state RE generation) – (1.5 x national average RE generation)
  - Rewards significant leadership
  - Limits impact on rule design
- Bank accumulates from 2017 – 2019
- State expends bank from 2030 – 2034
  - State target capped at 2012 emissions
- At 2035, state must meet final goal

		2030 Goal
MN	proposed	873
	revised	1036
	change	*163*
CO	proposed	1108
	revised	1203
	change	*95*
TX	proposed	791
	revised	874
	change	*83*

Note: States with early action credit have five additional years to achieve final goal

4. Block 3: Early Action Credit for Renewables Through Banking



4. Early Action Credit for Renewables Under Block 3 through Banking: Analysis

- Fifteen states have 2012 RE percentage above 1.5 x the national average
- Change in 2030 goal shown at right
- Where revised 2030 goal goes above 2012 adjusted emission rate, cap at 2012 adjusted emission rate
- 2035 goal remains same as per proposed rule

MANY OTHER EARLY ACTION DESIGNS ARE POSSIBLE

State	Current 2030 goal	2030 goal with banking	Change in 2030 goal
California	537	631	94
Colorado	1,108	1,203	95
Hawaii	1,306	1,540	234
Idaho	228	339	111
Iowa	1,301	1,552	251
Kansas	1,499	1,940	441
Maine	378	437	59
Minnesota	873	1,036	163
New Mexico	1,048	1,259	212
North Dakota	1,783	1,994	211
Oklahoma	895	1,032	137
Oregon	372	580	208
South Dakota	741	1,135	394
Texas	791	874	83
Wyoming	1,714	1,883	169

5. Technical Corrections

- Problem: Sherco 3 (900 MW) did not run in 2012, skewing the single-year baseline and raising Minnesota's emissions goal
- Solution: Add back proxy lbs and MWhs to 2012 MN fossil intensity rate
  - A simple add-back of 2010 Sherco 3's CO_2 emissions and MWh to the goal formula increases Minnesota's goal by 83 lbs/MWh
  - A multi-year baseline is another potential fix for this and other baseline anomalies nationwide

- Problem: EPA used nameplate capacity of NGCC units in Building Block 2, which does not reflect their actual capacity available for re-dispatch
- Solution: Use summer net capacity in place of nameplate

Capacity Correction

		Final Goal
MN	proposed	873
	revised	959
	change	*86*
CO	proposed	1108
	revised	1,155
	change	*47*
TX	proposed	791
	revised	815
	change	*24*

15

Xcel Energy®

RESPONSIBLE BY NATURE®

From: Dunham, Sarah
To: Barron, Alex
Sent: 11/18/2014 6:27:54 PM
Subject: Q A document on biomass
Attachments: Biomass-QAs-11 18 14 v4.docx

We clearly need to still think about what's we need to do further in terms of guidance etc, but this is the latest version of the Qs and As.

From: Gunning, Paul
To: Dunham, Sarah
Sent: 11/14/2014 8:18:45 AM
Subject: RE: biomass
Attachments: Biomass%20CPP%20Questionsv2 (BI).docx

Sarah – as a follow on to my previous note, attached is what we developed last night for the internal/substantive CPP Q&As . **Ex. 5 - Deliberative**

From: Dunham, Sarah
To: Gunning, Paul; Kocchi, Suzanne; Krieger, Jackie
Sent: 11/13/2014 1:08:49 PM
Subject: FW: biomass framework comms materials
Attachments: Biogenic CO2 Framework Internal QAs 11 13 14.docx; Biomass Memo to Regions 111314-cleanv2.docx; Biomass Roll out.docx; Desk Statement 11 13 14.docx

Fyi, and we can talk about this at 4, but I just want to make sure that we have a **Ex. 5 - Deliberative**
Ex. 5 - Deliberative
Ex. 5 - Deliberative I'm not sure if that's a separate list of Qs and As, or separate As, or its all the same thing. But we just need to have the specifics thgouth through as much as possible now, but just wait for later.

thanks

From: DeLuca, Isabel
Sent: Thursday, November 13, 2014 12:51 PM
To: Harvey, Reid; Tsirigotis, Peter; Culligan, Kevin
Cc: Dunham, Sarah; Gunning, Paul; Kocchi, Suzanne; Irving, Bill; Krieger, Jackie; Lemon, Mollie
Subject: biomass framework comms materials

Hi all,
Attached are draft communications materials for the biomass framework roll out (desk statement, roll-out plan with call list, and internal Q&As). Also attached is the latest draft of the memo to the Regions—OGC and OP are reviewing this now so there may be changes.

Jan Cortelyou-Lee is coordinating comments from OAQPS, but we wanted to make you see these as well. We could use your help **Ex. 5 - Deliberative**

It looks like the Memo will go out tomorrow, so if you could weigh in by this afternoon or tomorrow AM that would be great.

Thanks,

Isabel DeLuca
Climate Change Division, US EPA
(202) 343-9247

From: Kocchi, Suzanne
To: Dunham, Sarah; Gunning, Paul
Sent: 9/18/2014 9:11:16 AM
Subject: RE: Biomass Path Forward TPs 9 17 14

I don't know. Ex. 5 - Deliberative

Ex. 5 - Deliberative

From: Dunham, Sarah
Sent: Thursday, September 18, 2014 9:09 AM
To: Kocchi, Suzanne; Gunning, Paul
Subject: RE: Biomass Path Forward TPs 9 17 14

Ok thanks— Ex. 5 - Deliberative

From: Kocchi, Suzanne
Sent: Thursday, September 18, 2014 8:54 AM
To: Dunham, Sarah; Gunning, Paul
Subject: RE: Biomass Path Forward TPs 9 17 14

Thanks. 2 quick points if there is an opportunity to clarify with Joe before the mtg:

Ex. 5 - Deliberative

I know the second point is a mouthful but if Joe's rework is only talking points probably ok. If it is handed out it might be worth trying to rephrase?

Ex. 5 - Deliberative

From: Dunham, Sarah
Sent: Thursday, September 18, 2014 8:47 AM
To: Kocchi, Suzanne; Gunning, Paul
Subject: Fw: Biomass Path Forward TPs 9 17 14

Sent from my BlackBerry 10 smartphone.

From: Goffman, Joseph
Sent: Thursday, September 18, 2014 1:38 AM
To: Dunham, Sarah
Subject: Fwd: Biomass Path Forward TPs 9 17 14

- Joseph Goffman
Sent from my iPhone

Begin forwarded message:

From: "Goffman, Joseph" <Goffman.Joseph@epa.gov>
Date: September 17, 2014 at 11:57:02 PM EDT
To: Joseph Goffman **Ex. 6 - Personal Privacy**
Subject: Fwd: Biomass Path Forward TPs 9 17 14

- Joseph Goffman
Sent from my iPhone

Begin forwarded message:

From: "Goffman, Joseph" <Goffman.Joseph@epa.gov>
Date: September 17, 2014 at 9:53:10 PM EDT
To: "McCabe, Janet" <McCabe.Janet@epa.gov>, "Dunham, Sarah" <Dunham.Sarah@epa.gov>
Subject: Biomass Path Forward TPs 9 17 14

What do we think of giving this to the Administrator as TPs for tomorrow's meeting and/or handing it out? Thanks.

From: Kocchi, Suzanne
To: Dunham, Sarah; Gunning, Paul
CC: Irving, Bill; Friedman, Kristina
Sent: 8/26/2014 8:31:13 AM
Subject: RE: Biomass talking points

Ok sure. Will do it now. Thanks.

From: Dunham, Sarah
Sent: Tuesday, August 26, 2014 8:30 AM
To: Kocchi, Suzanne; Gunning, Paul
Cc: Irving, Bill; Friedman, Kristina
Subject: Re: Biomass talking points

Before feeding it up, suzie, will you please send to joe G and peter T (with ccs to the rest of us) and flag that this is what we plan to add and see if they have any concerns. If you don't hear from them by early afternoon then Kristina should go ahead and send to william and whoever Kristina heard from through OCIR. Thanks

Sent from my BlackBerry 10 smartphone.

From: Kocchi, Suzanne
Sent: Tuesday, August 26, 2014 8:20 AM
To: Dunham, Sarah; Gunning, Paul
Cc: Irving, Bill; Friedman, Kristina
Subject: RE: Biomass talking points

Ok, here are the points as you describe below and here is the attachment. If you are ok, perhaps Kristina you can do pass up? Unless, Sarah, you prefer I do that?

Ex. 5 - Deliberative

Ex. 5 - Deliberative

From: Dunham, Sarah
Sent: Monday, August 25, 2014 10:03 PM
To: Kocchi, Suzanne; Gunning, Paul
Cc: Irving, Bill; Friedman, Kristina
Subject: Re: Biomass talking points

Thanks--couple quick reactions:

Ex. 5 - Deliberative

Ex. 5 - Deliberative

Sent from my BlackBerry 10 smartphone.

From: Kocchi, Suzanne
Sent: Monday, August 25, 2014 8:50 PM
To: Dunham, Sarah; Gunning, Paul
Cc: Irving, Bill; Friedman, Kristina
Subject: RE: Biomass talking points

Just to get a head start before I shut down for the evening, I have taken a first crack at the bullets based on the materials for Gina. I pasted them below and added them in the larger document (attached). Also including Kristina on this email because she was also pinged for an update on these talking pts by OCIR. Just want to be sure she sees this as well. Sarah will wait to hear from you and make edits in the morning.

Ex. 5 - Deliberative

Ex. 5 - Deliberative

From: Dunham, Sarah
Sent: Monday, August 25, 2014 7:23 PM
To: Kocchi, Suzanne; Gunning, Paul
Cc: Irving, Bill
Subject: Re: Biomass talking points

Yes on conclusions and that we will do a cover memo that has conclusions. I actually think the main points should follow ths story janet had us put at the beginning of the gina briefing paper--and then go to process including memo that will have some conclusions and at a high level what those are. But this should be high level appropriate for gina to talk to shaheen -- I can give more in person that I can't write. I should probably look at this before it goes back to william.

Sent from my BlackBerry 10 smartphone.

From: Kocchi, Suzanne
Sent: Monday, August 25, 2014 7:18 PM
To: Dunham, Sarah; Gunning, Paul
Cc: Irving, Bill
Subject: Re: Biomass talking points

Sarah - Just to clarify the specifics you want us to add - Ex. 5 - Deliberative

Ex. 5 - Deliberative

be sure we put in the right points since you all will be in that retreat so other than BlackBerry limited opportunity for guidance. Thanks - Suzie
Sent from my BlackBerry

From: Dunham, Sarah
Sent: Monday, August 25, 2014 6:12 PM
To: Kocchi, Suzanne; Gunning, Paul
Subject: Fw: Biomass talking points

We need a talking point version that gives the gist of our next steps document, just a few points that say what we're planning to do. Can someone pull this together tomorrow first thing? With a focus on Ex. 5 - Deliberative

Ex. 5 - Deliberative

Sent from my BlackBerry 10 smartphone.

From: dunham.sarah@epa.gov
Sent: Monday, August 25, 2014 6:08 PM
To: Goffman, Joseph; Niebling, William
Cc: Gunning, Paul; Kocchi, Suzanne
Subject: Re: Biomass talking points

Hi william-
I talked to joe about what we should say on biomass--would you please send us the version you are starting with and we can add some points.
Thanks
Sarah

Sent from my BlackBerry 10 smartphone.

From: Goffman, Joseph
Sent: Monday, August 25, 2014 5:22 PM
To: Niebling, William
Cc: Dunham, Sarah
Subject: Re: Biomass talking points

+ Sarah.

- Joseph Goffman
Sent from my iPhone

On Aug 25, 2014, at 3:20 PM, "Niebling, William" <Niebling.William@epa.gov> wrote:

<image002.gif>
One more – the Administrator may be talking to Shaheen in the next couple of days about biomass accounting framework. Attached are the last version of the TPs that OCIR has. Josh sent them to OAQPS, so we should get some feedback from them, but if you have particular points you want to raise, feel free to let me know (or Nichole or the Administrator directly).

Sorry to pester you.

From: Lewis, Josh
Sent: Monday, August 25, 2014 3:12 PM
To: Terry, Sara; Ashley, Jackie
Cc: Niebling, William; Haman, Patricia
Subject: RE: Biomass talking points

Anything new on the biomass deferral issue since the attached were drafted in early July? The Administrator may have a call w/ Senator Shaheen (NH) in the next couple of days.

Josh

From: Lubetsky, Jonathan
Sent: Wednesday, July 02, 2014 12:15 PM
To: Haman, Patricia; Terry, Sara
Cc: Lewis, Josh; Niebling, William
Subject: RE: Biomass talking points

I take that back. OGC sent other edits after they said they were clear.

Clean and redline attached.

From: Lubetsky, Jonathan
Sent: Wednesday, July 02, 2014 12:08 PM
To: Haman, Patricia; Terry, Sara
Cc: Lewis, Josh; Niebling, William
Subject: RE: Biomass talking points

OGC and Joe G. have cleared the document. Minor date change and grammatical edit made.

Thank you

From: Haman, Patricia
Sent: Wednesday, July 02, 2014 10:41 AM
To: Lubetsky, Jonathan; Terry, Sara
Cc: Lewis, Josh; Niebling, William
Subject: RE: Biomass talking points

We now have a little more time – apparently she can't leave at 12:30 now.

Patricia Haman
Office of Congressional Affairs
U.S. EPA
202-564-2806

From: Lubetsky, Jonathan
Sent: Wednesday, July 02, 2014 10:39 AM
To: Terry, Sara; Haman, Patricia
Cc: Lewis, Josh; Niebling, William
Subject: RE: Biomass talking points

I am checking on IO clearance. Please update the date on the document in the meantime.

From: Terry, Sara
Sent: Wednesday, July 02, 2014 10:10 AM
To: Haman, Patricia
Cc: Lewis, Josh; Lubetsky, Jonathan; Niebling, William
Subject: RE: Biomass talking points
Importance: High

Pat,
Here is our draft – I've attached track changes and clean versions. I'd like Jonathan to weigh in on whether this needs IO clearance.

Thanks,
Sara

From: Haman, Patricia
Sent: Wednesday, July 02, 2014 9:31 AM
To: Terry, Sara
Cc: Lewis, Josh; Lubetsky, Jonathan; Niebling, William
Subject: RE: Biomass talking points

I am very sorry but Nichole just learned the Administrator has decided to leave earlier than

originally scheduled so we need this by noon. Can you make that happen???? Pat

Patricia Haman
Office of Congressional Affairs
U.S. EPA
202-564-2806

From: Haman, Patricia
Sent: Tuesday, July 01, 2014 12:02 PM
To: Terry, Sara
Cc: Lewis, Josh; Lubetsky, Jonathan; Niebling, William
Subject: Biomass talking points

Sara: As discussed, here is the cleared version from 3/12 with a few suggested revisions I made to get the ball rolling.

The Administrator is meeting with Senator King next week but Nichole would like to give her this revised paper tomorrow afternoon.

Nichole is primarily interested in the question of what happens when the deferral expires on 7/21 and also would like to make sure that the portion of the paper addressing the Supreme Court decision is updated. I used an internal Q&A we received from OGC to address the latter point but would appreciate help fleshing it out as well as any other changes you believe are needed.

Thanks, Pat

Patricia Haman
Office of Congressional Affairs
U.S. EPA
202-564-2806

<Biomass Deferral talking points 07 02 14 CLEAN .docx>
<Biomass Deferral talking points 07 02 14 CLEAN + ogc.docx>

From: Sarah Dunham
To: Kocchi, Suzanne
CC: Dunham, Sarah
Sent: 8/12/2014 2:25:07 PM
Subject: Re: draft table -deliberative

I sent you an email with edits on the power point and it's not going through from my epa email. The gist of what I said

Ex. 5 - Deliberative

Sent from my iPad

On Aug 12, 2014, at 2:17 PM, "Kocchi, Suzanne" <Kocchi.Suzanne@epa.gov> wrote:

Sure – I will ask Allen on the units.

Where do you want it to go? After slide 6? Or in the appendix?

From: Sarah Dunham [mailto: **(b)(6) privacy**
Sent: Tuesday, August 12, 2014 2:15 PM
To: Kocchi, Suzanne
Cc: Dunham, Sarah
Subject: Re: draft table -deliberative

Let's add this table to the briefing also, with a couple edits--

Ex. 5 - Deliberative

Sent from my iPad

On Aug 12, 2014, at 9:38 AM, "Kocchi, Suzanne" <Kocchi.Suzanne@epa.gov> wrote:

Here is the table from Allen.

Sent from my BlackBerry

From: Fawcett, Allen
Sent: Tuesday, August 12, 2014 9:21 AM
To: Kocchi, Suzanne; Irving, Bill
Subject: RE: draft table -deliberative

Here's my updated version of the table, let me know if you have any additional edits.

Thanks,
Allen

Ex. 5 - Deliberative

Ex. 5 - Deliberative

From: Kocchi, Suzanne

<Next Steps on Framework 081214.pptx>

From: Krieger, Jackie
To: Dunham, Sarah; Gunning, Paul
CC: Friedman, Kristina; Mason, Colleen
Sent: 4/23/2014 6:12:43 PM
Subject: Fw: Biomass Meeting Materials (including attachment)
Attachments: BiomassNextSteps 4_24_14.docx; PossibleRegulatoryApproachesBiogenicCO2_4-23-2014.docx

Just want to be sure you have this.

From: South, Peter
Sent: Wednesday, April 23, 2014 5:08 PM
To: Alfaro, Carlos; Alston, Lala; Atkinson, Emily; Browne, Cynthia; Dougherty, Joseph-J; Edwards, Crystal; Gray, Doris; Henigin, Mary; Knapp, Kristien; Koerber, Mike; Rush, Alan; Sanders, Maria; South, Peter; Stewart, Lori; Stewart, Mellonie; Walker, Jean; Wang, Weber
Cc: Krieger, Jackie; Heilig, Johnetta; Johnson, Yvonne W; Ling, Michael; Long, Pam; Lorang, Phil; Mathias, Scott; Santiago, Juan; Culligan, Kevin; Eck, Janet; Fruh, Steve; Hackel, Angela; Johnson, Tanya; McLaughlin, Kevin; Tammaro, Joanne; Thompson, Fred; Vasu, Amy
Subject: Biomass Meeting Materials (including attachment)

I have attached the briefing materials in prep for tomorrow's meeting with Janet on biomass. We plan to run through the "Next Steps" document (we may refer to the "Possible Regulatory Approaches" document also attached).

Feel free to call me or Mike Koerber with any questions.

Thanks

Pete South
OAR/OAQPS/IO
U.S. EPA
office: 919 541-5359
cell: 919 599-7213

Send Update

To... Goffman, Joseph; Wood, Anna; Gunning, Paul; Dunham, Sarah; Page, Steve; Koerber, Mike; Kornylak, Vera S.; Montanez, Jessica; Dunkins, Robin; Swanson, Nicholas; Brown, Cynthia; Atkinson, Emily; Simon, Karl; Tsirigotis, Peter; Culligan, Kevin; Mangino, Joseph

Subject: Biomass Meeting

Location: WJC-N 5400 Ex. 6 - Personal Privacy Rooms...

Start time: Thu 4/24/2014 4:00 PM All day event

End time: Thu 4/24/2014 4:45 PM

To: McCabe, Janet; Goffman, Joe; Wood, Anna; Gunning, Paul; Dunham, Sarah; Page, Steve; Koerber, Mike; Wood, Anna; Kornylak, Vera S.; Montanez, Jessica; Dunkins, Robin; Swanson, Nicholas; Tsirigotis, Peter; Culligan, Kevin; Mangino, Joseph

From: Harvey, Reid
To: Dunham, Sarah
Sent: 3/24/2014 6:48:43 PM
Subject: Fw: EGU GHG EG preamble & reg text for OP
Attachments: EGU_GHG_EG_NPRM_032414_440pm.docx

From: Lifland, David
Sent: Monday, March 24, 2014 6:35:32 PM
To: Harvey, Reid; Sherry, Christopher
Subject: Fw: EGU GHG EG preamble & reg text for OP

From: Vasu, Amy
Sent: Monday, March 24, 2014 4:49:51 PM
To: Eck, Janet
Cc: Culligan, Kevin; Wayland, Robertj; Thompson, Fred; McLamb, Marguerite; Lifland, David
Subject: EGU GHG EG preamble & reg text for OP

Janet,

Here it is.

Thank you.

Amy

~~~~~~~~~~~~~~~~~~~~~~~~

Amy B. Vasu
U.S. EPA / OAQPS
Sector Policies and Programs Division
email: vasu.amy@epa.gov
phone: 919.541.0107
~~~~~~~~~~~~~~~~~~~~~~~~

From: Dunham, Sarah
To: Murphy, Tina
Sent: 3/24/2014 11:29:39 AM
Subject: FW: Revised EGU preamble & reg text
Attachments: EGU_GHG_EG_NPRM_032114_330pm.docx

Would you please print double sided for me? it's really long. Thanks!

From: Harvey, Reid
Sent: Friday, March 21, 2014 5:39 PM
To: Dunham, Sarah
Subject: FW: Revised EGU preamble & reg text

FYI

From: Lifland, David
Sent: Friday, March 21, 2014 5:38 PM
To: Harvey, Reid; Stenhouse, Jeb; Sherry, Christopher; Fisher, Brian; Adamantiades, Mikhail; Bryson, Joe; Conlin, Beth; Sims, Ryan; Forte, Reynaldo; Kokopeli, Peter; Eschmann, Erich
Subject: FW: Revised EGU preamble & reg text

This just in.

From: Vasu, Amy
Sent: Friday, March 21, 2014 5:34 PM
To: Lifland, David; Boswell, Colin; McLamb, Marguerite
Cc: Culligan, Kevin
Subject: Revised EGU preamble & reg text

Here is the version we sent to Janet.

Thank you all.

Amy

From: Dunham, Sarah
To: Krieger, Jackie
Sent: 1/31/2014 9:28:06 AM
Subject: Fw: Biomass question

I actually do need a quick answer on this--can you track suzie down?

_____
From: Dunham, Sarah
Sent: Friday, January 31, 2014 2:23:01 PM
To: Gunning, Paul; Kocchi, Suzanne
Cc: Krieger, Jackie
Subject: Biomass question

Ex. 5 - Deliberative

From: Goffman, Joseph
To: Wood, Anna; Santiago, Juan; Gunning, Paul; Kocchi, Suzanne; Dunham, Sarah
Sent: 8/8/2013 9:30:37 AM
Subject: Fw: AF&PA Letter on Impact of Deferral Decision
Attachments: AF&PA Letter on Impact of Deferral Decision.pdf; image002.jpg

---

From: Missimer, Katie <Katie_Missimer@afandpa.org> on behalf of Noe, Paul <Paul_Noe@afandpa.org>
Sent: Tuesday, August 06, 2013 3:00:38 PM
To: Goffman, Joseph
Cc: Noe, Paul; Tim_hunt@afandpa.org; Poling, Jan; Frye, Russ; Jordan, Scott; Schmidt, Lorie; McCabe, Janet
Subject: AF&PA Letter on Impact of Deferral Decision

American Forest & Paper Association

AMER
WOO
COUN

August 6, 2013

Dear Joe:

At our July 23 meeting including you, the Deputy Administrator, and Janet McCabe, you asked us to let you know how many projects might be affected by the recent court decision on the Biomass Deferral Rule. Janet outlined three different bins or "buckets" of affected projects. The first are those that are already operating that relied on the deferral rule in their permitting process. The second are projects that are pending either in terms of starting up or breaking ground but relied on the deferral rule up to this point and have obtained the permits required under current regulations to install or run new equipment. And third, projects in the pipeline that have not yet obtained permits.

To date we have heard from about 20 companies, and slightly less than half of them have affected projects. There are about a dozen projects overall, since some companies have multiple projects. In addition, there are mills on the wood products side that would go from being minor sources to major sources for PSD purposes if biogenic CO2 emissions are counted, so any future modification would require more effort and time than before.

We are not authorized to disclose project details because of the potential for confidential business information associated with the unique nature of the projects, so I am providing a summary. Let me start by saying the examples we have heard come from both AF&PA and AWC member companies and so involve a broad range of forest product mills.

Half the cases fall into the **first "bucket,"** where a modification to the mill became operational in the last 18 months. The projects involve biomass boilers, recovery furnaces burning black liquor, or other process equipment that increased steam demand. Some of these projects were in anticipation of Boiler MACT and involve replacing coal boilers with biomass systems with significant reductions in PM, SO2 and NOx, often with cogeneration of electricity to meet mill energy demands or even export power that qualifies for a state RPS. If the mill needed a PSD permit for the project, that permit did not address BACT for greenhouse gases because biogenic CO2 emissions were not counted towards the significant net emissions increase threshold. At least one project did not require a PSD permit because of emission reductions associated with the project, but if biogenic CO2 was counted the project would need a PSD permit, with associated delays and permitting costs, and because it becomes a major source, additional pollutants would be subject to PSD evaluations.

There are three projects in the **second "bucket,"** for which the companies urgently want clarification of whether they will be obligated to do any additional permitting prior to completing or starting up the project. These projects are time-sensitive due to narrow construction windows that are coming up as soon as next month or equipment that is

being fabricated and will need to be installed very soon. Again, companies have the permits needed under current law to construct these modifications, but permitting requirements would be different if biogenic CO2 emissions were counted.

Finally, there are three projects in the near-term pipeline (**third "bucket"**) that we are aware of. Most are very time-sensitive and tied to Boiler MACT compliance, and they have long lead times given the engineering, vendor selection, fabrication, installation and testing needed in advance of the 2016 Boiler MACT compliance deadline. These projects would trigger PSD for other pollutants but not GHGs if biogenic emissions are excluded. More projects could be affected if EPA is delayed in getting a revised final Tailoring rule completed that addresses biogenic emissions.

In aggregate, these projects represent about three quarters of a billion dollars in capital investments.

We hope that the Agency can provide the necessary legal certainty so these investments are not jeopardized or thwarted. It would be particularly problematic if the DC Circuit Court opinion were interpreted to require retroactive consideration of biogenic CO2 for projects permitted since July 2011. We welcome the opportunity to continue to explore both administrative and legal means for protecting mill investments.

Let me close by reiterating what we said at our meeting - that it is very important for EPA to address business uncertainty and to move forward expeditiously with completing its Biogenic Framework and revising the Tailoring rule to exclude projects with qualifying biogenic emissions from the PSD process. If you have specific questions about this information, please contact Tim Hunt, Senior Director, Air Quality Programs, at 202-463-2588 or Tim_Hunt@afandpa.org.

Thank you for your consideration.

Best regards,

Paul Noe
Vice President, Public Policy

Paul Noe
Vice President for Public Policy
AMERICAN FOREST & PAPER ASSOCIATION
1111 19th Street, NW, Suite 800, Washington, D.C. 20036
Paul_Noe@afandpa.org
202-463-2777 (phone)
202-463-2772 (fax)
www.afandpa.org

American Forest & Paper Association

BETTER PRACTICES BETTER PLANET
Continuing AF&PA's Commitment to Sustainability

American Forest & Paper Association

AMERICAN WOOD COUNCIL

August 6, 2013

Dear Joe:

At our July 23 meeting including you, the Deputy Administrator, and Janet McCabe, you asked us to let you know how many projects might be affected by the recent court decision on the Biomass Deferral Rule. Janet outlined three different bins or "buckets" of affected projects. The first are those that are already operating that relied on the deferral rule in their permitting process. The second are projects that are pending either in terms of starting up or breaking ground but relied on the deferral rule up to this point and have obtained the permits required under current regulations to install or run new equipment. And third, projects in the pipeline that have not yet obtained permits.

To date we have heard from about 20 companies, and slightly less than half of them have affected projects. There are about a dozen projects overall, since some companies have multiple projects. In addition, there are mills on the wood products side that would go from being minor sources to major sources for PSD purposes if biogenic CO2 emissions are counted, so any future modification would require more effort and time than before.

We are not authorized to disclose project details because of the potential for confidential business information associated with the unique nature of the projects, so I am providing a summary. Let me start by saying the examples we have heard come from both AF&PA and AWC member companies and so involve a broad range of forest product mills.

Half the cases fall into the **first "bucket,**" where a modification to the mill became operational in the last 18 months. The projects involve biomass boilers, recovery furnaces burning black liquor, or other process equipment that increased steam demand. Some of these projects were in anticipation of Boiler MACT and involve replacing coal boilers with biomass systems with significant reductions in PM, SO2 and NOx, often with cogeneration of electricity to meet mill energy demands or even export power that qualifies for a state RPS. If the mill needed a PSD permit for the project, that permit did not address BACT for greenhouse gases because biogenic CO2 emissions were not counted towards the significant net emissions increase threshold. At least one project did not require a PSD permit because of emission reductions associated with the project, but if biogenic CO2 was counted the project would need a PSD permit, with associated delays and permitting costs, and because it becomes a major source, additional pollutants would be subject to PSD evaluations.

1111 Nineteenth Street, NW, Suite 800 ▪ Washington, DC 20036 ▪ 202 463-2700 Fax: 202 463-2785 ▪ www.afandpa.org

BETTER PRACTICES BETTER PLANET 2020
Continuing AF&PA's Commitment to Sustainability

There are three projects in the **second "bucket,"** for which the companies urgently want clarification of whether they will be obligated to do any additional permitting prior to completing or starting up the project. These projects are time-sensitive due to narrow construction windows that are coming up as soon as next month or equipment that is being fabricated and will need to be installed very soon. Again, companies have the permits needed under current law to construct these modifications, but permitting requirements would be different if biogenic CO2 emissions were counted.

Finally, there are three projects in the near-term pipeline (**third "bucket"**) that we are aware of. Most are very time-sensitive and tied to Boiler MACT compliance, and they have long lead times given the engineering, vendor selection, fabrication, installation and testing needed in advance of the 2016 Boiler MACT compliance deadline. These projects would trigger PSD for other pollutants but not GHGs if biogenic emissions are excluded. More projects could be affected if EPA is delayed in getting a revised final Tailoring rule completed that addresses biogenic emissions.

In aggregate, these projects represent about three quarters of a billion dollars in capital investments.

We hope that the Agency can provide the necessary legal certainty so these investments are not jeopardized or thwarted. It would be particularly problematic if the DC Circuit Court opinion were interpreted to require retroactive consideration of biogenic CO2 for projects permitted since July 2011. We welcome the opportunity to continue to explore both administrative and legal means for protecting mill investments.

Let me close by reiterating what we said at our meeting - that it is very important for EPA to address business uncertainty and to move forward expeditiously with completing its Biogenic Framework and revising the Tailoring rule to exclude projects with qualifying biogenic emissions from the PSD process. If you have specific questions about this information, please contact Tim Hunt, Senior Director, Air Quality Programs, at 202-463-2588 or Tim_Hunt@afandpa.org.

Thank you for your consideration.

Best regards,

Paul Noe
Vice President, Public Policy

From: mbooth.pfpi@gmail.com on behalf of Mary S. Booth
To: Ohrel, Sara; Irving, Bill; Cole, Jefferson; Eschmann, Erich; Goffman, Joseph
Sent: 12/4/2014 9:14:34 PM
Subject: You'll enjoy this article

Dear EPA friends -
You'll enjoy this article.
Lots of blah blah, skip to the end and read the last paragraph. Bob Cleaves is feeling pretty puffed!

Best regards,
Mary

http://bangordailynews.com/2014/11/25/politics/new-epa-report-could-be-a-boon-to-maine-biomass-energy-producers/

New EPA report could be a boon to Maine biomass energy producers

Print
Email
Share
Tweet

By Scott Thistle, Sun Journal
Follow on Twitter Find on Facebook
Posted Nov. 25, 2014, at 11:36 a.m.

LEWISTON, Maine — A new analysis by the federal Environmental Protection Agency may be good news for Maine firms that make electricity by burning wood, but some environmental groups are crying foul.

The new EPA analysis, issued last week, suggests how the federal government will count greenhouse gas emissions from wood-fired biomass facilities, and an accompanying memo from a top-ranking EPA official suggests biomass producers will likely get a pass when it comes to strict, new carbon dioxide regulations.

Carbon dioxide is a gas byproduct that comes from burning any carbon-based fuel, including coal, petroleum and wood, and it is largely blamed for the effects of global climate change.

But the new analysis suggests that because wood-fired biomass facilities are fueled with forest byproducts, namely leftover branches, limbs, chips and sawdust, the net impact on the environment is neutral over time.

The analysis involves some complex science that models the amount of CO_2 live trees absorb compared to the amount that's released when they either decompose naturally or are burned for energy.

Live trees and other plants absorb carbon dioxide, but once dead and decomposing they slowly release it back into the atmosphere and soil.

The EPA's new determination that biomass-generated electricity has no net impact on climate change means the biomass facilities may be exempted from some strict new federal air emission regulations on the horizon. The new analysis comes as the federal government moves to implement the Obama Administration's Clean Power Plan over the next two years.

"There have been differing definitions in various federal statutes for long periods of time but this is the

most clear ruling, decision by the federal government that makes clear that biomass has undeniable climate benefits for Maine and the country," said Bob Cleaves of Portland-based Biomass Power Association.

The association represents the state's 10 biomass producers and also advocates for national policy that favors biomass energy.

Maine's biomass industry includes independent power generators that sell the energy they make onto the New England electricity grid but also co-generation facilities that are operated by some of the state's paper mills. The mills either sell the power onto the grid or use it for their own consumption, depending on the power's overall value at the time and the mills' local demand for energy.

With about 345 megawatts of biomass generating capacity, Maine is the largest producer of that type of electricity in New England and one of the largest in the U.S.

"It does provide reassurance," said Sarah Boggess, a spokeswoman for ReEnergy Holdings, which employs about 105 workers at its four biomass plants in Maine.

ReEnergy owns and operates facilities in Eustis, Livermore Falls, Fort Fairfield and Ashland.

In all, the industry in Maine employs about 1,300 workers and associated jobs and contributes between $100 million to $200 million a year to the state's economy, according to the Biomass Power Association.

Boggess said the EPA analysis and subsequent memo issued to states by Janet McCabe, the EPA's acting administrator for Air and Radiation, recognizes biomass as a solution to the problem of climate change and not contributor to it.

But at least one opponent of biomass energy in the U.S., the Partnership for Policy Integrity, claims that burning trees to produce electricity actually produces more CO_2 than burning coal — long considered one of the dirtiest of fossil fuels.

Mary Booth, a Massachusetts-based ecosystem and climate-change research scientist, and the director of Partnership for Policy Integrity, said the McCabe memo essentially ignores the science in the EPA's own report.

She said the controversy over biomass and greenhouse gas is about net emissions over time. She said the amount of carbon dioxide released when wood is burned is much more than when it slowly decomposes. For burning wood to be "carbon neutral," she adds, a tree would have to grow back nearly as fast is it can be burned.

"Everyone pretty much acknowledges that it emits more CO_2 at the stack than burning fossil fuels," Booth said. "So how can it possibly be treated as climate friendly?"

Booth said the answer to that question is often that the wood fuels that are being burned would release their CO_2 naturally anyway or that they will grow back and "re-sequester carbon that's equivalent to what you would release by burning."

Booth said the theory is flawed in it doesn't consider the time it takes to grow a tree back and the net effect of CO_2 being released into the atmosphere by burning isn't made up for decades or even centuries.

She said the EPA got the science basically right in its analysis until it decided that it would exempt biomass that came from so-called "sustainably harvested" sources and treated as "zero carbon under the state's carbon plan."

Booth, who has also closely studied Maine's biomass industry, said the federal policy looks like it's set to go completely askew by treating an industry that not only pumps CO_2 into the atmosphere but also removes the vegetation that mitigates CO_2 emissions a pass. She said biomass should be compared on a level playing field to other energy sources, including no-fuel sources like solar, wind and tidal, and not stacked against other fossil fuels.

"They are receiving renewable energy credits alongside wind and solar, and in some cases are out-competing wind and solar for getting those ratepayer funded subsidies and taxpayer-funded subsidies," Booth said. "Yet they are filthy, super polluting when it comes to conventional emissions, and they are huge greenhouse gas emitters, too."

Maine's energy policies, including the state's renewable energy portfolio standards, 80 percent of which is made up by biomass energy, are likely to be a priority topic for state lawmakers in the coming legislative session.

How the state will meet the requirements in the federal Clean Power Plan and other changes to the state's energy policy, including how much of the renewable portfolio should come from which sector and what types of energy will qualify as renewable, will all be issues for debate and legislation in 2015.

Booth called the Maine biomass facilities, "some of the worst in the country."

But Cleaves, the industry spokesman in Maine, said the EPA analysis and subsequent memo "is just a huge win for us."

"It validates our industry; for years, because of people like (Booth), they have been out there saying things about the industry that have no basis in science," Cleaves said. "So for the EPA to emphatically and clearly say that sustainable biomass should be supported and promoted in the United States is a very good thing."

Mary S. Booth, PhD
Director, Partnership for Policy Integrity | landline: 413-253-3256 | mobile: 917-885-2573
mbooth@pfpi.net | www.pfpi.net

From: Ohrel, Sara
To: Noe, Paul
CC: Lancey, Stan; Tsang, Linda; Irving, Bill; Goffman, Joseph; Santiago, Juan; Wood, Anna
Sent: 6/9/2014 11:07:54 AM
Subject: RE: Paper on Forest Products Manufacturing Residuals

Thank you very much for sharing this new research with us, Paul. We will give it a close read and let you know if we have any comments or questions.
Best wishes,
Sara

From: Noe, Paul <Paul_Noe@afandpa.org>
Sent: Monday, June 9, 2014 10:58 AM
To: Ohrel, Sara
Cc: Lancey, Stan; Tsang, Linda; Irving, Bill; Goffman, Joseph; Santiago, Juan; Wood, Anna
Subject: Paper on Forest Products Manufacturing Residuals

Dear Sara:

At one of the meetings that American Forest & Paper Association (AF&PA)/American Wood Council (AWC) staff had with the EPA climate team regarding the biogenic carbon accounting framework, we discussed forest products industry manufacturing residuals and their alternative fates if they are not burned at the mill to generate energy. A question was raised about the likely alternative fates of the residuals.

To address this issue in a rigorous manner, we asked Forest2Market, a well-respected consulting firm that focuses on forest products industry economics, to prepare a short paper documenting the financial and logistical considerations that drive residual use. The paper is attached for your information.

The bottom line is that pulp and paper mill manufacturing residuals (black liquor, bark, and wood rejects) have few alternative uses and therefore would most likely be landfilled, thus producing methane, or incinerated without energy recovery. Moreover, these residuals would need to be replaced with fossil fuels.

Sawmill residuals, on the other hand, could potentially used to make wood panels such as medium density fiberboard and particle board. The Forest2market analysis shows that these product-related end-uses can pay much more than energy-related applications for sawmill residuals such as sawdust and shavings. Accordingly, these residuals would only be used for energy "when demand for composite panels is low or when the hauling costs to an MDF or particleboard mill are prohibitive."

Please let us know if you have any questions.

Best regards,

Paul Noe

Overview

To support communications between the American Forest & Paper Association (AF&PA)/American Wood Council (AWC) and the U.S. Environmental Protection Agency (EPA) concerning carbon accounting standards for biogenic emissions from stationary sources, this brief outlines the current market for forest products manufacturing residuals--including sawmill secondary chips, shavings, sawdust and bark. The purpose of this brief is to provide the EPA with a factual framework for its decision by outlining the current markets and market drivers for these products, the relative value of this material by type of consumer and the ramifications of these factors for carbon accounting purposes.

Manufacturing residuals are produced by sawmills, pressed wood products facilities such as plywood plants, and pulp and paper mills. Because pulp and paper mills consume the residuals from their manufacturing processes (black liquour, limbs, bark and wood rejects) to generate electricity for their own operations (the pulp and paper sector is a net buyer of fuelwood; their manufacturing residuals are not generally available on the open market), this brief will focus primarily on the disposition of sawmill residuals.

1. Market Price of Sawmill Residuals

The two classes of manufacturing residuals produced by sawmills are:

- Secondary residuals, including secondary chips from cants (rounded slabs), planer shavings and sawdust. Secondary chips are sold on the open market to pulp and paper, composite panel and pellet mills. Shavings and sawdust are purchased by medium-density fiberboard (MDF), particle board and wood pellet manufacturers.
- Fuelwood is used by pulp & paper mills, sawmills, pellet manufacturers and mulch distributors. *Fuelwood* generally refers to the bark and other rejects from logs used in manufacturing **and** in-woods logging residuals; because this brief specifically address manufacturing residuals only, *fuelwood* herein refers to bark and other manufacturing rejects only.

Currently, the cost of bark on a delivered basis is one-third to one-half the cost of secondary chips, shavings and sawdust in U.S. markets. In the South (the largest wood basin in the U.S.), for instance, the cost of secondary chips averaged $37 per short green ton (ranging from $34 - $38 per ton) in 1Q2014. The cost of fuelwood averaged $22 per short green ton (ranging from $19 - $25 per ton).

2. The Supply of Sawmill Residuals

- The yield of sawmill manufacturing residuals from logs varies by species, product class (determined by height and diameter of tree) and is mill-efficiency dependent. Over the last 15 years, the volume of residuals has decreased by 20-25% due to increased efficiencies made possible by the new technologies being employed by sawmills. The industry continues to make improvements in this area.
- In general, a sawmill's output is 50-60% lumber, 30-33% secondary chips, 3-5% shavings and dust and 7-12% bark.

© 2014 Forest2Market, Inc.

3. Sawmill Residuals Consumption

- MDF and particle board manufacturers do not consume roundwood (cost-related reasons) or bark (process-related reasons). While the raw material mix varies by mill and region, the raw material mix for these manufacturers is roughly 90-100% sawmill residuals (secondary chips, shavings and sawdust). Mills in the Northwest U.S. use close to 100% shavings and sawdust, though some use secondary chips. Mills in the U.S. South use closer to a 50% secondary chips/50% shavings and sawdust mix, though some use a small percentage of primary (whole tree) chips.
- Approximately 95% of secondary chips on the open market are consumed by composite panel and pulp and paper manufacturers; the remaining 5% is consumed by pellet mills.
- Shavings and sawdust available on the open market are consumed by composite panel manufacturers (100%).
- Roughly 95% of the bark available on the open market is consumed by pulp and paper mills, 2% is purchased by sawmill and veneer mills, 2% goes to energy production (pellets and electricity) and the remaining 1% goes to mulch.
- Any material that is not used by one or the other of these consumers--either because of seasonal demand factors or because the distance to market is too great--would be incinerated or landfilled. Sawmills have a vested interest in finding alternative uses for their remaining residuals as tipping fees for landfills erode profits.

4. Sawmill Residuals Market Drivers

Current markets for sawmill residuals are driven by economic factors. These factors—capacity to pay, the higher costs of other raw materials and the distance between the sawmill and the secondary market and seasonal factors—will continue to drive the market regardless of whether the EPA designates manufacturing residuals as carbon neutral or not.

- The price paid to the manufacturer for the end product minus the cost of production (or cash break even) points to the fact that the capacity to pay for sawmill residuals advantages panel manufacturers. Forest2Market calculates the capacity of composite panel manufacturers to pay for raw materials at $72/ton. By comparison, the capacity of a pellet manufacturer to pay for raw materials is $39/ton. Due to the number of variables affecting biomass electricity plants, including size and efficiency of plant and state-based regulatory requirements, capacity to pay varies significantly among these facilities.
- Because of their higher capacity to pay, MDF and particleboard manufacturers are likely to continue being the major consumers of sawmill residuals even in light of any regulations or incentives enacted to encourage biomass energy production.
- The average haul distance between the sawmill and the secondary market in 1Q2014 in the South averaged 66 miles (with a range of 56 - 78 miles) for secondary chips and 60 miles (with a range of 50 - 75 miles) for fuelwood. In the Midwest and the Northwest, the average distance from the sawmill to the secondary mill is approximately 90 miles; for fuelwood, the average distance is 60 miles. In general, haul distances longer than these ranges make it economically infeasible to ship sawmill residuals to a secondary consumer. In these cases, mill residuals are more likely to be used for energy production.
- Demand can be seasonal. Mills using their own residuals to manufacture pellets for the domestic heating market will either produce an alternative product during the summer, or the small volume of shavings and dust they produce will be available on the open market. As a result, only when there is no local market for pellets will the shavings and dust produced by these mills find alternative uses. Mulch is also subject to seasonal shifts in demand; little is sold during winter months.
- Mulch demand is limited by location: in urban/suburban areas demand is higher, while little is used in rural areas.

© 2014 Forest2Market, Inc.

Implications for Biogenic Carbon Emissions and EPA Standards

- When manufacturing residuals are used to manufacture composite panels, they become long-lived wood products that continue to store carbon. This table was sourced from the Forest Service's Northeastern Research Sation. It specifies both the fraction of the carbon sequestered in the primary wood product (i.e., the debarked tree) used to manufacture MDF and particleboard that is still sequestered in the panel for each decade following its manufacture.

MDF/Particle Board		
Year after production	Fraction of carbon in primary wood product sequestered	Fraction of primary wood product in landfill
10	0.741	0.163
20	0.569	0.261
30	0.450	0.321
40	0.364	0.361
50	0.301	0.388
60	0.252	0.408
70	0.214	0.424
80	0.183	0.436
90	0.159	0.446
100	0.138	0.454

Source: USDA Forest Service Northeastern Research Station, "Methods for Calculating Forest Ecosystem and Harvested Carbon with Standard Estimates for Forest Types in the United States" Gen. Tech. Rep. NE-343

- From a carbon release perspective, the use of both sawmill and pulp and paper mill residuals for energy is the next most logical use for them when demand for composite panels is low or when the hauling costs to an MDF or particleboard mill are prohibitive.
  - Harvest levels are driven by demand for pulp and paper and lumber, not by demand for residuals. As a result, the amount of manufacturing residuals eventually used for energy production has no effect on the volume of wood harvested from forests. From this perspective, when this material is used for energy production, the amount of carbon released into the atmosphere is the equivalent of what would be released even if the material was not used for energy production.
  - In addition, biomass energy displaces energy generated from fossil fuels, which are non-biogenenic sources of carbon and increase the net amount of carbon in the atmosphere.
- When mill residuals are not used for the production of panels or energy, they are disposed of through incineration (without energy production) or landfilling.

© 2014 Forest2Market, Inc.
www.forest2market.com

From: Kocchi, Suzanne
To: Irving, Bill; Goffman, Joseph
Sent: 7/12/2013 1:31:32 PM
Subject: RE: NAFO press release

And note the highlighted portion from Kavanaugh's concurrence. The concurrence itself is strongly worded against EPA having the authority to treat biogenic CO2 differently than fossil, especially in the first 2 pages.

The Bloomberg BNA Daily Environment Report is brought to you by EPA Libraries. Please note, these materials may be copyrighted and should not be forwarded outside of the U.S. EPA. If you have any questions or no longer wish to receive these messages, please contact Shari Clayman at clayman.shari@epa.gov, 202-566-2370.

Breaking News

D.C. Circuit Vacates EPA Rule Deferring Greenhouse Gas Permitting for Biomass

Posted July 12, 2013, 11:49 A.M. ET

By Andrew Childers

Federal appellate judges July 12 vacated an Environmental Protection Agency rule that would have exempted some industrial plants that burn biomass from requirements to obtain Clean Air Act permits for their greenhouse gas emissions (Center for Biological Diversity v. EPA, D.C. Cir., No. 11-1101, 7/12/13).

In a 2-1 decision the U.S. Court of Appeals for the District of Columbia Circuit ruled EPA did not have the authority under the act to treat biogenic greenhouse gas emissions differently than other emissions for the purposes of prevention of significant deterioration and Title V permitting. That means sources burning biomass such as wood waste will be required to obtain permits for their greenhouse gas emissions.

"This court has ruled that the statute requires pre-construction and operating permits for stationary sources that emit or have the potential to emit certain specified amounts of an air pollutant, including carbon dioxide," Judge Brett Kavanaugh wrote in his concurring opinion. "There is zero basis in the text of the Clean Air Act for EPA to distinguish biogenic carbon dioxide from other sources of carbon dioxide that EPA is required (under our precedent) to regulate for purposes of the PSD and Title V permitting programs."

Kavanaugh joined Judge David Tatel in vacating EPA's 2011 rule, which would have deferred the permitting requirements for industrial sources burning biomass such as wood waste, as well as landfills with emissions from decomposing biomass, from the greenhouse gas permitting requirements until July 21, 2014 (76 Fed. Reg. 43,490). Judge Karen Henderson dissented.

The Clean Air Act's prevention of significant deterioration program requires large industrial sources to install pollution controls known as best available control technology when they expand or make modifications that increase emissions.

EPA had argued the deferral was necessary because it needed the additional time to determine whether it should regulate emissions from sources burning biomass, which would decay and release its carbon dioxide anyway. The agency justified the deferral using the administrative doctrines of "one step at a time," "administrative necessity," and "absurd results," which would allow the agency to deviate from the text of the Clean Air Act if administering it as written would impose significant burdens on the agency or regulated sources.

Writing for the majority, Tatel rejected EPA's invocation of all three doctrines. However, he said the decision to vacate the deferral rule does not address whether EPA does have the

Clean Air Act authority to permanently exempt biogenic carbon dioxide emissions sources from prevention of significant deterioration permitting at a later date.

"If and when EPA adopts a permanent exemption for some or all biogenic carbon dioxide sources, we will have the benefit of three years of scientific study, as well as fully briefed and contextualized arguments about EPA's authority under the Clean Air Act," Tatel said.

In her dissent, Henderson said she would have upheld EPA's deferral rule under the one-step-at-a-time doctrine. EPA needed the deferral to determine whether permitting those emissions sources was warranted, she said.

"This procedure recognizes the reality and complexity of administrative regulation," Henderson said.

This email is published as a supplement to Daily Environment Report (ISSN 1521-9402) by The Bureau of National Affairs, Inc., 1801 S. Bell Street, Arlington, VA 22202. Full reports on the contents of this email will appear in the next regular edition of Daily Environment Report.

Request a FREE Web trial. For subscription information please contact your local Bloomberg BNA Account Executive. For other inquiries please call or send a request to the Bloomberg BNA Customer Contact Center: 1-800-372-1033, Monday - Friday, 8:00 a.m. to 8:00 p.m. ET, excluding most federal holidays.

To change your email preferences, visit http://webutil.bna.com/emailsignup.

Please do not reply to this message. Replies to this message are routed to an unmonitored mailbox. If you have questions please visit http://www.bna.com/contact.

Registered Web subscribers can access the full text of these articles by using the link supplied.

Copyright (c) 2013 by The Bureau of National Affairs, Inc., 1801 S. Bell Street, Arlington, VA 22202. Use of this service is subject to the email subscriptions terms and conditions of the license agreement with Bloomberg BNA. Unauthorized access or distribution is prohibited.

From: Irving, Bill
Sent: Friday, July 12, 2013 1:13 PM
To: Goffman, Joseph
Cc: Kocchi, Suzanne
Subject: NAFO press release

Just FYI – NAFO's initial reaction.

From: Irving, Bill
Sent: Friday, July 12, 2013 1:01 PM
To: Gunning, Paul
Cc: Kocchi, Suzanne
Subject: RE: Attached Image

NAFO's response.

DC Circuit Ruling Creates Urgency For EPA To Complete Its Work On Bioenergy Carbon Emissions « NAFO (National Alliance Of Forest Owners)

WASHINGTON, DC, July 12, 2013 – Forest owners are urging the Environmental Protection Agency (EPA) to proceed quickly with amendments to its greenhouse gas regulations (Tailoring Rule) following a ruling today by the U.S. Court of Appeals for the District of Columbia Circuit (DC Circuit) in *Center for Biological Diversity v. U.S.*

Environmental Protection Agency. The court decided that EPA did not adequately justify its decision to temporarily exempt biogenic emissions from its greenhouse gas regulations, but left the door open to EPA finalizing a permanent amendment to its rules regarding the treatment of such emissions. Importantly, the court's decision does not affect EPA's ongoing process to develop a permanent decision regarding whether to regulate biomass emissions based on the carbon benefits that forest bioenergy offers compared to fossil fuels.

"EPA did the right thing by deferring the regulations while it reconsiders whether forest bioenergy should be regulated the same as fossil fuel energy," said Dave Tenny, President and CEO of the National Alliance of Forest Owners (NAFO). "Forest Owners also did the right thing by defending EPA's action in court. Now the priority is for EPA to complete its amendments to the Tailoring Rule to fully recognize the carbon benefits of forest bioenergy and to do it promptly. The urgency of the situation has now increased significantly."

In June 2010, EPA adopted the Tailoring Rule to set the threshold that triggers the requirement for stationary sources to obtain Clean Air Act PSD permits for their carbon emissions. In an unexpected departure from the proposed rule and prior agency precedent, EPA for the first time in the final rule regulated carbon emissions from forest bioenergy production the same as fossil fuel emissions. Biomass fundamentally differs from fossil fuels as an energy source because biomass recycles atmospheric carbon through tree and plant growth while fossil fuel carbon emissions accumulate in the atmosphere over time. This means that the combustion of biomass does not lead to net GHG emissions into the atmosphere. EPA had consistently recognized this view prior to the final Tailoring Rule, which suddenly and unexpectedly reversed course from this longstanding policy.

In July 2011, EPA published the Deferral Rule after granting NAFO's petition to reconsider the treatment of bioenergy carbon emissions under the Tailoring Rule. The Center for Biological Diversity and others immediately challenged the deferral. NAFO and others* intervened in the case in support of EPA.

U.S. forests offset about 14% of total annual U.S. carbon emissions, a benefit to the public that is widely viewed as a key contribution to mitigating climate change. However, the Tailoring Rule amendments will heavily influence the extent to which private forest owners, who own and manage nearly 60% of the forests in our country, continue providing this benefit.

"EPA must now work with the U.S. Department of Agriculture on permanent amendments to the Tailoring Rule as part of the climate change solution," Tenny said. "The agencies can then engage forest owners on a broader policy framework promoting the considerable mitigation benefits private forests provide."

*Other intervenors include: American Forest & Paper Association, American Wood Council , Biomass Power Association, Corn Refiners Association, The Florida Sugar Industry, National Oilseed Processors Association, Rubber Manufacturers Association, Treated Wood Council, Utility Air Regulatory Group and Renewable Fuels Association.

###

NAFO is an organization of private forest owners committed to advancing federal policies that promote the economic and environmental benefits of privately-owned forests at the national level. NAFO membership encompasses more than 80 million acres of private forestland in 47 states. Working forests in the U.S. support 2.4 million jobs. To see the full economic impact of America's working forests, visit**www.nafoalliance.org/economic-impact-report**.

This entry was posted on Friday, July 12th, 2013 at 12:52 pm and is filed under Featured, Latest News. You can follow any responses to this entry through the RSS 2.0 feed. Responses are currently closed, but you can trackback from your own site.

Readability — An Arc90 Laboratory Experiment

Follow us on Twitter »

From: DeLuca, Isabel
To: Kocchi, Suzanne; Irving, Bill
Sent: 11/19/2014 5:16:33 PM
Subject: Biomass/CPP internal policy questions
Attachments: Biomass policy questions.docx

Hi Suzie and Bill,

I had stripped the internal Q&A language out of the Q&A doc for review by OGC and sharing with the regions, but it sounds like Sarah wants to keep moving on these questions. So here are the latest CPP/biomass Q&As, with the internal discussion language dropped back in. It's also on the G drive here: **Ex. 6 - Personal Privacy**
Ex. 6 - Personal Privacy

Thanks, and let me know if you need anything else.

Isabel DeLuca
Climate Change Division, US EPA
(202) 343-9247

From: Ohrel, Sara
To: DeLuca, Isabel; Kocchi, Suzanne; Irving, Bill; Cole, Jefferson
Sent: 11/18/2014 4:31:18 PM
Subject: RE: Biomass comms. materials for OGC review
Attachments: Biomass-QAs-11 17 14 v2 clean so.docx

Hi all,
Here are our comments, just a few minor edits – thanks Isabel!

From: DeLuca, Isabel
Sent: Tuesday, November 18, 2014 4:19 PM
To: Kocchi, Suzanne; Irving, Bill; Ohrel, Sara; Cole, Jefferson
Subject: FW: Biomass comms. materials for OGC review

Here's a clean version of the Q&As with OGC's edits and also Sara's edits. (The marked up version is also available here: **Ex. 6 - Personal Privacy**

Jeff/Sara—let me know if you still want to add a broad Q&A related to the case studies, and I can drop that in.

I'm going to do one more read through, and if anyone else has any final comments, please let me know.

I plan to send this to the comms group (Millet, CAMD, OAQPS, etc.) before I leave tonight.

From: Doster, Brian
Sent: Tuesday, November 18, 2014 1:50 PM
To: DeLuca, Isabel; Cortelyou-Lee, Jan
Cc: Santiago, Juan; Kornylak, Vera S.; Kocchi, Suzanne; Irving, Bill; Risley, David; Williams, Melina; Jordan, Scott; Zenick, Elliott; Hoffman, Howard
Subject: RE: Biomass comms. materials for OGC review

Here comments on the Q&A's from the OGC staff copied here.

From: DeLuca, Isabel
Sent: Tuesday, November 18, 2014 11:19 AM
To: Doster, Brian; Cortelyou-Lee, Jan
Cc: Santiago, Juan; Kornylak, Vera S.; Kocchi, Suzanne; Irving, Bill; Risley, David; Williams, Melina; Jordan, Scott; Zenick, Elliott; Hoffman, Howard
Subject: RE: Biomass comms. materials for OGC review

Thank you!

From: Doster, Brian
Sent: Tuesday, November 18, 2014 11:18 AM
To: DeLuca, Isabel; Cortelyou-Lee, Jan
Cc: Santiago, Juan; Kornylak, Vera S.; Kocchi, Suzanne; Irving, Bill; Risley, David; Williams, Melina; Jordan, Scott; Zenick, Elliott; Hoffman, Howard
Subject: RE: Biomass comms. materials for OGC review

Here are comments on the Desk Statement from the OGC staff copied here. We are still working on the Q&A's, but expect to have our thoughts consolidated before 2 pm this afternoon.

From: DeLuca, Isabel
Sent: Monday, November 17, 2014 3:43 PM
To: Doster, Brian; Williams, Melina; Jordan, Scott; Zenick, Elliott; Hoffman, Howard
Cc: Cortelyou-Lee, Jan; Santiago, Juan; Kornylak, Vera S.; Kocchi, Suzanne; Irving, Bill; Risley, David
Subject: Biomass comms. materials for OGC review
Importance: High

Hi all,
Attached for OGC review are comms materials (desk statement and Q&As) for Wednesday's release of biomass framework and memo to the regional ADDs. We'd like to distribute these to the press office and the Regions tomorrow COB and would appreciate any review and comment you could provide by then. In the Q&As, we could use your help in the response for #17 as well.

Apologies for the short turn-around time, and thanks in advance for your review.

Isabel DeLuca
Climate Change Division, US EPA
(202) 343-9247

From: DeLuca, Isabel
To: Kocchi, Suzanne; Irving, Bill
Sent: 11/14/2014 3:11:00 PM
Subject: Q&As
Attachments: Biomass Memo Q and As - permitting.docx; Biomass-CPP-Questions-v2-11.14.14.docx; Q&A Biomass Framework & PSD OAQPS.docx

I'm still waiting from the CPP team for their review of the CPP questions, but here are the edits I got from the PSD folks on the general Q&As (plus a doc of Qs they added). The third one (Framework & PSD) needs to be cleaned up, but I wanted you to see their comments.

Also, FYI, everything is on the G drive here: **Ex. 6 - Personal Privacy**

Isabel DeLuca
Director of Communications
Climate Change Division, US EPA
(202) 343-9247

From: Sherry, Christopher
To: Irving, Bill
Sent: 11/14/2014 2:45:17 PM
Subject: FW: update on Biomass Framework comms plan
Attachments: Biomass-CPP-Questions-v2-11.14.14.docx; Desk Statement 11.14.14.docx

FYI – was in a meeting, so just seeing this now

From: Risley, David
Sent: Friday, November 14, 2014 1:11 PM
To: Clouse, Matt; Conlin, Beth; Sherry, Christopher; Fisher, Brian
Cc: Harvey, Reid; Stenhouse, Jeb
Subject: RE: update on Biomass Framework comms plan
Importance: High

Hi all,
Please take a look at the CPP questions and desk statement with respect to interactions with the CPP. Please consider if the right questions are being asked and what the right responses are. If possible, let's try to coordinate on this by 2:30. I'll be at my desk if you'd like to come discuss. Or you can send something electronically.

Best,
David

From: DeLuca, Isabel
Sent: Friday, November 14, 2014 12:44 PM
To: Harvey, Reid; Stenhouse, Jeb; Adamantiades, Mikhail; Wilson, Erika; Risley, David; Conlin, Beth
Subject: update on Biomass Framework comms plan
Importance: High

Hi all,
Just wanted to give you an update and check in on the Q&As. The plan is now for the Memo and Framework will go out on Wednesday, and heads up calls will start Monday.

In the meantime, we're trying to get Joe and Janet Q&As to review by the end of today. We've broken CPP-related questions out of the Q&A list—many of the questions are the same but there are some additional new questions.

Joe is holding the pen on the memo right now but we'll share when we have an updated version. I'll also send a revised roll-out plan for your review momentarily.

Thank you!

Isabel DeLuca
Climate Change Division, US EPA
(202) 343-9247

From: Kocchi, Suzanne
To: Irving, Bill
Sent: 11/12/2014 3:54:39 PM
Subject: RE: CPP questions

Agree. Let's just help Paul articulate that to Sarah D so as much as possible we can draw clear lines around this and make sure we can keep OAP at least on the same page about expectations.

From: Irving, Bill
Sent: Wednesday, November 12, 2014 3:51 PM
To: Kocchi, Suzanne
Subject: RE: CPP questions

I think it's Sisyphean…

Ex. 5 - Deliberative

From: Kocchi, Suzanne
Sent: Wednesday, November 12, 2014 3:42 PM
To: Irving, Bill
Subject: RE: CPP questions

J

Ex. 5 - Deliberative

From: Irving, Bill
Sent: Wednesday, November 12, 2014 3:40 PM
To: Kocchi, Suzanne
Subject: RE: CPP questions

Jaded minds think alike?

From: Kocchi, Suzanne
Sent: Wednesday, November 12, 2014 3:37 PM
To: Irving, Bill
Subject: RE: CPP questions

You read my mind because I had just started editing almost the same way. J

From: Irving, Bill
Sent: Wednesday, November 12, 2014 3:36 PM
To: DeLuca, Isabel
Cc: Kocchi, Suzanne; Fawcett, Allen; Cole, Jefferson; Ohrel, Sara
Subject: RE: CPP questions

Answers/edits added to most questions – Ex. 5 - Deliberative

Ex. 5 - Deliberative

From: DeLuca, Isabel
Sent: Wednesday, November 12, 2014 2:39 PM
To: Irving, Bill
Cc: Kocchi, Suzanne; Fawcett, Allen; Cole, Jefferson; Ohrel, Sara
Subject: RE: CPP questions

Thanks, Bill. I've merged in some Q&As that Sarah had helped develop earlier. There may be some redundancy, but that's ok.

All—please add any other questions you can think of and circulate again. (This is also on the G drive here: Ex. 6 - Personal Privacy

Ex. 6 - Personal Privacy

In the meantime, Bill, now that you've added a bunch of Qs, can you help with the responses?

Thanks.

From: Irving, Bill
Sent: Wednesday, November 12, 2014 2:09 PM
To: DeLuca, Isabel
Cc: Kocchi, Suzanne; Fawcett, Allen; Cole, Jefferson; Ohrel, Sara
Subject: CPP questions

Isabel – some questions to add. You might have some already.

Ex. 5 - Deliberative

From: Miller, Julia
To: Adamantiades, Mikhail; Fisher, Brian; Victor, Meg; Wilson, Erika; Sarofim, Marcus; Schreifels, Jeremy; Eschmann, Erich; Meroney, William; Sims, Ryan; Smith, Eric; Bryson, Joe; Lifland, David; Sherry, Christopher; Mulholland, Denise; Dietsch, Nikolaas; Frushour, Charles; Clouse, Matt; Deck, Leland; Naik-Dhungel, Neeharika; Hight, Cate; Rosenberg, Julie; Conlin, Beth; Stevens, Gabrielle; Gordon, Jessica M; DeAngelo, Ben; Hockstad, Leif; Cole, Jefferson; Li, Jia; Stevens, William; DeYoung, Robyn; Mark, Jeremy; Steiner, Elyse; Critchfield, James; DeFigueiredo, Mark; Torres, Elineth; Noonan, Jenny; Strine, Lora; Cortelyou-Lee, Jan; Ashley, Jackie; Drinkard, Andrea; Kurlansky, Ellen; Irving, Bill
Sent: 10/27/2014 4:35:38 PM
Subject: 111d Draft Categorization Spreadsheet
Attachments: 111d Question Categorization 10 27 2014.xlsx

Attached is a spreadsheet that categorizes 111d questions that have come in from states through individual calls, Regional hub calls and the NACAA/ECOS/AAPCA calls. The idea is to get a general sense of questions/concerns from states sooner rather than later, given that we still have another five weeks before the comment period closes. To sort questions based on a subcategory, use the arrows in row 3, and make sure (Blanks) is unselected, and only 1 is selected. Also see the note below about how categories were color coded. I know several of you wanted this information ASAP, so I'm passing along before I've had a chance to QC the whole spreadsheet.

Please let me know if you see a question, or especially a category of questions, that were incorrectly characterized. Also, if you have additional questions that have come in through other channels, please send them to me and I'll have the contractor add them to the spreadsheet.

Thanks,

-Julia

From: Pederson, Lauren [mailto:Lauren.Pederson@icfi.com]
Sent: Monday, October 27, 2014 12:36 PM
To: Miller, Julia
Subject: RE: 111d Draft Categorization Spreadsheet

Hi Julia-

Attached is the 111d categorization spreadsheet for your review. Since the last draft version we sent you, we categorized all of the remaining questions, populated the notes column, performed QC, and added a count of questions per category on the lists worksheet.

On the lists worksheet, we thought it would be useful to add a count of questions, so we could easily see where the highest number of questions were being asked. If there were more than 50 questions asked under a certain category, we highlighted the cell yellow. If more than 100 questions were asked, we highlighted the cell red. The most questions (by far) were asked under state goals, and the state goal calculation, with 263 and 206 questions, respectively. The next highest was RE policies/programs (123 questions), followed by Interaction with building blocks and goal-setting (109 questions).
We hope you find this useful! We found it very insightful to go through these questions to see where states are coming from, and where questions exist. Please let us know if you have any questions, or if you would like to discuss.

Thanks,
Lauren