Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act—Standards for Existing Power Plants

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MJB&A

Foreword

The electric power industry today is changing and modernizing with significant capital investments flowing to cleaner and smarter technologies, including lower carbon energy resources. As a result of these investments and market dynamics driven by abundant supplies of low cost natural gas and reduced demand for electricity, carbon emissions from the industry have fallen 10 percent from 2005 levels.

New carbon pollution rules being developed by the U.S. Environmental Protection Agency (EPA) should further accelerate this trend. President Obama has directed EPA to work expeditiously to develop carbon standards for the power sector, using its authority under section 111 of the Clean Air Act. In particular, the President directs EPA to develop options "that allow the use of market-based instruments, performance standards, and other regulatory flexibilities" to ensure that emissions are reduced at the lowest cost.

Consistent with the President's goal, I am pleased to offer the following whitepaper on behalf of a group of leading power companies on options for the design of carbon pollution standards for fossil fuel power plants. Our companies support the need to reduce the industry's carbon emissions and believe that the right policies can deliver meaningful emissions reductions while ensuring affordable and reliable power supplies to meet our nation's energy needs.

We urge EPA and the states to adopt market-based regulatory approaches that encourage companies to find cost-effective compliance solutions and recognize early investments to reduce their emissions. In designing such a system, all generating facilities, regardless of age or fuel type, should be subject to the same economic incentives based on their carbon emissions. EPA has significant discretion under section 111 in determining both the appropriate level of the standards for existing power plants, as well as the form of the regulations. We believe EPA should work in cooperation with the states to develop cost-effective, pragmatic policy approaches based on proven market-based regulatory approaches.

The electric power sector is the most capital-intensive industry in the United States, and experience has shown that flexible, market-based solutions have been highly effective (and cost-effective) in transitioning to cleaner energy technologies. We look forward to continued engagement with EPA and other stakeholders on the development of the carbon pollution rules.

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Acknowledgements

The following report was prepared on behalf of the following electric companies dedicated to responsible energy and environmental stewardship. The participating companies (listed below) are some of the nation's largest generators of electricity, with over 130,000 megawatts of electric generating capacity (including 80,000 megawatts of fossil generating capacity) throughout the U.S.

Austin Energy
Calpine Corporation
Exelon Corporation
National Grid
New York Power Authority
NextEra Energy
Public Service Enterprise Group (PSEG)
Seattle City Light

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Introduction

There are a range of questions that EPA will need to address over the coming year as it develops greenhouse gas (GHG) performance standards for existing power plants under section 111(d) of the Clean Air Act (CAA). Key questions that have received significant stakeholder attention concern the appropriate stringency of the standards and the technical basis for the standards. Separate from these questions, but essential to understanding the potential impact of the standards, are questions about the form of the standard and the compliance flexibility measures allowed either by EPA or through state compliance plans. This discussion paper provides background on the CAA requirements for the regulation of GHGs for power plants and examines the potential form of the standard for existing sources, highlighting the potential pros and cons of different approaches.

I. Section 111 of the Clean Air Act

Section 111 of the CAA directs EPA to establish emissions standards for stationary sources of air pollution that "may reasonably be anticipated to endanger public health or welfare." Section 111(b) details EPA's authority to regulate new and modified sources. Section 111(d) establishes a process for EPA and states to regulate existing sources. Section 111(b) and 111(d) are each discussed in turn.

a. Section 111(b): New Sources

Section 111(b) directs EPA to establish emissions standards for *new* and *modified* sources of air pollution (e.g., fossil fuel-fired boilers). The term "standard of performance" is broadly defined as: "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."[1] Section 111 states that EPA may not prescribe a particular technological system that must be used by a new or modified source to comply with a NSPS. Rather, sources remain free to rely on any combination of measures it can demonstrate will achieve equivalent or greater control of emissions. Section 111(b) requires EPA to review standards for new and modified sources every eight years.

EPA has promulgated numerous section 111(b) standards, including standards for nitrogen oxides

[1] 42 U.S.C. § 7411(a)(1).

(NOx), sulfur dioxide (SO_2), and particulate matter (PM) standards for new and modified EGUs.[2]

Although EPA originally proposed standards for new fossil fuel-fired EGUs on April 13, 2012,[3] EPA re-proposed standards on September 20, 2013 consistent with President Obama's June 25, 2013 memo: "[i]n light of the information conveyed in more than two million comments on that proposal and ongoing developments in the industry, you have indicated EPA's intention to issue a new proposal. I therefore direct you to issue a new proposal by no later than September 20, 2013. I further direct you to issue a final rule in a timely fashion after considering all public comments, as appropriate."[4,5]

b. Section 111(d): Existing Sources

Once EPA establishes emissions standards for new and modified sources within a given category, section 111(d) directs EPA to establish standards for existing sources. Section 111(d), which has rarely been triggered, requires regulation of existing sources only where the pollutant in question is neither (1) a "criteria" air pollutant subject to national ambient air quality standards (NAAQS), nor (2) a toxic air pollutant regulated under section 112 of the CAA (e.g., mercury).[6] GHGs fall within this category. Because of the narrow applicability of section 111(d), there is limited regulatory precedent for this section of the Act and no direct case law.

Section 111(d) uses a different mechanism in regulating existing sources than section 111(b) uses for new and modified sources. Instead of giving EPA direct authority to set national standards applicable to existing sources, section 111(d) requires EPA to issue regulations establishing "a procedure" similar to the State Implementation Plan (SIP) process for regulating criteria pollutants subject to NAAQS. According to the Act, each state must submit a plan that (1) "establishes standards of performance" for the existing sources in the category, and (2) "provides for [their] implementation and enforcement." Section 111(d)(1) further states that the regulations have to allow each state "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." These state plans must be submitted to EPA for approval. In the event that a state

[2] For example, EPA promulgated revised NSPS for sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM) under section 111 for electric generating units (EGUs) (40 CFR part 60, subpart Da) in 2006 and 2012.
[3] The 2012 proposed standards would have require units greater than 25 megawatts (MW) to meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh).
[4] In President Obama's Memorandum to EPA, he directs EPA to address *modified* power plants at the same time EPA proposes and finalizes regulations for existing power plants.
[5] The White House: Office of the Press Secretary. Memorandum for the Administrator of the Environmental Protection Agency. Subject: Power Sector Carbon Pollution Standards. June 25, 2013.
[6] The Federalist Society published a White Paper in March 2013 arguing that EPA does not have authority to regulate GHG emissions from power plants under section 111(d) because electric generating facilities are regulated under the section 112 air toxics program. Haun, William H. The Clean Air Act as an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants. March 2013.

does not adopt and submit a satisfactory plan, EPA has the authority to issue a federal plan covering the affected sources.[7]

In 1975, EPA issued generic section 111(d) regulations that established an implementation framework for existing sources.[8] The regulations expressly state, however, that EPA may modify the framework as appropriate when proposing and promulgating the specific emission guideline that will apply to a particular category of existing sources. The framework regulations provide for EPA to issue an "emission guideline document" setting forth the performance level (called the "emission guideline") that reflects the "best system of emission reduction" for existing sources, which is the same language used to describe the standard required for new sources. However, both the statute and EPA's regulations implementing section 111(d) recognize that existing sources may not always have the capability to achieve the same levels of control at reasonable cost as new sources. Additionally, the statute and EPA's regulations in 40 CFR 60.24 authorize states and EPA to set less stringent standards or longer compliance schedules for a facility or class of facilities unless EPA specifies otherwise where warranted considering cost of control; useful life of the facilities; location or process design at a particular facility; physical impossibility of installing necessary control equipment; or other factors making less stringent limits or longer compliance schedules appropriate. When EPA reviews a state plan, it will have to approve any reasons for a less stringent standard.

Costs are considered in establishing section 111 standards—what some people call "existing source performance standards"—for a category or subcategory. EPA generally compares estimated costs and emission impacts of multiple, specific emission reduction options under consideration. As it evaluates available control strategies, EPA also has the authority to distinguish among "classes, types and sizes" of sources for purposes of regulating GHG emissions. For example, EPA has distinguished among fossil fuel-fired boilers on the basis of fuel types (e.g., coal, oil, natural gas) in past NSPS rulemakings. EPA could also establish separate standards by technology type (e.g., super-critical steam, sub-critical steam, or combined cycle). EPA also has significant discretion to determine the appropriate level for the standards.

On June 25, 2013, President Obama issued a memo establishing a schedule for EPA to issue proposed and final standards for existing power plants, as well as the state plans for implementing section 111(d) (see Figure 1 for a timeline):[9]

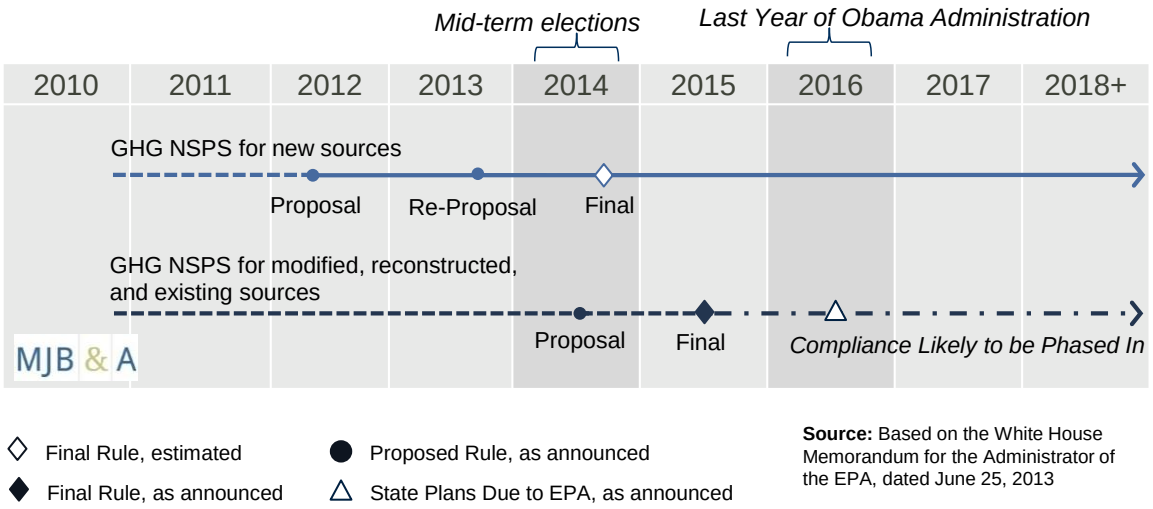
[7] 42 U.S.C. § 7411(d)(2).
[8] 40 C.F.R. §§60.20-60.24.
[9] The White House: Office of the Press Secretary. Memorandum for the Administrator of the Environmental Protection Agency. Subject: Power Sector Carbon Pollution Standards. June 25, 2013.

(i) issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;

(ii) issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and

(iii) include in the guidelines addressing existing power plants a requirement that States submit to 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.

Figure 1. GHG NSPS Rulemaking Schedule



II. Policy Options: Standards for Existing Sources

The rulemaking process under section 111(d) can be divided into two basic steps: (1) establishing the standards of performance; and (2) defining the form of the standard and options for compliance flexibility.

As described above, EPA's general implementing regulations for section 111(d) direct EPA to first establish "emissions guidelines," prescribing minimum thresholds for each state in developing their state plan. EPA's guidelines must be supported by a description of the systems of reduction, including the expected time to design, install, and start the identified systems. The regulations also allow EPA to subcategorize performance standards and compliance timelines in the guidelines, with different standards or timelines for sources of different sizes, fuel types, and age when costs of control, physical limitations, or other factors make subcategorization appropriate.

Some stakeholders argue that EPA's authority in establishing its emissions guidelines for GHGs is limited to options within the "fence-line," and the only available technologies are those that improve unit efficiency and/or involve co-firing with natural gas or biomass, where available.

Others advocate standards based on measures that go beyond heat rate or efficiency improvements. For example, in determining the best system of emission reduction for existing power plants, the Natural Resources Defense Council (NRDC) recommends that EPA take into account the full range of opportunities that are available to reduce GHG emissions, including: generation efficiency improvements, fuel switching to lower carbon fuels, co-firing with natural gas or biomass, redispatch of the existing generating fleet, increasing renewables and nuclear generation, and end-use efficiency/demand response.[10]

This debate over the stringency of the NSPS standard is not the focus of this whitepaper, however. Rather, the discussion that follows focuses on the potential form of the standard and the pros and cons of different approaches.

a. Compliance Options and State Flexibility

Section 111(d) requires that each state submit to EPA a plan for implementing and enforcing the emissions guidelines. The section 111(d) regulations require that "[state] emission standards shall be no less stringent than the corresponding emission guideline(s)…and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified in [the guideline]."[11] However, in establishing the emissions guideline, there is nothing in section 111(d) that specifies the specific form that the standards must take. The basic options include:

(1) plant-specific CO_2 emissions standards (lb/MWh, lb/mmBtu) or heat rate standards (Btu/kwh) (performance standard with limited or no flexibility);
(2) CO_2 emissions standards with the option of banking, averaging, and trading (performance standard with flexibility); or
(3) State budget approach—with banking and trading.

Consistent with precedent, and the less flexible language of section 111(b), EPA's proposal for new fossil-fired EGUs suggests a plant-specific performance standard (lb/MWh) with no averaging or emissions trading among affected sources. However, it seems unlikely that EPA would adopt the same

[10] NRDC. Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters. March 2013.
[11] 40 C.F.R. § 60.24(f).

approach for existing sources given the language of the statute and the potential cost savings from allowing compliance flexibility.

In general, courts give deference to an agency's interpretation of a statute if the language is ambiguous, as it is in section 111(d). Given the broad language of this section of the Act, several stakeholders have proposed a performance standard approach with flexibility (banking, averaging, and trading) allowed at the state level and facilitated through a model rule that would be proposed by EPA. Additionally, many stakeholders have expressed interest in EPA establishing a process by which state and regional cap-and-trade programs would be deemed equivalent to a performance standard.

b. Examples of Past Approaches under the Clean Air Act

Over the years, EPA has relied on a wide variety of approaches under the Clean Air Act to regulate air pollution emissions from stationary sources including: (1) performance standards with limited or no flexibility under sections 111(b) and 112; (2) alternative compliance pathways that allow limited trading of emission credits; and (3) cap-and-trade programs under sections 111(d) and 110. The following section summarizes examples of each to help illustrate the options that are potentially available for regulating GHG emissions.

Performance standard with no flexibility under section 111(b) (Subpart Da). Electric utility steam generating units built after certain dates are subject to NSPS standards—Section 111(b)—for criteria air pollutants (40 CFR part 60, subpart Da), commonly known as the subpart Da standards. EPA amended the standards in February 2006 and again in February 2012. Subpart Da establishes rate-based performance standards or percent reduction standards:

- The particulate matter (PM) emission limit for new and reconstructed units is 11 nanograms per joule (ng/J) or 0.090 pound per megawatt hour (lb/MWh) gross energy output regardless of the type of fuel burned.
- The SO_2 emission limit for new units 130 ng/J, or 1.0 lb/MWh gross energy output, or 97 percent reduction regardless of the type of fuel burned (with one exception).
- The NO_x emission limit for new units is 88 ng/J or 0.70 lb/MWh gross energy output regardless of the type of fuel burned with one exception.

Subpart Da does not provide compliance flexibility. Each affected facility must comply with the applicable emissions limits specified in the rule.

Performance standard with limited flexibility under Section 112 (MATS). The Mercury and Air Toxics Standards (MATS), under section 112 of the CAA, establish PM, hydrochloric acid (HCl), and mercury

emissions standards for coal- and oil-fired power plants. The standards apply to new and existing power plants and are expressed as both input-based (lb/MMBtu) and output-based (lb/MWh) standards. In demonstrating compliance, plant owners can average their emissions across individual boilers at the same facility and within the same subcategory, providing a *limited* degree of compliance flexibility.

Limited trading of NOx credits under Section 111(d) (Emissions Standards for Municipal Waste Combustors). EPA promulgated NSPS standards for new and existing municipal waste combustor (MWC) units in 1995, including NOx emission standards for Large MWC units.[12] The NOx standards, expressed as a rate in parts per million per volume, are based on the performance achievable with the application of a selective noncatalytic reduction or SNCR system. The regulations include two flexible compliance options: (1) large MWC plants can use emissions averaging to demonstrate compliance for two or more existing MWC units located at the same facility (the combination of units included in an emissions averaging plan at an MWC plant must meet emission limits approximately 10 percent more stringent than the single unit emission requirements); and (2) EPA also allows states to establish a program for owners or operators of existing municipal waste combustor plants to trade NOx emission credits.

Federal cap-and-trade program for mercury under Section 111(d) (Clean Air Mercury Rule). In 2005, the Bush Administration issued the Clean Air Mercury Rule (CAMR), under section 111(d), capping mercury emissions from coal-fired power plants. EPA based its proposed emissions caps on an assessment of available controls, but defined the "best system of emission reductions" to be the cap-and-trade system designed to implement the reductions.[13] At the time, EPA argued that a cap-and-trade system was the most cost-effective approach for limiting mercury emissions from the power sector. While the D.C. Circuit vacated CAMR, the court never reached the question of whether regulations under 111(d) could include a cap-and-trade program.

Regional cap-and-trade program for NOx based on EPA model rule under Section 110 (NOx SIP Call). The NOx SIP call, based on EPA's authority under section 110 of the CAA, established a regional cap-and-trade program for NOx emissions from power plants and industrial boilers in the Eastern

[12] 40 CFR 60.50b-60.59b (new sources) and 60.30b-60.39b (existing sources)

[13] At the time, there was an active debate over the commercial availability of mercury-specific controls, including activated carbon injection (ACI). According to EPA, in the final CAMR, "[ACI and other technologies] provide justification for a 2018 cap at a level below what is projected to be achieved from SO_2 and NOx reduction levels alone. Although EPA is optimistic that such controls may be available for use on some scale prior to 2018, it does not believe that such controls can be installed and operated on a national scale before that date."

U.S.[14] Similar to EPA's obligations under section 111(d), where states are required to develop an implementation plan, the NOx SIP call required states to submit a "SIP revision" prohibiting NOx emissions that were contributing to ozone nonattainment in neighboring states. In determining the appropriate level of emissions reductions, EPA conducted a technical analysis of the levels of NOx reductions that could be obtained by applying cost-effective and proven pollution control technologies (i.e., 0.15 lb/MMBtu for electric generating facilities). Specifically, EPA established state emissions budgets by using a 0.15 lb/MMBtu performance standard and the higher of 1995 or 1996 ozone season heat input data for each state. In establishing these budgets, EPA accounted for economic growth by adjusting the heat input data using state-specific growth factors derived from the Integrated Planning Model (IPM). For compliance with the state budget, states had the option of participating in a regional cap-and-trade program, based on a model rule developed by EPA.

c. Discussion of Different Approaches for Structuring a GHG Performance Standard

EPA faces a critical set of decisions in defining the regulatory structure under section 111(d). The structure of the standards will define the options that are available for complying with the rule, influence the overall costs of the program, and determine the incentives for capital deployment in one of the most capital intensive sectors of the economy. This paper examines three basic approaches for structuring a GHG standard for existing sources: (1) performance standard with limited or no flexibility; (2) performance standard with flexibility (averaging, banking, and trading); or (3) a state budget approach with banking and trading. There are trade-offs inherent in all of these approaches.

Option 1 (performance standard with limited or no flexibility). As described above, there is precedent under section 111(b) (standards for new and modified sources) for traditional, technology-based performance standards, expressed in lb/MWh.[15] Subpart Da, for example, includes standards for NOx, SO_2, and PM. Outside of section 111, under the Prevention of Significant Deterioration (PSD) program, new power plants have been subject to technology-based performance standards for CO_2.[16]

This command-and-control style regulation requires an affected facility to meet the standard or be subject to enforcement action. For GHG emissions, depending on the level of the standard, the options for compliance could include: (1) capital investments to improve plant efficiency; (2) operational changes that could potentially improve efficiency (e.g., operating at higher loads); (3) co-

[14] U.S. EPA. Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone. October 1998.
[15] EPA proposed an output-based greenhouse gas standard for new power plants and most stakeholders assume EPA will use the same for existing power plants.
[16] For example, the Lake Side Power Plant in Utah (Block #2), a 629 MW natural gas combined-cycle power plant, is subject to a Best Available Control Technology (BACT) emissions limit of 950 lb of CO_2/MWh (gross generation, 12-month rolling average basis). Rusty Ruby, Acting Executive Secretary, Utah Air Quality Board. Approval Order: Installation of Lake Side Block #2 at PacifiCorp's Lake Side Power Plant Project Number: N013031-0010. May 4, 2011.

firing with lower carbon fuels; (4) fuel switching; or (5) use of carbon capture technologies. With no additional flexibility, the owner of a generating facility might review these options and make the economic decision to retire the unit. Under a "no flexibility" scenario, there would be no opportunity for averaging across multiple plants or relying on GHG reduction credits. Under a "limited flexibility" scenario, in addition to the compliance options listed above, plant owners may be able to average emissions across individual boilers at the same facility (and within the same subcategory), as in the MATS rule and NSPS for municipal waste combustors.

For a performance standard with limited or no flexibility, the main decision that EPA would need to make would be the level of the standard(s) and any subcategorization (e.g., by fuel or technology). EPA would also need to make some relatively minor design choices, including: (1) whether to base the standard on gross MWhs or net MWhs;[17] (2) the method for monitoring CO_2 emissions (e.g., estimated based on fuel consumption or measured using CEMs); and (3) the averaging period.

The primary advantages of a performance standard with limited or no flexibility include the ease of administration and the predictability of the obligation. Power plants routinely monitor electric output and CO_2 emissions (or fuel consumption) and could readily compare their performance to the standard and demonstrate compliance. This option might arguably carry the least legal risk given EPA's past reliance on this framework.

However, there are several important disadvantages in adopting a performance standard with limited or no flexibility; first and foremost, would be the higher costs per ton of CO_2 reduced. Economic theory suggests that flexible, market-based compliance approaches can produce significant cost savings where marginal abatement costs vary among affected sources. For example, in a review of ten empirical studies, Dr. Thomas Tietenberg of Colby College found that command-and-control policies range in cost from 1.07 to 22.0 times that of the least-cost policy option.[18] Researchers at Resources for the Future (RFF) modeled a theoretical NSPS policy for coal-fired power plants, using RFF's Haiku Electricity Market Model, and concluded that an "inflexible" performance standard increased the costs of the policy by $3.5 billion per year, relative to a flexible performance standard that allowed trading around the standard and achieved the same level of emissions reductions.[19]

[17] "Gross" MWhs are generally based on direct measurement of the electrical output from a generator. "Net" MWhs deduct the electrical power utilized at the plant by auxiliary equipment such as pumps, motors and pollution control devices.
[18] Tietenberg, T. H. 1990. "Economic instruments for Environmental Regulation." Oxford Review of Economic Policy. 6:17-33.
[19] Burtraw, Dallas; Paul, Anthony; and Woerman, Matt. Retail Electricity Price Savings from Compliance Flexibility in GHG Standards for Stationary Sources. July 2011.

Additionally, a performance standard with limited or no flexibility may constrain EPA in establishing the stringency of the program. With limited flexibility, such an approach would exceed any given cost-effectiveness threshold before a more flexible compliance option and may require detailed plant-by-plant reviews to establish a reasonably achievable set of standards. A performance standard with limited flexibility may also require a greater administrative burden as regulators and affected sources conduct unit- or plant-specific evaluations of potential efficiency improvements and/or co-firing opportunities. A performance standard also does not limit overall emissions because it does not constrain the use of fossil fuels in response to increases in electricity demand.

Based on past precedent, some would argue that a performance standard with limited flexibility is the most legally conservative approach that EPA could adopt. However, a very narrow reading of section 111, that fails to reflect the potential cost savings from a more flexible compliance approach, is certain to invite legal challenges from states and environmental stakeholders who will argue that it is appropriate to interpret the "best system of emission reduction" more broadly and argue that more significant and cost-effective reductions are achievable.

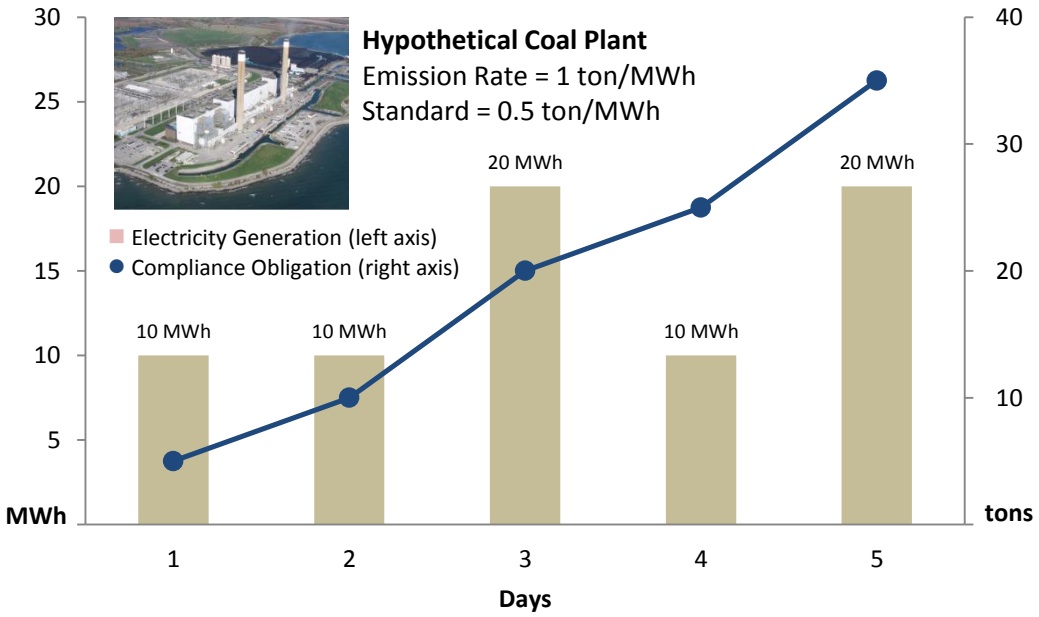
CO_2 molecules in the atmosphere mix uniformly over many decades; there are no local air quality concerns associated with CO_2 emissions. As a result, there is no environmental benefit in forcing CO_2 reductions at a specific power plant or within the borders of a specific state based on an inflexible performance standard. As discussed above, a performance standard with limited or no flexibility would be suboptimal in terms of reducing the total costs of mitigating GHG emissions.

Option 2 (performance standard with flexibility). A performance standard with flexibility (averaging, banking, and trading) is a market-based compliance mechanism designed around a lb/MWh emissions standard. Some describe it as two policies in one: (1) facilities that fail to meet the standard incur debits for every MWh of electricity they generate; and (2) facilities that perform below the level of the standard earn credits for every MWh of electricity they produce.[20] For example, Figure 2 below illustrates a hypothetical coal plant that produces 70 MWh of electricity over the course of five days. Assuming a standard of 1,000 lb/MWh (0.5 ton/MWh), the plant would generate a compliance obligation of 35 tons over the five days: (Emission Rate – Standard) x Total MWhs.[21] In order to demonstrate compliance, this facility would need to average its emissions with a lower emitting plant within its fleet or purchase credits from a lower emitting facility. This trading of credits would then

[20] Burtraw, Dallas; Fraas, Arthur; and Richardson, Nathan. Tradable Standards for Clean Air Act Carbon Policy. February 2012.
[21] In contrast, under a state-budget approach, this hypothetical coal plant would need to surrender an allowance for every ton of emissions generated (i.e., 70 tons).

reveal a market price for CO_2 to guide capital investment decisions. The hypothetical plant owner could also reduce its utilization to shrink its credit obligation.

Figure 2. Calculating Compliance Obligations under a Performance Standard



A performance standard with flexibility introduces design elements that EPA or states would need to address, in addition to those described in the discussion of an *inflexible* performance standard. These added design decisions include: (1) whether averaging or trading is allowed across subcategories (assuming separate standards by subcategory); (2) whether and how credit is awarded to existing and/or incremental non-covered sources, including renewables, nuclear, and end-use efficiency; and (3) to what extent EPA facilitates the interstate trade of GHG credits by issuing a model rule for states to adopt, establishing compatible state rules and programs.

The primary advantage of a flexible performance standard is the reduced costs (superior cost-effectiveness) relative to an inflexible performance standard. By allowing averaging and trading, the market would determine the most cost-effective combination of control strategies to meet the standard. This added compliance flexibility also addresses concerns that an individual plant or unit may be unable to meet a specific performance standard because of site-specific constraints. In the 2008 Advance Notice of Proposed Rulemaking (ANPR) for GHGs, EPA said that it might be possible

to consider deeper reductions because of the cost savings associated with a flexible compliance approach.[22]

A flexible performance standard avoids placing a specific limit on emissions. Fossil generators could increase their electricity output and emissions, as long as they collectively satisfy the performance standard. This may be viewed as an advantage or a disadvantage, depending on the degree of certainty that a stakeholder is seeking around a specific GHG reduction goal. In theory, a performance standard could be set at a level that achieves an equivalent level of reductions as a cap, but in the end the level of emissions reductions will depend on the market response to the standard.[23]

No court has ruled on the legality of EPA providing compliance flexibility under section 111(d) and there is limited precedent for EPA, especially if EPA credits reductions from outside the source category. While there are examples of EPA allowing flexibility, such as trading for compliance under 111(d) (as in the standards for existing municipal solid waste combustors), stakeholders disagree on how much flexibility EPA can consider as it sets the emissions standards and how much compliance flexibility is legal under the Act. For example, some argue that if EPA allows compliance flexibility, more emissions reductions are achievable and cost-effective and, therefore, EPA must set a more stringent standard.[24] Others argue that EPA should set a performance standard consistent with past precedent and states should have the authority to allow compliance through a broad range of flexible compliance measures including demand side energy efficiency programs and renewable portfolio standard (RPS) programs. It is unclear how a court would interpret EPA's authority and obligation to set the standards and states' ability to allow compliance flexibility.

Another potential challenge with a flexible performance standard will be developing methodologies to account for and credit contributions from non-covered sources, such as energy efficiency, renewables, or nuclear generation. This raises legal as well as implementation questions. From a legal perspective, as noted above, if EPA allows non-covered sources to earn credits but does not consider that reduction potential as it establishes the level of the standard, it may face challenges from the environmental community that it did not consider the full range of measures to reduce emissions as it

[22] U.S. EPA. Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act. Page 440. Signed July 11, 2008.
[23] The U.S. Energy Information Administration (EIA) publishes an annual projection of energy production, consumption, and emissions, known as the Annual Energy Outlook. The most recent forecast (AEO2013) projects a reduction in the CO_2 intensity of the electric power sector in the U.S. Emissions per kilowatt hour of electricity production are projected to decline six percent beginning in 2016 (from 2012 levels), and remain below this level throughout the forecast (through 2040). Despite the projected improvement in the average emission rate, however, total emissions are projected to increase: eight percent by 2030 and 12.4 percent by 2040.
[24] Ceronsky, Megan and Carbonell, Tomás. Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants. October 2013.

set the standard. From an implementation perspective, to include non-covered sources, EPA would likely have to establish crediting protocols or guidance for states. In the guidance, EPA would have to: (1) define a baseline year from which to credit new capacity or incremental generation; (2) provide guidance on the appropriate rate at which to credit non-emitting generation (i.e., what is the emission rate of the generation that is displaced?); and (3) for energy efficiency, develop measurement and verification protocols to provide the market and regulators with confidence that actual reductions are being achieved. State regulators warn that evaluation, measurement and verification (EM&V) programs can be "resource-intensive and air pollution control agencies may not have the appropriate staffing or expertise to 'certify' energy efficiency reduction credits."[25] They recommend that: "EPA should provide flexibility and resources to assist state and local agencies in quantifying the benefits of end-use energy efficiency and renewables, while ensuring that methods for quantifying benefits are consistent across the country."

Another set of issues to consider are the potential market implications of a flexible performance standard. As discussed above, a flexible performance standard is really two policies in one: (1) facilities that fail to meet the standard incur debits for every MWh of electricity they generate; and (2) facilities that perform below the level of the standard earn credits for every MWh of electricity they produce. Within a competitive power market, this credit mechanism will lead higher emitting plants to raise their bid prices, and lower emitting plants to reduce their bid prices. As a result, Burtraw and Woerman conclude that a flexible performance standard will result in a relatively small change in average retail electricity prices.[26] They argue:

> "the standard introduces a credit price representing the opportunity cost of emissions (measured in dollars per megawatt-hour) and the value is recycled to generators as an output subsidy (measured in dollars per megawatt-hour). This political advantage is an economic disadvantage because electricity consumers do not see a potent signal to reduce energy use. The disadvantage in the short run may be small, but over time the costs grow substantially if energy users invest in an inefficient capital stock."

Depressing wholesale electricity prices may be viewed as an advantage or disadvantage, depending on a stakeholder's perspective. Lower prices would be an advantage to consumers in the short run, but reduce the incentive to invest in cost-effective GHG reductions, raising program costs in the long run.

[25] Letter to Regina McCarthy, Administrator, U.S. EPA. From the National Association of Clean Air Agencies. August 21, 2013.
[26] Burtraw, Dallas and Woerman, Matt. Technology Flexibility and Stringency for Greenhouse Gas Regulations. July 2013. RFF DP 13-24.

A Variation on Option 2

Option 2 would require a credit tracking system and credit protocols, if non-covered sources were included in the program. Alternatively, rather than implementing a full emissions trading program, a state could develop a plan, similar to a SIP developed under section 110, that relies on a portfolio of measures to satisfy the emissions guidelines. Based on modeling, state regulators could demonstrate the reductions that would be achieved by a combination of enforceable emissions reduction programs, such as renewable performance standards or energy efficiency standards, along with performance standards that are used to directly regulate sources. The performance standards would be adjusted to reflect the anticipated benefits of the broader portfolio of measures. At the source level, an operator may be responsible for developing a compliance plan that met the required standard through a combination of investments within its fleet and actions that are implemented outside the source category, such as investments in nuclear uprates or other approved projects that produce additional and verifiable greenhouse gas emission reductions.

Such an approach would avoid the need to establish a trading program with discrete emission credits but would potentially create significant legal challenges around source enforceability and federal enforceability of state programs in addition to the accounting and legal concerns described above. To address concerns about source enforceability and federally enforceability of state programs, a state could propose contingency measures that would be applied if the state failed to meet its obligation.

Option 3 (state budget approach). A state budget approach would involve EPA deriving state-wide CO_2 emissions budgets for electric generating facilities in each of the states covered by the rule. States would then 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 CO_2 emissions and surrender an emissions permit for each ton of CO_2 released to the atmosphere. In this way, the budget restricts the level of emissions, but the industry would have the flexibility to determine the most cost-effective compliance strategy. EPA could facilitate interstate trading of emissions permits by developing a model rule or guidance that would establish consistent and compatible trading programs. This is the approach that EPA used under section 110 of the CAA to address the interstate

transport of NOx and SO_2 emissions and the approach EPA finalized and intended to use under CAMR.

Under a state budget approach, states would retain the flexibility to establish alternatives programs that were demonstrated to be equivalent. 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.

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 lb/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.

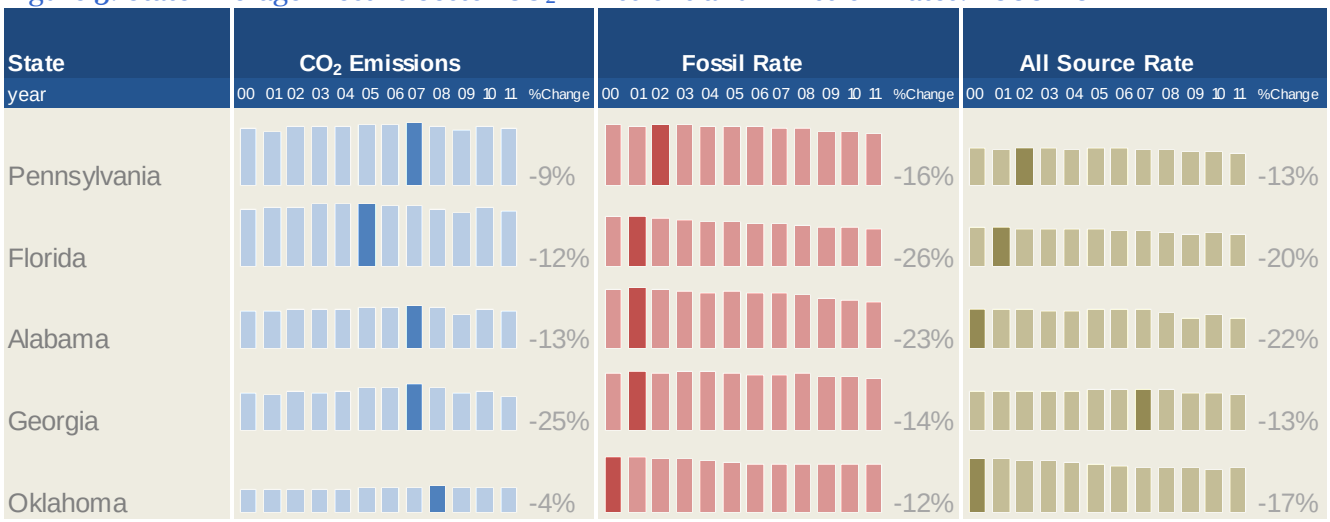
A key challenge under this approach would be establishing the appropriate baseline to ensure the state budget performs as intended. If state budgets are too high, the program may not deliver the anticipated reductions, and if they are too stringent, the negative political and economic implications would be significant. Predicting economic trends and natural gas prices are difficult, but both have the potential to dramatically affect the implications of states' budgets. This uncertainty presents a challenge for any state budget approach.[27]

Figure 3 highlights the CO_2 emissions trends (2000-2011) in a sampling of states. For example, Pennsylvania's average fossil emission rate declined 16 percent in 2011 (relative to its peak in 2002). Coal-fired generation in Pennsylvania has declined 18 percent since its peak in 2007; natural gas-fired generation has more than doubled over that same period. As a result, the state's total electric sector CO_2 emissions have declined 9 percent since 2007. Georgia's CO_2 emissions have declined 25 percent since 2007 after a 33 percent decline in coal generation and a 65 percent increase in natural gas-fired generation. In selecting a baseline period, states should understand these changes in the past

[27] Unlike Section 111(b), which requires EPA to review standards for new and modified sources every eight years, Section 111(d) does not require regular review and revision.

utilization of different fuel types as well as future projected emissions trends (e.g., nuclear plant retirements, coal plant retirements, and anticipated new plant construction).

Figure 3. State Average Electric Sector CO_2 Emissions and Emission Rates: 2000-2011



Note: Percentages represent the change in 2011 from peak emissions or emissions rates (darker bars). Rates are pound per megawatthour (net). Emissions are calculated based on fuel consumption for electricity generation only, rather than total fuel consumption for electric and steam production.

Source: MJB&A analysis based on U.S. EIA 923 data.

Establishing the appropriate methodology for allocating emission permits would also be a challenge. EPA could leave such decisions entirely to the states; it could provide specific direction through a model rule; or it could express general preferences through a guidance document.[28]

There are several important advantages of a state budget approach, including the environmental certainty that results from limiting total allowable emissions. In setting the state-wide budgets, EPA ensures that aggregate emissions will remain below the level of the combined national budget. Allowing the trading of emission permits also eliminates the need to establish special crediting mechanisms for energy efficiency, renewables, or nuclear generation. Investments in these alternative resources are accounted for under a state budget approach by lowering overall emissions, making a special crediting system unnecessary. Additionally, unlike a conventional performance standard approach, a state budget system creates an ongoing incentive for technology innovation and operational improvements.

[28] Among the decisions, EPA and the states will have to the frequency of allocations, the basic method of allocation (e.g., a grandfather approach, updating output-based allocation, or an auction), and the use of set-asides (e.g., set-asides for energy efficiency projects, renewable energy sources, or for new units).

A potential concern with proposing a state budget approach would be the political reaction. However, the political concerns could be mitigated by giving states the option of adopting and implementing a state budget approach, rather than mandating this approach for all states. Additionally, a state budget program has the potential to raise electricity prices higher than other design options, depending on the level of the budget and other program design decisions. Finally, the allocation choices by EPA or states would be politically charged.

Like the flexible performance standard, no court has ruled on the legality of EPA establishing a state budget system under section 111(d). EPA put forth several arguments in the CAMR case why such an approach is valid under 111(d), but the court never reached these questions, and it is unclear how a court would decide. However, to mitigate this legal risk and the political risk noted above, EPA could establish federal performance standards consistent with EPA precedent and allow states the option of implementing a budget approach. EPA could facilitate states' decisions by translating the standard into state budgets and providing guidance that states could adopt or adjust as appropriate. Thus, states that see greater advantages under a state budget approach would have the ability to implement it, and other states could implement a more traditional performance standard approach. However, greater consistency among state programs would likely generate significant reductions in overall compliance costs by facilitating interstate trading (directing capital to the lowest cost compliance options) and avoiding potential distortions in electric power markets.

III. Conclusion

EPA has significant discretion under section 111(d) in determining both the appropriate level of the standards for existing power plants, as well as the form of the regulations. EPA and the states should consider adopting flexible, market-based regulatory approaches that encourage cost-effective compliance solutions and investment, like Options 2 and 3 described in this report. States have often served as "laboratories" for innovative regulatory approaches, and that experience, implementing and enforcing effective air pollution programs, should help guide EPA's decision-making.