GHG New Source Performance Standards for the Power Sector: Options for EPA and the States

Prepared by the Pew Center on Global Climate Change

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About this Document:

The Pew Center prepared this document to inform EPA's development of greenhouse gas standards for fossil fuel-fired power plants (Docket ID: EPA-HQ-OAR-2011-0090). This document discusses how EPA might allow for and states might pursue market-oriented approaches to reducing greenhouse gas emissions from power plants under Section 111(d) of the Clean Air Act. The Pew Center prepared this document in consultation with representatives of business and nongovernmental organizations; however, this document is solely a product of the Pew Center and does not represent a consensus position of any coalition or group.

Contents

1. Executive Summary

This document explores market-oriented approaches for reducing greenhouse gas (GHG) emissions from electricity generation under Section 111 of the Clean Air Act (CAA). This document focuses in particular on how states might adopt market-oriented approaches to achieve the GHG emission reductions required from existing electricity generating units under Section 111(d) of the CAA as well as the implications of different design choices for these market-oriented approaches. This document also highlights policy and legal questions related to state-driven, market-oriented regulations under Section 111(d), describes stances EPA might take toward market-oriented state programs in its emission guidelines, and identifies an opportunity for beneficial interaction between GHG regulations and pending non-climate-related EPA regulations.

The bullets below summarize key points from the following sections.

- Market-oriented approaches offer the opportunity to achieve GHG emission reductions more cost-effectively than traditional "command-and-control" regulations.
- EPA could use its authority under Section 111 to create a national emissions trading program for new and existing sources. Such an approach, of course, has not been legally tested and some might argue would be politically contentious.
- Instead, EPA may issue traditional rate-based performance standards for GHG from power plants (for example, lbs of CO_2e per MWh, differentiated by source categories).
- The Clean Air Act appears to allow the flexibility for states who so choose to adopt market-oriented policies to achieve the GHG emission reductions that will be required by EPA's Section 111(d) emission guidelines.
- States that are already moving forward with market-oriented state or regional emission reduction programs (notably the Regional Greenhouse Gas Initiative and California's AB 32 cap-and-trade program) ought to be able to use those programs to meet the requirements for emission reductions under Section 111.
- To the extent that additional states would prefer to adopt market-oriented approaches to reduce GHG emissions from power plants, such states should be free to choose such approaches in order to achieve the emission reductions required under Section 111.
- The RGGI states already have an operational cap-and-trade program for CO_2 from power plants, and California is implementing an economy-wide cap-and-trade program. Other states interested in meeting their Section 111 requirements via more cost-effective market-oriented approaches might prefer a flexible emissions standard that allows for rate-based trading rather than a "hard cap" program with allowance trading. States might also be interested in clean energy standards that reduce emissions by requiring increases in lower-carbon generation. The policy approaches have different implications and present different policy design choices.
- Multi-state trading programs involving states that choose to pursue market-oriented regulations can expand the scope of trading and achieve aggregate emission reductions more cost-effectively. There are steps EPA could take to facilitate multi-state trading.
- There are several questions to be resolved pertaining to state-driven, market-oriented regulation of GHG emissions from power plants—including how best to demonstrate states' compliance with

EPA's binding emission guidelines if states allow for interstate trading, offsets usage, multi-sector trading, price floors/ceilings, or international trading.

- Lastly, EPA's NSPS rulemaking is not taking place in a vacuum. Over the next few years, power plant owners will have to make decisions about retrofitting, retiring, and replacing a large number of carbon-intensive coal plants in light of pending non-climate EPA air, water, and waste regulations. EPA and the states should recognize this situation when formulating GHG regulations and evaluate appropriate incentives for power plant owners to retire carbon-intensive units and replace them with low-carbon generation rather than making sub-optimal investments that "lock in" GHG emissions for years to come.

2. Pending Non-Climate EPA Regulations

As has been widely noted and analyzed, pending non-climate EPA regulations—namely, the Transport Rule, the "utility MACT" rule for mercury and other hazardous air pollutants (HAPs), new cooling water regulations under Section 316(b) of the Clean Water Act, and federal coal ash regulation under RCRA—will create new requirements and increased costs for existing coal power plants that may lead many plants to be retrofit (and derated) or retired. For example, a recent summary of several analyses of the potential coal plant retirements driven by just these pending non-climate EPA regulations found that estimates range from 6 to 65 gigawatts (GW) of retired coal-fired capacity by 2020, equal to about 2 to 20 percent of current coal-fired capacity; although, most estimates fall between about 25 and 50 GW.[1] In addition to delivering public health and environmental benefits, these retrofits and retirements may create challenges for maintaining system reliability and impose substantial costs. Moreover, power generators will likely have to make major capital investment decisions in the absence of a long-term, comprehensive federal climate policy (e.g., without a price on carbon), which may lead to widespread fuel switching to natural gas or retrofitting coal plants with environmental controls to meet the new EPA regulations and extending the life of these existing coal plants. These immediately available options may be suboptimal with respect to achieving long-term GHG emission reductions and needed investments in low-carbon technology deployment and "lock in" GHG emissions for years to come. While natural gas can play an important role in lowering power-sector GHG emissions, natural gas is only one option in the portfolio of lower- and non-emitting generation technologies anticipated to provide the least-cost decarbonization pathway for the power sector.

Policymakers have the opportunity address concerns about the potential costs impacts on consumers by promoting the replacement of some retired coal units with very low- or non-emitting generation and providing incentives for retirement to coal plants that would otherwise be retrofit to comply with pending non-climate EPA regulations. In particular, market-oriented approaches for implementing GHG emission standards under Section 111 could accommodate such incentives (See Section 4.3.14).

[1] Tierney, Susan, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," World Resources Institute (WRI), available at http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3. Forthcoming GHG NSPS for Power Plants

On December 23, 2010, EPA announced its intention, as part of a settlement agreement with various states and environmental groups, to issue new source performance standards (NSPS) for new and modified emitters in the power sector and emission guidelines for state regulation of existing power plants under Section 111 of the CAA.[2]

Section 111 of the CAA provides for setting emissions performance standards for new and modified sources (Section 111(b)) and existing sources (Section 111(d)) within categories of stationary sources.

3.1. NSPS for New and Modified Sources under Section 111(b)

Section 111(b) requires EPA to set emissions performance standards for new and modified stationary sources in categories that contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. A "standard of performance" is 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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Various court decisions make clear that EPA may take into account improvements in technology and performance that can be reasonably projected, taking into account available lead-time.

3.2. GHG Emission Reductions Required from Existing Sources under Section 111(d)

Although EPA has issued dozens of non-GHG emission standards for new and modified sources under Section 111(b), Section 111(d) has been used relatively rarely, so there are limited precedents for how GHG standards might be implemented under Section 111(d).[3]

Section 111(d) directs EPA to issue regulations requiring states to set emissions performance standards for existing sources. Section 111(d) specifically directs that the process for setting such standards be similar to the State Implementation Plan (SIP) process for criteria pollutants under Section 110, and states must adopt plans that establishes standards of performance for existing sources and submit the plans to EPA for approval. Of note, Section 110 allows for state plans to include "economic incentives such as fees, marketable permits, and auctions of emissions rights;" this suggests that states could adopt market-oriented approaches to meeting their Section 111(d) requirements. EPA has authority to establish a standard for a state if the state fails to act or if the state's standard is not approvable. Section 111(d)(1)(B) allows for the consideration of existing sources' "remaining useful life." Under EPA's Section 111(d) regulations, when EPA issues a standard of performance for new and modified sources, EPA also

[2] For details on the settlement agreement, see http://www.epa.gov/airquality/ghgsettlement.html.

[3] Section 111(d) applies only when sources regulated under Section 111(b) emit pollutants that are neither criteria pollutants (e.g., sulfur dioxide) nor hazardous pollutants (e.g., benzene). Section 111(d) applies to GHGs because they are not criteria or hazardous pollutants. Existing sources of criteria and hazardous pollutants are controlled under Sections 110 and 112, respectively.

issues "emission guidelines" setting forth the performance level that state standards for existing sources are expected to meet.

3.3. National GHG Trading Program under Section 111

In the Clean Air Mercury Rule (CAMR), EPA attempted to create a national trading program to reduce mercury emissions from new and existing coal-fired power plants under the agency's Section 111 authority. A similar national trading program for GHG emissions from power generators that covered new and existing sources would have the maximum scope of any market-oriented approach under Section 111 and thus achieve emission reductions most cost-effectively.

However, while it may be possible to use the Section 111 authority to create a national GHG emissions trading program covering new and existing sources, this approach is legally uncertain and politically vulnerable. EPA's legal authority for establishing a national trading program under Section 111, as it attempted to do under CAMR, is untested, and such an approach is politically vulnerable to attack as "backdoor cap and trade."[4] In fact, in announcing EPA's intention to regulate GHG emissions from power plants under Section 111, Assistant Administrator Gina McCarthy said that "this is not a cap-and-trade program."[5]

As such, EPA's approach to setting the standards for new and modified sources under Section 111(b) may be to set the standards in the form of maximum emission rates (e.g., lbs CO_2e per MWh) that must be met at each source. Of note, while EPA, under CAMR, would have bound new or modified sources and existing sources under a single cap with trading allowed among them, CAMR also included binding performance standards for new and modified sources.[6] This precedent suggests that even if EPA were to propose a market-oriented approach under Section 111 with trading allowed among new and modified sources and existing sources, new and modified sources might still need to comply with traditional performance standards.

Importantly, from a legal and political perspective, states acting on their own initiative may more safely pursue market-oriented emission reduction policies for existing sources under Section 111(d).

3.4. Issues to Consider Regarding State-Based Market-Oriented Programs

Assuming EPA proceeds with traditional rate-based performance standards for new and modified sources under Section 111(b) and issues emission guidelines that include traditional performance standard rates for states to follow in regulating existing sources under Section 111(d), states might have

[4] The D.C. Circuit Court vacated EPA's CAMR on other grounds without reaching the question of whether EPA's proposed cap-and-trade program and its design parameters were within the agency's authority.

[5] Feldman, Stacy, "EPA Sets Timetable on Carbon-Cutting Regs for Coal and Oil," *SolveClimateNews.com*, 23 December 2010, available at http://solveclimatenews.com/news/20101223/epa-sets-timetable-carbon-cutting-regs-coal-and-oil.

[6] Under the CAMR Trading Program, EPA proposed a single cap for new and modified sources and existing sources and allowed trading among them, but EPA also required that new and modified sources comply with traditional performance standards. Under the CAMR Trading Program, new and modified sources could not exceed the Section 111(b) performance standard by buying allowances.

several options for complying with the requirements of Section 111(d), and EPA can take a variety of steps to help states with an interest in adopting market-oriented approaches to do so.

The most straightforward approach for state standards would be to follow the form of the 111(b) standard, i.e., non-market-oriented, traditional source-specific emission rates for existing sources. However, as noted above states probably have some leeway under Section 111(d) to incorporate market-oriented compliance flexibility. States might design market-oriented flexible emissions standards (FES) that allow credit trading among regulated sources and that may be either rate-based or employ a "hard cap," or states might adopt policies to reduce emissions from existing sources by increasing generation from lower-carbon sources (different options for market-oriented regulations under Section 111(d) are discussed in detail in the sections below).

The following is a list of legal and policy issues pertaining to states' market-oriented options under Section 111(d):

- **Allowance Budget:** What is the appropriate allowance budget for a state that adopts a "hard cap" FES? This may be different in states where electricity output is rising vs. falling. One option may be to apply traditional performance standards from EPA's emission guidelines to the projected output from a state's existing sources to calculate the state's allowance budget.[7]
- **Scope:** How broad can the coverage of a state's market-oriented program be? Can a state allow for trading among different existing source categories (e.g., among coal and natural gas power plants or among power plants and industrial sources subject to 111(d) regulations)? Can a state allow multi-sector trading among sources covered by Section 111(d) requirements and other sources (e.g., as under California's state cap-and-trade program) and still comply with EPA's emission guidelines?
- **Interstate Trading:** Can states in existing (e.g., the Regional Greenhouse Gas Initiative, or RGGI) or new regional trading programs jointly demonstrate compliance with EPA's emission guidelines if aggregate emissions in some states may exceed those indicated by the emission guidelines? If interstate trading is permissible, what rules must govern it? Is credit trading permissible between a state with a rate-based FES and one with a "hard cap" FES?
- **Offsets:** May states allow for the use of emission offsets from non-covered sources in their Section 111(d) programs (e.g., offset usage under RGGI)? If so, what requirements might EPA establish for offset provisions?
- **Safety-Valve / Price Floor:** Would states be allowed to set minimum and maximum prices for tradable credit? If so, how might states implement such price floors and ceilings and coordinate them in the case of interstate trading?
- **International Jurisdictions:** How would EPA judge the stringency of regional trading programs that include jurisdictions from outside the United States (e.g., the Western Climate Initiative (WCI) includes Canadian provinces as members and Mexican states as observers)?

EPA might base its determination of whether states' market-based emission reduction programs are equivalent to EPA's emission guidelines for existing sources under Section 111(d) on ex ante modeling

[7] EPA's Transport Rule is based on projected electricity generation.

studies conducted by EPA and the states. As EPA explains, the agency's emission guidelines for state regulation of existing sources will "include targets based on demonstrated controls, emission reductions, costs and expected timeframes for installation and compliance."[8] States with existing market-based emission reduction programs and states that proceed with new market-based programs could conduct sophisticated modeling analyses to project expected GHG emission reductions from electric generating units—including a range of sensitivity analyses addressing such issues as natural gas prices—as part of their state plans under Section 111(d). If these modeling analyses project emission reductions from existing electric generating units of equal or greater magnitude to those required under EPA's emission guidelines, then EPA might judge the states' market-oriented approaches to achieve equivalent emission reductions to those required by the emission guidelines and approve the states' Section 111(d) plans (assuming the agency finds no other objections to the plans).

3.5. Addressing Market-Oriented Policies in EPA's Section 111(d) Emission Guidelines

EPA's approach to market-oriented programs under Section 111(d) could range from being proactive and prescriptive to simply responding to issues raised by states who take the initiative in developing market-oriented approaches to achieving the reductions required under Section 111(d). Three such options for EPA are outlined in Table 1. None of the approaches below are intended to preclude the adoption of market-oriented policies by states or to limit the ability of states to demonstrate the equivalency of existing market-oriented programs with the emission reductions required under Section 111(d).

Table 1: Overview of Options for EPA to Handle Market-Oriented State 111(d) Programs

	EPA Approach	Description	Pros	Cons
A.	Proactive and Prescriptive	EPA's emission guidelines would include a model rule for an interstate trading program; states could choose to pursue traditional performance standards, opt-in to the model rule trading program, or seek approval of their own market-oriented approaches.	Promotes a broad trading program without forcing any options on states. EPA may use the market-oriented approach as a justification for greater emission reductions.	Most politically vulnerable approach to attacks as "backdoor cap and trade."

[8] EPA, "Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries: Fact Sheet," available at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf.

	EPA Approach	Description	Pros	Cons
B.	Laying Out Preferred Approaches	EPA's emission guidelines would enumerate state options for pursuing market-oriented approaches to Section 111(d) as alternatives to traditional performance standards, make known the conditions under which SIPs following the market-oriented options could be approved, and offer recommendations for optimal market-oriented program design.	Addresses potential issues with state market-oriented programs proactively. Provides some guidance to states to steer them toward well-designed market-oriented programs that might be easily linked. Potentially less politically vulnerable than Option A.	May result in a "patchwork" of state programs that may prove difficult to link if states choose different options thus limiting the efficiency gains from a market-oriented approach. EPA still draws attention to "cap and trade" with its guidance which may prove politically challenging. EPA may not be able to set emission guidelines that reflect the greater cost-effective emission reductions available via a market-oriented approach.
C.	Silent on Market-Oriented Approaches and Reactive	EPA's emission guidelines provide no options or guidance related to market-oriented approaches. Rather, EPA leaves the pursuit of market-oriented approaches entirely to the states' own initiative. EPA judges the adequacy of any market-oriented programs proposed in SIPs and addresses issues (e.g., offset usage) as they come up.	Least politically vulnerable approach since EPA proposes no market-oriented approaches that resemble cap and trade.	Without a departure from traditional regulatory approaches on the part of states, the gains from market-oriented regulation may be left mainly to states with existing or nascent trading programs (e.g., the RGGI states and California). The lack of guidance from EPA makes an interstate trading system more difficult to design and requires more coordination among the states. EPA may not be able to set emission guidelines that reflect the greater cost-effective emission reductions available via a market-oriented approach.

4. State Policies to Achieve Section 111(d) Emission Reductions

4.1. Options for State Section 111(d) Plans

This section discusses three approaches to that states might take to achieving the emission reductions required from existing sources under Section 111(d) and EPA's emission guidelines.

4.1.1. Traditional Performance Standard

The first approach is the traditional, non-market-oriented, rate-based performance standards approach ("traditional performance standards"). Under this approach, a state would set rate-based performance standards (e.g., lbs CO_2e per MWh) for existing electric generating units equivalent to or more stringent than the emission reduction targets in EPA's Section 111(d) emission guidelines.

4.1.2. Rate-Based Flexible Emissions Standard (FES)

A second approach that states might take is a market-oriented, rate-based flexible emissions standard (FES), or "rate-based FES." Under a rate-based FES, a state would establish rate-based performance standards (e.g., lbs CO_2e per MWh) for existing sources (perhaps with standards differentiated by the type of electric generating unit) and allow covered sources the flexibility to: comply with such standards precisely; over-comply and accrue tradable credits to bank for future compliance or sell to other covered sources; or to under-comply and buy credits from sources that over-complied with the standards.

4.1.3. "Hard Cap" Flexible Emissions Standard (FES)

Under the third approach, a state would establish a fixed aggregate limit on GHG emissions from covered sources ("hard cap FES"), where this aggregate limit would be no higher than the projected emissions from existing sources net of the emission reduction targets in EPA's Section 111(d) emission guidelines. The cap would be enforced by requiring covered sources to surrender FES allowances for each unit of GHG emissions from a fixed pool of tradable allowances (the "hard cap"). A state that implemented a "hard cap" FES would allocate these allowances at its discretion.

4.1.4. Other Options for States to Achieve Required GHG Emission Reductions

The policy options described above are not the only ones that states might pursue to achieve the emission reductions required by EPA's Section 111(d) emission guidelines. Many states have in place policies that impact GHG emissions from existing electric generators by requiring increased renewable generation (e.g., state renewable portfolio standards, or RPSs) or electricity savings from energy efficiency and conservation programs. Increases in renewable generation displace and electricity savings from efficiency and conservation avoid fossil-fueled generation and thus lower GHG emissions. Utility resource planning processes overseen by public utility commissions might incorporate GHG emissions cost forecast assumptions and selection of lower-GHG-emitting portfolios. States might also have or adopt policies regarding utility planning that could result in utilities retiring carbon-intensive generators and replacing them with lower-emitting generation. If a state can demonstrate to EPA that the state's suite of relevant policies (e.g., state RPS, demand-side management programs, and utility planning policies) will achieve equal or greater aggregate GHG emission reductions than required under EPA's emission guidelines, then EPA could determine this suite of state policies to be equivalent and judge the state to be in compliance with the requirements of Section 111(d). Any EPA determination of equivalency should ensure that the required level of emission reductions is achieved. If, upon review, a state policy program has failed to deliver equivalent emissions reduction, EPA could require remedies such as modification of the ongoing policy program to achieve the required emission reductions.

4.2. Summary Evaluation of State Options under Section 111(d)

Table 2 provides an evaluation of the three regulatory approaches described above against various criteria.

Table 2: Evaluation of State Options for Achieving Emission Reductions Required from Existing Sources under Section 111(d)

Evaluation Criteria	**Traditional Performance Standards**	**Rate-Based FES**	**"Hard Cap" FES**
Emission Reductions	Rate-based standards do not create a "hard cap" on emissions, and the actual level of emissions reduction will depend on power producers' responses to rate-based standards.	States might consider deeper emission reductions than under a traditional performance standard owing to cost savings from trading. However, the more limited scope of reduction options and the inherent output subsidy could limit reductions, relative to a "hard cap" approach.	A "hard cap" ensures a certain level of emission reduction. States might consider deeper emission reductions than under a traditional performance standard owing to cost savings from trading.
Cost-effectiveness	Least cost-effective owing to no or limited trading	More cost-effective than traditional standards because of trading, but subsidizes generation and emissions via implicit allocation. Ex post nature of credit accrual may limit cost-effectiveness compared to "hard cap" FES because of limited market liquidity	Cost-effectiveness depends on states' allowance allocation decisions. Potentially the most cost-effective option with efficiency-enhancing allocations

Evaluation Criteria	Traditional Performance Standards	Rate-Based FES	"Hard Cap" FES
Electricity Rate Impacts	Highly dependent on each unit's compliance requirements and the regulatory structure of the state	For the same level of emission reductions, rate impacts may be lower than under a traditional performance standards approach given greater cost-effectiveness of a market-oriented approach.	Rate impacts are a function of allocation decisions in cost-of-service markets. Perhaps larger rate impacts than rate-based FES in competitive electricity markets (owing to output subsidy to lower-emitting price-setting generators under the rate-based FES)
"Windfall Profits"[9]	Not anticipated to be an issue	Not anticipated to be an issue, assuming careful design of any shut-down credit mechanism	Only expected if states grandfather excessive allowances (i.e., more than required to cover any gap between power price increases and compliance costs) to generators in competitive markets
Uncompensated Impacts on Regulated Entities	No mechanism for compensating producers in competitive markets who cannot recover compliance costs via higher electricity prices	No mechanism for compensating producers in competitive markets who cannot recover compliance costs via higher electricity prices	States have discretion to provide free allocation to generators to ameliorate excessive uncompensated costs—like the merchant coal allocations in recent congressional cap-and-trade proposals.
Incentives for End-Use Efficiency and Conservation	Requires specific provisions to allow compliance via demand reduction	Requires specific provisions to allow compliance via demand reduction	By the nature of a "hard cap," reductions in electricity demand help meet the aggregate emission reduction requirement.
Compliance via Unit Retirement or Lower Utilization	Reducing emissions via lower utilization of emitting units does not count toward compliance.	Reducing emissions via lower utilization of emitting units does not count toward compliance without special provisions (e.g., shut-down credits).	By the nature of a "hard cap," lower utilization of emitting units helps meet the aggregate emission reduction requirement.

[9] Here "windfall profits" refers to the transfer of wealth (e.g., in the form of tradable credits) to competitive power generators that is in excess of any compliance costs that they cannot recover from higher electricity prices. It does not refer to any increase in the value of lower-emitting generating units as a result of the policy.

Evaluation Criteria	Traditional Performance Standards	Rate-Based FES	"Hard Cap" FES
Rate Impact Mitigation for Industrial Customers	State utility regulators have some discretion in terms of how compliance costs are borne by customer classes.	State utility regulators have some discretion in terms of how compliance costs are borne by customer classes.	In addition to any discretion on the part of state utility regulators, allowance allocation can mitigate rate impacts.
Inclusion of Industrial Sources in Program	n/a – no trading	May be possible, including via opt-in	May be possible, including via opt-in

4.3.Policy Design Options and Implications

This section examines different design choices that states would face for the three approaches to regulating GHG emissions from existing sources under Section 111(d) of the CAA.

4.3.1. Market-Oriented Compliance Flexibility

A large body of economic research establishes the advantages of market-oriented emission regulations compared to traditional non-market-oriented (or command-and-control) regulations. Market-oriented regulations promote economic efficiency and the achievement of a given level of emission reduction at a lower cost compared to non-market-oriented approaches. Unlike uniform emission standards, market-oriented regulations accommodate the wide range of abatement options and costs faced by different emitters and allow for a lower-cost mix of abatement options, with emitters facing lower abatement costs reducing emissions more than those facing higher abatement costs. Moreover, by putting a price on emissions, market-oriented regulations create incentives for firms to continuously improve their environmental performance via innovation and new technology development.

The traditional performance standards option is the least market-oriented. States who pursue this approach to comply with EPA's Section 111(d) emission guidelines might be able to include some limited trading or averaging (e.g., across facilities owned by a single entity), but this approach would likely reap few of the benefits of market-oriented regulation and would, for a given level of emission reductions, prove more expensive than the market-oriented FES approaches.

The rate-based and "hard cap" FES approaches are market-oriented and would establish a carbon price for the power sector either explicitly if tradable credits are denominated in units of GHGs (e.g., tons CO_2) or implicitly if tradable credits are denominated in units of emissions-intensity (e.g., tons CO_2 per MWh). The carbon price signal would help drive a lower-cost set of emission abatement measures than under a traditional performance standard and provide an incentive for innovation that is lacking under a traditional performance standard.

Any approach that is limited to rate-based controls (i.e., that does not have a "hard cap" on emissions) raises questions about the amount of emission reductions that will be achieved; moreover, a rate-based, market-oriented approach can, in theory, create counterproductive incentives for regulated sources—though the practical importance of such incentives is uncertain.[10]

4.3.2. Scope

A state that pursued the traditional performance standard approach could enforce rate-based emission standards for existing sources differentiated by source category (e.g., coal-fueled and natural gas-fired electric generating units).

The broader the scope of a trading program, the more efficiently it can achieve a given level of emission reductions. States could achieve a given level of emission reduction more cost-effectively via rate-based or "hard cap" FES programs that allowed for trading among different types of sources (e.g., coal and natural gas power plants) and among sources in multiple states.

From an overall economic perspective, the least-cost emission reduction pathway for the power sector involves both demand reduction via efficiency and conservation and a lowering of the GHG emissions intensity of total electricity generation that can come from a combination of changes among fossil-fueled generators (i.e., retirement of generators, efficiency improvements, co-firing or fuel switching from coal to biomass or natural gas, and use of carbon capture and storage) and increases in generation from non-emitting technologies (e.g., nuclear and wind power). A "hard cap" FES provides an incentive for each of the aforementioned options for reducing GHG emissions from existing electricity generating units by its nature, and emission reductions from all of these options contribute to overall compliance with a "hard cap" FES. A rate-based FES whose scope is limited to fossil-fueled electricity generators, however, focuses exclusively on driving changes in the emissions intensity of those covered generators. A state that implements a rate-based FES might be able to include special provisions for electricity savings from energy efficiency and conservation and replacement of higher-carbon generation with lower-carbon generation.

4.3.3. Emission Reductions

Emission reductions under the different regulatory options are a function of the emission reduction targets set by EPA in its Section 111(d) emission guidelines based on technical analyses of emission reduction options and their costs and other impacts, the states' decisions in their Section 111(d) plans, and the power sector's response to the policies implemented.

Of the three approaches, only the "hard cap" FES includes a binding aggregate limit on GHG emissions from existing electricity generating units. The traditional performance standards and the rate-based FES regulate only the GHG-intensity of electricity generation, and thus the overall GHG emissions from existing electricity generating units could be more or less than under a "hard cap" FES depending on the electricity demand faced by from covered entities. In practice, though, the differences among emission

[10] In its Advance Notice of Proposed Rulemaking (ANPR) for GHGs, EPA explained that "a drawback of the [market-oriented] rate-based approach is that it provides an incentive to increase whatever is used in the denominator of the rate [e.g., electricity] . . . [such that] rate-based policies can encourage increased production because production can be rewarded with additional credits [which] . . . in turn has the potential to encourage increased emissions and thus to raise the overall cost of achieving a given level of emissions." EPA, 2008, *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act*.

levels achieved by the various policy approaches might be small if each policy approach targets the same level of emission reduction.

In its Advanced Notice of Proposed Rulemaking for GHGs (ANPR), EPA said that "recognizing that existing sources do not have as much flexibility in the levels of control that may realistically be achieved at a new source, a section 111(d) standard regulating GHG[s] from existing sources would at this time most likely focus on currently available measures to increase the energy efficiency at the facility."[11,12] EPA has estimated that such efficiency improvements at existing coal-fired power plants might reduce GHG emissions from the existing coal fleet by less than 5 percent and that co-firing of biomass might additionally reduce emissions by 2 to 5 percent across the entire fleet.[13,14] According to EPA, there are fewer options for improving the efficiency and thus the emission intensity of natural gas combustion turbines and combined cycle generators.[15]

4.3.4. Emission Credit Distribution

The distribution of emission credits or allowances is relevant for the rate-based and "hard cap" FES approaches.

Under a rate-based FES, tradable credits accrue to covered sources only to the extent that sources over-comply with relevant performance standards (i.e., have emission intensities lower than the applicable standard). A rate-based FES requires not only the tracking of credits (i.e., their trading and submission for compliance) but also monitoring of actual emissions and electricity generation (and perhaps fuel consumption depending on the nature of the performance standard) in order to judge compliance with the standard and for credits to accrue to covered entities for over-compliance. Given existing EPA and Department of Energy (DOE) monitoring and reporting programs (e.g., EPA's GHG Reporting Program) most or all of these data are already collected from power generators. Under a rate-based FES, the key decision that determines which generators accrue credits and how many credits they accrue is the setting of the performance standards (e.g., the emissions rates and any differentiation of performance standards by fuel type, plant age, or other factors). Save for any special treatment of unit retirements and electricity savings from efficiency and conservation, once the performance standards are set under a rate-based FES, the main role of states implementing such programs would be to collect and verify emissions and generation data in order to issue credits for over-compliance, as well as to assess each

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[11] EPA, 2008, *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act*.

[12] Some concern has been expressed that efficiency improvements at a particular power plant, while lowering its emissions rate, may increase the annual aggregate emissions from the plant as it displaces less efficient units in the dispatch order. This could trigger New Source Review (NSR) thus requiring more stringent environmental controls.

[13] EPA, 2008, *Technical Support Document for the Advanced Notice of Proposed Rulemaking for Greenhouse Gases; Stationary Sources, Section VII*. EPA reports that "for steam boiler plants the range of options typically includes optimizing the performance of any of the feed water, boiler, turbine-generator, condenser, heat rejection, and auxiliary systems, improving control systems, installing higher efficiency pumps, fans, and drives, and reducing the moisture content of solid fuels."

[14] In the ANPR and its technical support document, EPA does not consider the large potential contribution to emission reductions from the retirement of existing coal plants.

[15] EPA, 2008, *Technical Support Document for the Advanced Notice of Proposed Rulemaking for Greenhouse Gases; Stationary Sources, Section VII*.

facility for compliance with the program. Once the standards are set, the accrual of credits is a function of individual generators' decisions as to whether to over-comply with the performance standards.

Because over-compliance with a rate-based FES could only be determined retrospectively, credit issuance would take place retrospectively, and this could lead to market liquidity issues.[16] Covered sources might lack timely information about credit availability in order to make the most economically efficient investment decisions. Under a rate-based FES, covered sources that want to use credits to satisfy compliance could either: a) use their own or buy others' banked credits from previous compliance periods; b) wait until the end of the compliance period to find out if credits are available and at what price, or c) rely on contractual agreements, with inherent risk, to reserve expected credits before their issuance. The ex-post nature of credit issuance under a rate-based FES could thus increase the transaction costs and decrease the economic efficiency of a rate-based approach relative to a "hard cap" FES. The liquidity challenges posed by ex post credit issuance under a rate-based FES might lessen over the life of an FES program as the number of cumulative banked credits increases (thus improving market liquidity) and as covered sources have more experience anticipating the degree of over-compliance and the supply of credits. Policy options to address the market liquidity issue under a rate-based FES include longer compliance periods and more frequent issuance of tradable credits for over-compliance.

If a state were to pursue a "hard cap" FES to achieve the emission reductions required under Section 111(d), the state might calculate a state allowance budget by applying the standards contained in EPA's Section 111(d) emission guidelines to existing sources in the state in light of the sources' projected electricity output. The state could then distribute tradable emission allowances at its discretion. For example, a state could auction some or all allowances, provide allowances for free to generators based on historical emissions, or allocate allowances to local distribution companies.

4.3.5. Offsets

States may want to allow compliance with a rate-based or "hard cap" FES via the use of offsets (in particular, the purchase of credits for emission reductions from sources not subject to regulation under Section 111(d), such as methane emission reductions from landfills). In particular, the Regional Greenhouse Gas Initiative (RGGI), which is an example of a "hard cap" FES program, allows for offset usage as does the multi-sector GHG cap-and-trade program under development in California.

[16] For example, in reviewing rate-based trading programs, analysts from Natsource wrote: "Market liquidity has suffered because sources typically have received tradable permits at the end of each compliance period, unlike most cap-and-trade programs, in which sources receive an allocation of tradable permits at the programs' outset. Small- and mid-sized firms may encounter difficulty in attempting to sell future vintage permits that they do not yet possess as a means of financing the installation of emissions abatement equipment. The result of this programmatic element could be sub-optimal environmental results, less market liquidity due to less permit supply, and higher overall compliance costs." See Rosenzweig, Richard and Matthew Varilek, *Key Issues To Be Considered in the Development of Rate-Based Emissions Trading Programs: Lessons Learned From Past Programs*, Prepared for EPRI Workshop, 29 April 2003.

4.3.6. Banking and Borrowing

The ability to bank and/or borrow emission credits under a rate-based or "hard cap" FES would lower the cost of achieving a given level of emission reduction.

4.3.7. Price Collar

Implementing a price collar (i.e., a price ceiling and price floor for tradable credits) is theoretically feasible under a rate-based or "hard cap" FES. A price ceiling would require that states agree to sell an unlimited number of tradable credits at a set and perhaps escalating price. Under a "hard cap" FES, a price floor could be maintained by reserving a certain portion of allowance budgets for auction with a minimum auction price. In the case of a rate-based FES, a price floor is more challenging as it would require a state to buy credits from the market to drive up their price. If states pursue interstate trading programs, they would need to coordinate their efforts to set and maintain price floors and or ceilings.

4.3.8. Treatment of Retirements

Policy decisions related to the retirement of covered sources and new sources are relevant for the rate-based and "hard cap" FES approaches. Policymakers may want to avoid creating disincentives for carbon-intensive generators to shut down or disadvantaging investments in new lower- or non-emitting generation compared to the continued operation of more carbon-intensive generators.

Under a "hard cap" FES, the shut-down of an existing source might be a cost-effective option for overall compliance with the emissions cap, and the shut-down of a source would free up allowances for use by other sources. However, a "hard cap" FES program in which allowances are grandfathered to generators but only as long as they continue to operate creates a disincentive for the retirement of emitting units which would forgo a stream of valuable future free allowances if they shut down.[17]

Under a rate-based FES states might provide credits in for some amount of time to fossil-fueled generators that retire in order to make shut-down a compliance option. Providing shut-down credits to retired units under a rate-based FES might increase the aggregate emissions intensity of existing power generators compared to what it otherwise would have been, but such shut-down credits could also lower aggregate absolute emissions from existing sources compared to what they otherwise would have been.

4.3.9. Energy Efficiency and Conservation

As noted above, in terms of total social cost, the least-cost emission reduction pathway for the power sector involves avoiding GHG emissions via end-use energy efficiency and conservation. By its nature, the "hard cap" FES option allows for end-use efficiency and conservation to contribute toward required emission reductions, and different means of allowance distribution and uses of allowance value can incentivize efficiency and conservation to varying degrees.[18,19] The northeastern states participating in

[17] For example, to alleviate this effect, EPA's proposed Transport Rule would continue to give free allowances to retired units for six years after shut down.

[18] For example, auctioning emission allowances under a "hard cap" FES provides the largest price signal to consumers to spur end-use efficiency and conservation, and the use of allowance value to fund demand-side management (DSM) programs can promote emission reductions via efficiency and conservation.

RGGI, the nation's only operational GHG cap-and-trade program, have devoted substantial portions of the cap-and-trade allowance value to funding energy efficiency, which has the potential to mitigate any electricity bill impacts from the program's compliance costs. Each of the RGGI states agreed to use at least 25 percent of their allowance auction proceeds for consumer benefit or strategic energy purposes, including energy efficiency and renewable energy investments. Although, state budgetary pressures owing to the economic downturn have led some states to direct RGGI allowance auction proceeds to the states' general funds.[20]

Without special provisions, the traditional performance standards and the rate-based FES do not allow for compliance via end-use efficiency and conservation (since end-use efficiency and conservation do not affect the GHG emissions per unit of electricity generated by or fuel consumed at covered sources). In theory, one option for promoting cost-effective emission reductions via end-use efficiency and conservation under a rate-based FES program would be for states to grant credits for documented electricity savings that could be used for compliance. Such credits could be based on a formula that took into account some baseline level of electricity sales (e.g., a historical baseline or a "business as usual" projection) and some estimate of the GHG emissions associated with the avoided electricity demand (i.e., avoided CO_2 emissions per "negawatt-hour").

4.3.10. Compliance via Lower Utilization of Emitting Units

A power generator faced with the goal of reducing aggregate GHG emissions from a set of existing power plants has the option of simply running some of the relatively more carbon-intensive units at lower capacity factors and filling in for their lower output with increased generation from existing or new lower-carbon generators. For example, in order to reduce its aggregate emissions, a power generator might run an inefficient coal plant for fewer hours and fill in for its decreased output with a combination of generation from an existing efficient natural gas power plant and a new wind farm. Such emission reduction measures count toward compliance to varying degrees under the policy approaches described above.

Simply utilizing an existing power plant for fewer hours without reducing its emission rate (e.g., lbs CO_2e per MWh) will not help a power generator comply with a traditional performance standard even though this measure can provide substantial cost-effective emission reductions. As explained above, a rate-based FES might offer credits for unit retirements, but without similar credits just for lower utilization, a rate-based FES also does not allow for compliance via reducing emissions by simply running a unit less. In contrast, by the nature of a "hard cap" FES, lowering the utilization of an existing plant is a compliance option under a "hard cap" FES without special provisions.

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[19] In competitive electricity markets, end-use demand reductions are not a direct compliance option for covered emitters; however, to the extent that end users reduce their electricity demand either in response to price signals or policies and programs, the avoided demand for electricity from competitive power producers also leads to lower GHG emissions from these covered sources.

[20] Peters, Joey, "The RGGI Raid: How Cap-and-Trade Revenues Went to Fix State Budgets," *Stateline.org*, http://www.stateline.org/live/details/story?contentId=494460.

4.3.11. Early Action

Early action refers to steps taken by regulated entities to reduce GHG emissions in advance of regulatory requirements for such reductions. Defining what constitutes early action requires both determining eligible actions and the timeframe during which such actions qualify for recognition. Policymakers might take into account several considerations with respect to the treatment of early action. First, policies might be designed so as to avoid creating disincentives for entities to reduce emissions before such reductions are required by regulations. Second, policy provisions might be designed to recognize early actions taken prior to a policy's enactment. In some cases, recognition for early action may limit the aggregate emission reductions that a policy achieves compared to "business as usual." However, the aggregate GHG emissions over time depend on both the reductions from the optional early actions taken prior to a policy's enactment, and the reductions from the policy after enactment. Certain utility actions taken in response to carbon costs assumed in integrated resource plans, for example, might warrant consideration as early actions.

Under a rate-based FES, regulated entities might be granted bonus credits as a reward for early action; this approach would, though, allow for greater aggregate GHG emissions than identical policies without credits for early action. Under a "hard cap" FES, credits from under the cap could be allocated to entities to reward early action without increasing aggregate GHG emissions. To the extent that source-specific performance standards take into account prior reductions in units' emission rates, then this approach can also recognize early action; however, it may prove difficult or impossible to incentivize early action under a traditional performance standards approach or to reward early action that takes any form other than plant-specific heat-rate improvements or biomass co-firing (e.g., displacement of fossil generation with renewables or demand-side management).

4.3.12. Existing State Emission Reduction Programs

There are already state and regional GHG emission reduction programs covering the power sector that are operating or in development—namely, the northeastern RGGI power-sector cap-and-trade program, California's multi-sector cap-and-trade program under A.B. 32, and the Western Climate Initiative (WCI). The programs might be the basis of the plans states submit to EPA to achieve the emission reductions required from existing sources under Section 111(d), in which case EPA would need to judge the programs against the agency's binding emission guidelines (e.g., in terms of stringency) and determine whether or not these state and regional programs suffice. EPA might need to consider state and regional programs when developing its emission guidelines if it does not intend to preclude sufficiently stringent state and regional programs from being adequate means of implementing Section 111(d) requirements. For example, EPA could allow multiple states to jointly demonstrate equivalency of their programs—e.g., the states participating in RGGI could demonstrate that the RGGI cap on power sector emissions is as stringent as the aggregate emission reductions required from those states' existing sources under EPA's Section 111(d) emission guidelines, even though a regional cap does not require a specific level of emission reductions in any single state. Also, EPA would need to examine the use of offsets under any state or regional program in determining equivalency.

Given the CAA Section 116 provision for the retention of state authority, it is unlikely that EPA GHG regulations under Section 111 could pre-empt state and regional emission reduction programs.

4.3.13. Industry

There are two distinct issues related to industry in the context of potential Section 111(d) GHG regulations. One is the impact on electricity rates for industrial ratepayers from GHG NSPS regulations for electricity generators. Second, trading programs under Section 111(d) might include large industrial sources (such as off-grid power plants for industrial facilities) in some manner.

Industrial ratepayers are particularly sensitive to electricity price increases. Recent congressional GHG cap-and-trade proposals included provisions to buffer industrial ratepayers from electricity price increases.[21] Under a "hard cap" FES, allowance allocation could be used to mitigate electricity price increases for industrial ratepayers via allocation decisions analogous to those in recent congressional cap-and-trade proposals. The other regulatory options considered herein provide limited to no discretion for policymakers to mitigate any electricity rate increases for particular customer classes. For example, under a rate-based FES there is no equivalent to allowance allocation to mitigate any price impacts for industrial customers. To the extent that GHG regulations under the CAA impose more modest emission reduction requirements than recent congressional GHG cap-and-trade proposals, there may be less need to mitigate costs for industrial ratepayers as any such costs may be substantially smaller. Moreover, state utility regulators may have some discretion with respect to how the compliance costs associated with GHG regulations are distributed among different customer classes.

One possibility for including industrial sources in a trading program for electricity generating units is to allow industrial sources to "opt in" to such a program. The incentives industrial sources would face under an "opt-in" provision may affect the emission reductions such a provision would achieve.[22]

4.3.14. Interaction of GHG and non-GHG EPA Regulations

Section 2 describes the substantial number of decisions that power generators will soon face regarding retrofitting, retiring, and replacing existing electricity generating units in light of pending non-climate EPA air, water, and waste-management regulations. With respect to existing coal plants, there is an opportunity for Section 111(d) regulations to tilt power generators' decisions toward retirement and replacement with low-carbon generation.

In particular, a state that chooses to implement either a rate-based or "hard cap" FES could design the program so as to provide incentives to owners of coal plants that are economically "at risk" from non-climate air, water and waste-management regulations to retire such units rather than retrofitting them with required environmental controls and "locking in" their GHG emissions for several more years.

Under a "hard cap" FES, if a state grandfathers allowances to generators, continuing to grandfather allowances to retired units (at least for some period) avoids creating a disincentive for retirement. A

[21] For example, the Waxman-Markey cap-and-trade bill required that LDCs pass through to industrial retail ratepayers their ratable shares of allowance value allocated to the LDCs, and the bill's Inslee-Doyle output-based allowance allocation provisions for energy-intensive, trade-exposed industry included allocations to buffer such industrial entities from increases in the cost of purchased electricity.

[22] For example, an "opt-in" option for industrial sources may, in some cases, provide tradable credits to industrial emitters for emission reductions they would have made anyway thus achieving no net environmental benefit compared to "business as usual."

state might allocate some allowances from its emissions budget for use as bonus allowances for early retirement of coal plants.

A rate-based FES that provides shut-down credits for coal plant retirements would also provide an economic incentive for plant owners to retire their units rather than retrofitting them.

A traditional performance standards approach might lead to some additional coal plant retirements compared to the case without any GHG regulations for existing sources. However, there is no mechanism under traditional performance standards for existing sources to provide economic incentives for retirement and associated avoided GHG emissions to existing plants for which the best financial decision (absent any incentives) is to retrofit with required environmental controls and continue generating electricity and emitting GHGs.