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Technology Flexibility and Stringency for Greenhouse Gas Regulations

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RESOURCES FOR THE FUTURE

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Abstract

The Clean Air Act provides the primary regulatory framework for climate policy in the United States. Tradable performance standards (averaging) emerge as the likely tool to achieve flexibility in the regulation of existing stationary sources. This paper examines the relationship between flexibility and stringency. The metric to compare the stringency of policies is ambiguous. The relevant section of the act is traditionally technology based, suggesting an emissions rate focus. However, a specific emissions rate improvement averaged over a larger set of generators reduces the actual emissions change. A marginal abatement cost criterion to compare policy designs suggests cost-effectiveness across sources. This criterion can quadruple the emissions reductions that are achieved, with net social benefits exceeding $25 billion in 2020, with a 1.3 percent electricity price increase. Under the act, multiple stringency criteria are relevant. EPA should evaluate state implementation plans according to a portfolio of attributes, including effectiveness and cost.

Key Words: climate policy, efficiency, EPA, Clean Air Act, coal, compliance flexibility, regulation

JEL Classification Numbers: K32, Q54, Q58

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Executive Summary

The Clean Air Act provides the current regulatory framework for climate policy in the United States. A key component of US policy as called for in President Obama's recent memorandum to the US Environmental Protection Agency (EPA) will be the use of flexible approaches in achieving reductions of greenhouse gas emissions. EPA is expected to regulate existing stationary sources using tradable performance standards (averaging) under section 111(d) of the act. This section requires states to develop plans to implement the regulation. EPA will issue guidelines for states and may provide a model rule representing their ideal regulation for states to potentially incorporate in their plans, but many states are expected to propose additional flexibility mechanisms.

This paper considers a variety of policy approaches that EPA will need to evaluate, whether as part of a model rule or if introduced by states. Unlike other parts of the Clean Air Act, section 111(d) requires consideration of multiple criteria. This section has a technological basis, so emissions rate changes would be a justified metric. The eventual outcome of interest is environmental performance, so emissions reductions also are meaningful. This section also calls for consideration of costs, and evaluation of policies according to a common marginal abatement cost could be used to compare stringency. This approach is especially interesting because it leads to cost-effective regulation among the affected sources, and could be observed in modeling that states will provide to support their implementation plans. We find that expanding flexibility enables an increase in ambition along any one of these metrics, but it can lead to ambiguous results with respect to other metrics, again suggesting that multiple criteria should be balanced to fit the legal justification of the regulation.

Using a highly parameterized model of the electricity sector, we simulate a tradable performance standard regulation at coal-fired power plants to achieve a 4 percent reduction in the average emissions rate, based on recent engineering studies that identify technical opportunities to improve plant efficiency. The regulation results in a reduction of 93 million short tons of carbon dioxide emissions. We then expand flexibility by enlarging the set of generators that could contribute. At the same marginal abatement cost, a tradable performance standard that covers all generation sources results in nearly four times the emissions reductions. This approach

maximizes net benefits, achieving more than $25 billion per year in net benefits (2009$ in 2020), split roughly evenly between climate-related benefits and reductions of other air pollutants, with an electricity price increase of only 1.3 percent.

These reductions could be expected to take the United States past 15 percentage points of the 17 percentage-point reduction from 2005 levels that President Obama pledged in Copenhagen in 2009. President Obama has asked his cabinet to look across federal rules and regulations to identify further opportunities to reduce emissions. Calibration to a consistent marginal abatement cost would be important to achieve cost-effectiveness in this effort. The marginal abatement cost we model in the electricity sector builds on a technical foundation of what is achievable at existing coal-fired power plants. Coincidentally, it is similar to recent estimates of the social cost of carbon dioxide emissions, suggesting a focal point for coordinating other regulatory efforts.

Contents

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Dallas Burtraw and Matt Woerman*

1. Introduction

In 2007, the US Supreme Court affirmed the authority of the Environmental Protection Agency (EPA) to regulate greenhouse gases, and today the Clean Air Act provides the primary regulatory framework in the United States.[1] This authority was used to strengthen fuel economy standards for mobile sources that took effect in 2011 and were subsequently extended to require an improvement in efficiency and a reduction in emissions from mobile sources by approximately 3.5 to 5 percent per year, resulting in average fuel economy of 54.5 miles per gallon by model year 2025. In 2011, new rules also took effect requiring greenhouse gas standards for preconstruction permitting of new and modified stationary emissions sources (known as Prevention of Significant Deterioration).[2]

The third area for regulation under the Clean Air Act, and the focus of this paper, is the emissions performance of new and existing stationary sources. Standards for new sources are determined at the national level under Section 111(b). A draft final rule for electricity, the first sector to be regulated, was issued in September 2013. EPA will issue standards for existing sources beginning with the important electricity sector under Section 111(d), which places the authority for planning and implementation with the states. States have discretion in developing plans to regulate these sources. Flexible approaches might be suggested in EPA guidelines to the states, or they might be suggested by the states in implementation plans. Existing electricity generators account for almost 40 percent of US carbon dioxide (CO_2) emissions, making the

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[1] *Massachusetts v. EPA*, 549 US 497 (2007).

[2] The authority to issue permits under federal guidelines resides with states, which are currently developing the technology design standards that apply. By mid-2013, the states issued about 100 permits, which for the first time included standards for greenhouse gases.

electricity sector the largest source of emissions in the United States and an important sector from which to achieve emissions reductions (EIA 2011).[3]

Performance standards under the Clean Air Act traditionally have prescribed an engineering-based emissions rate benchmark associated with a specific technology. However, several legal analyses (EPA 2005; EPA 2008; Wannier et al. 2011; Enion 2012) have argued that flexible approaches would be legal for regulation of existing stationary sources under section 111(d). A flexible approach would give the regulated entities greater choice in determining how to achieve emissions reductions, including potentially enabling emissions rate averaging across sources, referred to as a tradable performance standard.[4] This approach is not new to regulation under the Clean Air Act; it was a key feature of the phaseout of lead in gasoline in the 1980s (Nichols 1997; Newell and Rogers 2003). Emissions trading (cap and trade) might be possible if EPA were to claim that trading itself was the "'best system of emissions reduction' that has been 'adequately demonstrated'"(Richardson et al. 2011, citing CAA § 111(a)(1)).[5] Lashof (2012) has suggested that flexibility could be expanded to encourage substitution to nonemitting electricity generators to reduce the average emissions rate over all electricity generation. They further propose that efficiency improvements from other aspects of the electricity system such as transmission line upgrades and end-use energy efficiency improvements that contribute to reduced emissions from regulated sources also could be given credit under the system. However, many observers identify a trade-off between legal risk and greater flexibility in the regulation, and crediting for activities outside the regulated sector is expected to increase that risk (Richardson 2011; Tarr 2013)

A tradable performance standard introduces market-like flexibility through the opportunity to trade credits to achieve an emissions rate average. It has the political advantage that it results in a relatively small change in average retail electricity price compared to other policy instruments such as cap and trade or an emissions tax with the government collecting the revenues because the value of the emissions rate credits that are traded is retained in the electricity sector. That is, the standard introduces a credit price representing the opportunity cost

[3] Carbon dioxide (CO_2) is the most important greenhouse gas. The electricity sector emits about 33 percent of total greenhouse gases (CO_2 equivalent) in the United States.

[4] Fraas(2012) describe how a tradable performance standard for greenhouse gases could function.

[5] EPA has said that it does not intend to use the Clean Air Act to introduce cap and trade after Congress failed to enact such a program after consideration of various proposals including the Waxman-Markey bill (HR 2454) which passed the House of Representatives in 2009 before stalling in the Senate.

of emissions and the value is recycled to generators as an output subsidy. 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.

However, compared to an inflexible prescriptive technology standard, economic analysis suggests that the cost savings from using a flexible approach would be substantial. Burtraw et al. (2012b) find that compliance flexibility for coal-fired power plants reduces overall costs of emissions reductions by two-thirds, holding emissions reductions across the electricity sector constant. Linn et al. (2014) find that investment costs per ton reduced would be an order of magnitude greater under a traditional standard than under a flexible standard that allowed emissions rate averaging.

This paper examines a central issue to the introduction of flexibility—the relationship between flexibility and stringency of the regulation. These two ideas pose a trade-off if flexibility allows regulated entities to take credit for actions that would have happened even in the absence of the regulation. In this case, flexibility would reduce the environmental contribution of the regulation. However, flexibility also is expected to lower the cost of emissions reductions, so it also could enable greater emissions reductions to be achieved at any given cost. The fundamental question is to whom the benefits of flexibility should accrue. At issue is whether those gains are captured by the productive sector through lower costs for consumers or shareholders without changing the stringency of the policy, on behalf of the environment by changing the stringency, or are shared. Previous regulation provides examples where increased stringency is required where parties elect to use optional compliance flexibilities. This will be an important consideration in the EPA's regulatory guidance and in its evaluation of implementation plans developed by the states to comply with the regulation. Equally important is the challenge of how to measure stringency.

This analysis is focused on where emissions reductions occur; that is, the population of electricity generating sources (the technology group) that is regulated directly, or could be given credit for helping achieve emissions reductions from the regulated sources. In general, one would expect that a broader group could achieve the same emissions reductions at less cost. Although nonemitting sources such as renewables and nuclear likely would not be regulated directly, they could be given incentives to expand production under the program in order to achieve emissions reductions at regulated sources. We consider three definitions of the population to be covered by the regulation: all coal-fired power plants, all fossil-fired power plants, and all electricity generating units including nonemitting technologies. Crediting end-use energy efficiency programs as proposed by Lashof (2012) is not analyzed.

A key concern for EPA will be how to evaluate the stringency of scenarios involving varying degrees of flexibility, especially as they may differ among the states' implementation plans. EPA can be expected to require that flexible approaches achieve outcomes that are at least as stringent as inflexible prescriptive standards; however, the concept of stringency is ambiguous. Will stringency be based on an equivalent reduction in emissions rate, or on an equivalent reduction in emissions? Or, alternatively, can EPA use a cost criterion to evaluate state plans? We demonstrate that these criteria do not move together under various program designs that introduce flexibility. These designs may be further ambiguous if they enable firms to take credit for actions that would have happened in the absence of the regulation.[6]

EPA must provide guidance to states for the preparation of implementation plans and how they will be evaluated. In the more familiar context of regulation of conventional air pollutants, the standard of performance hinges most importantly on the single criterion of achieving the National Ambient Air Quality Standards. In the statute other criteria are mentioned such as protecting health and welfare with an adequate margin of safety, but this describes the interpretation of the central criterion. In practice, there are considerations in the timing, conformity of transportation plans, air quality monitoring and where emissions monitors and emissions occur. These factors are considered ex ante in approving implementation plans, and revisited in retrospective evaluation. But conceptually, performance is measured according to the single criterion of ambient air quality.

However, regulation of greenhouse gases for existing stationary sources under Section 111(d) involves consideration of multiple criteria. Emissions change is an obvious criterion. The relevant portion of the Clean Air Act is traditionally technology based, so demonstration of reduction in emissions rate supports that purpose. Moreover, the relevant portion calls for consideration of cost. Section 111(d) calls for a multi-attribute evaluation of implementations plans, taking environment, technology and cost into consideration. Therefore, we suggest that a

[6] For example, some firms may have plans to reduce utilization or shut down a coal-fired plant in order to comply with other environmental regulation or because of the cost disadvantage compared to low natural gas prices. Flexibility might enable the firm to take credit for this action with respect to greenhouse gas regulations. This would be a good thing from the perspective of reducing costs, but it erodes the incremental environmental benefit of the specific greenhouse gas regulation.

portfolio of criteria needs to be addressed in the state implementation plans and evaluated by EPA.

Four possible criteria could be used to evaluate if the state's approach is of equivalent stringency to a model rule or guidelines provided by EPA: emissions rates, emissions, marginal cost, and total (average) cost. These four criteria are used to compare the outcome of the three policy scenarios involving varying levels of flexibility.[7] We find that averaging to achieve a specific emissions rate improvement over a broader set of generation sources will reduce the actual change in emissions. Conversely, crediting emissions reductions at a broader set of sources to achieve a specific level of reductions will yield a larger reduction in emissions rate on average.

Marginal abatement cost is an especially interesting stringency criterion because it suggests that the emissions reduction efforts distributed across sources is cost-effective. The marginal abatement cost would not be implemented as a constraint in the operation of the policy, as would an emissions tax. Rather the measure would be a criterion in the evaluation of state implementation plans, which generally involve substantial modeling to indicate expected outcomes. This introduces technical efficiency into the regulation even if marginal costs are not necessarily tied to marginal benefits, which are very uncertain with respect to climate change impacts. However, coincidentally we find the marginal abatement cost of measures identified in previous the Sargent & Lundy engineering study are roughly comparable with recent estimates of the social cost of carbon (Interagency Working Group on Social Cost of Carbon 2010; Interagency Working Group on Social Cost of Carbon 2013). We find that using the marginal abatement cost derived from the specified emissions rate improvement at coal plants as the stringency criterion, and applying it to a broad group of sources yields nearly four times the emissions reductions that would be achieved if the standard were applied to only coal-fired units. The greatest emissions reductions across scenarios we model results in an electricity price increase of only 1.3 percent.

These emissions reductions would be expected to take the United States past 15 percentage points of the 17 percentage point emissions reduction from 2005 levels that President Obama pledged in Copenhagen in 2009. Moreover, as President Obama has pledged to look across federal rules and regulations to identify opportunities to reduce emissions, calibration to

[7] Subsequently we compare the net economic benefits of each approach.

the US government's social cost of carbon could signify that cost-effective measures are taken. Further, we find this approach maximizes environmental improvement from reductions in greenhouse gases and other pollutants, yielding more than $25 billion per year in net benefits (2009$ in 2020). Those benefits are split roughly evenly between climate-related benefits and reduction in other air pollutants.

The next section of this paper provides further background on regulation of greenhouse gas emissions from existing stationary sources, including a discussion of the policy options. Section 3 describes our modeling strategy to evaluate possible outcomes. We use a highly parameterized model of the national electricity system to compare outcomes, which are presented in Section 4. Section 5 describes how policy can be designed with these results in mind, and Section 6 concludes.

2. Background

In this section, we provide further background on options for policy and criteria to evaluate those options. EPA has identified Section 111 of the Clean Air Act as the basis for regulating stationary sources. For existing stationary sources, Section 111(d) requires EPA to develop performance standards and guidelines for achieving those standards and places responsibility with the states to develop plans to achieve those standards, while EPA ultimately is responsible for approving those plans. In principle, states have discretion, but in practice, they may lack the resources to deviate far from a template that might be provided by EPA or from the actions of other leading states.

Performance standard regulation is traditionally highly technical, involving data-intensive analysis of regulated source categories to identify the technology behind the "best system of emissions reduction" (Richardson et al. 2011). As a technical foundation for the regulation, we imagine at the outset that the EPA guidelines specify a CO_2 emissions rate performance standard that technically can be achieved by various generation technologies. Emissions rates are measured in tons of CO_2 per megawatt-hour (MWh) of electricity generation and vary across electric generating facilities. Coal-fired plants have the highest rates, and considerable heterogeneity exists within this group, depending on boiler configurations, maintenance, fuel use, location, and the way the facility is used (Linn et al. 2014).

An inflexible performance standard might specify the maximum allowable rate, forcing all units with a greater rate to make efficiency improvements or retire. However, some units have idiosyncratic or localized economic value on the electricity grid, and overall cost savings might result if these sources could trade their responsibility to achieve the emissions rate standard.

The engineering literature suggests there are varying opportunities for efficiency improvements that could achieve a 4 to 5 percent improvement on average across the population of coal plants. Additional options, which we include in the model, are cofiring with biomass or natural gas.[8] A difficulty regulators face, however, is identifying ex ante the opportunities at a specific plant. If the emissions rate standard were expected to achieve a 4 percent reduction in the emissions rate on average across the coal fleet, then emissions rate reductions might be achieved through both investments to improve the performance of facilities wherever it is cost-effective to do so and changes in utilization so that efficient units are used more often.

The other important fossil fuel for electricity generation is natural gas. These facilities have an average emissions rate that is slightly greater than half of that for coal plants. Turbines have higher emissions rates than combined cycle units, but within each of these groups there is relatively little variation compared with that found within the coal fleet. There is no analysis suggesting that substantial opportunities exist for emissions rate improvements at existing gas facilities but opportunities may exist. Newer combined cycle plants have lower emission rates than older ones, which is captured in our model. Moreover, it may be possible to replace older turbines with more efficient ones while retaining the heat-recovery steam generating unit, but that is not represented in this analysis. Combined cycle plants and turbines serve different functions within the electricity system, so they cannot easily substitute for each other. The primary opportunity for substitution we observe is between existing coal units and existing natural gas combined cycle plants which are often not fully utilized, and to a much lesser extent between existing coal units and new nonemitting generators including renewables and nuclear power.

2.1. Policy Options

In a memorandum to EPA in June 2013, President Obama articulated the political directive to "ensure, to the greatest extent possible, that [EPA] … develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities; [and] ensure that the standards enable continued reliance on a range of energy sources and technologies."[9] A fundamental decision for EPA in trying to attain this directive is whether to

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[8] In this analysis each of these is given an emissions rate equal to the actual emissions observed at the plant, without crediting the potential value of biomass in carbon sequestration.

[9] See: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards (accessed July 8, 2013).

issue a strong framework for the states to adopt or to provide guidance encouraging states to propose flexible regulatory approaches. For EPA to issue standards that achieve substantial emissions reductions or to introduce substantial flexibility in the standard would appear likely to invite court challenge. Consequently, EPA might decide to signal deference to the states in the introduction of flexible approaches. Alternatively, EPA could provide one measure of flexibility, and consider other approaches separately.

Three terms that we employ loosely in this paper have specific legal meaning and help explain the sequence of events.

Model rule: EPA's ideal, but not yet final regulation until it appears in a SIP. If a state adopts a model rule for a SIP, that portion of the SIP will be approved automatically.[10]

Guideline document: Establishes the criteria by which EPA will evaluate state plans that do not strictly adhere to EPA's model rule.[11]

Guidance document: An EPA statement of general applicability and future effect, other than a regulatory action that sets forth a policy on a statutory, regulatory or technical issue or an interpretation of a statutory or regulatory issue.[12]

In this modeling exercise, we imagine a market-based policy as a tradable performance standard, and consider three sets of policy scenarios that embody potential technology groupings (potential sets of sources) that would be regulated. The first is restricted to the population of coal-fired power plants. Engineering studies (Sargent & Lundy 2009) and econometric analysis (Linn et al. 2014) have identified opportunities for emissions rate reductions among these plants at marginal costs that are comparable to the US government's identified social cost of carbon (Interagency Working Group on Social Cost of Carbon 2010; Interagency Working Group on Social Cost of Carbon 2013). Specific measures might be prescribed for these plants if the regulator had the information to do so, but the engineering studies indicate that every plant is unique in various ways. Typically the opportunities at each plant are not known until after a study of that plant has been conducted. Ex ante, the government cannot know the technologies that would be efficient, and the opportunities across plants with the same fundamental technology are heterogeneous (Linn et al. 2014). Flexibility would enable firms to take

[10] http://www.epa.gov/ttn/caaa/t1/fact_sheets/omtrfact.pdf.

[11] http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[12] http://www2.epa.gov/laws-regulations/definitions-guidance-documents#guidance.

advantage of private information to achieve cost-effective investments and would encourage substitution to plants with lower emissions rates to achieve the performance standard on average across the regulated group.[13]

The second potential technology grouping is all fossil-fired power plants, including coal, natural gas, and oil plants. The same or a different performance standard, or measure of regulatory stringency, could be applied across this group. There is substantial heterogeneity in emissions rates across these technologies and fuels, and rates at coal facilities are nearly double those at natural gas combined cycle units. However, there is typically less opportunity to make efficiency improvements at any specific gas plant. The difference in emissions rates among gas generators results from different functions within the electricity system. Turbines run fewer hours and with higher emissions rates and provide power at times of peak demand, combined cycle units run more often and operate with lower emissions rates, and steam boilers operate significant hours in only some locations. If gas were regulated as a separate category, there would be little opportunity to improve emissions rates either through improvements at specific units or through changes in utilization within the group. However, if regulated within a category with other fossil units, there would be an incentive to increase the utilization of natural gas plants relative to the higher-emitting coal plants.

In defining the sets of coal-fired plants and all fossil-fired plants, we assume new fossil-fired plants will be subject to a new source performance standard that will be stricter than the benchmark for existing sources. We assume they would not be eligible to average emissions rates with the existing fleet, although this is not certain.[14]

The third potential definition of the trading group is all electric generating units, including nonemitting sources (no credit is given for improvements in end-use efficiency), and again the same or a different standard could be applied across this group. Although there are no opportunities for emissions rates improvements at nonemitting sources, the average emissions rate over all sources could improve if nonemitting sources expanded generation. In this scenario, we assume that existing nonemitting sources are not dispatchable or have very low variable cost

[13] We do not consider efficiency improvements apart from electricity generating units, although they could provide important additional opportunities to reduce costs and emissions.

[14] Under the Clean Air Interstate Rule, EPA suggested that new sources could be eligible to participate in the nitrogen oxide trading program (*Federal Register*, 2005, 70(163): 49708–49833).

and already run as much as possible. Hence, we include only incremental (new) nonemitting sources within this technology group.

2.2. Stringency Criteria

EPA will consider stringency of the regulation in designing its regulatory proposal, which is likely to include a model rule, and in evaluating the implementation plans submitted by the states that may differ from the model rule and may introduce a variety of approaches. We compare the policy scenarios, representing three different technology groupings, introduced in Section 2.1 according to four possible criteria that could be used to evaluate the stringency of the program. The average emissions rate applied specifically to the group of sources identified in the policy design (technology grouping) is the most obvious stringency criterion if the performance standard is defined in terms of an emissions rate goal. We calculate the intertemporal model equilibrium through 2035 for an equivalent improvement in the average emissions rate within each program design (technology grouping): among coal-fired plants only (e.g., all existing coal plants), among the group of all fossil facilities (e.g., existing fossil units but not including new units), and within the group labeled all generators (e.g., existing fossil and new nonemitting generators). The outcomes for the year 2020 under each of the three program designs are evaluated according to each of the possible criteria.

The second stringency criterion is the level of emissions, which is determined by the change in emissions throughout the electricity sector. An emissions target is credible because environmental improvement is the underlying motivation for the regulation. In a second comparison, we require the same reduction in emissions within each of the three program designs.

The third stringency criterion is marginal cost, which is especially relevant because cost-effectiveness is achieved within a technology group by equating the marginal cost among regulated sources. It is also relevant because marginal cost of emissions abatement provides a measure that can be applied to align regulations within the electricity sector with other federal rules and regulations, which would help achieve cost-effectiveness across the economy. Under a tradable performance standard, the marginal cost would be revealed in a market price index of tradable performance standard credits. In a third comparison, we require the same marginal abatement cost within each of the three program designs.[15]

A fourth stringency criterion is the cost incurred under each regulatory design. We measure total cost as the sum of changes in producer surplus (producer profits), changes in consumer surplus, and changes in government expenditures.[16] Average cost is the total cost divided by the emissions reductions. The overall cost and average cost may vary substantially, because different levels of emissions reductions are achieved.[17]

We expect and find that the three technology groupings yield different outcomes measured according to the four stringency criteria. In providing guidance to the states about how their plans will be evaluated or in choosing among their own preferred regulatory designs, EPA may consider stringency according to a portfolio of criteria and require the states to address each criteria explicitly in their plans. The stringency criteria are likely to come into conflict. For example, an emissions rate standard applied only to coal plants versus a different standard

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[15] There are two important observations to make about the overall efficiency of a tradable performance standard. It is important to note that the price of an emissions rate credit is not equal to the marginal social cost of emissions reductions. Within a general equilibrium context, the marginal social cost of policy measures may vary from the price achieved within a market because of several factors, including the interaction with preexisting policies and taxes, preferred activities under the tax code, tax avoidance behavior, or leakage of emissions or economic activity to unregulated sectors or jurisdictions. These factors may increase or decrease social cost compared with the observed price, thereby affecting the overall efficiency of the regulations. However, if the credit price (marginal abatement cost) is equal across sources, then the partial equilibrium cost-effectiveness of the regulation is not sacrificed by ignoring these elements of social cost.

It is also useful to note that a tradable performance standard introduces a subsidy to electricity production, because credits are earned per unit of the MWh of electricity that is produced. The allocation of credits lowers the variable cost of generation for any given level of output, leading to greater overall output. Hence, to achieve the same level of emissions will yield a different marginal abatement cost than would result from other policy designs.

The alignment of marginal costs across federal rules and regulations would not be fully efficient or cost-effective, because policies under each are likely to introduce distortions away from first-best economic efficiency. However, approximate cost-effectiveness can be achieved by aligning observable marginal abatement cost, taking as given the difference between that measure and marginal social cost in each case.

[16] Producer surplus is the sum of revenues minus costs, including annualized capital expenditures. Consumer surplus is a partial equilibrium measure that holds the demand function fixed at *Baseline* levels and uses price changes between the *Baseline* and policy scenarios. Government revenues include the renewable energy production and investment tax credits.

[17] Consumers prices do not equal the real-time marginal costs in the electricity industry and in the model. Hence, although consumer demand responds to increased prices, the marginal price signal is inconsistent with the marginal cost of generation that reflects the credit price. As a consequence, total and average cost do not correspond to the same cost schedule as marginal cost. In principle, average cost could be greater than marginal cost, because they are determined by two different functions.

applied to a larger group of generators might lead to greater total cost but fewer emissions reductions. However, it also might lead to fewer differences between winners and losers among sources affected by the regulation, which might be another potentially relevant consideration, especially by states as they design their implementation plans.

2.3. Additional Policy Criteria

A flexible regulation promotes a cost-effective outcome by enabling regulated sources to identify where emissions rates improvements are going to occur.[18] However, the same flexibility introduces the possibility that emissions reductions are not additional to the baseline because the regulated source has the incentive to take credit for emissions reductions that would have happened even in the absence of the regulation, thereby eroding the environmental improvement that is intended by the regulation. For example, if a plant with a high emissions rate were planning to retire for other reasons, this would lower the average emissions rate over a group of plants, and any apparent emissions reductions would not be additional. If this retirement were given credit, it might allow a group of plants to achieve the benchmark emissions rate standard without any incremental environmental improvement resulting from the regulation. Adverse selection would also undermine an estimate of the change in emissions rates that could be attributed to the regulation.[19] In the omniscient setting of a computer model, this can be prevented, but in practice one would expect this to occur to the extent it is possible. To the degree this occurs, it also erodes the political support for flexible approaches to environmental regulation and leads back to calls for prescriptive approaches to achieve identifiable and specific environmental improvements, albeit at potentially much greater costs. Thus, another consideration in the policy design is to lessen the impact of adverse selection.[20]

A marginal cost criterion may perform best in reducing adverse selection; if it were calibrated to an external measure, then it would not be affected by decisions to retire or invest that would have happened even in the absence of the program. In this vein, President Obama has

[18] This is almost but not precisely equivalent to where emissions reductions will occur. The two can differ because of potential changes in the utilization of plants. Other aspects of program design could allow for greater flexibility by enabling the banking of emissions rate improvements.

[19] The average emissions rate would be affected by retirement of existing facilities or investment in new facilities.

[20] A related consideration is the crediting for actions already taken to reduce emissions by companies or states. If these entities face the same requirement for incremental emissions reductions as others who have taken no action, then they would perceive higher overall costs. Changing the baseline year against which actions would be measured is one way to give credit for early action, but it does not solve the adverse selection problem looking forward.

announced the intent to look across federal rules and regulations to find opportunities for emissions reductions; in order for this to be cost-effective, the marginal cost of these emissions reductions actions should be equal. Efforts to calibrate these activities hinge on a comparison to a single number, such as the marginal social cost of carbon, as identified by a US government interagency task force, recently updated to $41 per short ton of CO_2 emissions in 2020 (2009$) (Interagency Working Group on Social Cost of Carbon 2010; Interagency Working Group on Social Cost of Carbon 2013). The social cost of carbon has been used in a variety of recent regulatory impact assessments (Johnson 2012) and is an obvious focal point for aligning efforts within the electricity sector with other sectors of the economy.

A second strategy to mitigate the impact of adverse selection is for the regulator to forecast a future without greenhouse gas regulations, including projected retirements, new investments, and any other changes within the electricity sector. The tradable performance standard can then be benchmarked to the emissions rate that results from this forecast, so any activities that the regulator projected in the absence of the regulation will not erode the environmental effectiveness of the standard. This is the approach we take in this analysis, benchmarking the regulations to emissions rates in a forecast of the future as opposed to historical data. Modeling such as this is likely to be part of the implementation plan, but various parties will have strong incentives to influence the assumptions in the model and also to keep some information private so as to influence the modeling outcome. Hence, in practice, moral hazard also challenges the regulatory process, reinforcing the likely usefulness of a portfolio of stringency criteria.

The fundamental question is to whom should the benefits of flexibility accrue, specifically to the environment through more stringent regulation or to industry and consumers? Previous regulation has included some examples of requiring increased stringency where parties elect to use optional compliance flexibilities. For example, Pacyniak (Forthcoming) cites as one example the 1990 rule for heavy-duty engines that articulates a rationale for requiring a 20 percent discount on traded or banked credits.[21] According to EPA's rationale in the rulemaking, the discount provided an additional environmental benefit to the program (by requiring increased stringency), while continuing to provide an incentive to industry through the increased efficiencies expected to be available through banking and trading. Similar rules are common in

[21] Banking and Trading for Heavy Duty Engines Final Rule (55 FR 30584). The key passage appears on FR page 30592.

emissions reduction credit programs where geographic trades in nonattainment areas require greater than 1:1 emissions reductions per ton of emissions at a new source or where credits are banked over time.

3. Modeling Strategy

We use a highly parameterized electricity market simulation model to characterize the response of the electricity system to a variety of potential existing source performance standards for CO_2 under the Clean Air Act.

3.1. The Haiku Electricity Market Model

The simulation modeling uses the Haiku electricity market model,[22] which is a partial equilibrium model that solves for investment and operation of the electricity system in 22 linked regions of the continental United States, starting in 2013 out to the year 2035. Each simulation year is represented by three seasons (spring and fall are combined) and four times of day. For each time block, demand is modeled for three customer classes (residential, industrial, and commercial) in a partial adjustment framework that captures the dynamics of the long-run demand responses to short-run price changes. Supply is represented using 58 model plants in each region, including various types of renewables, nuclear, natural gas, and coal-fired power plants. Assumed levels of power imports from Mexico and Canada are held fixed for all scenarios. Thirty-nine of the model plants in each region aggregate existing capacity according to technology and fuel source from the complete set of commercial electricity generation plants in the country. The remaining 19 model plants represent new capacity investments, again differentiated by technology and fuel source. Each coal model plant has a range of capacity at various heat rates, representing the range of average heat rates at the underlying constituent plants.

Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation, and a reserve margin is enforced based on

[22] In terms of its sectoral and geographic coverage, Haiku is comparable to several other national electricity sector models, including the Integrated Planning Model (IPM, owned by ICF Consulting and utilized by EPA), ReEDS (maintained at the National Renewable Energy Laboratory), and the Electricity Market Module of the National Energy Modeling System (NEMS, maintained by the Energy Information Agency). The first three model the electricity sector and partially model factor markets, such as fuel, for the continental United States, and NEMS links its electricity sector model to the entire economy and models all fuel markets. For more information about the Haiku Electricity Market Model, see Paul et al. (2009)

margins used by the Energy Information Administration in the *Annual Energy Outlook* (AEO) for 2011 (EIA 2011).[23] Fuel prices are benchmarked to the AEO 2011 forecasts for both level and supply elasticity. Coal is differentiated along several dimensions, including fuel quality and content and location of supply, and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region, depending on the mix of biomass types available and delivery costs. Coal, natural gas, and biomass are modeled with price-responsive supply curves, so these fuel prices respond to endogenous changes in demand for these fuels. Prices for nuclear fuel and oil, as well as the price of capital and labor, are held constant.

Investment in new generation capacity and the retirement of existing facilities are determined endogenously[24] for an intertemporally consistent (forward-looking) equilibrium, based on the capacity-related costs of providing service in the present and into the future (going-forward costs) and the discounted value of going-forward revenue streams. Existing coal-fired facilities also have the opportunity to make endogenous investments to improve their efficiency. Discounting for new capacity investments is based on an assumed real cost of capital of 7.5 percent. Investment and operation include pollution control decisions to comply with regulatory constraints for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury, hydrochloric acid (HCl), and particulate matter (PM), including equilibria in emissions allowance markets where relevant. All currently available generation technologies as identified in AEO 2011 are represented in the model, as are integrated gasification combined cycle coal plants with carbon capture and storage and natural gas combined cycle plants with carbon capture and storage.[25] Ultra-supercritical pulverized coal plants and carbon capture and storage retrofits at existing facilities are not available in the model. The model does not capture the role of complex fuel contracts on a plant's retirement decisions. Although short-term contracts are common in coal markets, long-term contacts could play an important role in retirement decisions. If long-term contracts incentivize some plants to remain in operation, this modeling omission leads to an overestimate

[23] For an overview of how closely AEO forecasts from 1994 to 2012 have matched realized outcomes, see (EIA 2013). For example, the average absolute percent difference between AEO projections of average electricity prices (nominal $) between 1994 and 2012 and the realized values is 12.5 percent.

[24] Investment (in both generation capacity and pollution controls) and retirement are determined according to cost minimization. This fails to account for the potential Averch-Johnson effect (Averch and Johnson 1962), which tends to lead to overinvestment in capital relative to fuel and raise costs.

[25] There have been changes in capital costs since 2011, especially for solar photovoltaic. However, this is expected to have little effect on the outcome because we see relatively little change in renewable capacity due to the expected continuation of renewable portfolio standards at the state level, which determine the quantity supplied in those states.

of coal-fired retirement projections and potentially of other new investment. Price formation is determined by cost-of-service regulation or by competition in different regions corresponding to current regulatory practice. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to competitive pricing continue that practice, and those that have not made that move remain regulated.[26] The retail price of electricity does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

The model requires that each region have sufficient capacity reserve to meet requirements drawn from the North American Electric Reliability Corporation. The reserve price reflects the scarcity value of capacity and is set just high enough to retain just enough capacity to cover the required reserve margin in each time block. In competitive regions, the reserve price is paid within a capacity market framework within each time block to all units that generate electricity and to those that provide additional capacity services. We do not model separate markets for spinning reserves and capacity reserves. Instead, the fraction of reserve services provided by steam generators is constrained to be no greater than 50 percent of the total reserve requirement in each time block.

3.2. Modeling Scenarios

We use this policy laboratory to analyze three major technology groups that could be included in a tradable performance standard program in the electricity sector: coal-fired units, all fossil-fired units, and all generators including nonemitting sources.[27] The analysis is built on a baseline scenario that forecasts a business-as-usual future in the electricity sector in the absence of greenhouse gas regulation. Each policy scenario introduces a tradable performance standard regulation within one of the three technology groups with varying levels of stringency that

[26] There is currently little momentum in any part of the country for further electricity market regulatory restructuring. Some of the regions that have already implemented competitive markets are considering reregulating parts of the industry.

[27] As described in Section 2, the actual coverage of the standards is more precise than these descriptions because two groups of generators are excluded from coverage in all modeling scenarios. First, new fossil-fired generators are expected to be subject to a separate new source performance standard. It is legally uncertain whether they would be covered by this policy, and we assume not. Second, most nonemitting sources, such as nuclear and renewables, are not dispatchable or generate at full capacity, so their inclusion in this policy would provide no environmental benefit. Despite these omissions, we still refer to the coverage by these more general descriptions for the sake of simplicity.

enable a comparison of outcomes. Seven modeled outcomes allow comparison along two dimensions (three technology groups and three levels stringency), as illustrated in Table 1.

3.2.1. Baseline Scenario

The *Baseline* includes all of the major environmental policies affecting the US power sector. This includes the SO_2 trading program under Title IV of the Clean Air Act, the Regional Greenhouse Gas Initiative (RGGI), the federal renewable energy production and investment tax credit programs, and all of the state renewable portfolio standards (RPS) and renewable tax credit programs. The California cap-and-trade program is not included. The *Baseline* also includes the Mercury and Air Toxics Standards (MATS), which have been finalized by EPA and fully take effect in 2016 in our model. Finally, the *Baseline* includes the Cross-State Air Pollution Rule (CSAPR) in place of the Clean Air Interstate Rule (CAIR). Although CSAPR has been struck down by the court, it represents a future regulation on SO_2 and NO_x that EPA is required to issue in place of CAIR.[28] The *Baseline* is calibrated to the EIA's *Annual Energy Outlook* (AEO) for 2011. This forecast may lead to an overestimate of emissions compared to the most recent forecast because of the anticipated decline in coal generation and further expansion of natural gas in the baseline; however, the effect on the cost of incremental emissions reductions is ambiguous.[29] All of the characteristics of the *Baseline* are held constant in the policy scenarios except as discussed below.

3.2.2. Policy Scenarios

The first policy scenario is *Coal*, a tradable CO_2 emissions rate standard covering existing coal-fired power plants. The policy requires existing coal plants to reduce their fleet-wide average emissions rate by 4 percent, relative to *Baseline*, beginning in 2020 and to maintain that emissions rate through the end of the modeling horizon. That number is chosen because it is within the range of technical possibility identified by Sargent & Lundy (2009). In the model, this is achieved by allocating emissions credits to generators at a benchmark rate equal to the target emissions rate, guaranteeing the average emissions rate is equal to this benchmark; the emissions

[28] Our previous modeling has shown only small changes to the electricity sector if CAIR is replaced with CSAPR when MATS is also in effect (Burtraw et al. 2012). Thus the choice of SO_2 and NO_x regulations is of little significance in this analysis.

[29] Coal's share of electricity generation is projected to be 40 percent in 2020 in AEO 2013 compared to 46 percent in AEO 2011. Conversely, the share of electricity generated by natural gas in 2020 is projected to be 24 percent in AEO 2013 compared to 18 percent in AEO 2011. As a result, baseline power sector CO_2 emissions in 2020 are 6.5 percent lower in AEO 2013 compared to AEO 2011.

rate benchmark is uniform for all generators. Although the stringency of this policy is determined by the 4 percent emissions rate reduction among coal generators, the market equilibrium results in a level of emissions within the electricity sector and a marginal cost (equal to the credit price) for emissions reductions, both of which are also measures of stringency. We use all three of these metrics—emissions rate reduction, total emissions, and marginal cost—to specify the remaining six policy scenarios.

Table 1. Policy Scenarios All Using a Tradable Performance Standard

	Coal	***Fossil–ER***	***Fossil–Em***	***Fossil–MC***	***AllGen–ER***	***AllGen–Em***	***AllGen–MC***
Equivalent emissions rate reduction	X	X			X		
Equivalent electricity sector emissions	X		X			X	
Equivalent marginal abatement cost	X			X			X

As indicated in Table 1, the next three policy scenarios expand the coverage of the tradable CO_2 emissions rate standard to all existing fossil-fired power plants. The first is *Fossil–ER*, which is similar to *Coal* in requiring a 4 percent emissions rate (ER) reduction from all existing fossil plants in 2020, and for that rate to be maintained thereafter. The second is *Fossil–Em*, which remains a tradable emissions rate standard but with the benchmark emissions rate set to yield total emissions in the electricity sector equal to those in *Coal*. The emissions target takes as a constraint the emissions achieved in each year starting in 2020, but they vary over subsequent years to account for growth in electricity demand. Emissions changes in this paper are measured in short tons. The third is *Fossil–MC*, a tradable emissions rate standard that yields a marginal cost of CO_2 emissions equivalent to the marginal cost (or credit price) that results from *Coal* starting in 2020, and again they vary over subsequent years.

The final three policy scenarios further expand the coverage of the tradable CO_2 emissions rate standard to include existing fossil-fired power plants and incremental generation from nonemitting generators (including nuclear and all renewables). The first is *AllGen–ER*, which is similar to *Coal* in requiring a 4 percent emissions rate reduction from existing fossil plants and incremental nonemitting sources beginning in 2020 and held constant at that rate thereafter. The second is *AllGen–Em*, a tradable emissions rate standard that yields total emissions in the electricity sector equal to those in *Coal* starting in 2020, but they vary over subsequent years to account for growth in electricity demand. The third is *AllGen–MC*, a tradable emissions rate standard that yields a marginal cost of CO_2 emissions equivalent to the marginal cost (or credit price) that results from *Coal* starting in 2020, and again they vary over subsequent years.

4. Results

The results of these modeling scenarios in year 2020 are displayed in Table 2, with elements of the table shaded to highlight the metric that is held constant across scenarios. In one comparison, we hold the emissions rate (*ER*) reduction constant (shaded in row 1). In another comparison, we hold the emissions change (*Em*) constant (shaded in row 2). In the third, we hold the credit price (*MC*) constant (shaded in row 3). More detailed results, including emissions rate, emissions, and generation by technology, are shown in the appendix tables. We discuss the key results for each technology grouping in the subsections below. Social benefits are compared with costs in a later subsection. All costs are reported in 2009$.

Table 2. Stringency Results for Year 2020

Stringency criteria	*Coal*	*Fossil–ER*	*Fossil–Em*	*Fossil–MC*	*AllGen–ER*	*AllGen–Em*	*AllGen–MC*
Emissions rate reduction for covered units (%)	4.0	4.0	6.1	17.7	4.0	7.3	17.7
Electricity sector emissions reductions (M short tons)***	93	58	93	340	71	92	379
Marginal abatement cost (credit price) ($/ton)*	33.2	6.5	10.2	33.2	6.8	8.7	33.2
Total social cost (B$)**	1.4	0.5	1.0	7.5	0.7	1.0	9.7
Average*** social cost of emissions reductions ($/ton)	15.2	8.5	11.0	22.2	10.3	11.3	25.6

Notes: The shaded cells identify the constraint defining the model run represented in each column. Additional detail is provided in the appendix.
*This is the shadow value of the regulatory constraint at a given level of output that includes the effect of the incentive to expand production under the tradable performance standard.
**Total social cost includes changes in all factors presented in Table 3.
***Numbers may not equate due to rounding or model convergence criteria.

4.1. Coal Results

The *Coal* scenario achieves an average emissions rate reduction of 4 percent among existing coal-fired power plants in 2020, down from 2,093 lbs/MWh in *Baseline* to 2,010 lbs/MWh. This change results in a reduction of 93 million tons of CO_2 emissions across the entire electricity sector.[30] This reduction is achieved through two primary means. First, the coal fleet invests an additional $2.3 billion in increased heat rate efficiency at coal generators, which reduces emissions rates at all plants where these investments occur. Second, utilization is reduced at higher-emitting coal plants in favor of increased utilization at lower-emitting coal plants and natural gas-fired generators; natural gas-fired generators are not covered by the regulation in this scenario, but they increase utilization in response to changing market conditions including increased electricity prices in some regions.

The coal generators undertake these efficiency investments and utilization changes facing a marginal abatement cost (credit price) of $33.2 per ton of CO_2. Of the 93 million tons of emissions reductions, about 79 percent are achieved by these improvements (assuming baseline levels of utilization at these facilities), and the rest are achieved by fuel switching. Because there is a very small change in electricity price we find little contribution to emissions reduction from reduced electricity consumption. These changes impose a total social cost of $1.4 billion in 2020 and an average social cost of emissions reductions of $15.2 per ton of CO_2.

4.2. Fossil Results

When the technology grouping is expanded to include all existing fossil-fired generators, a regulation achieving a 4 percent reduction in emissions rate, *Fossil-ER*, achieves only 58 million tons of total emissions reductions in 2020, somewhat less than under the *Coal* scenario. This is because the *Coal* scenario sufficiently reduces emissions to achieve an emissions rate reduction among all existing fossil plants that is greater than 4 percent, and thus *Coal* is a more stringent policy by this metric. However, regulating all existing fossil-fired generators (*Fossil-ER*) achieves emissions reductions at a lower cost, as shown by the marginal abatement cost of only $6.5 per ton. This is because it provides a direct incentive to increase utilization at natural gas plants, and thus more fuel switching to natural gas occurs. In contrast, under the *Coal* scenario, relatively more investment in efficiency improvements at coal plants occurs, and relatively less fuel switching. In *Fossil-ER*, the coal fleet invests only $0.4 billion in increased

[30] Total electricity sector CO_2 emissions in *Baseline* in 2020 are 2,354 million tons.

heat rate efficiency, and the average emissions rate reduction among existing coal units is 1.1 percent. About 35 percent of the emissions reductions are achieved by these improvements, and the rest are achieved by fuel switching. The total social cost of this scenario is $0.5 billion in 2020, resulting in an average social cost of $8.5 per ton of CO_2 reduced.

The *Fossil-Em* scenario captures emissions reductions that are equivalent to those under *Coal*, 93 million tons in 2020. To do so, the average emissions rate among existing fossil plants is reduced by 6.1 percent; the reduction among existing coal units is only 1.7 percent. These reductions are achieved through the same means as *Fossil-ER*, fuel switching from coal to natural gas and efficiency improvements at coal generators. Both sources of reductions are utilized to a greater extent but in similar proportions, so heat rate improvements across the coal fleet are again responsible for about 35 percent of emissions reductions, with the rest achieved by fuel switching to natural gas. Because the *Fossil-Em* policy scenario achieves greater reductions than *Fossil-ER*, it also incurs a greater cost, but it is able to achieve the same reductions as *Coal* at a lower cost. The marginal abatement cost is $10.2 per ton of CO_2; total social cost in 2020 is $1.0 billion, yielding an average social cost of $11.0 per ton of CO_2 reduced. Thus, *Fossil-Em* is more stringent than *Fossil-ER* across all metrics; it is more stringent than *Coal* according to environmental criteria but is less stringent in economic terms.

The *Fossil-MC* scenario has a marginal abatement cost of reductions equivalent to that in *Coal*, $33.2 per ton of CO_2 in 2020. This regulation yields an average emissions rate reduction of 17.7 percent among existing fossil generators; the reduction only among coal units is 4.5 percent. The scenario yields total emissions reductions of 340 million tons. Under this scenario, only 25 percent of the reductions are due to efficiency investments at coal plants, with the remaining portion due to fuel switching from coal to natural gas. Because this policy yields much larger emissions reductions than *Coal* or the other *Fossil* scenarios, it also incurs a larger cost—a total social cost of $7.5 billion in 2020 and an average social cost of $22.2 per ton of CO_2 reduced—making this regulation more stringent than *Coal* or the other *Fossil* scenarios. In addition it introduces a cost outside the electricity sector through an important change in the delivered price of natural gas, which increases by 12 percent.

4.3. All Generation Results

The final three policy scenarios expand the technology group to include existing fossil-fired generators and incremental (new) nonemitting generators. When this group achieves a 4 percent reduction in the average emissions rate, in the *AllGen*-ER scenario it yields emissions reductions in 2020 of 71 million tons, between those observed under *Coal* and *Fossil-ER*. As with the other policy scenarios, these reductions are achieved through a combination of efficiency investments across the coal fleet and fuel switching from coal generators to less carbon-intensive generators. The emissions rate improvement among coal plants is only 1.2 percent. By expanding the covered technologies to include new nonemitting generators, one might expect to achieve additional emissions reductions through fuel switching to these sources. However, in the *Baseline* and all policy scenarios, state RPS policies dictate the minimum amount of generation from renewable generators, which constitute a large portion of nonemitting units. As a result, the additional incentive provided under *AllGen-ER* yields only a small increase in generation from nonemitting units, but it does lower the cost of meeting state RPS policies, which is a benefit to consumers in these states. The small expansion in generation from renewables also leads to a small expansion in the use of the renewable production tax credit, which imposes a small additional cost on government. The costs of this policy are consequently similar to *Fossil-ER* in 2020, with a marginal abatement cost of $6.8 per ton of CO_2 (effectively the same as for *Fossil-ER*, given the convergence criteria in the model), a total social cost of $0.7 billion, and an average social cost of $10.3 per ton of CO_2 reduced. *AllGen-ER* is less stringent than *Coal* among these economic metrics but is comparable in stringency to *Fossil-ER*.

The *AllGen-Em* scenario achieves emissions reductions of 92 million tons in 2020, comparable to *Coal* and *Fossil-Em*. This results in a 7.3 percent reduction in the average emissions rate among the covered technology group; the reduction only among coal units is 1.5 percent. This policy yields a small increase in the amount of fuel switching to nonemitting sources, but this amount is still much less than the fuel switching to natural gas, and only 30 percent of the emissions reductions are due to efficiency investments at coal plants. *AllGen-Em* has a marginal abatement cost of $8.7 per ton of CO_2 in 2020; the total social cost of the policy in this year is $1.0 billion, yielding an average social cost of $11.3 per ton of CO_2 reduced. Across all measures of stringency, *AllGen-Em* is roughly in the middle of all policies modeled.

The *AllGen-MC* scenario has a marginal abatement cost of $33.2 per ton of CO_2, equivalent to that in *Coal* and *Fossil-MC*. This credit price does not induce substantial fuel switching to nonemitting sources because the credit price in the state-level RPS programs remains positive. Consequently in those states the RPS programs determine the quantity of nonemitting generation. The modest additional emissions reductions moving from *Fossil-MC* to *AllGen-MC* are due to additional renewables in states that do not have an RPS in place, and a small increase in nuclear capacity. This scenario yields emissions reductions of 379 million tons, the most of any scenario modeled. Of these reductions, only 22 percent are due to efficiency investments at coal plants; the remaining reductions are realized through fuel switching to natural gas and nonemitting generators. The average emissions rate for this group declines by 17.7 percent; the reduction only among coal units is 4.6 percent. The cost to achieve such large emissions reductions is high, amounting to a total social cost of $9.7 billion in 2020, which yields an average social cost (including the cost of federal subsidies to renewable generation) of $25.6 per ton of CO_2 reduced. Across all measures, *AllGen-MC* is the most stringent policy scenario modeled.

4.4. Comparison across Policy Scenarios

Looking across the policies in Table 2, we observe that increasing flexibility reduces costs.[31] However, determining the relative stringency of the approaches is ambiguous. For example, reaching beyond only coal to include all fossil generation reduces the cost of achieving a specific emissions rate reduction by two-thirds but yields fewer emissions reductions.

A question of general interest is the change in generation at coal-fired facilities, which is reported in the appendix table. In principle, energy efficiency improvements at existing facilities could lead to greater utilization. We find that generation from coal in 2020 falls in every scenario. It falls by 1.6 percent in the *Coal* scenario and by 4 to 6 percent in the *ER* (emissions rate) and *EM* (emissions) scenarios. In the *MC* (marginal cost) scenarios, we see a much greater reduction in coal generation, about 25 percent.

[31] The exception is under *AllGen-MC*, where the crediting of additional renewable generation leads to an increase in the cost of federal subsidies for renewable power.

Table 3. Cumulative Results for 2020 to 2035

Stringency criteria	***Coal***	***Fossil–ER***	***Fossil–Em***	***Fossil–MC***	***AllGen–ER***	***AllGen–Em***	***AllGen–MC***
Reduction in electricity sector emissions in 2020 (M short tons; from Table 1)	93	58	93	340	71	92	379
Percent reduction from baseline	*4.0*	*2.5*	*4.0*	*14.4*	*3.0*	*3.9*	*16.1*
Reduction in electricity sector emissions, cumulative 2020–2035 (M short tons)	1,230	1,013	1,229	2,743	749	1,230	3,660
Percent reduction from baseline	*3.3*	*2.7*	*3.3*	*7.4*	*2.0*	*3.3*	*9.9*
Reduction in electricity sector emissions, cumulative 2020-2050 (M short tons)	2,305	2,150	2,303	4,011	1,393	2,305	6,135
Percent reduction from baseline	*3.1*	*2.8*	*3.1*	*5.3*	*1.8*	*3.1*	*8.1*

Note: Shading indicates those policies that are designed to achieve comparable emissions reductions relative to 2020 baseline. Emissions reductions 2035-2050 are extrapolated.

The compliance requirement has a small effect on capacity, as a very small amount chooses to retire as a consequence of the regulation. However, units that make investments in energy efficiency benefit from lower variable costs that could improve their competitive position in the long term and delay retirement. Therefore, it is possible especially in the future that total generation from coal and total emissions could increase as a result of the regulation. Table 3 reports changes in cumulative emissions from all sources and cumulative generation from coal, from 2020, the year the policy is implemented, through 2035, which is the model horizon, and extrapolated to 2050. We find some erosion of the emissions reduction when measured in percentage terms in almost every case. For example, the three shaded cases calibrated to have the same emissions reduction in 2020 of about 4 percent below baseline achieve a reduction of about one-half percentage point less in cumulative emissions through 2035, and a bit less through 2050. In general, the emissions reductions remain substantial in every case.[32]

4.5. Cost and Benefits Results

We estimate total social cost as the sum of three components: consumer surplus, producer surplus, and government revenue. Changes in prices lead to behavioral responses such as investments in energy efficiency by consumers, which are represented in the model as a shift in the demand curve. The change in consumer surplus is measured relative to the demand curve in the baseline. The change in producer surplus is the change in net revenues, accounting for variable costs and annualized capital costs and including investments in energy efficiency at coal plants. In the baseline, we find $600 million of efficiency investments at coal plants in 2020. Under the *Coal* scenario, to achieve a 4 percent improvement in emissions rate, we find investments of $2.9 billion, which is the greatest across scenarios. Results are presented in the appendix table. Finally, the change in government surplus reported in Table 4 results from changes in the federal production tax credit.

Changes in the profile of generation yield reductions in emissions of CO_2 and also of sulfur dioxide (SO_2) and other pollutants. The benefits of reducing CO_2 are highly uncertain. A recent US government interagency working group developed four schedules over time of estimates of the benefits of emissions reductions, reflecting the findings of three different models and various socioeconomic trends and other assumptions. In 2010, the government identified a medium case estimate of $25 per (short) ton of CO_2 reduction in 2020 (2009$) (Interagency Working Group on Social Cost of Carbon 2010). In 2013, the estimates were revised, yielding a medium case estimate of $41 per ton of CO_2 (Interagency Working Group on Social Cost of Carbon 2013). Across the four schedules, the estimates range from $11 to $61, with a tail estimate of $121, illustrating the uncertainty underlying the estimates. The marginal abatement cost that we use when holding marginal costs constant is $33, which falls between the government's 2010 and 2013 medium case findings of $25 and $41. In calculating the benefits of

[32] This is not a definitive assessment, however. The model baseline may underestimate the repowering of existing facilities to take advantage of existing transmission connections and for easier construction permitting. Measured against a modified baseline, the greater utilization or extended life of emitting facilities could erode emissions reductions beyond what is represented in the model

reductions, we use the 2013 medium case finding; hence, marginal benefits exceed marginal costs.[33]

To evaluate the benefits of reductions in SO_2 , we rely on average benefit per ton estimates used in EPA(2011) for eastern and western parts of the country.[34] We do not include estimates associated with reductions in other pollutants, but the lion's share of benefits from reduction of conventional pollutants is expected to come from reduction in SO_2. Although SO_2 is regulated by quantity constraints under CAIR, the MATS rule causes emissions to be below those constraints and emissions are further reduced by the greenhouse gas policies we study.

Table 4 reports the net benefits (benefits minus costs) associated with each scenario. Because marginal benefits exceed marginal costs in every case, net benefits grow with the overall level of emissions reductions. Marginal benefits are assumed to be constant, but marginal costs grow over time, so the marginal and average net benefits (not reported) fall slightly over this range.

Especially visible measures of costs from a political perspective include the change in retail electricity price, which contributes to the calculation of net benefits. Burtraw et al. (2011) found that the introduction of flexibility through a tradable performance standard reduced the change in price by 60 percent compared with an inflexible performance standard. The appendix table reports that when looking across the scenarios in this paper, we find very little change for the *Coal* and *ER* (emissions rate) scenarios. The *Em* (emissions) scenarios yield a decrease of one-half of 1 percent. For the *Fossil-MC* scenario, we see the greatest change, 2.3 percent, and for the *AllGen-MC* scenario, we see a change of 1.3 percent. These two scenarios are also the ones that lead to an important change in the delivered cost of natural gas, 12 percent in each case, which will introduce costs outside the electricity sector. These two are also the scenarios with the greatest emissions changes and the greatest net benefits.

[33] Note that neither the cost nor benefit estimate is a perfect measure of marginal social cost.

[34] In the eastern United States, the value is $30,000 per short ton of SO_2, and in the West, it is $8,600 (2009$).

Table 4. Social Cost and Benefit Results for Year 2020 (Billion 2009$)

	Coal	*Fossil–ER*	*Fossil–Em*	*Fossil–MC*	*AllGen–ER*	*AllGen–Em*	*AllGen–MC*
Total social cost	1.4	0.5	1.0	7.5	0.7	1.0	9.7
Loss of consumer surplus	0.6	–0.3	–1.6	7.9	–0.9	–1.9	4.1
Loss of producer surplus	0.3	0.8	2.7	–0.2	0.9	1.9	3.2
Loss of government revenue	0.5	0.0	–0.1	–0.2	0.8	1.0	2.4
Total social benefits	6.4	5.2	8.1	32.8	6.1	7.7	34.8
Climate benefits	3.8	2.4	3.8	13.8	2.9	3.7	15.3
Ancillary health benefits	2.6	2.8	4.3	19.0	3.2	3.9	19.5
Net social benefits	5.0	4.7	7.1	25.2	5.3	6.6	25.1

Finally, political attention is likely to be paid to the distribution of costs and benefits across regions of the country. In brief, the Plains states and Texas carry a significant portion of the cost across all policies, the Big 10 states including the upper Midwest and Appalachia do worse when the technology grouping is expanded from coal to fossil or all generators while the opposite is true of the West, and the remaining regions always incur a cost less than the national average. Figure 1 shows the regional cost for *Coal* and *Fossil–Em*. The distribution of costs in *Fossil-EM* is representative of the regional distribution of costs under the all of the *Fossil* and *AllGen* policies. The cost is measured as the social cost incurred by the region normalized by the amount of electricity consumed in the region, resulting in a cost metric in terms of $/MWh. Figure 2 depicts a map of the 22 regions in the electricity model and their aggregation into 6 regions reported in Figure 1. Note also the map indicates the representation of competition and cost-of-service market structure in model.

Figure 1. Costs by Region of 93 million ton Emissions Reduction in 2020 (2009$/MWh)

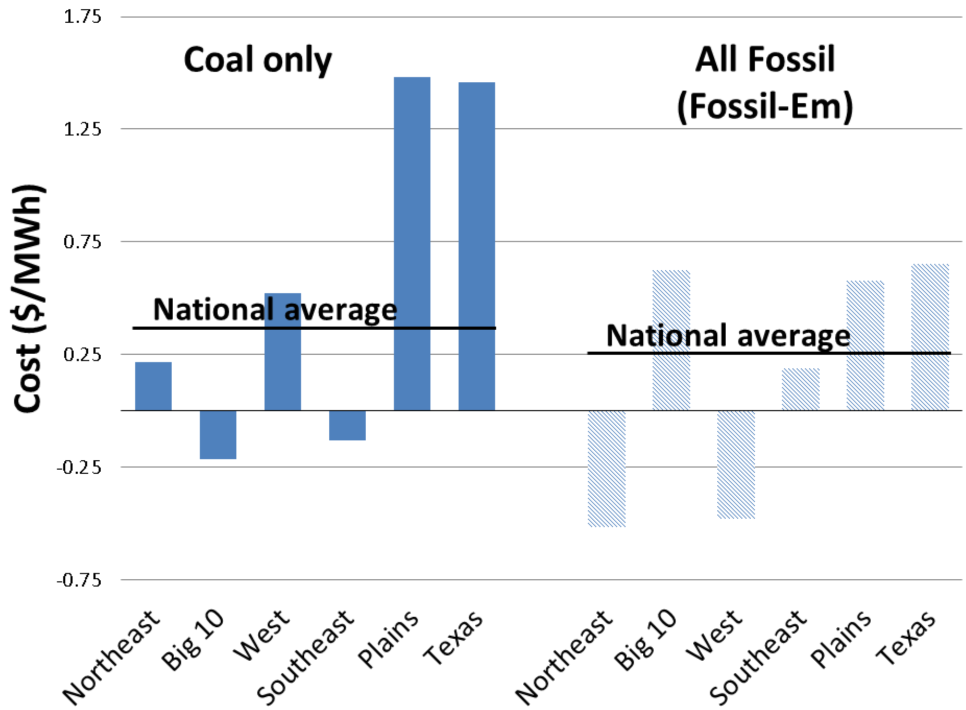
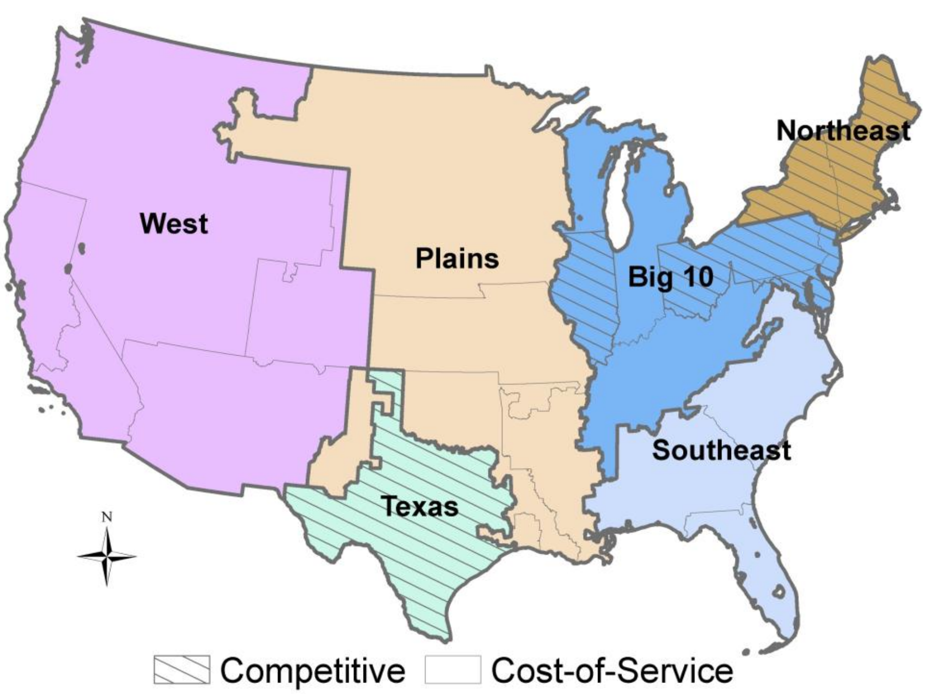


Figure 2. Map of Regions



The Plains and Texas bear such a large portion of the cost in all cases because the coal generators in these states are relatively inefficient. Additionally there is little natural gas capacity in the Plains and the gas generators in Texas are roughly average in terms of efficiency. These states must purchase credits from other parts of the country, thus incurring an additional cost to operate. The Big 10 states have a relatively efficient coal fleet, but little natural gas capacity so the entire fossil fleet is relatively inefficient, so this region is able to sell credits when the technology group includes only coal but must purchase credits when the group expands to include fossil or all generators. The opposite is true in the West, however, where the coal fleet is relatively inefficient but the entire fossil fleet is relatively efficient, so credits flow in the opposite direction as the Big 10 states. The remaining regions – the Northeast and Southeast – are relative efficient across both the coal fleet and the entire fossil fleet, so these states incur a cost less than the national average, or even experience an improvement in social welfare, across all policy scenarios.

5. Policy Design

We use three approaches to compare the stringency of flexible policies applied in different settings—emissions, emissions rates, and marginal abatement cost—and each of these has a direct analogue in other policy designs. That is, from analytical and modeling perspectives, the tradable performance standard can be used to approximate other policy instruments. A regulatory focus on environmental outcomes points to emissions, and the policy design could be similar to cap and trade, which is analytically equivalent to the tradable performance standard that we model if allocation is based on output. An emissions rate standard places the focus on technology performance and could be used to achieve an outcome analogous to a renewable portfolio standard or clean energy standard (Paul et al. 2013). If the policy aligns marginal costs at various facilities the program would appear similar to a carbon tax except that revenues would not be collected but instead returned to generators proportional to generation.

It is noteworthy that each of these approaches has been given credibility by the executive branch as it has searched for a policy framework to address climate change. President Obama supported the development of cap and trade early in his administration. The president mentioned the clean energy standard in his 2011 and 2012 State of the Union addresses. And in the 2013 State of the Union, the president made a statement that could justify the use of marginal abatement cost as a metric to evaluate policy. The president said he would look across executive agencies for actions that can be taken to mitigate climate change. In order for that to happen in a cost-effective way, the actions should be calibrated to the same marginal abatement cost. The recent updating of the social cost of carbon estimate provides that opportunity and could be extended to cover activities taken by the states in their implementation plans.

With the Clean Air Act now the vehicle for climate policy, and states with responsibility for the development of implementation plans, one might expect a variety of approaches to be proposed. The focus of this paper is to describe how EPA might evaluate and these different approaches. The challenge is that flexibility can lead to different outcomes with respect to various measures. It can enable compliance entities to take credit for reductions that would have occurred even in the absence of regulations. This leads to our proposal that flexible measures proposed within an implementation plan process be evaluated according to a portfolio of criteria. Specifically, a state plan should demonstrate to EPA how it will perform with respect to changes in emissions, emissions rates, marginal abatement costs, and total costs.

EPA is expected to develop guidelines for the preparation of state implementation plans, and these are likely to include a model rule. However, as crafted by EPA, the model rule is likely to introduce regional disparities, and if it exercises maximal flexibility, it is likely to encounter legal risk. This leads us to offer two proposals for the design of EPA guidance.

First, EPA's model rule should be severable in its parts. If one aspect is found illegal under court challenge, the rest of the rule should remain enforceable and the requirements recalibrate automatically. For this to happen the technical justification for the rule should be built up from a core requirement on plants in each category of sources identified under the rule before introducing flexible approaches that allow averaging across source categories or states or give credit for emissions reductions stemming from policies affecting unregulated generation sources. Also for this to happen, EPA and the states have to have an automatic way to realign the evaluation of state implementation plans. This invites a second, proposal that EPA evaluate plans according to multiple attributes. The ambiguity of any single criterion under the requirements of Section 111 of the Clean Air Act, and especially after introducing flexible regulatory approaches, supports a multi-attribute process. The use of a portfolio of criteria as we suggest allows for a meaningful evaluation, even as the scope of covered entities is expanded or contracted in the regulatory process. It also will enable states to pursue innovative approaches that take advantage of local characteristics and respond to local interests but also are accountable to the federal standard. However, EPA would have to be explicit in providing guidance to states about how multiple attributes will be balanced.

As to the ambition of the regulation, the social net benefits are growing in our model as long as marginal costs are less than marginal benefits. The social cost of carbon provides a working estimate of marginal benefits from mitigating carbon emissions, but these benefits over the range of policies we examine are actually less than those from the ancillary reduction in SO_2. The most stringent policy we describe is calibrated to a marginal abatement cost that is roughly midpoint between the 2010 and 2013 medium case estimates of the social cost of carbon, yielding emissions reductions of 379 million tons of CO_2 in 2020. This represents about 5.7 percent of US emissions in 2005. In Copenhagen in 2009, President Obama pledged that the United States would achieve reductions of 17 percent from 2005 levels by 2020. (Burtraw and Woerman 2012a) estimate that the United States is already on course to achieve reductions approaching 10 percentage points of this 17 percentage point goal. A marginal abatement cost set to the recent social cost of carbon would come close to closing the gap.

6. Conclusion

The Clean Air Act is a powerful institution in American society. It also is a popular one, and voters are favorable toward a regulatory approach to addressing climate policy under the Clean Air Act.[35] However, the cost of regulations can vary significantly depending on how they are designed and, in particular, whether they provide for flexibility in their implementation. In this context, President Obama has directed EPA to implement flexible approaches in achieving greenhouse gas reductions.

The regulation of greenhouse gases under the Clean Air Act places states in a leadership role in the development of implementation plans to be approved by EPA. One possibility is that EPA develops a flexible mechanism to achieve emissions reductions but gives states little flexibility in implementing the policy. Because of limits to the likely creativity of EPA, difficulty of addressing idiosyncratic regional concerns and opportunities, and the varied initiatives to reduce emissions that are already under way at the state level, EPA might be expected to give states great deference in the design of their policies. The problem this introduces for EPA, however, is how to evaluate the relative efficacy of state implementation plans otherwise varying in method, scope, and ambition.

Using a detailed electricity sector model, we have demonstrated the potential effects of a tradable performance standard. We explored three degrees of flexibility: regulation applied only to coal facilities, regulation applied to all fossil facilities, and regulation that applies to all generation. We nominated several metrics by which stringency of these approaches could be

[35] See, for example, American Lung Association Bipartisan Poll (2011) at http://www.lung.org/press-room/press-releases/bipartisan-clean-air-poll.html (accessed July 8, 2013) and Krosnick and MacInnis (2013).

evaluated—emissions, emissions rates, marginal abatement costs, and total costs—and we showed that these measures do not move in unison when expanding the flexibility of the program. For example, expanding flexibility beyond only coal units to include all fossil units in order to achieve the same change in the average emissions rate would reduce the change in emissions. In general, measuring the stringency of different plans that vary in their flexibility is ambiguous. The problem is exacerbated by the potential that greater flexibility could enable regulated entities to take credit for actions that would have happened even in the absence of regulation.

The implementation plan process for conventional air pollutants can be evaluated by a single metric—the National Ambient Air Quality Standards. However, Section 111(d) calls for a multiattribute evaluation of implementation plans, taking environment, technology, and cost into consideration. Hence, EPA needs to evaluate a portfolio of stringency criteria to evaluate plans that introduce flexible approaches in different ways. We propose that the entire set of metrics that we have evaluated should be addressed in implementation plans and evaluated by EPA.

We also propose that EPA design an evaluation procedure under which features of the implementation plan can be evaluated independently if necessary and are severable from other aspects of the plan. This approach also may have the advantage that changes in the regulation that might be precipitated by court decisions might be implemented without reinitiating the development of regulations. If a plan is adopted based on a portfolio of criteria, and if a change in the regulation causes a change in one metric, that change could be evaluated in a larger context without necessarily triggering the need for new technical findings on which to base the revised regulations.

All of the policy scenarios that we evaluated yield positive net benefits. While the climate-related benefits are substantial, the larger share comes from the reduction in ancillary pollutants, including SO_2. The most ambitious policy yields emissions reductions that move the United States most of the way to achieving the Copenhagen pledge of reductions of 17 percent below 2005 levels by 2020.

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Appendix A. Technology and Market Results for Year 2020

	Baseline	*Coal*	*Fossil–ER*	*Fossil–Em*	*Fossil–MC*	*AllGen–ER*	*AllGen–Em*	*AllGen–MC*
CO_2 emissions rate (lbs/MWh)	1,157	1,113	1,128	1,110	999	1,121	1,111	979
Coal	2,085	2,005	2,062	2,050	1,993	2,060	2,054	1,988
Existing coal	2,093	2,010	2,070	2,057	2,000	2,068	2,062	1,997
New coal	1,907	1,911	1,894	1,914	1,880	1,896	1,893	1,846
Natural gas	875	870	892	895	907	887	894	910
Existing natural gas	921	923	922	923	924	922	923	924
New natural gas	700	696	681	654	609	692	640	680
Fossil	1,729	1,640	1,683	1,652	1,465	1,677	1,637	1,487
Existing fossil	1,792	1,704	1,719	1,682	1,474	1,722	1,665	1,498
New fossil	1,105	1,063	1,205	1,233	1,317	1,156	1,231	1,315
Ex. fossil & new nonemitting	1,700	1,620	1,635	1,604	1,407	1,632	1,576	1,400
CO_2 emissions (M tons)	2,354	2,261	2,296	2,261	2,014	2,283	2,262	1,976
Coal	1,924	1,821	1,825	1,764	1,388	1,813	1,782	1,351
Existing coal	1,846	1,743	1,747	1,686	1,310	1,735	1,704	1,274
New coal	78	78	78	78	77	78	78	77
Natural gas	342	348	385	412	554	385	395	549
Existing natural gas	285	283	348	381	534	340	365	525
New natural gas	57	65	37	31	20	45	29	24
Fossil	2,318	2,191	2,258	2,222	1,943	2,244	2,183	1,937
Existing fossil	2,183	2,048	2,144	2,112	1,846	2,122	2,076	1,837
New fossil	135	143	114	109	97	123	107	100
Ex. fossil & new nonemitting	2,186	2,060	2,149	2,118	1,853	2,128	2,086	1,844
Generation (TWh)	4,068	4,063	4,071	4,072	4,032	4,071	4,073	4,037
Coal	1,846	1,816	1,770	1,721	1,393	1,760	1,735	1,359
Existing coal	1,764	1,735	1,688	1,639	1,310	1,678	1,653	1,276
New coal	82	81	82	82	82	82	82	83
Natural gas	780	801	863	921	1,221	868	883	1,207
Existing natural gas	618	613	755	825	1,156	737	791	1,137
New natural gas	162	187	108	96	65	131	92	69
Fossil	2,681	2,673	2,684	2,689	2,652	2,677	2,667	2,605
Existing fossil	2,437	2,404	2,494	2,511	2,504	2,464	2,493	2,453
New fossil	244	269	190	178	148	213	174	152
Nonemitting	491	494	491	485	485	498	509	528
Existing nonemitting	357	356	355	354	356	355	355	346
New nonemitting	134	138	135	131	129	143	154	182
Ex. fossil & new nonemitting	2,571	2,542	2,630	2,642	2,633	2,607	2,647	2,634
Coal efficiency investments (B$)	0.6	2.9	1.0	1.2	2.0	1.0	1.1	1.9
Natural gas price ($/MMBtu)	4.9	4.9	5.0	5.1	5.5	5.0	5.0	5.5
Retail electricity price ($/MWh)	89.1	89.2	89.0	88.6	91.2	88.8	88.6	90.3

Appendix B. Technology and Market Results for Year 2025

	Baseline	*Coal*	*Fossil–ER*	*Fossil–Em*	*Fossil–MC*	*AllGen–ER*	*AllGen–Em*	*AllGen–MC*
CO_2 emissions rate (lbs/MWh)	1,167	1,128	1,136	1,130	1,065	1,144	1,129	1,040
Coal	2,080	2,004	2,037	2,030	1,996	2,057	2,042	1,993
Existing coal	2,088	2,010	2,044	2,036	2,003	2,065	2,050	2,000
New coal	1,895	1,881	1,881	1,903	1,877	1,889	1,886	1,855
Natural gas	839	836	892	896	905	863	883	905
Existing natural gas	920	922	921	922	922	920	921	921
New natural gas	723	715	663	599	535	713	652	628
Fossil	1,734	1,658	1,688	1,677	1,558	1,712	1,672	1,580
Existing fossil	1,861	1,778	1,720	1,698	1,565	1,795	1,710	1,591
New fossil	969	955	1,232	1,315	1,414	1,039	1,174	1,379
Ex. fossil & new nonemitting	1,749	1,678	1,625	1,609	1,487	1,678	1,601	1,475
CO_2 emissions (M tons)	2,455	2,369	2,381	2,369	2,210	2,399	2,368	2,159
Coal	2,044	1,951	1,923	1,900	1,670	1,972	1,922	1,624
Existing coal	1,965	1,872	1,844	1,820	1,591	1,894	1,844	1,547
New coal	79	78	79	79	78	79	79	78
Natural gas	323	325	374	385	468	341	358	460
Existing natural gas	209	210	343	364	456	263	321	444
New natural gas	114	115	32	20	12	78	37	17
Fossil	2,418	2,304	2,345	2,331	2,138	2,362	2,293	2,123
Existing fossil	2,225	2,111	2,235	2,232	2,048	2,206	2,178	2,029
New fossil	193	193	110	100	90	156	116	94
Ex. fossil & new nonemitting	2,228	2,124	2,238	2,236	2,055	2,210	2,191	2,033
Generation (TWh)	4,207	4,198	4,194	4,193	4,152	4,195	4,194	4,154
Coal	1,966	1,947	1,888	1,872	1,673	1,917	1,882	1,630
Existing coal	1,882	1,863	1,805	1,789	1,589	1,834	1,799	1,547
New coal	84	83	84	83	83	83	83	84
Natural gas	769	777	839	858	1,034	790	810	1,017
Existing natural gas	455	456	744	790	990	572	697	964
New natural gas	315	321	95	68	44	218	114	53
Fossil	2,789	2,780	2,778	2,780	2,745	2,759	2,744	2,687
Existing fossil	2,391	2,375	2,599	2,628	2,618	2,458	2,547	2,550
New fossil	398	405	179	151	127	301	197	137
Nonemitting	513	513	512	508	504	531	544	554
Existing nonemitting	357	356	357	356	357	356	355	348
New nonemitting	157	158	155	152	147	175	189	206
Ex. fossil & new nonemitting	2,547	2,532	2,754	2,780	2,765	2,634	2,736	2,757
Coal efficiency investments (B$)	0.9	3.3	1.9	2.1	2.5	1.3	1.7	2.4
Natural gas price ($/MMBtu)	5.6	5.6	5.7	5.8	6.1	5.6	5.7	6.0
Retail electricity price ($/MWh)	90.0	90.3	90.9	90.7	91.8	90.6	90.9	92.2

Appendix C. Technology and Market Results for Year 2035

	Baseline	*Coal*	*Fossil–ER*	*Fossil–Em*	*Fossil–MC*	*AllGen–ER*	*AllGen–Em*	*AllGen–MC*
CO_2 emissions rate (lbs/MWh)	1,135	1,104	1,107	1,109	1,104	1,117	1,106	1,070
Coal	2,074	2,003	2,022	2,023	2,011	2,057	2,041	2,008
Existing coal	2,082	2,010	2,028	2,029	2,017	2,065	2,049	2,015
New coal	1,884	1,862	1,880	1,889	1,872	1,887	1,875	1,859
Natural gas	794	788	859	859	862	813	825	857
Existing natural gas	915	916	916	918	919	914	917	917
New natural gas	739	731	725	724	710	737	717	732
Fossil	1,659	1,598	1,624	1,626	1,592	1,648	1,619	1,619
Existing fossil	1,921	1,847	1,720	1,724	1,677	1,855	1,775	1,722
New fossil	871	858	979	976	980	889	902	972
Ex. fossil & new nonemitting	1,775	1,720	1,603	1,607	1,576	1,703	1,636	1,549
CO_2 emissions (M tons)	2,561	2,489	2,485	2,489	2,476	2,518	2,489	2,396
Coal	2,084	2,011	1,957	1,961	1,943	2,029	1,993	1,892
Existing coal	2,002	1,932	1,877	1,881	1,863	1,949	1,913	1,812
New coal	82	80	80	81	80	81	80	80
Natural gas	388	385	440	439	444	399	404	420
Existing natural gas	140	138	330	327	344	193	244	304
New natural gas	248	248	111	112	100	207	160	116
Fossil	2,523	2,429	2,448	2,451	2,402	2,479	2,417	2,359
Existing fossil	2,193	2,101	2,257	2,259	2,222	2,192	2,176	2,163
New fossil	330	327	191	193	180	287	240	196
Ex. fossil & new nonemitting	2,197	2,122	2,260	2,262	2,238	2,196	2,200	2,167
Generation (TWh)	4,513	4,510	4,489	4,490	4,486	4,506	4,501	4,480
Coal	2,010	2,008	1,936	1,939	1,933	1,973	1,952	1,884
Existing coal	1,923	1,922	1,851	1,854	1,848	1,888	1,867	1,798
New coal	87	86	86	85	85	85	85	86
Natural gas	977	979	1,025	1,023	1,031	983	979	981
Existing natural gas	307	301	720	713	749	421	532	664
New natural gas	670	678	305	310	282	562	447	317
Fossil	3,041	3,039	3,014	3,016	3,017	3,010	2,985	2,914
Existing fossil	2,283	2,276	2,624	2,621	2,650	2,363	2,452	2,512
New fossil	758	763	390	395	368	647	533	403
Nonemitting	548	547	552	550	546	572	584	602
Existing nonemitting	356	355	356	356	356	355	347	314
New nonemitting	192	192	196	194	190	217	237	287
Ex. fossil & new nonemitting	2,476	2,468	2,820	2,815	2,839	2,580	2,689	2,799
Coal efficiency investments (B$)	1.0	3.4	2.5	2.5	2.9	1.4	1.8	2.7
Natural gas price ($/MMBtu)	6.3	6.4	6.5	6.5	6.5	6.4	6.4	6.4
Retail electricity price ($/MWh)	93.0	93.1	94.1	93.9	94.0	93.2	93.4	93.9