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A Proximate Mirror: Greenhouse Gas Rules and Strategic Behavior under the US Clean Air Act

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RESOURCES FOR THE FUTURE

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Abstract

The development of climate policy in the United States mirrors international developments, with efforts to initiate a coordinated approach giving way to jurisdictions separately taking actions. The centerpiece of US policy is regulation in the electricity sector that identifies a carbon emissions rate standard (intensity standard) for each state but leaves to states the design of policies, including potentially the use of technology policies, emissions rate averaging, or cap and trade. Differences in policies among states within the same power market could promote predatory behavior resulting in a geographic shift in generation and investment in new resources. This paper examines the coordination problem using a detailed partial equilibrium model of operations and investment. We demonstrate that leading jurisdictions have available a rich set of design options that can protect them against strategic predation and, in fact, give them opportunities to proactively advance climate goals, to the economic detriment of laggards.

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

JEL Classification Numbers: K32, Q54, Q58

Contents

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1. Introduction

The development of climate policy in the United States mirrors international developments, with efforts to initiate a coordinated approach giving way to regimes in which jurisdictions are separately taking actions with differing policy designs. Independent policy design introduces opportunities for strategic behavior that can lead to leakage of economic activity and emissions and increase overall costs or emissions or both. Jurisdictions that exercise policy leadership in the stringency or design of their policy may be especially vulnerable to strategic interaction. Their costs may rise because of the policy choice of neighboring jurisdictions, which in turn may benefit from predatory behavior, undermining the prospect for climate policy. Using the US electricity sector as a laboratory, we demonstrate that leading jurisdictions have available a rich set of design options that can protect them against strategic predation and in fact give them opportunities to proactively advance climate goals, to the economic detriment of laggards.

US climate policy is taking shape through the Climate Action Plan, announced by President Obama in June 2013. The plan encompasses improved motor vehicle standards, additional appliance efficiency standards, and regulation of greenhouse gases from a variety of sources. It includes an inflexible carbon dioxide (CO_2) emissions rate standard for new fossil-fired facilities comparable to that of a new natural gas combined-cycle unit. This standard effectively requires the application of carbon capture and storage at new coal-fired facilities; however, few new coal-fired facilities were likely to be built in the near term. The centerpiece, the Clean Power Plan (CPP), is directed at existing sources in the electricity sector, which are

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responsible for about 38 percent of total national emissions. The CPP introduces regulations under the federal Clean Air Act aimed at reducing emissions in the electricity sector by 30 percent from 2005 levels by 2030, achieving most of this goal on an annual basis by 2020.

The CPP embodies the familiar framework of cooperative federalism in US environmental law. It establishes a carbon emissions rate standard of performance (intensity standard) for each state, but leaves to states the responsibility for planning, implementation, and enforcement to achieve the standard. The standard is founded on technology-based building blocks that identify options in each state, while the proposed rule assumes a system-based approach to implement emissions reductions across the electricity sector to achieve the standard. States are granted remarkable flexibility, including the possibility of using technology policies or economic incentives such as emissions rate trading (averaging), cap and trade, or taxes to achieve the performance standard.[1] States may develop multistate plans to average emissions rates across states, or adopt regional cap-and-trade approaches. The US Environmental Protection Agency (EPA) will issue its final rule in the summer of 2015, and states will have one year to prepare a plan, with possible extensions of up to two additional years for states developing multistate plans. Initial compliance is expected in 2020.

The recent change of course in US climate policy is abrupt. In 2009 the US House of Representatives passed comprehensive national climate legislation that would have introduced economy-wide cap and trade as a centerpiece. The legislation did not come to a vote in the Senate and its demise in 2010 cast a shadow on the prospects for climate policy in the United States. Three years later, policy of similar stringency began taking shape. In the electricity sector, the centerpiece is a bottom-up process in which state jurisdictions make separate choices about how they will comply.

The change in course within the United States somewhat parallels changes that have occurred in international climate negotiations. The Conference of the Parties to the international negotiations met in Berlin in 1995 to launch the process that eventually led to the Kyoto Protocol in 1997 and introduced an ambitious obligation on signatories. The refusal of the United States to ratify the treaty and the disaffection of other parties undermined that coordinated approach. Strategic and competitive interactions have since influenced the international debate. If one were

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[1] In principle, states might use a cap-and-trade policy to achieve the emissions rate target, but EPA has given states explicit ability to convert their emissions rate target to an emissions mass target that would facilitate the use of cap and trade.

to imagine the Kyoto Protocol as a cooperative solution to a strategic problem, it shared a characteristic inherent to cooperative game theory in general: the solution did not specify incentive-compatible steps to achieving the outcome.

Internationally, the current potential for optimism resides in the prospects for a bottom-up process of nationally determined contributions. This pledge and review process among nations more closely resembles a noncooperative solution. The theoretical question with relevance internationally and in the United States is whether this type of bottom-up approach can solve the difficult coordination challenge to achieve an outcome that is effective.

One step to solving the challenge to date appears to involve the proliferation of technology policies, which are often described as enabling or complementary to the emergence of comprehensive approaches. For example, in the European Union, renewable policies have contributed to low prices in the emissions trading system, encouraging the adoption of more stringent emissions targets (Koch et al. 2014). In the United States, the stringency of the CPP is based on findings about the technical feasibility of reducing carbon emissions, drawing on the variety of technology policies already in place in the states.[2] The economics literature has broadly characterized these policies as a potentially inefficient way to achieve emissions reductions (Böhringer and Rosendahl 2010; Fischer et al. 2013). However, we suspect that if a bottom-up climate policy is going to succeed, perhaps eventually leading to a coordinated and comprehensive solution, it is likely to require the learning and coalition building that are achieved through such an incremental process (Keohane and Victor 2013).

In the United States, the coordination challenge is perhaps simplified because EPA has determined the stringency of state goals, while there is nothing comparable internationally. However, the nearly absolute flexibility in policy design under the CPP provides states with a monumental coordination challenge as complex as that at the international level. Emerging as a central question for states is the form and reach of their plans. Form pertains to the policies that will be enacted in each state, such as technology standards, incentives for renewables and energy

[2] For example, currently 40 states have renewable portfolio standards (NCSU 2013) and 25 have meaningfully funded long-term (3+ years) energy savings targets or energy efficiency resource standards (ACEEE 2014). In California, which has economy-wide cap and trade in place, approximately 83 percent of the emissions reductions necessary to achieve the state's climate goals for 2020 will be achieved by regulatory standards and measures.

efficiency, and cap and trade. Reach pertains to the interaction of each state with its neighbors.[3] Multistate plans would allow states to capture the efficiency of harmonizing policies across diverse situations. Even more important, however, is the overlap between compliance activities at the state level and the power planning regions and markets that cover multiple states and sometimes divide states. As we describe below, the policy designs chosen by states may interact with power markets to cause unintended geographic shifts in electricity generation and investment in new facilities, raising costs, emissions, or both. A state might respond to decisions of its neighbors to its own benefit and at their expense. Even if states choose the same design, the variation in stringency among states that is inherited from EPA could lead to negative outcomes.

This paper examines the coordination problem in the context of the US electricity sector using a detailed partial equilibrium model of operations and investment through 2035 to examine interactions among state policies and power markets. We focus on policy options in one region, the upper Midwest, holding stable the policy choice of an emissions rate standard in the rest of the nation. This region is of interest because it comprises states with both cost-of-service regulation and competitive market structures, and it has a variety of resource options.

We compare an emissions rate standard with emissions cap and trade in the upper Midwest. Under some forms of cap and trade, the interaction of these policies can provide substantial cost advantages to the jurisdiction with an emissions rate standard, causing operations and investment to shift into that region. Because the emissions rate standard does not place a cap on total emissions, this policy combination can increase emissions overall compared with the outcome if both regions have an emissions rate standard. However, under other forms of cap and trade, the interaction can lead to zero leakage if states use targeted output-based allocation to mimic the incentives created under the emissions rate standard. Recognizing that this equivalence is possible, one can therefore imagine negative leakage, with operations and investment flowing into the region with an emissions cap and lowering emissions over the entire interstate region, which we show is achievable.

The ability of states to use targeted output-based allocation to preserve the level of operations and investment that would occur if they used the emissions rate standard means that

[3] Multi-state discussions to develop regional compliance plans have already begun in several regions of the country. A consensus on the policy design has so far emerged only the northeast region, where there is a pre-existing cap-and-trade program encompassing nine states, and that is the region's preferred approach for compliance with the CPP.

states can address the strategic issues that are introduced by using emissions cap and trade while achieving that approach's many administrative advantages over an emissions rate standard. Costs under these outcomes vary under different policy combinations between neighboring jurisdictions. Costs may be less in the leading jurisdiction but may be greater nationally because of the strategic response we identify, with the difference imposed on other jurisdictions that may be initially perceived as predatory. Perhaps as importantly, the distribution of costs among consumers, incumbent generators, and new investors also varies. The lowest costs overall and for various jurisdictions would be achieved under a coordinated approach.

In the next section of this paper we describe the US policy context in more detail and review the international literature on the interaction between emissions rate (intensity) standards and cap and trade. In Section 3 we introduce the model and describe the scenarios that reflect state policy options. In Section 4 we describe results, including the possibility for perverse outcomes and strategic predatory behavior, and defensive responses to prevent this outcome. Section 5 provides a concluding discussion.

2. Policy Background and Literature

EPA proposed a version of the CPP in June 2014. The rule establishes an *adjusted* emissions rate performance standard for each state. The numerator of the emissions rate calculation includes emissions from existing electricity generating units (built before January 8, 2014) of a minimum size and utilization. The denominator includes energy production from these sources and production from existing and new nonemitting resources, avoided generation attributable to energy efficiency, and 6 percent of generation from existing nuclear units.[4]

2.1. Policy Options under the Clean Power Plan

The stringency of the emissions rate standard is derived from technical findings about the opportunity for emissions rate reductions from four "building blocks" in each state:

- increased efficiency at coal-fired units, anticipating a 6 percent improvement in heat rates;
- more effective use of existing natural gas combined-cycle units, anticipating 70 percent utilization of capacity;

[4] An important issue on which EPA seeks comment is whether and how new emitting sources should be treated.

- increased renewable generation, based on accomplishments already achieved among states in each region and preservation of nuclear units now in operation; and
- expanded energy efficiency programs, ramping up to a 1.5 percent annual incremental savings rate.

These measures are used to determine the emissions rate targets for individual states, which can vary by a factor of 6, depending on the situation.

The Climate Action Plan and the CPP encourage flexible implementation.[5] The cost savings from a flexible approach to implementation could be substantial, especially if implemented on a regional or national basis. Burtraw et al. (2012) and Linn et al. (2014) show that a national uniform tradable performance standard for reducing CO_2 emissions from the electricity sector can cost 70 to 90 percent less than a traditional (nontradable) performance standard.

States are also given the option of converting the emissions rate target to an emissions budget (mass-based) goal, which would simplify many aspects of implementation, including evaluation of energy efficiency programs and interstate collaboration.[6] In principle, conversion to an emissions budget is achieved by multiplying the emissions rate standard (lbs CO_2/MWh) by the activity level (MWh); in practice, the determination of the appropriate activity level remains in debate and is one of the many issues to be clarified in the final rule.[7] Although states are not required to adopt any specific measure as elements of their compliance strategy, a state plan must identify the compliance activities that will be used to achieve the goal and identify corrective measures as a backstop if the actual reported emissions deviate substantially from the goal over the next decade.

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[5] 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." See http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards (accessed December 20, 2014).

[6] Fowlie et al. (2014).

[7] EPA offered some examples of how such a conversion might be done in EPA (2014b).

2.2. Potential Policy Interactions

A central issue for states is how their measures will interact with those of other states. For example, double-counting might occur if one state provided incentives for renewable projects (or energy efficiency) that were built in another state. The first state might want to claim credit in its emissions rate calculation to justify the investment, while the second state could point to an observable reduction in its emissions rate. EPA suggested in its proposed rule that the state purchasing and consuming renewable energy gets the credit for compliance. For the time being, virtually all renewable power is financed with a power purchase agreement that makes such accounting possible, but if renewables reach a scale where they are built as merchant facilities contributing to power pools the tracking of credit becomes problematic. There is also a challenge in assigning credit between states with rate-based and mass-based compliance plans. EPA has sought comment on alternative ways to structure guidelines to address these issues. Further, state emissions rate targets differ in stringency, which could complicate interstate collaboration. If states submit a regional emissions rate compliance plan, the CPP appears to imagine that a blended (weighted average) emissions rate would apply on a regional basis, but this may disadvantage the state that otherwise would have a less stringent standard.[8] Michel and Nielsen (2014) describe emissions rate trading weighted on the basis of the relative standards in each state, which would preserve the incentives associated with the state's own standard but allow for regional compliance.

The subject of this paper is another way that state policies will interact—through the movement of power and new investment in the electricity market. Besides introducing a price on emissions, an emissions rate standard provides an incentive for production because the firm earns emissions credits per unit of production (Fischer 2003). If the facility's emissions rate is less than the standard, the facility has a net credit from the difference between its observed performance and the standard. If two states have different emissions rate standards, incentives may exist to shift generation and investment to the jurisdiction with a less stringent standard. The shift may lead to the utilization of different fuels and technologies, ultimately increasing emissions of CO_2 as well as changing the location and magnitude of other pollutants, including sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

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[8] In principle, states might comply with a regional rate but implement differentiated rates among the states in a region, although it is unclear whether this would meet EPA approval.

States are given the option of converting the emissions rate target to an emissions budget (mass-based) goal. However, differences in production incentives would be even greater if one state chooses to use conventional cap and trade without a production incentive and a neighboring jurisdiction retains its emissions rate standard. In effect, the production incentive in the capped region is zero; for example, if emissions allowances are distributed through an auction, then facilities must purchase all of their allowances. Even if a cap-and-trade program distributes emissions allowances for free, as was the practice under the Title IV Acid Rain Program for SO_2 emissions and in the early phases of the European Union's Emissions Trading System, there typically does not exist a production incentive because the volume of allowances distributed to facilities does not depend on its generation activity. In this case, capping emissions in one jurisdiction creates incentives for a shift in production and investment to neighboring jurisdictions that do not cap emissions with negative environmental consequences (Marschinski 2008; Bushnell et al. 2014).

2.3. Production Incentives under Various Policy Designs

The policy strategy we investigate is the incorporation of a production incentive in the design of an emissions constraint. One way this can be accomplished is through the allocation of emissions allowances on the basis of economic activity (electricity generation) for a targeted set of electricity generators. First we evaluate a scenario in which all states use a tradable emissions rate policy to comply with the emissions rate target assigned to states under the CPP. We compare this scenario with various scenarios in which policies vary across regions. We consider the interaction of the emissions rate policy in the rest of the nation with various formulations of an emissions budget (cap-and-trade) policy in the upper Midwest. We find the possibility for leakage to be present, depending on the form of the cap-and-trade program. In one case, we imagine the emissions allowances in the cap-and-trade policy are auctioned, with revenues leaving the electricity sector (equivalent to an emissions tax or lump-sum climate dividend), resulting in leakage of generation and emissions to other regions and an increase in overall emissions. In another case, we imagine the revenues remain in the electricity sector and are directed to consumers through their local distribution company, as proposed in 2009 in the Waxman-Markey proposal for national-level cap and trade, and again we find substantial leakage and an increase in emissions. In other cases, we imagine targeted production incentives (updated output-based allocation) that reward utilization of specific technologies, and we show that negative leakage can occur, with a decrease in total emissions, compared with tradable emissions rate policies in all states.

In general, the production incentive leads to more production from the targeted technologies, but it is informative to consider an example where that might not happen. If there were only one type of technology and a binding emissions cap were in place, the only way to achieve emissions reductions would be through a proportional reduction in generation from these facilities. The production incentive would drive up allowance prices, with no change in the generation mix (Bushnell and Chen 2012). In a dynamic model with an opportunity for investment, decisionmakers also anticipate the consequences of generation or emissions with respect to their allocation in a subsequent period, driving up short-run allowance prices (Harstad and Eskeland 2010).[9] Hence, the price of emissions allowances is not a good measure of the marginal cost of emissions reductions when there is a production incentive because it is actually the marginal cost conditional on the subsidy.

However, one way that output based allocation can be effective is by directing the production subsidy to the promotion of greater use of and investment in low- or non-emitting resources within the regulated region (Fischer 2003; Burtraw et al. 2006). The difference between the demand for electricity services and generation from the emitting technology could come from nonemitting sources. Further, the CPP treats energy efficiency as a nonemitting resource, and some states may prefer to direct allowance value to energy efficiency, as has been done in the Northeast’s Regional Greenhouse Gas Initiative cap-and-trade program, where approximately two-thirds of the value of emissions allowances is directed to investments in energy efficiency (Burtraw and Sekar 2014b). Holland (2012) shows that output-based allocation can dominate a tradable performance standard in economic efficiency if it can mimic the optimal combined emissions price and output subsidy. The potential superiority of output-based allocation, Holland notes, can be attributed to its flexibility. We note that the CPP allows states such flexibility.

The ability of states to use targeted output-based allocation to preserve the level of operations and investment obtained under an emissions rate standard means that states can address strategic issues introduced by using emissions cap and trade while achieving the administrative advantages of that approach. Economic costs vary under different policy combinations and are lowest under a coordinated approach (Holland 2012). Perhaps as

[9] Rosendahl and Storrøsten (2011) show that if allowances were based on the updated share of emissions, investment and retirement would be equivalent to grandfathered allocation, but the result hinges on the assumption of no banking of emissions allowances across periods.

importantly, the distribution of costs among consumers, incumbent generators, and new investors also varies because the production incentive has different effects on the variable cost of the marginal electricity generator under various scenarios. Consumers may prefer to coordinate around a tradable performance standard that provides incentives for production, while producers may prefer to coordinate around cap and trade with revenues used to provide incentives for consumption (Burtraw et al. 2014a) or not to coordinate (Bushnell et al. 2014).

3. Model and Scenario Descriptions

We use a highly parameterized electricity market simulation model to characterize the response of the electricity system to a variety of potential climate policies undertaken by states and examine the regional interactions of those policies.

3.1. The Haiku Electricity Market Model

The simulation modeling uses the Haiku electricity market model,[10] which is a partial equilibrium model that solves for investment in and operation of the electricity system in 22 linked[11] regions of the continental United States, from 2013 to 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 53 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 17 model plants represent new capacity investments, again differentiated by technology and fuel source. Each model coal plant has a range of capacity at various heat rates, representing the range of average heat rates at the underlying constituent plants.

[10] Haiku is comparable in sectoral and geographic coverage to the Integrated Planning Model (IPM, owned by ICF consulting and the model of record for 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). Haiku, IPM, and ReEDS model the electricity sector and partially model factor markets, like fuel, for the continental United States. NEMS also 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).

[11] Interregional transmission capability is drawn from EIA (2013).

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 margins used by the Energy Information Administration in the Annual Energy Outlook (AEO) for 2013 (EIA 2013). Fuel prices are benchmarked to the AEO 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 the 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[12] 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 plant-specific opportunities[13] to make endogenous investments to improve their efficiency. Discounting for new capacity investments is based on an assumed real cost of capital of 5 percent. Investment and operations include pollution control decisions to comply with regulatory constraints for SO_2, NO_x, mercury, hydrochloric acid, and particulate matter, including equilibria in emissions allowance markets where relevant. All currently available generation technologies identified in AEO are represented in the model, as are integrated gasification combined-cycle coal plants and natural gas combined-cycle plants, both with carbon capture and storage. 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 in decisions to retire a plant. Although short-term contracts are common in coal markets, long-term contacts could play a role in retirement decisions. If long-term contracts incentivize some plants to remain in operation, this modeling omission likely leads to an overestimate of coal-fired retirement projections and, potentially, 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

[12] Investment (in both generation capacity and pollution controls) and retirement are determined according to cost-minimization.
[13] Linn et al. (2014).

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.[14] The retail price of electricity does not vary by time of day in any region, though all customers face prices that vary from season to season.

The model requires that each region have sufficient capacity reserve to meet requirements drawn from AEO. 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 and compare a tradable emissions rate performance standard program and various forms of cap and trade in the electricity sector, and we examine the policy interaction across regions under various settings.

3.2.1. Baseline Scenario

The Baseline includes all of the major environmental policies affecting the electricity sector. This includes the SO_2 trading program under Title IV of the Clean Air Act, the Regional Greenhouse Gas Initiative, the federal renewable energy production and investment tax credit programs, California's cap-and-trade program, and all of the state renewable peformance standards and renewable tax credit programs.[15] The Baseline also includes the Mercury and Air Toxics Standards, which have been finalized by EPA and fully take effect in 2016 in our model, and state-level mercury standards. Finally, the Baseline includes the Clean Air Interstate Rule in place of the Cross-State Air Pollution Rule, which was struck down by the court and recently reinstated but is not yet in effect. This can be taken to represent a future regulation on SO_2 and

[14] 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.

[15] We assume the production tax credits expire by 2017 but some investments receive credits over a duration of 10 years.

NO_x.[16] The Baseline is calibrated to the AEO (EIA 2013). All of the characteristics of the Baseline are held constant in the policy scenarios except for the Regional Greenhouse Gas Initiative and California's cap-and-trade program, which for simplicity are not maintained in these experiments, and otherwise as discussed below.

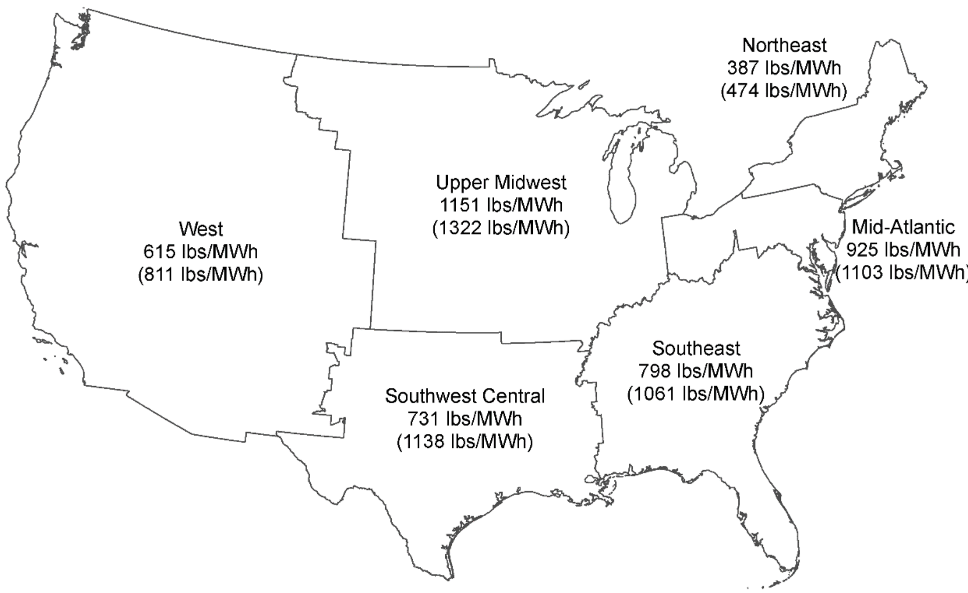
3.2.2. Policy Scenarios

We model six compliance regions, of which only one region (upper Midwest) has varying policy formulations across scenarios; the other five regions keep the same policy, a rate-based tradable performance standard. The regions and emissions rate standards are shown in Figure 1. The various annual emissions rate standards do not vary under alternative scenarios, but emissions can vary. In contrast, we calibrated the upper Midwest to achieve a CO_2 emissions trajectory in every scenario for each year through 2035 that matches the emissions outcome under the tradable performance standard. These emissions rates and emissions targets are based on a careful representation of the CPP in Haiku[17] and result in emissions reductions close to EPA's estimate for the CPP. This regional policy configuration facilitates the study of emissions leakage.

[16] Our previous modeling has shown only small changes to the electricity sector if the Clean Air Interstate Rule is replaced with Cross-State Air Pollution Rule when the Mercury and Air Toxics Standards are also in effect. Thus the choice between modeling these two SO_2 and NO_x regulations is of little significance in this analysis.

[17] We simulated six tradable performance programs in six compliance regions with emissions rate targets that are the blended (generation weighted average) emissions rate goals for each state in the region established in the CPP for the compliance period 2020–2035. The CPP allows for moderate interannual flexibility between 2020 and 2029, followed by annual compliance through 2035. We solve the model to find a least-cost emissions rate pathway over this period and then implement the identified regional emissions rate targets on an annual basis in the scenarios we model. We use the observed emissions in each year to determine the emissions budget in the upper Midwest over the compliance period.

Figure 1. Regional Configurations with 2020 Emissions Rate Targets (with Baseline Emissions Rates)



Besides the regional differences, the policy treatments in all the scenarios have shared features across regions. The population of generators covered by regulation is the same: all fossil-fired generators,[18] all renewables (except existing hydro), and new and at-risk[19] nuclear generators.[20] The treatment of energy efficiency (EE) programs in compliance is also the same and is constant across all scenarios at a level of funding determined by a system benefit charge of $3/MWh, and effectiveness is described by end-use demand reduction at a first-year program

[18] The CPP is ambiguous with respect to inclusion of new fossil sources.

[19] The CPP views an approximately 5.8 percent share of nuclear capacity as a reasonable proxy for the amount of nuclear capacity at risk of retirement (Clean Power Plan Proposed Rule: GHG Abatement Measures, Technical support document, U.S. EPA, 2014).

[20] The covered sources are the denominator in the CPP's formula for state goal plus new natural gas combined-cycle.

cost of $180/MWh.[21] We assume an equal participant cost for EE investment is paid by the consumer and include that cost in our economic surplus estimates.

In policy experiments, we compare several approaches in the upper Midwest that differ in the form of the policy and allocation of allowance revenue. The first is a rate-based tradable performance standard (TPS). The others have a mass basis, with differences in the allocation of the asset value created by introducing a price on carbon: allocation to government, to consumers, and to producers. These policies correspond to revenue-raising auction (government), an emissions budget with allocation to local distribution companies (LDCs), and an emissions budget with targeted updated output-based allocation (OBA) with several variants.

Tradable Emissions Rate Performance Standard

A tradable emissions rate performance standard sets an emissions rate that the regulated sources must meet on average. This could be achieved through a regulatory process or planning process within a firm, but we imagine a market analogue in which generators are obligated to surrender credits equal to their actual emissions rate multiplied by their annual generation and are entitled to earn credits equal to the benchmark emissions rate multiplied by their annual generation. The net compliance obligation stems from the difference between the benchmark and actual emissions rates. In this scenario, we implement tradable performance standards in six regions. In the following scenarios, we implement tradable performance standards in five regions; only the upper Midwest varies the policy design, and in doing so states in the Midwest region use the asset value created by the emissions constraint in various other ways.

Emissions Budget with Auction Revenues to Government

The remaining scenarios involve the translation of the emissions rate standard to a mass-based emissions budget for the upper Midwest. The emissions outcome in the region in the remaining scenarios is the same as under the tradable emissions rate performance standard.

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[21] All values are in 2011 dollars. Factoring EE programs in assessing compliance is consistent with the the fourth building block—investment in energy efficiency to reduce electricity demand growth—in the Best System of Emissions Reductions used to construct states' emissions rate goals in the CPP. The modeling of EE programs affects electricity prices and generation investment endogenously in a dynamic timeframe. Energy savings persist and decay over time based on the partial-adjustment structure of the Haiku demand system. EE expenditures are allocated to consumer classes based on consumption shares.

One approach is to characterize the program as an emissions cap-and-trade program with allowances auctioned and revenues from the auction accruing to the, equivalent to an emissions tax with the level of the tax calibrated to achieve the emissions budget. In this scenario, the allowance asset value leaves the electricity sector.

Emissions Budget with Allocation to Local Distribution Companies

In this scenario, cap and trade is implemented in the upper Midwest and the allowance asset value stays in the electricity sector and is allocated to LDCs in proportion to their share of consumption. As regulated entities, LDCs are assumed to direct the value to the benefit of consumers. This could be achieved in a variety of ways; the assumption in this scenario is that the value is applied as a credit on customers' electricity bills. Consequently, consumers are expected to pay lower retail electricity prices in this scenario than in the Government scenario and react to lower prices by increasing consumption.

Emissions Budget with Targeted Updated Output-Based Allocation

We investigate several forms of cap and trade in the upper Midwest with allowance value allocated to different sets of eligible electricity producers based on their share of electricity generation within the set. Because shares of generation change over time, this approach is labeled *updated* output-based allocation. It is modeled as a contemporaneous equilibrium; in practice this approach is implemented by looking back to a recent period when data are complete. We describe this as *targeted* allocation because the allowance revenue is concentrated to a subset of all resources. We describe four approaches in Table 1.

Table 1. Policy Scenarios Using Targeted Updated Output-Based Allocation

Generator Type		*Covered Sources*	TPS (OBA-All Covered)	*Government*	*OBA-All*	*OBA-ExCoal*	*OBA-New NonEm*
			Production Eligible for Allowance Allocation				
Fossil	Coal	X	X		X		
	Natural Gas	X	X		X	X	
	Oil	X	X		X	X	
Renewables	Existing Wind	X	X		X	X	
	Other Existing	X	X		X	X	
	New	X	X		X	X	X
Nuclear	Existing				X		
	New, At-Risk	X	X		X	X	X
Hydro					X		
Efficiency		X					

OBA = output-based allocation; TPS = tradable performance standard

The policy scenario labeled TPS (OBA-All Covered) allocates the allowance value to the set of covered (regulated) generators on the basis of their share of production by these generators. Hence, this approach is conceptually identical to a tradable performance standard covering the same set of generators, and the modeling of these two policies is identical if the emissions outcomes are constrained to be equal.

The OBA-All scenario allocates the allowance value to all generators including existing nuclear and hydro. These resources can respond to a production incentive to only a small degree since they produce at their maximum availability in the Baseline. Consequently, their eligibility for an allocation waters down the production incentive that is available to other technologies that can respond to the production incentive.

In the scenario OBA-ExCoal, allocation occurs to covered generators except coal. This would appear to focus the production incentive more directly on lower-emitting resources.

However, in equilibrium, because coal does not receive the incentive, there is likely to be less coal generation, and the scarcity value of emissions credits or allowances will be reduced. These factors have somewhat offsetting effects on the production incentive that is delivered to the eligible sources.

Finally, under the scenario OBA-New NonEm, only new renewables, new nuclear, and at-risk nuclear are eligible to receive allocation.

The introduction of production incentives influences the variable cost of electricity generation, and the variation under the policy options can promote the use of one technology at the expense of another. If the favored technology is new investment, the incentives could lead to greater investment. Nonetheless, existing sources may continue to be available even if they do not receive the production incentive.

Figure 2. The Variable Cost Schedule under Cap and Trade when Revenues are Distributed to Government and the Same Plant Ordering With Targeted Output-Based Allocation Excluding Coal (Upper Midwest, 2020)

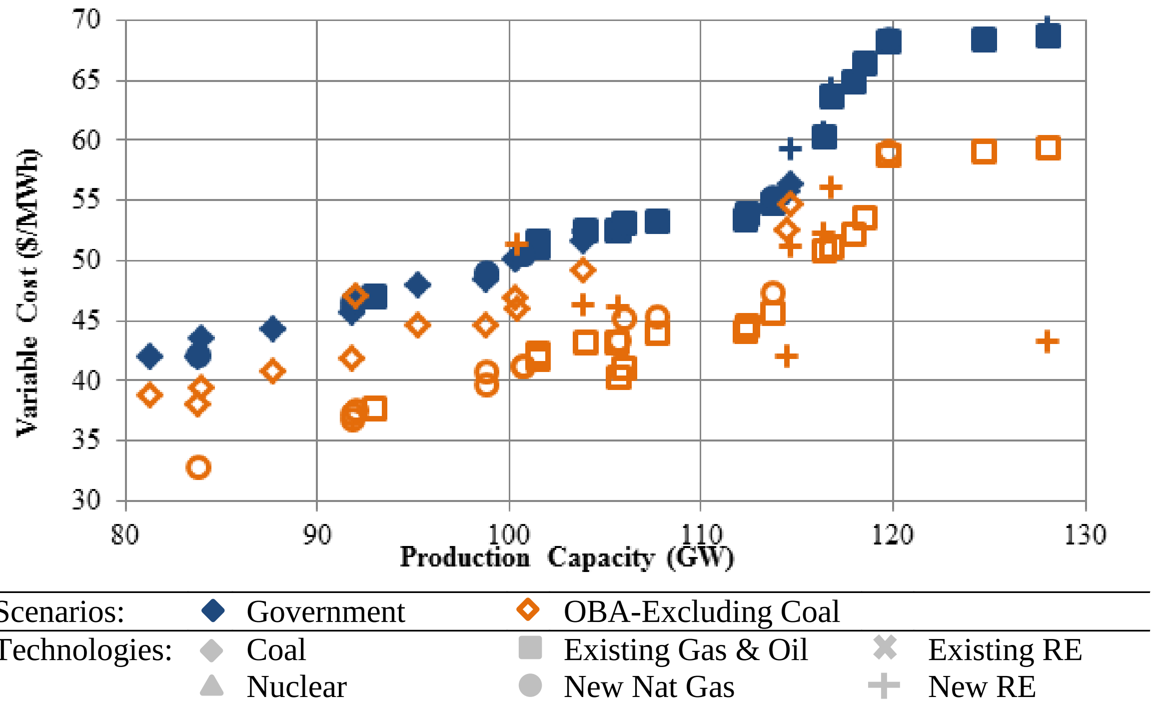
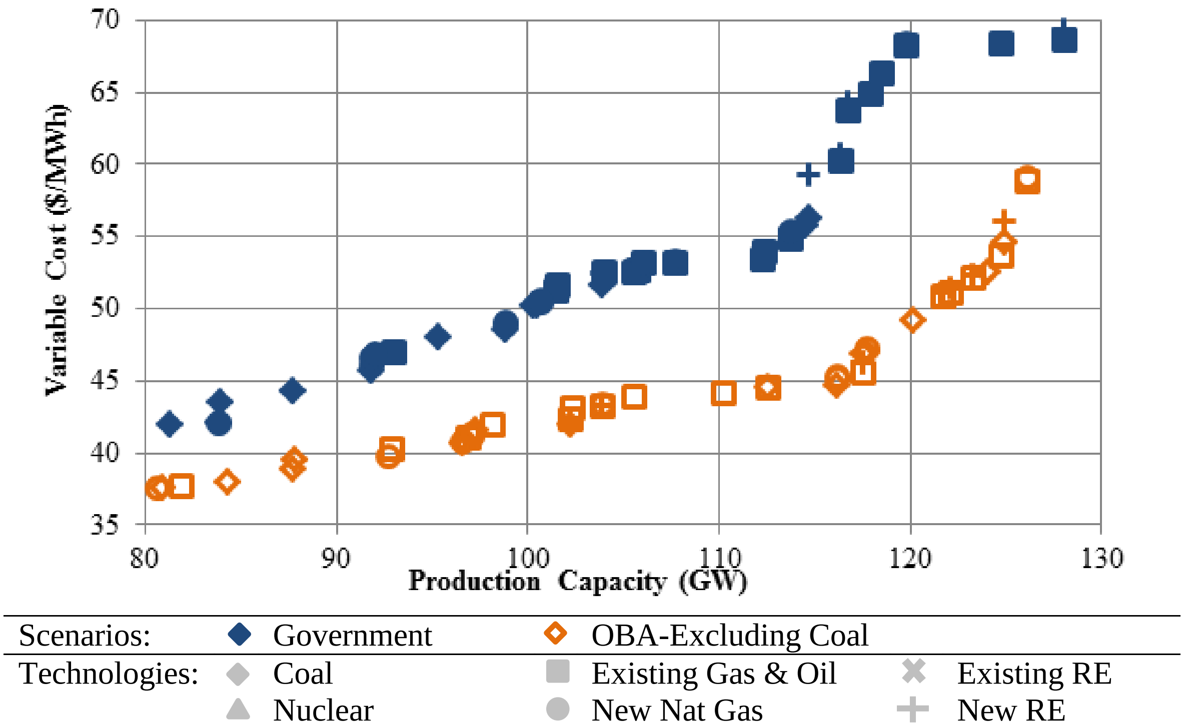


Figure 2 displays the forecast merit cost ordering for electricity generation for a portion of the supply curve. Generation is organized into six generation types for the upper Midwest during the baseload summer block in 2020 under two policy scenarios.[22] The solid symbols represent the variable costs under the Government scenario, organized according to merit order. The available production capacity in this scenario is measured on the horizontal axis. The second set of costs displayed on the figure reflects the variable costs under output-based allocation to all covered sources excluding coal (OBA-ExCoal), without any reordering of the plants according to the new variable cost schedule. The variable cost of each plant is affected by the change in the carbon price and in many cases by the availability of a production incentive.

[22] Individual generating units are aggregated as model plants, as in the Haiku model.

Figure 3. The Variable Cost Schedule under Cap and Trade when Revenues are Distributed to Government Compared with the Reordered Schedule with Targeted Output-Based Allocation Excluding Coal (Upper Midwest, 2020)



Three observations are evident. One is that the variable costs under OBA-ExCoal are generally lower than under the Government scenario, as would be expected because of the production subsidy, which is likely to result in more generation from within the region than under the Government scenario, helping to reduce leakage. Second, the difference in variable costs depends on technology. As evident in the next section, coal generation is advantaged under OBA-ExCoal because the allowance price that emerges in equilibrium is less than under the Government scenario, renewables are advantaged because they receive the production incentive, and natural gas benefits for both these reasons. Third, the variable costs under OBA-ExCoal are not monotonically increasing under the ordering of technologies that is presented. A reordering of the technologies will favor greater utilization of some technologies and a change in capacity.

Figure 3 portrays the new merit order under OBA-ExCoal compared with the merit order under the Government scenario after the plants have been reordered. Changes in plant retirement and investment by 2020 are evident in different available capacity, and the lower variable cost under targeted updated allocation is evident over the entire range displayed. The equilibrium that results under these scenarios is reported in Section 4.

4. Results

We solve the model over a 22-year horizon from 2013 to 2035, within which 2020 to 2035 is the compliance period for policy scenarios. Here we report results only for 2020, but the results reflect investment and compliance decisions in an interannual context. Results for 2025 appear in the appendix. First we examine results in the upper Midwest and then we report results at the national level. The primary comparison is between the outcome of various policy choices compared to a tradable performance standard in the upper Midwest, when the rest of the nation uses a tradable performance standard. Bushnell et al. (2014) explore similar comparisons to illustrate the possibility for leakage. We do not consider the benefits of reductions of any of the pollutants that we discuss, but it is noteworthy that EPA expects changes in emissions of conventional pollutants, especially SO_2, to have economic benefits that are at least as great as those from reductions in CO_2 (EPA 2014a).

4.1. Upper Midwest

We find that the CPP, if implemented through six regional tradable performance standards, would reduce electricity sector CO_2 emissions in the upper Midwest to 484 million short tons, a reduction of 11 percent from Baseline levels for 2020 in that region (Table 2). The CO_2 emissions in the upper Midwest are held constant at the level observed in the TPS scenario across all the other policy scenarios, but changes in the generation technology mix used in the region lead to changes in emissions of SO_2 and NO_x. These co-pollutants tend to be associated especially with changes in coal-fired generation in the region.

In the Baseline, the upper Midwest exports about 4 percent of the power it generates. Under TPS, the export share doubles to 8 percent and total generation increases slightly. This reflects the region's relatively high emissions rate standard and opportunity for renewable investment. Under the Government scenario, the export share falls to 2 percent (demonstrating the possibility for leakage). The Government scenario leads to higher electricity prices and reduced demand and generation. It leads to virtually no generation from new gas units and thus makes room for more generation from coal, with an associated increase in emissions of SO_2 and NO_x.

When revenues are directed to the local distribution company, they reduce the electricity price compared with the Government scenario and serve as an incentive for consumption. The electricity price is almost as low as under TPS. In most other ways the results obtained under the LDC scenario are similar to the Government scenario except for an important further decrease in net exports, which are lowest of all under the LDC scenario, yielding the greatest amount of leakage.

Under output-based allocation, as under TPS, the production incentive is reflected in the allowance price. Under OBA-All, it is directed as a production incentive to all generation, including generation that is not covered by the CPP. The allowance value is greatest under OBA-All, reflecting the scarcity value of emissions allowances when all sources are eligible for a production incentive. This leads to the greatest amount of generation in the region, the highest allowance price, and the greatest export of power, resulting in negative leakage compared with TPS.

Similar amounts of exports and negative generation leakage result under OBA-ExCoal, when the production incentive is not given to coal. In this case, the substantial entry of new gas crowds out existing coal, leading to the lowest SO_2 emissions. In contrast, under output-based allocation directed exclusively to new nonemitting sources (OBA-New NonEm), generation leakage is almost unchanged compared with TPS. The substantial entry of new wind in this scenario crowds out new gas generation, making room under the cap for more coal generation and returning it to the level observed under the Government scenario. This phenomenon—the lowest-emitting sources enable the highest-emitting sources to coexist—has been observed in other contexts (Böhringer et al. 2010).

Table 2. Upper Midwest Results for 2020

	Baseline	*TPS (OBA-All Covered)*	*Government*	*LDC*	*OBA-All*	*OBA-ExCoal*	*OBA- New NonEm*
Emissions							
CO_2 (million short tons)*	540	484	485	483	487	484	482
SO_2 (thousand short tons)	760	609	652	644	620	572	642
NO_x (thousand short tons)	515	457	477	469	452	463	475
Electricity Price ($/MWh)	90	92	98	94	94	93	92
Natural Gas Price ($/MMBtu)	4.3	5.3	5.3	5.3	5.3	5.4	5.3
Allowance Price ($/ton)	-	15	7	8	17	5	2
Total Generation (TWh)**	816	822	753	756	835	831	820
Coal	471	419	431	431	416	399	431
Existing CC Gas	30	32	19	22	35	37	16
New CC Gas	9	30	1	1	44	66	1
New Wind	18	55	17	18	55	42	89
Existing Nuclear	191	191	191	191	191	191	191
New Nuclear	0	0	0	0	0	0	0
Net Exports (TWh)	31	64	15	3	81	76	60
CO_2 Emissions Change-Nation from TPS	-	-	26	32	-17	-8	0
Econ Surplus Change from Baseline (B$)	-	(1.1)	(0.8)	(1.6)	(0.7)	(1.5)	(0.9)
Producer Surplus	-	0.7	0.6	1.0	1.8	0.4	0.4
Consumer Surplus***	-	(1.8)	(4.6)	(2.3)	(2.4)	(1.8)	(1.4)
Government Surplus****	-	(0.0)	3.2	(0.3)	(0.0)	(0.0)	0.2
Avg. Cost ($/ton CO_2 Reduced)	-	20	15	28	13	26	15

*CO_2 emissions vary slightly due to convergence in the model.
**Total includes sources not listed.
***Consumer surplus includes $2.1 billion in participant costs for energy efficiency paid by consumers that are assumed to be equal to program costs.
****The change in government surplus excludes costs associated with the federal production tax credit, which would be hidden to the states.

CC = combined cycle; LDC = local distribution company; OBA = output-based allocation; TPS = tradable performance standard

The production incentive is the least under the OBA-New NonEm scenario. When coal and gas do not receive a production incentive, they have less incentive to generate electricity, thereby reducing the scarcity of emissions allowances. Consequently, the allowance price falls, resulting in a smaller asset value for distribution to the eligible sources.

The change in economic surplus is measured as the sum of changes in producer and consumer surplus and government revenue.[23] We report the change from Baseline. The change in consumer surplus stems from changes in the electricity price, which includes the system benefits charge for programmatic expenditures on EE as well as other changes in equilibrium, and it includes the participant contribution to EE measures, which is assumed to equal the programmatic contribution ($2.1 billion). Although the costs of EE expenditures are recorded in the current year, the benefits accrue over several years into the future. Hence, the net costs appear greatest in the first year of implementation in CPP. By 2025, the consumer surplus associated with the program turns positive in all scenarios, reflecting the benefits of accumulated investments in EE (Appendix Table 1).

The greatest loss in consumer surplus occurs under the Government scenario because of the increase in electricity price, but this is offset by the relative gain in government surplus. Changes in government expenses due to the federal production tax credit for renewables affect the government surplus at the national level under all scenarios, but this cost is excluded in the accounting of government within the region because the cost is hidden from the states. The change in producer surplus from the Baseline is positive in each scenario, reflecting in part the increase in net exports in several scenarios compared with the Baseline. This change occurs entirely in Illinois, the only state in the upper Midwest with market-based electricity pricing. By design in the model, states with cost-of-service regulation will have zero producer surplus.

The electricity sector (consumers and producers) is best off when the value of emissions allowances stays in the sector, but the total change in economic surplus, including the change in government surplus in the region, is lowest when there is no consumption or production

[23] 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. Quantity changes account for the programmatic energy efficiency expenditures that are proportinal to consumption level across the scenarios. Government revenues include the federal renewable energy production and investment tax credits, as well as conventional taxes on retail electricity.

incentive, as under the Government scenario. This is consistent with many previous findings, even in a partial equilibrium model where there is no tax interaction effect (Burtraw et al. 2001; Böhringer and Lange 2005).

Finally, we report the average cost, measured as the change in economic surplus, per ton of CO_2 reduced in the region. These values range from $13 per ton under Government scenario to $26 per ton under OBA-ExCoal. As noted, a substantial portion of this cost is attributable to the program and participant shares of investment in EE, and the benefits of these investments are expected to accrue for years into the future. Under these assumptions, by 2025 the costs per ton in the upper Midwest are negative (Appendix Table 1).

4.2. Nation

We find that the CPP, if implemented through six regional tradable performance standards, would reduce electricity sector CO_2 emissions in the United States in 2020 by 491 million short tons, or 23 percent from the level forecast in the Baseline (Table 3). Under the other scenarios, emissions in the upper Midwest are held constant under an emissions cap but vary in other regions.

The introduction of cap-and-trade with auction revenues distributed to the government in the upper Midwest leads to a modest increase in emissions at the national level compared with TPS. Electricity exports from the upper Midwest fall by 49 TWh and consumption falls by nearly 20 TWh, cumulating to a decline of 69 TWh in generation (Table 2). This is offset by an increase of 49 TWh in generation, including an 8 TWh increase in generation from coal outside the region. Nationally, these changes in generation result in a 26 million-ton (2 percent) increase in CO_2 emissions, a 42,000-ton (4 percent) increase in emissions of SO_2, and a 31,000-ton (3 percent) increase in NO_x, which is associated with the greater generation from coal.

The leakage in electricity generation and increase in total emissions observed under the Government scenario is amplified under the cap-and-trade policy when revenues are directed to consumers through the local distribution company in the LDC scenario. In this case, the allocation reduces electricity prices and encourages consumption in the region. Net exports from the upper Midwest fall to their lowest level. Nationally, CO_2 emissions increase by 34 million tons (2 percent), SO_2 emissions increase by 23,000 tons (2 percent), and NO_x emissions increase by 27,000 tons (3 percent) compared with the TPS. The CO_2 emissions change is the result of increased generation outside the upper Midwest. However, virtually all of the increase in SO_2 and most of the increase in NO_x occur within the upper Midwest.

Table 3. National Results for 2020

	Baseline	*TPS (OBA-All Covered)*	*Government*	*LDC*	*OBA-All*	*OBA-ExCoal*	*OBA-New NonEm*
Emissions							
CO_2 (million short tons)	2,134	1,643	1,669	1,675	1,626	1,635	1,643
SO_2 (thousand short tons)	1,854	1,180	1,222	1,203	1,181	1,131	1,200
NO_x (thousand short tons)	1,749	1,190	1,221	1,217	1,174	1,194	1,197
Electricity Price ($/MWh)	96	100	101	100	102	100	100
Natural Gas Price ($/MMBtu)	4.3	5.4	5.4	5.4	5.4	5.5	5.3
Total Generation (TWh)*	4,067	3,915	3,895	3,913	3,899	3,913	3,920
Coal	1,554	1,025	1,045	1,052	1,009	1,005	1,024
Existing CC Gas	543	613	617	609	619	616	595
New CC Gas	415	612	605	615	616	634	624
New Wind	81	195	157	167	192	188	209
Existing Nuclear	833	836	836	837	834	836	837
New Nuclear	44	44	44	44	44	44	44
Econ Surplus Change from Baseline (B$)	-	(21.3)	(19.3)	(20.5)	(20.4)	(22.1)	(21.8)
Producer Surplus	-	(0.8)	(1.4)	(1.7)	5.8	(1.7)	(2.1)
Consumer Surplus**	-	(14.4)	(16.6)	(13.8)	(19.9)	(14.6)	(13.2)
Government Surplus***	-	(6.1)	(1.3)	(5.1)	(6.3)	(5.9)	(6.6)
Avg. Cost ($/ton CO_2 Reduced)	-	43	41	45	40	44	44

*Total includes sources not listed.
**Consumer surplus includes $11.2 billion in participant costs for energy efficiency paid by consumers that are assumed to be equal to program costs.
***Includes costs associated with the renewable production tax credit.

CC = combined cycle; LDC = local distribution company; OBA = output-based allocation; TPS = tradable performance standard

The change in national emissions is reversed under targeted output-based allocation. Allocation on an equal basis per MWh of production to all sources (OBA-All) yields the lowest emissions outcome across the scenarios, 15 million tons (1 percent) less than under TPS. Emissions fall by 8 million tons when the production incentive is removed from existing coal (OBA-ExCoal), and they are virtually equivalent when the production incentive is directed only to new nonemitting units (OBA-New NonEm). However, there are more significant differences in the other pollutants. Emissions of SO_2 rise slightly under OBA-All compared with TPS, but they fall by 49,000 tons (4 percent) to their lowest level when coal is excluded from the production incentive (OBA-ExCoal). In contrast, they increase compared with TPS when the production incentive is directed only to new nonemitting sources (OBA-New NonEm), reflecting the recovery of coal to the detriment of gas-fired generation when the latter is excluded from receiving the production incentive.

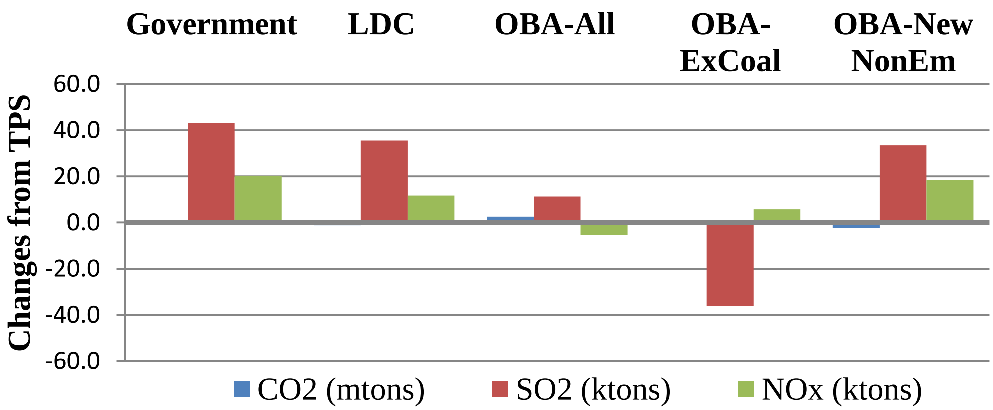
Comparison of economic surplus at the national level across scenarios is ambiguous because emissions outcomes are not equal. However, one factor that is noteworthy at the national level is the change in the natural gas price, which reflects changes in the use of gas for electricity generation. The change in the gas price signals changes in economic costs accruing outside the electricity sector but not reported explicitly in our results.

The average change in economic surplus per ton of CO_2 reduced is least ($39) under OBA-All and greatest ($44) under three other scenarios. By 2025, after the benefits of investments in EE begin to accrue, the costs fall to $4 per ton under the Government scenario and range up to $10 per ton under OBA-ExCoal (Appendix Table 2).

4.3. Summary

In the upper Midwest, CO_2 emissions are held stable across the scenarios but there are changes in emissions of SO_2 and NO_x. Figure 4 illustrates that compared with the TPS scenario, these emissions increase under all the scenarios except OBA-ExCoal, which gives a production incentive to covered sources excluding coal. In this and subsequent figures in this section, lower values would generally be considered desirable. The change in emissions will be an important consideration for states because of other obligations to achieve National Ambient Air Quality Standards, and because a substantial portion of benefits is associated with reducing these emissions.

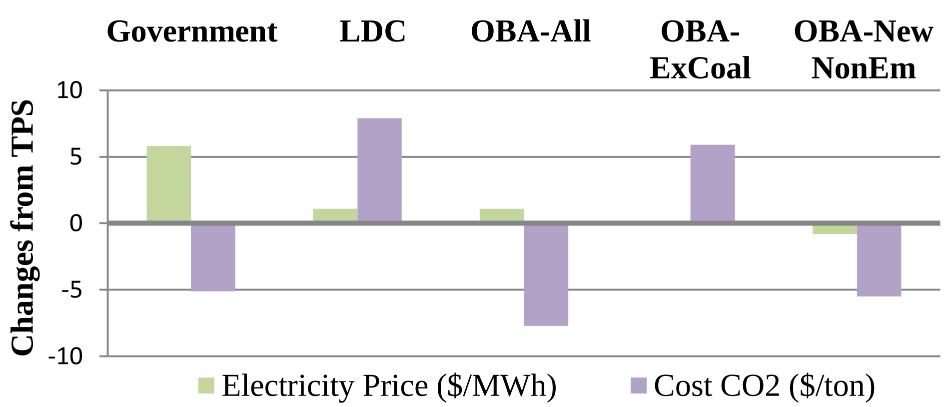
Figure 4. Emissions Changes from TPS in Upper Midwest



OBA = output-based allocation; TPS = tradable performance standard

Figure 5 illustrates that electricity prices vary little, except in the case of the Government scenario, when they are highest. However, the average cost per ton incurred within the region is among the lowest under the Government scenario.

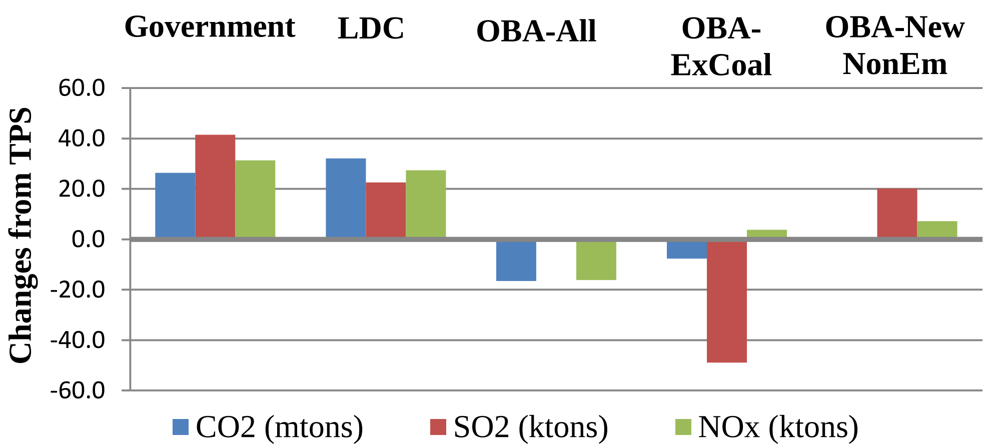
Figure 5. Price and Cost Changes from TPS in Upper Midwest



OBA = output-based allocation; TPS = tradable performance standard

In the upper Midwest, the OBA-All scenario stands out as one that has nearly the lowest average cost per ton of CO_2 reduced (negative generation leakage) and only slightly more SO_2 emissions than TPS. Compared with the TPS scenario, OBA-All erodes the potency of the production incentive by directing some of it to existing sources that have little opportunity to change their behavior. In cost-of-service states, this value would be captured by consumers because it would contribute to total revenues and reduce the electricity price. However, in the upper Midwest, nearly half of the existing nuclear and hydro capacity that benefits under this scenario is in Illinois, which is a competitive state, where this incentive would represent a transfer to producers and a windfall profit. From the welfare perspective of the partial equilibrium model, the value of this lump-sum transfer to producers yields the same outcome as if these funds were directed as a lump-sum payment to consumers. Meanwhile, the production incentive for coal generation is reduced, leading to relatively low emissions of SO_2 and NO_x.

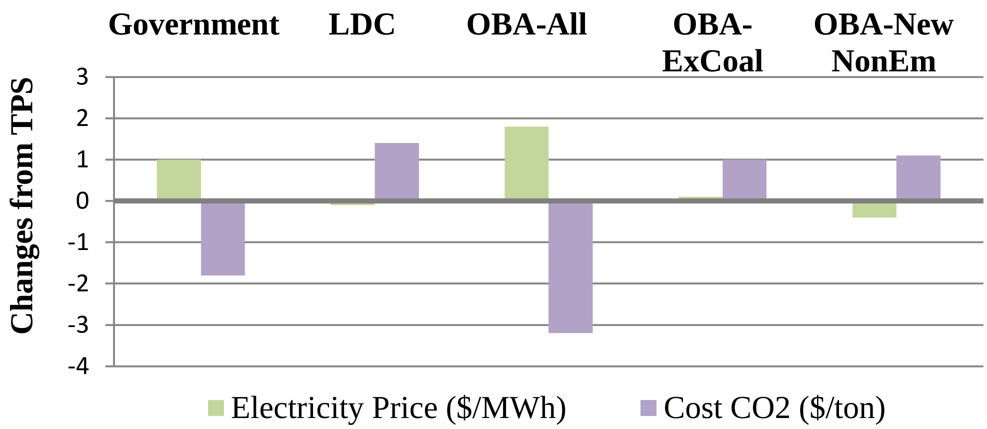
Figure 6. Emissions Changes from TPS for Nation



OBA = output-based allocation; TPS = tradable performance standard

Figure 6 illustrates that at the national level, CO_2 emissions increase under the Government and LDC scenarios compared with TPS, but they decrease or are nearly unchanged under the three targeted allocation scenarios, indicating negative leakage. Emissions of other pollutants increase in three of the scenarios relative to TPS, but they are reduced when the production incentive is directed to all generation and when coal is excluded from receiving the production incentive. Figure 7 illustrates that the change in the national average electricity price is virtually zero across all the scenarios except Government and OBA-All. The average cost per ton reduced is similar at the national level across the scenarios, but the lowest values are observed under the Government and OBA-All scenarios.

Figure 7. Price and Cost Changes from TPS for Nation



OBA = output-based allocation; TPS = tradable performance standard

5. Conclusion

The landscape for international climate policy has moved away from a coordinated effort to one in which nations are encouraged to make nationally determined, independent contributions. This change is reflected in the United States, where climate policy has emerged under the Clean Air Act in the form of the Clean Power Plan, which gives states primary responsibility for planning, implementation, and enforcement. Compared with the international setting, the situation in the US power sector has the advantage that a performance goal for each state is identified at a higher level of government. However, that goal is an intensity standard covering a crafted set of generation resources, including energy efficiency, each of which has effects on the power system across state lines. State decisions may have a substantial effect on the aggregate costs and emissions outcomes that are achieved.

The default policy for states is an emissions rate standard, but states are given the latitude to convert to an emissions mass-based (emissions budget) approach that would directly facilitate cap and trade. Unintended outcomes are possible, including strategic behavior by some states to capture market share through the design of their state policies. The potential interaction among states with rate-based intensity standards and those with mass-based emissions caps could result in economic and emissions leakage and increase overall emissions and degradation of air quality compared with national uniform implementation of either the intensity standard or cap and trade. Unfortunately, stronger federal direction about program implementation by states appears to be difficult politically and legally, just as such direction from above is difficult at the international level. The coordination problem among US states is substantial.

We use a detailed model of the US electricity system to show that states can design their cap-and-trade policies to avoid leakage, or even to achieve negative leakage, through the allocation of emissions allowances. A tradable emissions rate standard provides a production incentive at the emissions rate standard. Updating output-based allocation can mimic this production incentive by allocating allowances according to the same formula and thereby evade the potential negative interaction of some states' emissions rate standards with other states' cap-and-trade policies. From that starting point, we show that targeting allocation to provide a production incentive to selected technologies can result in negative leakage and a reduction in total emissions. This option allows states to consider policies that can capture the administrative advantages of cap and trade without undermining the overall policy objective. The lessons in the United States may reflect back on the international stage, where leakage and policy interactions have been prominent in the policy dialogue.

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Appendix Table 1. Upper Midwest Results for 2025

	Baseline	*TPS (OBA-All Covered)*	*Government*	*LDC*	*OBA-All*	*OBA-ExCoal*	*OBA- New NonEm*
Emissions							
CO_2 (million short tons)	564	449	449	449	451	449	450
SO_2 (thousand short tons)	820	533	592	588	553	479	578
NO_x (thousand short tons)	561	395	419	418	397	431	419
Electricity Price ($/MWh)	92	95	101	93	96	94	96
Natural Gas Price ($/MMBtu)	4.6	5.6	5.5	6	6	5.7	5
Allowance Price/Tax ($/ton)	-	28	12	13	29	11	7
Total Generation (TWh)*	842	809	721	723	822	837	803
Coal	491	384	407	406	379	349	408
Existing CC Gas	29	36	14	17	53	58	11
New CC Gas	11	51	0	1	51	100	0
New Wind	18	55	17	18	55	42	91
Existing Nuclear	192	192	192	192	192	192	192
New Nuclear	0	0	0	0	0	0	10
Net Exports (TWh)	39	77	19	(11)	99	106	74
CO_2 Emissions Change-Nation from TPS	-	-	27	40	-18	-17	6
Econ Surplus Change from Baseline (B$)	-	0.8	3.8	1.7	1.8	0.5	(0.1)
Producer Surplus	-	(0.8)	(0.8)	(0.5)	0.9	(1.9)	(1.3)
Consumer Surplus**	-	1.8	(0.3)	2.6	1.1	2.5	1.0
Government Surplus***	-	(0.1)	4.9	(0.4)	(0.2)	(0.1)	0.1
Avg. Cost ($/ton CO_2 Reduced)	-	(7)	(33)	(15)	(16)	(4)	1

*Total includes sources not listed.
**Consumer surplus includes participant costs for energy efficiency paid by consumers that are assumed to be equal to program costs.
*** The change in government surplus excludes costs associated with the federal production tax credit, which would be hidden to the states.

CC = combined cycle; LDC = local distribution company; OBA = output-based allocation; TPS = tradable performance standard

Appendix Table 2. National Results for 2025

	Baseline	*TPS (OBA-All Covered)*	*Government*	*LDC*	*OBA-All*	*OBA-ExCoal*	*OBA- New NonEm*
Emissions (M short tons)							
CO_2 (million short tons)	2,243	1,550	1,577	1,590	1,532	1,533	1,556
SO_2 (thousand short tons)	2,026	1,040	1,097	1,103	1,071	988	1,071
NO_x (thousand short tons)	1,874	1,069	1,094	1,102	1,060	1,106	1,082
Electricity Price ($/MWh)	97	100	101	100	101	100	100
Natural Gas Price ($/MMBtu)	4.8	5.8	5.7	6	6	6	6
Total Generation (TWh)*	4,227	3,899	3,866	3,897	3,879	3,896	3,904
Coal	1,644	945	967	976	927	914	955
Existing CC Gas	452	559	556	552	577	561	541
New CC Gas	551	701	698	711	682	723	688
New Wind	81	195	157	167	192	189	211
Existing Nuclear	853	855	856	855	855	856	856
New Nuclear	45	63	51	55	65	69	73
Econ Surplus Change from Baseline (B$)	-	(5.9)	(2.5)	(5.3)	(3.7)	(7.0)	(5.3)
Producer Surplus	-	(12.6)	(12.0)	(11.9)	(5.9)	(13.4)	(12.5)
Consumer Surplus**	-	8.8	6.4	8.7	4.8	8.5	9.0
Government Surplus	-	(2.1)	3.1	(2.1)	(2.6)	(2.1)	(1.9)
Avg. Cost ($/ton CO_2 Reduced)	-	8	4	8	5	10	8

*Total includes sources not listed.
**Consumer surplus includes participant costs for energy efficiency paid by consumers that are assumed to be equal to program costs.
***Includes costs associated with the renewable production tax credit.

CC = combined cycle; LDC = local distribution company; OBA = output-based allocation; TPS = tradable performance standard