DISCUSSION PAPER

June 2005 ■ RFF DP 05-25

Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program

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RESOURCES FOR THE FUTURE

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Summary

Cap-and-trade programs for air emissions have become the widely accepted, preferred approach to cost-effective pollution reduction. One of the important design questions in a trading program is how to initially distribute the emissions allowances. Under the Acid Rain program created by Title IV of the Clean Air Act, most emissions allowances were distributed to current emitters on the basis of a historic measure of electricity generation in an approach known as grandfathering. Recent proposals have suggested two alternative approaches: allocation according to a formula that is updated over time according to some performance metric in a recent year (the share of electricity generation or something else) and auctioning allowances to the highest bidders.

Prior research has shown that the manner in which allowances for carbon dioxide (CO_2) are initially distributed can have substantial effects on the social cost of the policy as well as on who wins and who loses as a result of the policy. Another concern with a regional cap-and-trade program like the Regional Greenhouse Gas Initiative (RGGI) is the effect that different approaches to allocating emissions allowances will have on the level of CO_2 emissions outside the region, commonly called emissions leakage.

In this research we model historic, auction, and updating approaches to allowance allocation that we call bookends, then model various variations on these approaches. We consider changes in measures such as electricity price, the mix of generation technologies, and the emissions of conventional pollutants inside and outside the RGGI region. We examine the social cost of the program, measured as the change in economic surplus, which is the type of measure used in benefit–cost analysis. We also examine the effects of different approaches to distributing allowances on the net present value of generation assets inside and outside the RGGI region.

We find that how allowances are allocated has an effect on electricity price, consumption, and the mix of technologies used to generate electricity. Electricity price increases the most with a historic or auction approach. Coal-fired generation in the RGGI region decreases under all approaches but decreases the most under updating. Gas-fired generation decreases under historic and auction approaches but increases substantially under updating. Renewable generation increases under historic and auction approaches but decreases slightly under updating as a consequence of the expanded generation from gas. Consistent with the changes in the composition of generation, the decline in emissions of conventional pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury that was expected as a result of the Clean Air Interstate Rule is accelerated substantially as a result of the RGGI policy, particularly under updating. The cost of complying with SO_2, NO_x, and mercury rules declines similarly.

We find that the social costs of the bookend auction and historic approaches are comparable and that the social cost of updating is roughly three times that of the other approaches. At the same time, updating yields greater emissions reductions on a national basis (because it produces less emissions leakage) and greater cumulative reductions in emissions at the national level than historic allocation. Varying the design of the updating approach can reduce its

social costs but generally would increase leakage at the same time. An updating approach with allocation to all generators, including all nuclear and renewables has the lowest social cost within the RGGI region of any policy analyzed, although this result comes at the expense of costs imposed outside the region.

When the approaches to allocation are mixed, we find the changes in electricity price, generation, and emissions are roughly a combination of the performance of each individual approach. In particular, social costs typically are lower under the scenarios that combine an auction with updating than when updating is the exclusive approach to distributing allowances.

Who wins and who loses from the policy varies with the approach to allocation. Under a historic approach, producers in the RGGI region gain substantially and generally are better off than without the program; such is not true under an auction or updating. Producers also gain overall from the policy when a historic allocation is combined with an auction, but the gains are substantially less than in the 100% historic case. Producers outside the region tend to benefit considerably from the higher electricity price in the RGGI region but benefit the least under updating because the effect on electricity price is lowest.

Consumers both inside and outside the RGGI region are adversely affected under all allocation approaches but much less so under updating because the change in electricity price is lowest. One exception is when eligibility for allowances under an updating allocation is limited to nonemitters only, in which case the electricity price increases substantially.

Different types of generators fare differently under the various allocation approaches. Asset values for all types of generators are highest under a historic approach, although the difference between historic and auction approaches is small for nuclear generators. Compared with the baseline, both nuclear and existing gas-fired generators in the RGGI region gain under an auction. Only gas-fired generators gain under the bookend approach to updating, although nuclear generators benefit as well under updating designs that include them among those eligible for allowances. Coal-fired generators lose the most under updating.

Moving from 100% updating to auctioning an increasingly larger share of allowances generally has a positive effect on asset values for all fuel types including coal. The one exception is that moving from 50% auction and 50% updating to 100% auction has a negative effect on the asset values for coal.

Finally, we conduct sensitivity analyses with higher natural gas prices and constraints on electricity transmission capability. The social cost of the RGGI program does not appear to be sensitive to these constraints. Higher gas prices or transmission constraints alone impose significant costs that are larger than the effect of adding the RGGI policy. For example, their substantial effect on electricity price is greater than the added effect imposed by the RGGI program. The constraints that are modeled do not appear to have a strong impact on RGGI implementation. We also conduct a sensitivity analysis with renewables portfolio standard policies in place throughout the region. The resulting prices of electricity and CO_2 emissions allowances are slightly lower than without the renewables policy.

Key Words: emissions trading, allowance allocations, electricity, air pollution, auction, grandfathering, generation performance standard, output-based allocation, cost-effectiveness, greenhouse gases, climate change, global warming, carbon dioxide, sulfur dioxide, nitrogen oxides, mercury

JEL Classification Numbers: Q2; Q25; Q4; L94

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1. Introduction

The Regional Greenhouse Gas Initiative (RGGI) is an effort by nine Northeast and Mid-Atlantic states to develop a regional, mandatory market-based cap-and-trade program to reduce greenhouse gas (GHG) emissions. The effort was initiated formally in April 2003 when Gov. George Pataki of New York sent letters to governors of the Northeast and Mid-Atlantic states. Each of the nine participating states (Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) has assigned staff to a working group that is charged with developing a proposal in the form of a model rule by 2005. Initially, the program will address carbon dioxide (CO_2) emissions from the electric power sector. If successful, the program could serve as a model for a national cap-and-trade program for GHG emissions.

One of the most important and contentious features of an emissions trading program is how emissions allowances are initially distributed. Several distribution approaches have been considered in other regulatory contexts. One such approach is to distribute allowances on the basis of **historic** measures of electricity generation; this approach is often called *grandfathering* because it distributes allowances without charge to incumbents in the industry. Another approach is to regularly **update** the calculation underlying the allowance distribution based on current- or recent-year data. Like distribution based on historic data, an updating approach distributes allowances free of charge and also could distribute according to various measures, such as the share of electricity generation, emissions, or heat input (related to fuel use) at a facility. The primary alternative to these free distribution approaches is the sale of allowances through an

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auction, directly or indirectly (e.g., allowances may be distributed for free to third parties such as energy consumers or their trustees, which then sell allowances through an auction). A key feature distinguishing types of auction approaches is the dispensation of revenues raised under the auction. Revenues could be returned to industry or consumers, used to compensate communities, invested in energy conservation, or used to offset other needs for tax revenue by government.

Each of these approaches has proponents, and each has a precedent. The most well known emissions cap-and-trade program—the sulfur dioxide (SO_2) emissions trading program initiated under the 1990 Clean Air Act Amendments—distributes allowances primarily on the basis of a historic measure of generation (heat input) at electricity-generating facilities. The second-largest U.S. emissions trading program is the nitrogen oxides (NO_x) regional cap-and-trade program in 19 eastern states. Under this program, distribution is determined at the state level. Most states use some historic measure as a basis for distribution, but states also use updating for some portion of the allowances. Updating is also evident in one form in Sweden, where beginning in 1992 the revenues from a tax on NO_x emissions were recycled to industry on the basis of each emitter's share of electricity generation.[1] Auctioning has a precedent in the state of Virginia, which distributed a small portion of its NO_x allowances in the regional cap-and-trade program through a revenue-raising auction. Recent legislative proposals for the regulation of multiple pollutants from the electricity sector also have involved all three of these basic approaches to various degrees.

There is little evidence comparing the experience with different approaches to initial allowance distribution, but several theoretical and policy studies have examined efficiency and distributional issues. These studies have examined various pollutants, and their findings differ somewhat depending on which pollutant is modeled. Moreover, an important distinction is that the RGGI policy is aimed specifically at a nine-state region of the country. The RGGI region has its own mix of technologies for electricity generation that have a direct bearing on the evaluation of the approaches to distributing allowances. The region is characterized by competition in retail electricity markets, setting it apart from the nation as a whole, which has a mix of regulation. Also, open state borders and the electricity transmission grid pose challenges to policy enforcement. Any environmental policy that increases costs in the region is likely to cause some emissions leakage to outside the region as economic activity or electricity generation moves to

[1] Hoglund (2000); Sterner and Hoglund (2000).

avoid regulation. It is noteworthy that the Northeast faces higher natural gas and electricity prices than other parts of the nation.

Two major types of issues affect the choice of a mechanism for distributing allowances in the RGGI region. **Distributional issues** affect consumers vis-à-vis producers through electricity price changes and affect various producers in different ways through changes in the valuation of generation assets. **Economic efficiency issues**—the cost-effectiveness of the program within the electricity sector—affect everyone. We do not consider secondary costs imposed outside the electricity sector due to changes in electricity price or fuel prices.

1.1. Project Goals

The questions that we sought to address in this research are the implications of different approaches to the initial distribution of CO_2 allowances.

- What are the effects on the costs of the program? We note that cost—and other indicators of efficiency—can be measured in various ways.
- What are the distributional consequences? Attention can be focused on distribution between consumers and producers or among producers that have a diverse set of interests with various portfolios of generation technologies.
- How effective are allocation methodologies that favor certain technologies (including energy conservation technologies) on the consumer side of the meter, and what are the trade-offs?
- Would combinations of auctioning (or "grandfathering to consumers," a form of auctioning) and no-cost allocation compensate companies but still provide for an efficient outcome?

In the course of the research, additional questions surfaced that also are discussed below.

1.2. Summary of Findings

In brief, we find that

- The CO_2 allowances created by the program have a value that is at least four times as large as the social cost of mitigation, suggesting that allowance distribution is a potentially important source of compensation.
- Because of electricity deregulation in the Northeast, allowance value is reflected in electricity price to an equal degree for auction and historic approaches to distribution.
- The social costs of auction and historic approaches are similar. However, producers gain substantially under a historic approach, and in the aggregate, they are better off than without the program.
- Updating yields a higher allowance price, a lower electricity price, and more electricity generation in the RGGI region than the other approaches.
- The social cost of an updating approach is about three times greater than that of an auction or a historic approach.
- The effect on producers is measured by the change in the market value of generation assets. Under the historic approach, the market value of all types of generation assets gain substantially, and in the aggregate, the industry gains substantially.
- Under an auction, the market value of coal assets falls substantially, but in the aggregate, the industry is not affected dramatically.
- The market value of coal assets—and of all assets in the aggregate—fall by the greatest margin under an updating approach.
- Coal-fired generation falls under all approaches but falls the most under updating.
- Gas-fired generation falls under historic and auction approaches but increases substantially under updating.
- Leakage of CO_2 emissions to outside the RGGI region is greatest under historic and auction approaches and lowest under updating.
- Emissions of conventional pollutants in the RGGI region fall substantially under all approaches to allocation but fall the most under updating.

- The cost of complying with SO_2, NO_x, and mercury rules falls considerably within the RGGI region because of efforts to reduce CO_2 emissions.
- Varying the approach to updating (including who is eligible to receive allowances) can yield very different results. One approach, updating allocation to all generators, has the lowest social cost within the RGGI region of any policy analyzed. However, the benefit comes at the expense of costs imposed outside the region.
- Combined approaches generally lead to intermediate outcomes.
- In the aggregate, variations in baseline assumptions such as higher natural gas prices or transmission capability constraints tend to benefit producers in the absence of the RGGI policy. These constraints have a substantial effect on electricity price that is greater than the added effect imposed by the RGGI program.
- The cost of the RGGI program does not appear to be sensitive to the price of natural gas or the existence of constraints on electricity transmission capability.
- The existence of a renewable portfolio standards (RPS) policy causes the CO_2 allowance price to fall slightly. Coal generation remains at a level that is greater than in the absence of the RPS, and gas generation falls to a lower level.

1.3. Conceptual Background

Allowance distribution is one of the most contentious issues policymakers face when designing a cap-and-trade program. Allowances are a valuable asset, and their distribution has implications for both equity and efficiency. Many economists and other analysts advocate auctioning allowances rather than distributing them at no cost. The benefits of auctioning include providing a source of revenue that could potentially address inequities brought about by a carbon policy (e.g., by compensating consumers for high prices or communities that are severely affected) or be used to make investments in energy conservation. Alternatively, the revenues from auctioning allowances may have economy-wide efficiency benefits if they are used to reduce taxes.

In contrast, companies participating in a cap-and-trade program usually oppose auctions. They argue that because they already bear the costs of emissions reduction obligations, they should not also have to purchase the emissions allowances up front. The net cost to producers of the emissions trading program depends on the difference between the change in producer revenue and the change in cost. Regardless of how allowances are distributed, firms are expected to pass along some of the resource cost associated with reducing emissions and some of the opportunity cost (market value) of emissions allowances in product prices, thereby causing revenues to increase. The justification for the free distribution of emissions allowances is to reduce the change in costs for industry and thereby provide compensation. An auction does not provide this form of compensation because it makes firms pay for allowances.

The degree to which producers pass on (in electricity prices) the resource and allowance costs varies with the presence or absence of price regulation and with the technology that sets marginal cost in competitive regions. In the case of nationwide CO_2 regulation, Burtraw et al. (2002) find that the free allocation of emissions allowances can dramatically overcompensate the electricity industry in the aggregate, although different parts of the industry are affected very differently. In the case of SO_2, Bovenberg et al. (2003) also find that free allocation as envisioned under the Bush administration proposal for SO_2 control would overcompensate industry. A central issue for RGGI planners is whether the free allocation of CO_2 emissions allowances in the Northeast provides a level of compensation that is proximate to or potentially surpasses (perhaps by a significant degree) compliance costs.

Recent research also has shown that the initial distribution of allowances can affect the economic cost of the policy as well as who wins and loses. Two separate bodies of literature have developed with regard to the economic costs or general efficiency issues related to trading programs for emissions permits. One explores the role of preexisting distortions away from economic efficiency in labor and capital (factor) markets due to the presence of taxes on labor or capital income (Bovenberg and de Mooij 1994, Parry 1995) and relies primarily on computable general equilibrium simulation models to estimate the potential efficiency consequences of different approaches to allocation (Bovenberg and Goulder 1996, Goulder et al. 1997, Goulder et al. 1999, Parry et al. 1999, Smith et al. 2002). Cap-and-trade programs for CO_2, SO_2, and NO_x have been analyzed in competitive product markets (electricity regulation is not considered explicitly), and results favor an auction as the most efficient approach to the initial distribution of emissions allowances when the revenues are used to reduce preexisting taxes. We do not consider these issues in this paper.

The second body of literature, to which this paper contributes, examines the role of preexisting distortions away from economic efficiency in product markets (such as electricity) due to the difference between price and marginal cost, a condition that is common throughout the economy and endemic in the electricity sector. In the case of CO_2, an auction approach to distributing emissions allowances results in a substantially lower social costs than an updating approach based on output or a historic approach (Burtraw et al. 2001, 2002; Beamon et al. 2001). This result is largely attributable to the fact that electricity prices are set by cost-of-service regulation in much of the country, and these prices differ from marginal cost. In regulated regions, the opportunity cost of an emissions allowance given to a firm for free under an updating or a historic approach is not directly reflected in the electricity price (i.e., it is valued at an original cost of zero). However, the cost of an auctioned allowance is reflected in regulated electricity prices, and this cost can widen or narrow the gap between regulated prices and efficient prices. Typically, though, it tends to narrow the gap between price and marginal cost and improves economic efficiency.

In the RGGI region, however, electricity markets are deregulated, and retail prices are based on marginal costs rather than regulated average cost of service. In this case, the previous literature suggests there is little difference between auction and historic approaches to distributing allowances from an efficiency perspective. In one case, the revenues go to government; in the other, they go to industry. However, because investment and compliance behavior are expected to be nearly identical, so is the change in electricity price. In competitive electricity markets, an updating approach is expected to have greater social costs than an auction or a historic approach because it does not provide the same incentive through higher prices for consumers to improve the energy efficiency of energy use.

In addition to distributional and efficiency effects, a third measure that also may distinguish approaches to allocation is the creation of incentives for the introduction of new or cleaner technology (Energy and Environmental Analysis, Inc. 2003). An updating approach provides generators with an incentive to increase generation by all sources because of the implicit output subsidy, whereas dirty sources are penalized in terms of variable costs due to the cost of allowances. In the case of CO_2, Burtraw et al. (2002) find updating leads to substantially more generation with natural gas and less with coal.

Another issue of central interest to the RGGI is the leakage of electricity generation, CO_2 emissions, and economic activity to outside the RGGI region. For instance, leakage could result if electricity generators decide to use power plants outside the region to generate more electricity to be imported into the region over the transmission grid. Leakage could also occur if electricity customers decide to self-generate rather than purchase electricity off the grid in response to increased electricity price. Previous analysis suggests that the method of distributing emissions allowances can have an effect on the degree of leakage and ultimately on the cost-effectiveness of the emissions trading program.

2. Research Strategy

We use a model that has a high level of detail about technology and institutions to calculate investment and dispatch of generation capacity in the electricity sector. The model projects changes in the economic behavior of consumers and producers in response to the climate policy and other changes that result from those behavioral responses.

Point estimates of changes in key variables such as electricity price, electricity consumption, and producer profits are reported, but the main focus of this exercise is the changes that are predicted to result from baseline in response to variations in the policy design. The RGGI staff working group is planning a detailed modeling exercise using the Integrated Planning Model (IPM) at a greater level of detail and with greater precision regarding assumptions about the future of the electricity industry in the region and the design of the CO_2 policy and other regional policies. Our model simulations are expected to produce results very close to those of the more comprehensive effort, as they are conducted with the same general assumptions. We do not adopt the precise assumptions of the RGGI modeling group, partly because of the expense involved and also because we aim to characterize the landscape of qualitative considerations with more model runs than we could afford otherwise. For example, two key differences include our lack of modeling of rules governing transmission that could mitigate leakage and our lack of modeling of recent renewable policies in the Northeast. Our simulation model provides a laboratory for examining a wide range of options as well as the variations among these options while preserving the important quantitative and qualitative differences of the different options, which can then be validated in IPM.

We solve the model for a baseline scenario (described below) through 2025. Then, in policy scenarios, we introduce the RGGI and vary the approach to the initial distribution of emissions allowances. Results are reported first for three distinct approaches that represent "bookends" for the type and mix of approaches that have been widely discussed. The analysis of bookend policies provides a useful pedagogy for understanding the trade-offs among approaches. Subsequently, we investigate several variations on the bookend approaches, mixed approaches, and changes in the baseline parameters.

The level of aggregation in the model has both strengths and limitations. It is appropriate for estimating costs from a social and regional perspective and for understanding the distribution of costs between consumers and producers. The model also captures differentiation among fuels and technologies and the effects of policies on the market value of existing and new generation assets. The effect on existing assets can be aggregated to represent the portfolio owned by firms and thereby to provide a good measure of how shareholders are affected. However, the model does not capture some short-run idiosyncrasies that affect individual plants such as take-or-pay fuel contracts. Intra-regional transmission bottlenecks that may cause a spread between the regional high and low electricity prices are not reflected in the model. However, to the extent such constraints are observed, they are represented—albeit somewhat imprecisely—through out-of-merit-order dispatch and must-run constraints, which are captured with a shadow price component of variable costs that is calibrated to approximate actual operation in recent years.

The model also does not capture the effects of long-term contracts for electricity generation from nuclear plants and some fossil fuel–fired units. In several RGGI states, when nuclear and other plants were divested by the local integrated utility, the distribution utility signed long-term contracts for much of the generation from those facilities. These contracts limit the ability of certain generating units to profit from increases in the short-term market price of electricity resulting from a RGGI policy. However, in a post-transition competitive market, the contracts do not limit the electricity retailer's ability to charge a price based on the marginal cost of electricity sold in shorter-term markets, because the retailer that has purchased power under a long-term contract with a generator could turn around and sell that power in the spot market, where the RGGI policy could be raising costs of the marginal generator. Therefore, the spot market price defines the opportunity cost of selling power to retail customers, and electricity retailers (not explicitly represented in our model) will profit from the RGGI policy at the expense of those generators that have their power committed for sale under long-term contracts. Thus, in a competitive market, the existence of long-term contracts for wholesale power will affect which producers and retail suppliers profit from the RGGI policy but will not affect consumer costs.[2]

Finally, this study does not investigate the issue of leakage in detail. We find evidence that the approach to the initial distribution of emissions allowances affects leakage, but we do not offer a systematic analysis. Also, we do not compare the impact of allocation methods with other factors, such as the level of the cap. We do explore alternative natural gas prices in a sensitivity analysis.

2.1. Modeling Scenarios

The model is solved for a baseline, and policy scenarios are analyzed relative to measures in the baseline. We describe the central case baseline first. Later, we vary baseline assumptions about natural gas prices and transmission capability in a sensitivity analysis.

[2] Electricity retailers will be constrained from passing on wholesale market price increases resulting from the RGGI policy during the transition period if retail prices are effectively capped or if prices are set based on the weighted average of prices for different term contracts for power, as is done for default power in several RGGI states. Our analysis is about the longer-term effects of RGGI on electricity prices and not effects during the transition period.

2.1.1. Central Case Baseline

Throughout this analysis, we make several assumptions about underlying policies—federal and state environmental policies as well as market regulatory policies—that affect the performance of electricity generators. In the baseline case, we assume electricity generators face requirements under the Nitrogen Oxides (NO_x) State Implementation Plan (SIP) Call; Title IV of the 1990 Clean Air Act Amendments; and the Bush administration's draft Clean Air Interstate Rule (CAIR) for SO_2, NO_x, and associated mercury. The seasonal NO_x SIP Call for 19 eastern states is in force for the 2008 simulation and replaced by the annual NO_x constraint for a 28-state region under CAIR for the other simulation years.[3] The annual emissions constraints for SO_2 are drawn from the U.S. Environmental Protection Agency's (EPA's) modeled solution for how the regional CAIR rule would interact with the national Title IV regulation. Regional annual SO_2 allowance distributions are capped at 3.9 million tons beginning in 2010 and 2.7 million tons beginning in 2015. Actual emissions will be higher over the modeling time horizon because of the allowance bank. We follow EPA modeling of the SO_2 CAIR and Title IV within one national trading regime. A single national region is characterized using model results that account for the opportunity to use Title IV allowances within the CAIR region at an offset ratio that changes over time.[4] The actual emissions caps that we model are reported in Table 1.

Under CAIR, regional annual NO_x emissions distributions are capped at 1.6 million tons beginning in 2010 and 1.3 million tons beginning in 2015. In the model, the NO_x caps include an adjustment of about 331,000 tons for units outside the CAIR NO_x region but within the Mid-Continent Area Power Pool (MAPP) and New England electricity regions.

The national annual allocation of mercury emissions allowances is to be capped at 34 tons beginning in 2010 and 15 tons beginning in 2018. We model a cap-and-trade program for mercury. We adopt as our mercury emissions cap EPA's prediction of annual emissions in the presence of a $35,000/pound ceiling on the price of mercury permits and the ability to bank allowances. Under the cap-and-trade programs for the three conventional pollutants, emissions allowances are distributed on a historic basis.

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[3] The 28 states are Alabama, Arkansas, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

[4] Docket OAR-2002-0056-0338.

We include all announced new source review (NSR) settlements in our technical assumptions about emissions control at existing generators.[5] We also include a representation of two federal policies to promote renewables. We assume that the renewable energy production credit (for dedicated biomass and wind generation) is extended. Additionally, we incorporate a perpetual 10% investment tax credit for new geothermal resources.

We also include several state-level environmental and renewables policies. To capture the anticipated effects of compliance with state-level RPS and other state-level renewables policies and programs (including green pricing on investment in new renewables), we incorporate the U.S. Energy Information Administration's (EIA's) estimates of several new renewable resource investments to be put into place to comply with these policies. In the Northeast, we include policies in Connecticut, Massachusetts, and New Jersey.[6] However, we do not include policies in Maine, New York, Rhode Island, Maryland, or Pennsylvania in our central baseline case or policy cases. We expect that in the baseline scenario (e.g., in the absence of the RGGI policy) these policies could reduce emissions, CO_2 allowance price, investment in gas-fired generation, incremental compliance cost, and leakage. We conduct a sensitivity analysis of the baseline and historic bookend cases to identify the effects of including the RPS policies in one of the RGGI policy cases. The emissions reductions in our model could therefore be thought of as a more stringent policy on CO_2 because emissions reductions are greater than in the baseline scenario. We also include the anticipated effects of state-level multipollutant policies in Connecticut, Massachusetts, Missouri, New Hampshire, North Carolina, Texas, and Wisconsin.[7]

We assume that electricity prices are set competitively in six North American Electric Reliability Council (NERC) regions (New York, New England, Mid-Atlantic states [MAAC], Illinois area [MAIN], the Ohio Valley [ECAR], and Texas [ERCOT]) and that there is time-of-day pricing of electricity for industrial customers in these regions. In all other regions of the

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[5] NSR settlements are those that electricity generating companies have reached with the federal government to bring their plants into compliance with NSR requirements for emissions reductions that the government claims were not met by past investments at specific facilities.

[6] We also include the effects of state-level RPS policies in Arizona, California, Nevada, Texas, and Wisconsin; the effects of green pricing programs in several states; and renewables mandates in Minnesota. For more information see EIA 2004.

[7] Several states have passed laws limiting emissions of some combination of NO_x, SO_2, mercury, and CO_2 from electricity generators. Most of these laws or regulations—such as new regulations in Connecticut and Massachusetts that limit nonozone season emissions of NO_x—are formulated as limits on emission rates. The largest state actions are in North Carolina and New York, which have recently placed emissions caps on its largest coal-fired plants. A similar plan has been adopted in New Hampshire for all existing fossil fuel–fired generators.

country, we assume that prices are set according to cost-of-service regulation at average cost. We simulate the model through 2025 and extrapolate our results to 2030 in order to calculate returns to investment choices.

2.1.2. Policy Scenarios

In all policy cases, the annual CO_2 emissions target is set by calculating a 20% decline from 2008 baseline emissions levels in the RGGI region, with the emissions reduction to be phased in on a linear basis between 2008 and 2025. The RGGI region is characterized as the nine-state region including New England, New York, New Jersey, and Delaware.

We give special consideration to new plants forecast for the MAAC region of NERC. Unless otherwise noted, we assume all new plants fired by fossil fuel (e.g., natural gas) located in MAAC are built anywhere in the Mid-Atlantic region in the baseline scenario and built outside the RGGI region (i.e., in Maryland and Pennsylvania) in all policy cases. Where plants will be built many years into the future is unknowable today. Access to transmission is one important factor, along with others that cumulatively may be more important than the presence of the RGGI policy. However, given the lack of transmission constraints within the Mid-Atlantic region in the model, with all other things equal, it makes sense that a plant locating in the region would choose a location that avoids the constraints of the RGGI program. This model design is one way in which model-estimated leakage is likely to overestimate the actual leakage that would occur. Hence, we do not focus on the quantity of leakage but instead compare the different approaches to allocation in qualitative terms.

Furthermore, when nonemitting renewable plants qualify for the allocation of emissions allowances, we assume that all new plants built in the Mid-Atlantic region qualify. This assumption is for modeling convenience but also accounts for the expectation that a qualifying facility would be more likely to locate on the RGGI side of a political boundary, all other things equal, if it could realize cost reductions by doing so. In fact, the portion of the Mid-Atlantic region located inside the RGGI region has limited renewable resources. However, to facilitate a consistent comparison between the baseline and policy cases, we always account for all new renewable investments in the entire Mid-Atlantic region as locating within the RGGI region.

The three bookend approaches to the distribution of emissions allowances that we analyze are historic (to emitters on the basis of historic generation in 1999), auction, and updating (to emitters on the basis of recent-year generation with a 2-year lag). Variations for each bookend case are listed in Table 1. Two choices characterize each scenario: Which generators are eligible for emissions allowances, and on what basis are allowances distributed?

We consider four mixed approaches. We also consider two types of constraints on the future of electricity supply: constrained transmission capability and higher natural gas prices.

2.2. Measures for Evaluation

The measures for evaluating these policy scenarios include changes in electricity price, economic measures of efficiency (including resource costs and changes in economic surplus), and changes in the value of existing generation assets. Efficiency results are measured in 1999$ from 2003 to 2030 and valued according to the usual method used in benefit–cost analysis, that is, the net present value (NPV) of Change in Economic Surplus = Change in Producer Surplus + Change in Consumer Surplus + Change in Government Revenues.

Producer surplus is the change in economic profit—that is, the value of revenues in excess of costs, where costs include payments to all factors of production, including labor, fuel, and annual capital costs. This measure is different from an accounting measure of profit, which typically also includes payments to invested capital, which are not considered economic profit unless those payments exceed the market rate of payments to capital. Consumer surplus is an analogous measure, reflecting the well-being of consumers in excess of what they have to pay for electricity services.

The auction mechanism also yields government revenues that could be used to fund public benefit programs, to compensate those who are adversely affected by the program, or for some other purpose. In any case, these revenues have a value that offsets some of the cost reflected in a decline in producer and consumer surplus under the auction. The public finance literature offers the guidance that the value of a dollar raised from emissions fees is greater than face value when that revenue is used to offset preexisting taxes such as labor or capital income taxes that impose inefficiency in the economy (Goulder et al. 1999). We take a cautious posture in this regard, assuming revenues have a social value just equal to their face value.

One should note that economic efficiency is only one measure of public policy. Equity and other concerns may override efficiency. An increase in electricity price may be viewed as enhancing efficiency, for example, because it provides a signal to encourage the purchase of energy-efficient appliances, but it also could cause hardship.

We look at the distributional consequences of different approaches to allocation for the industry by evaluating how these approaches affect the market value of generating assets. Asset values are measured in 1999$ by calculating the NPV of producer surplus from different types of electricity generators from 2003 to 2030. We aggregate generators by fuel, for new and existing generators, and look at regulated and competitive regions separately as well as the nation as a whole.

2.3. Simulation Model

We use Resources for the Future's (RFF's) electricity market model, Haiku, to analyze the effects of different approaches to allocation under a RGGI cap-and-trade program for GHGs focused on the electricity sector.[8] Haiku looks at the effects of the policies on the behavior of electricity producers and consumers as well as the resulting implications for costs, prices to consumers, and the emissions levels and locations. It is a national equilibrium model of 13 regional U.S. electricity markets with endogenous investment in and retirement of generation and pollution control capital.

The supply side of the model is built using capacity, generation, and heat rate data for the complete set of commercial electricity plants in the United States from various EIA datasets. For modeling purposes, these plant-level data are aggregated into 39 representative plants in each region. The capacity for a model plant is determined by aggregating the capacity of the individual constituent plants in a given region that are of the same type as the model plant.[9] However, no region contains every one of these model plants. For example, the New England region does not contain any geothermal plants. Factor prices (such as the cost of capital and labor) are held constant, and fuel price forecasts are calibrated to match EIA price forecasts (EIA 2004). Fuel market modules for coal and natural gas calculate prices that are responsive to factor demand.

The demand side of the market is characterized by three customer classes, with demand divided across three seasons and four time blocks within each season. The quantity of electricity demand responds to changes in electricity price. The level of electricity demand is calibrated to match EIA forecasts for the baseline and elasticity estimates drawn from the academic literature

[8] The model has been used in several peer-reviewed publications and was compared with other models in two sessions of the Energy Modeling Forum (EMF 1998, 2001). Paul and Burtraw (2002) provide further documentation.

[9] A model plant is defined by the combination of its technology and fuel source (coal, natural gas, oil, hydro, or nuclear). For example, some steam plants run on oil, others on natural gas; the same is true for gas turbine plants. Coal is different from the other fuels in that it has 14 subcategories based on the originating region and sulfur content. Coal users are broken down into demand regions that have different costs associated with each type of coal, which reflect the varying interregional transport costs. To reduce SO_2 or mercury emissions, model plants might find it more cost-effective to change the type of coal used than to install new pollution controls.

and other sources. Electricity trade between regions is also allowed, subject to transmission losses and physical transmission constraints.

3. Results for "Bookend" Scenarios

In this section, results are presented first for a set of bookend scenarios that are compared with a baseline scenario that represents a forecast in the absence of the RGGI. In subsequent sections, results are presented for several sensitivity analyses that consider variations on the bookend scenarios, combinations of features, or different assumptions about features of the baseline.

Baseline emissions for the nation and for the RGGI region are presented in Table 2. Emissions of the conventional pollutants (NO_x, SO_2, and mercury) are expected to fall between 2008 and 2025 in the baseline scenario because of CAIR implementation. State multiple-pollutant rules that are not modeled would strengthen this trend.

However, CO_2 emissions in the baseline scenario are shown to rise by 20% over the same period nationally and by nearly the same rate within the RGGI region. In 2008, CO_2 emissions in the RGGI region form the basis for calculating emissions targets. Under the RGGI targets, CO_2 emissions are assumed to decline linearly by 20% between 2008 and 2025, leading to an emissions target of 100 million tons in 2025.

Results comparing the baseline scenario with the three bookend policy cases are reported in Tables 3–5. In the baseline, the average annual retail electricity price is expected to be $103.4/MWh in 2025 in the nine-state RGGI region and $66.6/MWh nationally—about two-thirds of the price in the RGGI region.

The policy bookends include 100% allocation through three different mechanisms: The historic approach would distribute allowances to CO_2 emitters in the region on the basis of their historic share of generation in 1999, the auction would distribute allowances through sale by the government or another public institution, and the updating approach would distribute allowances to emitters on the basis of their share of total generation by emitters during the 2 preceding years. We make several key observations by comparing the pure versions (100% allocation in each case) of these approaches.

Electricity price increases in all scenarios. As indicated in Table 3, the average electricity price is higher in each case than in the baseline.

Consumers prefer the updating approach because it leads to the lowest electricity price of the three policy scenarios. Similarly, in each case, total generation within the RGGI region falls relative to the baseline, but it falls the least—by less than one-half as much—under updating than under the other approaches. This attribute of updating follows from the incentive to increase electricity generation in order to earn a larger award of emissions allowances.

Coal-fired generation falls under all approaches but falls the most under updating. The greater decline in coal under the updating approach—to one-half the level of the other approaches—is a result of the improvement in the relative cost of generation with natural gas compared to coal.

Gas-fired generation falls under the historic and auction approaches but increases substantially under updating. The emissions rates for natural gas are below the average for emitting sources, whereas those for coal are above average. Hence, natural gas is the preferred technology for responding to the incentive to expand production under updating. Generation with natural gas increases by 33% under updating relative to the baseline but falls by about 12% under the other approaches. The price of CO_2 emissions allowances is twice as high in the updating case because of the overwhelming incentive to increase gas-fired generation, which more than compensates for the decreased average emissions from natural gas sources.

Figure 1 illustrates the going-forward costs of electricity generation for a representative existing coal plant and a new natural gas combined cycle plant in the RGGI region. *Going-forward costs* are the expenses associated with bringing power from this plant to market in the future: fuel cost, fixed costs, and operating and maintenance costs. For existing and new plants, going-forward costs also include new capital investments in post-combustion pollution controls, operational costs, and the cost of emissions allowances net of the permit allocation to comply with the CAIR rule; for new plants, they also include capital costs.

In Figure 1, the component labeled CO_2 represents the opportunity cost of using CO_2 allowances under the RGGI policy that is added to going-forward costs, and permits represent the value of the allocation of CO_2 permits to the plant. In the bookend updating case, emissions allowances are earned by generating electricity, and their value is subtracted from other costs to arrive at the net cost of future generation. Because the change in net cost is less than the change in gross cost, the change in electricity price in a competitive power market is relatively small with an updating approach.

The value of CO_2 allowances awarded per megawatt-hour of generation is the same for the coal and gas plants; however, the CO_2 cost is more than twice as great for the coal plant. Hence, the allocation is equal to less than half of the CO_2 cost at the existing coal plant and greater than the CO_2 cost at the new natural gas plant. Net costs at the coal plant (about $48/MWh) remain slightly below the net costs at the gas plant (about $52/MWh). Nonetheless, the cost difference is negligible compared with the difference in the absence of the RGGI CO_2

policy, where the cost of the coal plant ($30/MWh) is substantially less than the cost at the gas plant ($53/MWh).

With the bookend historic approach, only the existing coal plant earns an allocation. The plant is endowed with the allowance value, regardless of whether it generates electricity. Hence, the value is not subtracted from going-forward costs. The magnitude of the CO_2 cost is much smaller with a historic approach than with an updating approach because the price of emissions allowances is lower.

Figure 1 also illustrates the influence of the RGGI CO_2 policy on the cost of compliance with the CAIR rule for conventional pollutants. One sees that the cost of SO_2 and mercury control per megawatt-hour at the existing coal plant is greater under historic allocation of CO_2 emissions allowances than under updating, primarily because the cost of acquiring allowances for SO_2 and mercury exceeds the plant's endowment under CAIR and Title IV. Generation at the existing coal plant under the historic approach to CO_2 allowances is roughly twice as large as under updating. The values represented in the graph are model solutions after costs are spread over the equilibrium level of generation under each policy. Note also that fuel costs per megawatt-hour are greater under the historic approach when the plant is more heavily used because more expensive fuel is used to help the plant comply with the CAIR rule.[10]

Renewable generation does relatively poorly under an updating approach. Renewable generation is less than with the historic approach and even less than in the baseline scenario. The lower level of renewable generation is a familiar result in this and other models. Typically, natural gas and renewables compete for new generation, and market share gains for one come at the expense of the other (Palmer and Burtraw 2004). This result changes when renewables qualify for a share of emissions allowances.

The decline in conventional pollutant emissions in the Northeast accelerates dramatically under the RGGI. Emissions are expected to fall substantially over time in the baseline scenario. However, the RGGI policy dramatically accelerates this trend. Emissions of conventional pollutants fall in all cases, but as a consequence of the shift in generation from coal to natural gas, conventional pollutant emissions are substantially lower under an updating

[10] This representative plant is a "model plant" in the simulation model that aggregates constituent plants of similar technological characteristics, so the results are the average for this group of constituent plants. Under the historic approach, nearly twice the capacity of this plant still exists in 2025 compared with under updating, and the amount of wet scrubbing in place is greater in absolute terms but less in proportion to generation capacity. The unscrubbed capacity uses more expensive, lower-sulfur fuel.

approach than under a historic or auction approach. Annual NO_x emissions are reduced by more than 40%, and annual SO_2 emissions are reduced by about 46% under the historic and auction approaches. Under the updating approach, the annual NO_x emissions are reduced by more than 65%, and annual SO_2 emissions are reduced by 81% from baseline levels. Mercury emissions are reduced by almost as large of a percentage. In every case, however, national emissions of NO_x, SO_2, and mercury do not change because of emissions caps, so the decrease in emissions inside the RGGI region is offset by an increase outside the region.

The RGGI policy leads to a substantial reduction in the cost of complying with regulations on conventional pollutants. The activities to comply with RGGI lessen the need to install post-combustion controls to reduce emissions of SO_2, NO_x, and mercury. In 2025, the avoided investment in control cost is about $100 million under historic and auction approaches and about $180 million under the updating approach. The use of SO_2, NO_x, and mercury emissions allowances also is reduced. In 2025, emissions reductions lead to savings on emissions allowances of about $80 million under the historic and auction approaches and about $250 million under the updating approach. Total avoided compliance cost with SO_2, NO_x, and mercury rules is about $180 million under the historic and auction approaches and about $436 million under the updating approach.

CO_2 emissions leakage to outside the RGGI region is lowest under an updating approach. In almost all cases, the greatest decrease in CO_2 emissions at the national level occurs with updating. The power generated outside the RGGI region (at plants not subject to the emissions cap) for import into the region increases. However, the incentive to increase generation within the RGGI region under an updating approach offsets this increase somewhat, causing less emissions leakage to outside the region.

In all scenarios, electricity price increases for the rest of nation because of the increased demand for electricity to be imported into the RGGI region. The demand for generation that is not subject to the emissions cap drives up marginal cost in the regions supplying power, which increases prices. Nationally, leakage is lowest and emissions reductions are greatest with the updating approach.

Findings about leakage should be interpreted with caution. We find the percentage of leakage to be sensitive. For example, a small change in natural gas prices due to changes in gas demand in the RGGI region can lead to a small change in the investment profile on the other side of the country in 2025, having a large effect on the leakage calculation for the whole horizon. This effect highlights the importance of modeling institutions that may be put in effect to properly mitigate leakage and to focus on the proper metric.

One may reasonably question whether national forecast changes for 2025 under a RGGI policy have meaning if the rest of the country pursues a business-as-usual policy. Many observers expect other regions of the country or the nation to follow the RGGI example and adopt some form of CO_2 policy. In subsequent analysis, we intend to address these issues to develop a transparent measure of leakage. For this discussion, we focus on cumulative emissions reductions at the national level to identify qualitative relationships among the approaches to distributing allowances.

The social cost of updating is three times that of the other approaches. From a broad social perspective, the change in economic surplus represents the social cost of meeting emissions targets. The change in economic surplus reported in Table 4 is the partial equilibrium measure of social cost within the electricity sector only. Three components of social cost (consumer surplus, producer surplus, and CO_2 revenue) are reported for 2025.

The social costs of the auction and historic approaches are the same, but who bears the cost differs. The auction and historic approaches have almost identical social costs of about $300 million in 2025. The auction imposes a substantial cost on consumers, which is offset by government revenue that can be expected to flow back to households (i.e., to taxpayers) or through other programs. The historic approach imposes a similar burden on consumers, but the revenues from allowance sales flow to producers rather than the government because producers receive the value of the emissions allowances through the allocation mechanism.

The updating approach imposes the least direct cost on consumers because it leads to the smallest increase in electricity price. However, it imposes a cost on producers that is almost as great as under the auction approach, because the lower electricity price means less revenue per unit of electricity generated. The total social cost within the RGGI region electricity sector for the updating approach is $700 million—40% greater than that of the other approaches.

Under the historic and auction approaches, total economic surplus outside the RGGI region increases slightly because of resources allocated to supplying electricity to the RGGI region. However, a sizeable redistribution between consumers and producers occurs. Producers outside the RGGI region that supply power to the RGGI region benefit at the expense of consumers outside the region, who face higher prices. A similar pattern in the allocation of surplus changes between consumers and producers outside the RGGI region occurs under updating, but the net effect is a decrease in total surplus.

In the aggregate, producers realize the lowest value of existing generation assets under updating. Table 5 summarizes the change in the NPV of generation assets in the baseline scenario and the change in value under each approach. It differs from the change in producer surplus reported in Table 4, which is a snapshot for just 2025.

The effect of allocation on asset values varies significantly across types of generators. Table 5 indicates that the aggregate of existing and new gas-fired generation generally gains value relative to the baseline under historic and updating approaches and slightly loses value under an auction approach. Under all approaches, the asset value of gas-fired generation that was in existence as of 1999 increases. The aggregate of existing and additional gas capacity increases in asset value under historic and updating approaches and declines slightly under an auction approach.

Note that Table 5 indicates a negative value for gas-fired assets in the baseline. This measure includes a rental cost of capital for payment on capital investments. In cases where investments have proven uneconomic, the calculation of asset value is negative. Facilities generally continue to operate because revenues remain greater than going-forward variable costs. In some cases, debt service has been written down for accounting purposes, and our baseline measure therefore would not correspond to an accounting measure. However, this practice does not have a bearing on our calculation of the change in asset value from baseline under various policy scenarios.

No new coal-fired or nuclear generating capacity is built in the RGGI region, so the change in asset value for these technologies applies only to existing assets. Coal-fired generation assets just break even under the historic approach and do the worst under updating, losing substantial value relative to the baseline scenario. Existing nuclear assets benefit substantially under a historic or auction approach compared with the baseline. However, nuclear assets lose value under the updating approach, which has a lower electricity price than under historic and auction approaches and leads to lower variable costs for gas units that qualify for allowances, thereby pushing some incremental nuclear generation out of the dispatch order. In variations of updating discussed below, we find that nuclear units do substantially better when they qualify for emissions allowances.

When all types of assets are aggregated, the NPV of generation assets increases substantially under historic allocation and decreases slightly under an auction. The fact that the market value of industry assets is minimally affected under the auction approach may appear to be a paradox but can result from several factors: the long-lived nature of capital investments, the distribution of capital intensity, emissions intensity and fuel intensity of different technologies for generating electricity, and variation in electricity demand by time of day. Meanwhile, in the aggregate, the value of generation assets under the updating approach declines by more than three times the decline under an auction.

In Maryland and the part of Pennsylvania that together constitute the portion of the MAAC region of NERC outside the RGGI region, the change in the NPV of generation is positive for all types of assets. This result follows from the increased sales supplied to the RGGI region and from the increase in electricity price that applies to every unit of production, including that delivered to native customers outside of the RGGI region.

Figure 2 illustrates the change in the value of generation assets under various approaches, including the bookend approaches and variations discussed in the following sections. The technologies listed include nuclear and coal, for which are composed of only existing plants since all the plants are existing because no new plants are built, and gas, for which plants are both existing and new. The overall generation technologies for the industry also are represented (as All). The three bookend cases discussed previously are indicated by the labels: Heg (historic), Auction, and Demit (updating). Labels at the bottom of the graph correspond to the scenario and the general type of approach; to identify precise mappings, compare the labels on the specific points with the scenarios listed in Table 1.

Even before discussing the variations on the bookend approaches in detail, Figure 2 allows several general observations. Nuclear assets almost always gain value under RGGI. The one exception is the bookend updating case in which natural gas generation expands and there is little change in electricity price. However, in the cases in which nuclear generation earns an allocation, it does substantially better, as indicated by the peaks in its line graph.

Gas-fired generation assets always maintain and sometimes gain value. The only exception is under the auction approach, in which gas loses value slightly. Meanwhile, the only time coal-fired generation assets do not lose substantial value is under the historic approaches and the mixed approaches that combine historic allocation with an auction. Under a couple of the historic approaches, existing coal-fired plants actually gain value because of the generous allowance allocation.

In the aggregate, the change in value for the industry is a weighted average of changes in the value of individual plants. Hence, although some technologies and some firms may gain or lose substantial value, the change in value for the industry is muted because winners offset losers. The industry does the worst under the bookend updating approach, but in the aggregate, the industry experiences little change in value under most non-bookend updating approaches and the auction approach. However, in the aggregate, the industry gains substantial value under the historic approach. The following sections provide more details on the variations in allocation approaches that were modeled.

4. Variations in Results for Historic Approach

Two variations to the bookend historic approach are described in Tables 6–8. The bookend distributes allowances to emitters on the basis of historic generation. One variation distributes allowances to emitters on the basis of historic emissions; another distributes allowances to all generators on the basis of historic generation.

Price and generation differ little among these variations on the historic approach. The overview of electricity price, generation, and emissions in Table 6 shows the main difference: Cumulative national CO_2 emissions are much higher under the scenario in which allowances are distributed to all generators on the basis of generation.

The differences that emerge among the historic approaches are largely due to the characterization of stranded asset recovery policies in the model. The term *stranded assets* describes generation assets that lost value as a result of electricity industry restructuring. We assume that 90% of stranded assets (and 0% of stranded benefits) are recovered through a surcharge on electricity price that is expected to continue for 10 years after the transition from regulation to competition. We assume the award of emissions allowances is considered in calculating the value of existing assets, so the surcharge is adjusted, leading to very slight changes in electricity price. When the model is exercised without stranded asset recovery, the historic approaches solve to exactly the same outcome with respect to electricity price and other measures listed in Table 6.

The market values of various types of assets differ widely under the various approaches to historic allocation. Table 7 indicates there is very little difference in the social cost of the historic approaches or the distribution in cost between consumers and producers. However, Table 8 indicates that one can expect a difference in the incidence of the program among producers, depending on their portfolio of generation assets. Coal-fired generators within the RGGI region are significantly better off when they are allocated permits on the basis of emissions because their share of total emissions is higher than their share of total generation. Additionally, nuclear generators are much better off when permits are distributed to all generators on the basis of historic generation.

5. Variations in Results for Updating Approach

Several variations to the updating approach are reported in Tables 9–11. In the bookend approach, allowances are distributed to emitters on the basis of generation two years previous. Variations that are reported include distribution to all generators and separately adding the eligibility of incremental nonemitters, which include renewable and nuclear generation in excess of 1999 levels. Another variation adds updating to emitters on the basis of heat input, with an additional factor favoring coal.

In another variation, allowances are distributed only to nonemitters (renewable and incremental nuclear generation), including nonemitters located anywhere in the nation; this variation can be viewed as a type of offset program that might reduce leakage. Finally, in another variation, only nonemitters within the RGGI region qualify. Both of these last two approaches provide incentives to expand generation from nonemitters, somewhat analogous to an RPS. Recall that all renewables in the MAAC region of NERC are always included as part of RGGI when we characterize qualifying renewable generation. We also include incremental nuclear generation in the nonemitters category.

Most of the variations on updating maintain lower increases in electricity price than other approaches. Electricity price increases are small when emitters receive some share of the allocation through updating. The two updating approaches with distribution only to nonemitters yield greater increases than do historic and auction approaches.

CO_2 allowance prices remain relatively high in most of the updating approaches. Total generation in the RGGI region is relatively high except when only nonemitters qualify. Total generation is highest of any approach examined when allocation is on the basis of heat input. The price of a CO_2 allowance is high in the updating runs whenever electricity generation is relatively high because the allowances have a greater opportunity cost. The allowance price is highest when allowances are allocated on the basis of heat input because the allocation provides an incentive for coal-fired generation, which has a greater emissions rate and hence raises the opportunity cost of emissions allowances. The allowance price is lower—comparable to that under auction and historic approaches—when only nonemitters qualify.

It is noteworthy that electricity price in the rest of the nation actually falls below baseline levels when nonemitters nationwide qualify for allowances. Cumulative emissions reductions at the national level are relatively high in this case.

Updating distribution to all generators imposes the lowest social cost within the RGGI region of any policy examined. The economic surplus cost of the program varies among these approaches to updating and in some cases is substantially less than in the bookend case. Distribution to all generators reduces social cost because it reduces each generator's share of allowances and therefore the value of the output subsidy that is awarded to changes in electricity generation. Although the change in social cost is very small within the RGGI region, additional social cost is imposed outside the region.

The dynamic bookend approach was run with an allocation to demand conservation investments, but the results were not sufficiently different to warrant further investigation.

Within the RGGI region, distribution to nonemitters imposes large costs, whereas outside the region, benefits accrue as a result of subsidized investments.

Updating affects different technologies in different ways. In general, these effects depend directly on whether a technology qualifies for distribution and on the value of the allowances in each case. The larger the number of kilowatt-hours generated that qualify for a share of the allowances, the lower the value to each individual facility. It is noteworthy that compared with the bookend approach, distribution to generators—including incremental generation by nonemitters—improves the value of every class of generation asset. We observe that

- the NPV of gas-fired generation does relatively well in most updating approaches,
- the NPV of coal-fired generation suffers under all updating approaches, and
- the NPV of nuclear generation benefits substantially whenever it qualifies for a share of allowances under updating and suffers otherwise, because there is little change in electricity price and the expansion in gas-fired generation crowds out some incremental nuclear generation.

6. Mixed Approaches

Several scenarios in which allowances are distributed through a combination of approaches are described in Tables 12–14. In the overview of changes in electricity price, generation, and emissions, the outcome is roughly a combination of the performance of each individual approach. One way this is not true is with respect to the CO_2 allowance price, which tends toward the price for the auction bookend when the auction is combined with updating. The scenarios that combine an auction with dynamic allocation result in more emissions reductions at the national level than the scenarios that combine an auction with historic allocation.

Changes in economic surplus measures for the combination of an auction with an updating approach are between those for the auction bookend and the updating bookend approaches. The economic cost for consumers is less than for the auction bookend, and like the auction, the cost to consumers is less than the gain in government revenues. Similarly, in the mixed auction–historic approach, as with each approach taken individually, producers outside the RGGI region benefit considerably from the opportunity to supply power at a higher electricity price to consumers in the RGGI region. Modifying the combined auction–historic case to compensate coal-fired generators more than gas-fired generators per kilowatt-hour of historic generation has no effect on the economic surplus costs of that mixed allocation approach.

The changes in the components of economic surplus under the various mixed approaches are compared with the other scenarios in Figure 3 for 2025. Changes in consumer surplus, producer surplus, CO_2 revenue, and total surplus are plotted. The policy scenarios are ordered in terms of the size of their associated CO_2 auction revenues and are grouped by general category of approach (updating, historic, mixed, or auction).

Figure 3 shows that all the mixed scenarios produce revenues for the government that can be used for compensation or other purposes. The mixed scenarios that include historic allocation tend to substantially reduce gains to producers found under the pure historic approaches without imposing substantial costs in terms of total surplus losses or greater losses in consumer surplus than under the pure historic or the pure auction approach. Combining updating and auction approaches in equal proportions has a bigger adverse effect on consumers in the form of higher electricity prices than a pure updating approach that rewards incremental generation by nonemitters. All of the mixed approaches have very similar effects on total economic surplus but distinguish themselves in terms of effects on the different components of surplus.

The increase in asset values for gas-fired generation in the mixed auction–updating approaches is close to that for the auction bookend, which is less than that for the updating bookend. The increase is slightly less when coal-fired generators earn twice as many allowances as gas-fired generators per kilowatt-hour of generation. The decrease in value for coal-fired generation is worse than for the auction approach but not as bad as under updating. The mixed auction–historic approach reduces the losses to coal-fired generators compared to the auction approach, especially when coal-fired generators earn twice as many allowances as gas-fired generators do per unit of historic generation. Nuclear generation benefits in the mixed approach cases because the increases in electricity price are greater than under updating. For the industry as a whole, the change in asset values is small in the aggregate because the mixed approaches yield greater increases in electricity price than the updating bookend does. Increasing the fraction of allowances that are auctioned while updating the remaining allowances generally has a positive impact on the asset values of all types of generators, including coal-fired generators. The one exception is that moving from a 50% auction–50% updating approach to a 100% auction approach has a negative effect on the asset value of gas-fired generators in the RGGI region.

The mixed auction–historic approaches have a positive effect on average asset values across the industry and produce a much smaller drop in the value of coal-fired generation assets than the mixed auction–updating approaches. Interestingly, the increase in average asset values for existing units in the RGGI region under the auction–historic approach based on generation is the roughly the same as that for generators outside the RGGI region. In the RGGI region, these assets experience the program costs and receive a share of allowance allocation that is approximately equal, resulting in a financial situation similar to that of assets outside the RGGI region.

7. Constrained Cases

Several constraints in the electricity system affect the operation of individual facilities and the adjustment in prices in ways that are not fully represented in the model. Many are short-run constraints, such as fuel supply contracts that would be renegotiated over time. Others, such as requirements to balance load on the grid, affect individual facilities but are not expected to have a noticeable effect on the behavior of the entire system. However, two types of constraints in the Northeast seem to be potentially important in the long run: the ability to supply natural gas to the Northeast, and the capability of the transmission grid to deliver power.

If natural gas is an important component of achieving compliance with RGGI, then changes in gas prices or demand could be important. To address this issue, we ran a scenario in which gas prices at the national level were 15% above baseline levels. In addition, any increase in Northeast gas demand above baseline levels in 2008 resulted in a regional change in price that was twice as sensitive as in the baseline scenario.

Our findings from the standard baseline are repeated in the first columns in Tables 15 and 17, and in the second column of Table 16. The second columns of Tables 15 and 17 consider the historic bookend approach with higher gas prices. The differences in electricity prices and the choice of generation technology are substantial, largely because of the change in natural gas prices that we assume occurs independent of changes in gas demand as a result of the RGGI program. Another result is interesting, nonetheless: The NPV of all technologies is substantially higher in the constrained gas case than in the baseline scenario (Table 17). This finding follows from the increase in the cost of natural gas–fired generation, which is the technology that determines marginal electricity price in most time blocks. Hence, a higher gas price translates into a higher electricity price, and the change in revenue generally is greater than the change in cost for the industry.

A second potentially important constraint is transmission capability. In the baseline model inter-regional transmission capability is represented by quantity constraints. In the constrained transmission model, inter-regional transmission capability is also constrained by additional prices, cost thresholds, and line losses. Intra-regional line losses also are represented on average. Intra-regional quantity constraints are not captured directly, but some of the implications of those constraints are represented. For example, the model is calibrated to achieve what would otherwise appear to be out-of-merit-order dispatch of oil-fired facilities, which tend to run because of the limitations to transmission into the New York metropolitan area and the difficulty of siting new sources in the area.

The first column under "Constrained baseline" in Tables 15–17 is a new baseline that includes both the natural gas constraint described above and a 10% reduction in inter-regional transmission capability; the subsequent column describes the historic bookend under these constraints.

The effect of adding constraints on natural gas supply and electricity transmission capability is larger than the effect of adding the RGGI policy. The constraints cause substantial changes in the absence of the RGGI policy (evident from a comparison of the first and third columns of Table 15). Moreover, the changes in electricity price and other overview measures that occur as a result of adding the RGGI policy to the constrained no-policy baseline (third and fourth columns of Table 15) are comparable to those that occur when the policy is added to the central case baseline (Table 3). Also, the constraint on natural gas price is more important than the constraint on inter-regional transmission capability (Table 15). The model with both constraints varies little compared with the model with only high gas price.

Producers benefit substantially in the face of constraints on natural gas price or transmission capability. Table 16 presents the change in economic surplus reported as the difference from the central case baseline. The higher gas price negatively affects consumers and benefits producers. Again, the change in surplus due to adding the constraints in the absence of the policy tends to be larger than the change due to adding the policy.

The value of every type of generation asset in the RGGI region improves with the additional constraints, and the value of every type of asset improves further with the implementation of the policy. Even the value of natural gas–fired generation assets improves with the constraint of higher gas prices.

The modeled constraints do not appear to have a strong impact on RGGI implementation. Overall, the changes in electricity price, technology choices for electricity generation, and the cost distribution due to implementation of the RGGI policy do not vary substantially in the presence of constraints on natural gas supply or transmission capability in the way we have modeled them. In the historic, auction, and many updating approaches, an expansion of natural gas–fired generation does not play a significant role in compliance. Hence, changes in the cost of natural gas will affect the baseline and the policy scenario equally. Incorporating transmission rules aimed at reducing leakage could play a big role, but that modeling is left to future research.

8. Renewable Portfolio Standard Cases

Our standard base case and policy scenarios do not include all of the state-level policies to promote renewables used in the RGGI states. To get a sense of how policies to encourage renewables might affect the results of a RGGI policy, we ran a baseline scenario against one policy case with an aggregate regional RPS. These results are presented in Tables 18–20.

The RPS policy scenario we developed is intended to reasonably reflect all of the existing renewables policies for states in the three NERC regions covered or partially covered by RGGI (i.e., the New England states, New York, and the MAAC NERC region). It is not intended to be an exact representation of RPS policies in the included states but a plausible approximation of existing policies that probably represents a slightly higher level of renewables requirements than embodied in current policy because of rounding. The policy is specified as mandated increments to existing non-hydro renewable generation of 4.4%, 9.5%, 11.5%, and 12.6% in 2008, 2015, 2020, and 2025, respectively. It also includes increased imports from Canada to New York that are largely expected to come from hydro generation.

In an RPS baseline (e.g., in the absence of the RGGI policy), renewable generation increases by 67% relative to the standard baseline within the three NERC regions by 2025, whereas electricity price remains roughly the same and CO_2 emissions decrease 9%, by 14 million tons. The increase in renewable generation mostly replaces gas-fired generation because coal-fired generation remains nearly the same and gas-fired generation declines by 18%. The price of a renewable credit is $16/MWh in 2025.

We model the addition of the RGGI policy by assuming CO_2 allowances are distributed to emitters on the basis of historic generation, in a scenario analogous to the bookend historic approach. The RPS policy by itself is much more potent than the RGGI policy by itself with respect to generation by renewables (Table 18). The big difference between these policy scenarios is the effect on technology: The increased renewable generation displaces gas-fired generation under the RPS policy, whereas coal-fired generation declines by more than gas-fired generation under the RGGI policy.

When the RGGI policy is combined with the RPS baseline, the level of generation by coal is intermediate—above the level with just the RGGI policy and below the level with just the RPS. However, gas-fired generation declines even more than under just the RPS policy, to 75% of the standard baseline and 91% of the RPS baseline. The price of electricity in the RGGI region rises to $106/MWh (an increase of $2.70/MWh from the RPS baseline), causing generation within the RGGI region to fall by 37 billion kWh below the RPS baseline. However, electricity price in 2025 with the RPS and the RGGI policy is $1.1/MWh lower than with the RGGI policy alone. The electricity price is lower because the RPS encourages generation by renewables, which have lower variable costs and thus exert downward pressure on electricity price.

Having an RPS in place lowers baseline CO_2 emissions and thus the cost of CO_2 allowances. The CO_2 allowance price in 2025 is $15.6/ton, about $2.50/ton less than without the RPS. The incentive for renewable generation clearly makes compliance with the regional CO_2 cap easier. The price of a renewable credit is $12/MWh in 2025 with the RGGI policy. Total renewable generation is slightly less than under just the RPS policy because total generation in the region is lower; the share of total generation made up by renewables remains equal to the RPS policy target.

The economic cost of the policies is reported in Table 19. In the baseline scenario with RPS, the consumer surplus within the RGGI region is approximately the same as under the baseline alone, but producers are better off than under the standard baseline, at the expense of consumers outside the region. When the RGGI policy is added, the cost to consumers in the RGGI region is offset by an almost equal benefit to producers, with no net change in economic surplus from the standard baseline. Consumers are worse off because of the increase in electricity price. Compared with the bookend historic approach without the RPS, consumers in the RGGI region are substantially better off and producers are slightly better off. Nationally, the economic surplus results are similar to those in the RPS baseline. In both the RPS baseline and the combined RPS–RGGI policy cases, additional costs stem from the tax credits offered by the federal government and realized because of the expanded generation by renewables. This cost is not shown as a separate item but is evident in the subtotals and the national total in Table 19.

The asset values of various types of generation are affected differently by the RPS and CO_2 cap (Table 20). Within the RGGI region under the RPS policy, gas-fired and nuclear generation decline slightly in value, whereas coal-fired generation remains the same. Meanwhile, renewable generation increases substantially in value (not reported in the table). Outside the RGGI region but in the MAAC NERC region, the value of gas-fired generation increases modestly. Adding the CO_2 cap causes the value of gas-fired and nuclear generation to increase within the RGGI region relative to the standard baseline, whereas coal-fired generation loses value. The effects on asset values of the RGGI policy with historic allocation are usually smaller in the presence of the RPS than in the bookend case.

9. Conclusion

In this research, we model historic, auction, and updating approaches to the allocation of emissions allowances that we call bookends, then model several variations on these approaches.

We find that how allowances are initially allocated has a substantial effect on electricity price and consumption, the mix of technologies used to generate electricity, the emissions levels of conventional pollutants, and the cost of controlling the emissions of conventional pollutants.

The value of CO_2 allowances created by the RGGI program is at least four times the social cost of mitigation. The fact that changes in electricity price depend on how emissions allowances are initially distributed suggests that allowance distribution offers a potentially important source of compensation. We assess the effects of different distribution approaches on the change in the market value of generation assets and find substantial variation depending on the method of allocation.

The measure of compensation that is required to preserve asset value varies according to whether it is calculated at the level of the facility, business unit, firm, or state. Change in shareholder value depends on the portfolio of assets held by the firm. We do not calculate the change in value at the firm level in this paper, but policymakers may be interested in this information when considering how different parties are affected.

A general pattern emerges from our modeling results of allocation approaches: A historic or auction approach is most efficient. The updating approach has about three times the social cost of the historic or the auction approach but has the political advantage of a lower electricity price and can be designed to reduce leakage.

Recognizing that updating has attracted interest in the RGGI process, we explore several variations on the updating approach, with various consequences. It is noteworthy that one variation—updating allocation on the basis of all generation—has the lowest social cost within the RGGI region of any approach we modeled, partly because it imposes costs outside the region. Ultimately, however, updating has less attraction as a model for a national (or international) policy because of its higher social cost, and because of the difficulty in establishing a consistent allocation method across different sectors of the economy. Hence, we suggest that updating may be a useful tool for the initial implementation of RGGI but not at the national level.

The approaches vary significantly in their aggregate effects on asset values and specific types of generation technology. The industry benefits most with the historic approach, and consumers benefit least. The auction approach is the intermediate case with respect to the effect on market value, and the updating approach leads to the greatest aggregate decline in market value for the industry.

The auction approach that we model might be implemented in various forms. One is allocation to consumers, or a public benefit allocation, which endows a trustee with allowances that can be sold to the industry with the revenue applied to a variety of purposes. Some observers have suggested that investments in energy conservation or renewables research could be funded through this kind of approach.

Important limitations to these results stem from the level of aggregation used in the analysis. Intra-regional transmission constraints are not modeled. Electricity imports from Canada are parametric and do not change in response to the RGGI policy, which could affect the amount of emissions leakage that occurs. Out-of-merit-order dispatch that may result from long-term fuel contracts or intra-regional transmission constraints is approximated based on evidence from recent years. We conduct sensitivity analyses with constraints on natural gas prices and transmission capability and find that the social cost of the RGGI program does not appear to be sensitive to these constraints.

The variation that we discover in the measures and the performance of various policies suggests that policymakers have latitude in providing compensation to industry through the distribution of emissions allowances. We suggest that greater emphasis could be placed on compensation in the short run and on efficiency in the long run and indicate what some types of mixes in approaches to allocation would accomplish. In the long run, on the national stage, a CO_2 cap-and-trade policy could impose significant costs on the economy. Hence, we suggest that efficiency concerns should be a central consideration in the long-run policy design.

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Tables

Table 1. Modeled Scenarios

Approach		*Eligibility*	*Basis for Allocation*
Historic			
Heg	a. (Bookend)	Emitters	Historic generation
Hag	b.	Generators	Historic generation
Hee	c.	Emitters	Historic emissions
Auction			
Auc	d. (Bookend)	Emitters	Auction
Updating			
Demit	e. (Bookend)	Emitters	Recent generation
Dag	f.	Generators	Recent generation
Dagig	g.	Generators	Generation (emitters) or incremental generation (nonemitters)
Dn3ig	h.	Nonemitters	Incremental generation for nonemitters
DnNig	i.	Nonemitters nationwide	Incremental generation for nonemitters
Dehi	j	Emitters	Recent heat input with factor favoring coal
Mixed			
MAHeg	k.	Historic (a) (50%) / Auction (d) (50%)	Historic generation / Auction
MADagig	m.	Auction (d) (50%) / Updating (e) (50%)	Auction / Recent generation
MA20Dagig	n.	Auction (d) (20%) / Updating (e) (80%)	Auction / Recent generation
MaHee	o.	Historic (a) (50%) / Auction (d) (50%)	Historic emissions / Auction
MAHeg_coal	p.	Historic (a) (50%) / Auction (d) (50%)	Historic emissions / Auction; coal-fired generation counts double
MADeg_coal	q.	Auction (d) (50%) / Updating (e) (50%)	Auction / Recent generation; coal-fired generation counts double
Constrained			
HegGhi	r. Higher gas price	Emitters (Historic a)	Historic generation
HegT10Ghi	s. Constraints[a]	Emitters (Historic a)	Historic generation

[a] New baseline: constrained transmission capability (assuming interregional capability in the Northeast reduced by 10%) and higher gas price.

Notes: Historic generation and historic emissions = 1999. Recent generation is based on two years previous to allocation. Incremental generation includes generation beyond 1999 levels. Higher gas price has national (Henry Hub) prices pegged 15% above baseline and supply price sensitivity scenarios for imports into the Northeast above baseline levels doubled.

Table 2. National Annual Baseline Emissions and Annual Policy Emissions Targets

Pollutant	*2008*	*2015*	*2020*	*2025*
Nationwide				
CO_2 (million tons)	2,755	2,910	3,102	3,311
NO_x (thousand tons)	3,891	2,551	2,615	2,670
SO_2 (thousand tons)	7,181	4,963	4,293	3,178
Mercury (tons)[a]	62	40	38	36
RGGI region				
CO_2 (million tons)	124	129	136	147
NO_x (thousand tons)	106	111	117	118
SO_2 (thousand tons)	415	238	196	193
Mercury (tons)[a]	1.7	1.2	1.2	1.2
Reduction target				
CO_2 (million tons)	124	114	107	100

[a] Includes mercury emissions from uncontrolled municipal solid waste facilities that in fact have already begun to achieve important emissions reductions.

Table 3. Overview for Bookend Cases, 2025

Eligibility:		*Emitters*	*Emitters*	*Emitters*
Basis:		*Historic generation*	*Auction*	*Recent generation*
RGGI region	Baseline	Historic	Auction	Updating
Average electricity price (1999$/MWh)	$103.4	$107.1	$107.2	$103.9
TOTAL generation (billion kWh)	393	348	348	371
Coal	73	48	48	23
Gas	130	115	116	173
Nuclear	107	108	108	106
Renewable	34	40	40	32
TOTAL new capacity[a] (GW)	28	31	31	33
Gas	23	24	24	28
Renewable	5	6	6	5
CO_2 price (1999$/ton)	n/a	$18.1	$18.3	$35.3
Emissions				
CO_2 (million tons)	147	100	99	98
NO_x (thousand tons)	118	70	70	41
SO_2 (thousand tons)	193	101	107	36
Mercury (tons)	1.2	0.8	0.8	0.3
Rest of nation[b]				
Average electricity price (1999$/MWh)	$66.6	$66.8	$66.8	$66.9
TOTAL generation (billion kWh)	4,847	4,885	4,886	4,861
CO_2 reduction for nation cumulative (2008–2025) (million tons)	n/a	201	233	289
Model	BL	Heg	Auc	Demit

[a] Numbers may not sum because of rounding.

[b]Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 4. Change in Economic Surplus from Baseline (Social Cost), Bookend Cases, 2025 (billion 1999$)

Eligibility:	*Emitters*	*Emitters*	*Emitters*
Basis:	*Historic generation*	*Auction*	*Recent generation*
RGGI region	Historic	Auction	Updating
Consumers	–1.6	–1.6	–0.2
Producers	1.2	–0.6	–0.5
CO_2 revenue	0.0	1.8	0.0
SUBTOTAL[a]	–0.5	–0.5	–0.7
Rest of nation[b]			
Consumers	–1.2	–1.2	–1.3
Producers	1.5	1.5	1.2
SUBTOTAL[a]	0.2	0.2	–0.2
National TOTAL[a]	–0.3	–0.3	–0.9
Model	Heg	Auc	Demit

[a] Numbers may not add because of other categories including change in tax credit costs.

[b] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 5. NPV of Existing and New Generation Assets, Change from Baseline, Bookend Cases (1999$/kW)

Eligibility:		*Emitters*	*Emitters*	*Emitters*
Basis:		*Historic generation*	*Auction*	*Recent generation*
RGGI region	Baseline (NPV)	Historic	Auction	Updating
Gas	–273	54	–13	45
Coal	434	8	–185	–240
Nuclear	611	67	55	–51
Average ALL[b]	164	60	–13	–45
Existing capacity only[c]				
Gas	–375	228	17	102
Coal	434	8	–185	–240
Nuclear	611	67	55	–51
Average ALL[b]	300	104	–3	–51
MD and PA[a]				
Gas	–255	6	12	12
Coal	364	50	–185	24
Nuclear	653	51	51	20
Average ALL[b]	229	23	26	8
Model	BL	Heg	Auc	Demit

[a] Maryland and the portion of Pennsylvania within MAAC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

[c] Existing in 1999.

Table 6. Overview of Historic Allocation Cases

Eligibility:	*Emitters*	*Emitters*	*Generators*
Basis:	*Historic generation*	*Historic emissions*	*Historic generation*
RGGI region			
Average electricity price (1999$/MWh)	$107.1	$106.8	$107.5
TOTAL generation (billion kWh)	348	349	348
Coal	48	48	48
Gas	115	116	115
Nuclear	108	108	108
Renewable	40	40	40
New capacity[a] (GW)	31	31	31
Gas	24	24	24
Renewable	6	6	6
CO_2 price (1999$/ton)	$18.1	$18.2	$18.3
Emissions			
CO_2 (million tons)	100	100	100
NO_x (thousand tons)	70	72	71
SO_2 (thousand tons)	101	107	105
Mercury (tons)	0.8	0.8	0.8
Rest of nation[b]			
Average electricity price (1999$/MWh)	$66.8	$66.8	$66.9
TOTAL generation(billion kWh)	4,885	4,886	4,887
CO_2 reduction for nation cumulative (2008–2025) (million tons)	201	219	249
Model	Heg	Hee	Hag

[a]Numbers may not sum because of rounding.

[b]Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 7. Change in Economic Surplus from Baseline (Social Cost), Historic Cases, 2025 (billion 1999$)

Eligibility:	*Emitters*	*Emitters*	*Generators*
Basis:	*Historic generation*	*Historic emissions*	*Historic generation*
RGGI region			
Consumers	–1.6	–1.4	–1.7
Producers	1.2	1.0	1.3
CO_2 revenue	0.0	0.0	0.0
SUBTOTAL[a]	–0.5	–0.5	–0.5
Rest of nation[b]			
Consumers	–1.2	–1.1	–1.3
Producers	1.5	1.3	1.4
SUBTOTAL[a]	0.2	0.1	–0.1
National TOTAL[a]	–0.3	–0.4	–0.6
Model	Heg	Hee	Hag

[a]Numbers may not add because of other categories including change in tax credit costs.

[b]Includes the MAAC region of NERC outside the RGGI region.

Table 8. Change from Baseline of Net Present Value of Generation Assets, Historic Cases (1999$/kw)

Eligibility:	*Emitters*	*Emitters*	*Generators*
Basis:	*Historic generation*	*Historic emissions*	*Historic generation*
RGGI region			
Gas	54	19	33
Coal	8	34	–61
Nuclear	67	48	169
Average ALL[b]	60	36	68
MD and PA[a]			
Gas	6	2	23
Coal	50	55	46
Nuclear	51	51	48
Average ALL[b]	23	23	24
Model	Heg	Hee	Hag

[a]Maryland and portion of Pennsylvania within the MAAC region of NERC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

Table 9. Overview for Updating Allocation Based on Generation, 2025

Eligibility:	*Emitters*	*Generators*	*Generators*	*Nationwide nonemitters*	*Nonemitters in NY, NE, & MAAC*	*Emitters*
Basis:	*Recent generation*	*Recent generation*	*Recent generation (emitters), incremental generation (nonemitters)*	*Recemt incremental generation*	*Recent incremental generation*	*Recent heat input with add'l factor favoring coal*
RGGI region						
Average electricity price (1999$/MWh)	$103.9	$104.0	$103.9	$107.0	$106.5	$103.8
TOTAL generation (billion kWh)	371	374	367	350	356	376
Coal	23	43	39	48	52	22
Gas	173	129	137	114	104	169
Nuclear	106	108	107	108	108	107
Renewable	32	58	46	43	55	38
New capacity[a] (GW)	33	35	33	32	34	32
Gas	28	25	25	24	23	26
Renewable	5	10	8	7	11	6
CO_2 price (1999$/ton)	$35.3	$23.7	$26.1	$18.1	$16.4	$45.9
Emissions						
CO_2 (million tons)	98	100	100	100	100	100
NO_x (thousand tons)	41	65	63	69	73	51
SO_2 (thousand tons)	36	82	65	104	115	34
Mercury (tons)	0.3	0.7	0.6	0.8	0.8	0.4
Rest of nation[b]						
Average electricity price (1999$/MWh)	$66.9	$66.7	$66.7	$66.5	$66.8	$66.8
TOTAL generation (billion kWh)	4,861	4,862	4,870	4,888	4,878	4,860
CO_2 reduction nation, 2008–2025 (million tons)	289	232	282	461	310	204
Model	Demit	Dag	Dagig	DnNig	Dn3ig	DEhi

Table 10. Change in Economic Surplus from Baseline (Social Cost) for Updating Cases, 2025 (billion 1999$)

Eligibility:	*Emitters*	*Generators*	*Generators*	*Nationwide nonemitters*	*Nonemitters in NY, NE, & MAAC*	*Emitters*
Basis:	*Recent generation*	*Recent generation*	*Generation (emitters), incremental generation (nonemitters)*	*Incremental generation*	*Incremental generation*	*Recent heat input with add'l factor favoring coal*
RGGI region						
Consumers	–0.2	–0.2	–0.2	–1.5	–1.3	–0.2
Producers	–0.5	0.1	–0.1	–0.5	0.4	–0.6
CO_2 revenue	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL[a]	–0.7	–0.2	–0.4	–2.1	–1.2	–0.8
Rest of nation[b]						
Consumers	–1.3	–0.6	–0.6	0.3	–0.9	–0.8
Producers	1.2	0.3	0.6	1.5	1.6	0.4
SUBTOTAL[a]	–0.2	–0.3	–0.1	1.3	0.5	–0.4
National TOTAL[a]	–0.9	–0.5	–0.6	–0.8	–0.6	–1.3
Model	Demit	Dag	Dagig	DnNig	Dn3ig	DEhi

[a]Numbers may not add because of other categories including change in tax credit costs.

[b]Includes the MAAC region of NERC outside the RGGI region.

Table 11. Change from Baseline in Net Present Value of Generation Assets, Updating Cases (1999 $/kW)

Eligibility:	*Emitters*	*Generators*	*Generators*	*Nationwide nonemitters*	*Nonemitters in NY, NE, & MAAC*	*Emitters*
Basis:	*Recent generation*	*Recent generation*	*Generation (emitters), incremental generation (nonemitters)*	*Recent incremental generation*	*Recent incremental generation*	*Recent heat input with add'l factor favoring coal*
RGGI region						
Gas	45	–2	16	7	–3	–1
Coal	–240	–231	–223	–159	–175	–235
Nuclear	–51	136	53	93	147	–21
Average ALL	–45	5	–1	20	30	–57
MD and PA[a]						
Gas	12	–5	10	23	21	22
Coal	24	35	43	50	48	31
Nuclear	20	35	37	65	129	25
Average ALL[b]	8	9	14	30	47	13
Model	Demit	Dag	Dagig	DnNig	Dn3ig	Dehi

[a]Maryland and portion of Pennsylvania within the MAAC region of NERC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

Table 12. Overview for Mixed Approaches

Eligibility:	*Generators*	*Generators*	*Emitters*	*Emitters*	*Emitters*	*Emitters*
Basis:	*Auction 20%/ Recent gen. 80%*	*Auction 50%/ Recent gen. 50%*	*Auction 50%/ Historic gen. 50%*	*Auction 50%/ Historic emissions 50%*	*Auction 50%/ Historic gen. 50%*[a]	*Auction 50%/ Recent gen. 50%*[a]
RGGI region						
Average electricity price (1999$/MWh)	$103.9	$105.5	$107.5	$107.1	$107.5	$105.5
TOTAL generation (billion kWh)	359	354	348	349	348	356
Coal	43	45	48	48	48	42
Gas	130	121	115	115	116	130
Nuclear	108	108	108	108	108	108
Renewable	42	42	40	40	40	40
New capacity[b] (GW)	32	32	31	31	31	32
Gas	25	25	25	24	24	25
Renewable	7	7	6	6	6	6
CO_2 price (1999$/ton)	$24.4	$21.8	$18.3	$18.2	$18.4	$23.8
Emissions						
CO_2 (million tons)	100	100	99	100	100	99
NO_x (thousand tons)	64	67	69	69	70	61
SO_2 (thousand tons)	83	99	104	103	105	78
Mercury (tons)	0.7	0.8	0.8	0.8	0.8	0.7
Rest of Nation[c]						
Average electricity price (1999$/MWh)	$66.7	$66.8	$66.8	$66.8	$66.8	66.8
TOTAL generation (billion kWh)	4,878	4,882	4,883	4,885	4,882	4,880
CO_2 reduction nation, 2008–2025 (million tons)	283	284	234	190	199	241
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

[a] Coal-fired generation counts twice.

[b] Numbers may not sum because of rounding.

[c] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 13. Change in Economic Surplus from Baseline (Social Cost), Mixed Cases, 2025 (billion 1999$)

Eligibility:	*Generators*	*Generators*	*Emitters*	*Emitters*	*Emitters*	*Emitters*
Basis:	*Auction 20%/ Recent gen. 80%*	*Auction 50%/ Recent gen. 50%*	*Auction 50%/ Historic gen. 50%*	*Auction 50%/ Historic emissions 50%*	*Auction 50%/ Historic emissions 50%[a]*	*Auction 50%/ Recent gen. 50%[a]*
RGGI region						
Consumers	–0.2	–0.9	–1.8	–1.6	–1.8	–0.9
Producers	–0.7	–0.6	0.3	0.2	0.3	–1.0
CO_2 revenue	0.5	1.1	0.9	0.9	0.9	1.4
SUBTOTAL[b]	–0.5	–0.5	–0.6	–0.5	–0.6	–0.5
Rest of nation[c]						
Consumers	–0.7	–0.9	–1.1	–1.0	–1.0	–1.2
Producers	0.6	0.8	1.4	1.2	1.4	1.3
SUBTOTAL[b]	–0.1	–0.1	0.2	0.2	0.3	0.0
National TOTAL[b]	–0.6	–0.6	–0.4	–0.3	–0.3	–0.5
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

[a] Coal -fired generation counts twice.

[b] Numbers may not sum because of other categories including change in tax credit costs.

[c] Includes the MAAC region of NERC outside the RGGI region.

Table 14. Change in Net Present Value of Generation Assets from Baseline, Mixed Cases (1999 $/kW)

Eligibility:	*Generators*	*Generators*	*Emitters*	*Emitters*	*Emitters*	*Emitters*
Basis:	*Auction 20%/ Recent gen. 80%*	*Auction 50%/ Recent gen. 50%*	*Auction 50%/ Historic gen. 50%*	*Auction 50%/ Historic emissions 50%*	*Auction 50%/ Historic emissions 50%*[z]	*Auction 50%/ Recent gen. 50%*[a]
RGGI region						
Gas	7	14	28	5	11	4
Coal	–221	–198	–88	–77	–50	–222
Nuclear	49	51	68	53	62	40
Average ALL[b]	–13	–8	32	14	19	–21
MD and PA[c]						
Gas	–4	14	27	11	21	6
Coal	39	46	54	50	59	59
Nuclear	35	47	56	48	52	55
Average ALL[b]	14	24	33	23	28	25
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

[a] Coal-fired generation counts twice.

[b] ALL includes all generation capacity including types not listed separately.

[c] Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 15. Overview of Constrained Cases

Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:	*None*	*Higher gas price*	*Higher gas price & transmission limits*	
RGGI region	Standard baseline		Constrained baseline	
Average electricity price (1999$/MWh)	$103.4	$112.2	$108.4	$112.7
TOTAL generation (billion kWh)	393	345	386	347
Coal	73	50	74	49
Gas	130	96	97	97
Nuclear	107	108	108	108
Renewable	34	47	37	47
New capacity[a] (GW)	28	30	28	30
Gas	23	22	22	22
Renewable	5	8	6	8
CO_2 price (1999$/ton)	n/a	$20.6	$0.0	$20.5
Emissions				
CO_2 (million tons)	147	99	149	100
NO_x (thousand tons)	118	76	115	77
SO_2 (thousand tons)	193	127	250	130
Mercury (tons)	1.2	0.8	1.2	0.8
Rest of nation[b]				
Average electricity price (1999$/MWh)	$66.6	$67.5	$67.2	$67.5
TOTAL generation (billion kWh)	4,847	4,867	4,838	4,864
CO_2 reduction for nation cumulative (2008–2025)	n/a	n/a[c]	n/a	238[d]
Model	BL	HegGhi	BLT10Ghi	HegT10Ghi

[a] Numbers may not sum because of rounding.

[b]Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

[c]No baseline was run for only high natural gas prices.

[d] Compared with Constrained Baseline.

Table 16. Change in Economic Surplus from Standard Baseline (Social Cost), 2025, Constrained Cases (billion 1999$)

Eligibility:	*Emitters*		*Emitters*
Basis:	*Historic generation*		*Historic generation*
Constraints:	*Higher gas price*	*Higher gas price & electricity transmission limits*	
RGGI region	Standard baseline	Constrained baseline	
Consumers	–3.8	–2.2	–4.0
Producers	2.4	1.0	2.6
CO_2 revenue	0.0	0.0	0.0
SUBTOTAL[a]	–1.5	–1.2	–1.5
Rest of nation[b]			
Consumers	–4.1	–2.4	–4.0
Producers	2.8	0.9	2.9
SUBTOTAL[a]	–1.9	–2.3	–1.7
National TOTAL[a]	–3.4	–3.5	–3.2
Model	HegGhi	BLT10Ghi	HegT10Ghi

[a] Numbers may not add because of other categories including change in tax credit costs.

[b] Includes the MAAC region of NERC outside the RGGI region.

Table 17. Net Present Value of Generation Assets in Baseline, Changes from Standard Baseline for Constrained Cases (1999$/kW)

Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:		*Higher gas price*	*Higher gas price &electricity transmission limits*	
RGGI region	Standard baseline		Constrained baseline	
Gas	–273	47	1	54
Coal	434	147	154	156
Nuclear	611	208	146	206
Average ALL[b]	164	125	76	124
MD and PA[a]				
Gas	–255	–14	–13	–11
Coal	364	161	78	145
Nuclear	653	173	87	157
Average ALL[b]	229	94	47	77
Model	BL	HegGhi	BLT10Ghi	HegT10Ghi

[a] Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

Table 18. Overview of RPS Case

Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:	*None*	*None*	*RPS*	*RPS*
RGGI region	Standard baseline		RPS baseline	
Average electricity price (1999$/MWh)	$103.4	$107.1	$103.3	$106.0
TOTAL generation (billion kWh)	393	348	387	350
Coal	73	48	70	55
Gas	130	115	107	97
Nuclear	107	108	107	107
Renewable	34	40	57	54
New capacity[a] (GW)	28	31	31	33
Gas	23	24	21	23
Renewable	5	6	10	9
CO_2 price (1999$/ton)	n/a	$18.1	n/a	$15.6
Emissions				
CO_2 (million tons)	147	100	133	99
NO_x (thousand tons)	118	70	110	76
SO_2 (thousand tons)	193	101	190	120
Mercury (tons)	1.2	0.8	1.2	0.9
Rest of nation[b]				
Average electricity price (1999$/MWh)	$66.6	$66.8	66.7	66.9
TOTAL generation (billion kWh)	4,847	4,885	4,844	4,875
CO_2 reduction for nation cumulative (2008–2025)	n/a	201	n/a	141[c]
Model	BL	Heg	RPS_BL	Heg_RPS

[a] Numbers may not sum because of rounding.

[b] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

[c] Compared with RPS Baseline.

Table 19. Change in Economic Surplus from Standard Baseline (Social Cost), 2025, RPS Case (billion 1999$)

Eligibility:	*Emitters*		*Emitters*
Basis:	*Historic generation*		*Historic generation*
Constraints:	*None*	*RPS*	*RPS*
RGGI region		RPS Baseline	
Consumers	–1.6	0.0	–1.1
Producers	1.2	0.6	1.3
CO_2 revenue	0.0	0.0	0.0
SUBTOTAL[a]	–0.5	0.5[c]	0.0[c]
Rest of nation[b]			
Consumers	–1.2	–0.7	–1.4
Producers	1.5	0.0	1.1
SUBTOTAL[a]	0.2	–1.4[c]	–1.0[c]
National TOTAL[a]	–0.3	–0.9	–1.0
Model	Heg	RPS_BL	Heg_RPS

[a] Numbers may not add because of other categories including change in tax credit costs.

[b]Includes MAAC outside RGGI.

[c]Subtotal includes cost of federal tax credits.

Table 20. Net Present Value of Generation Assets in Baseline, Changes from Standard Baseline for RPS Case (1999$/kW)

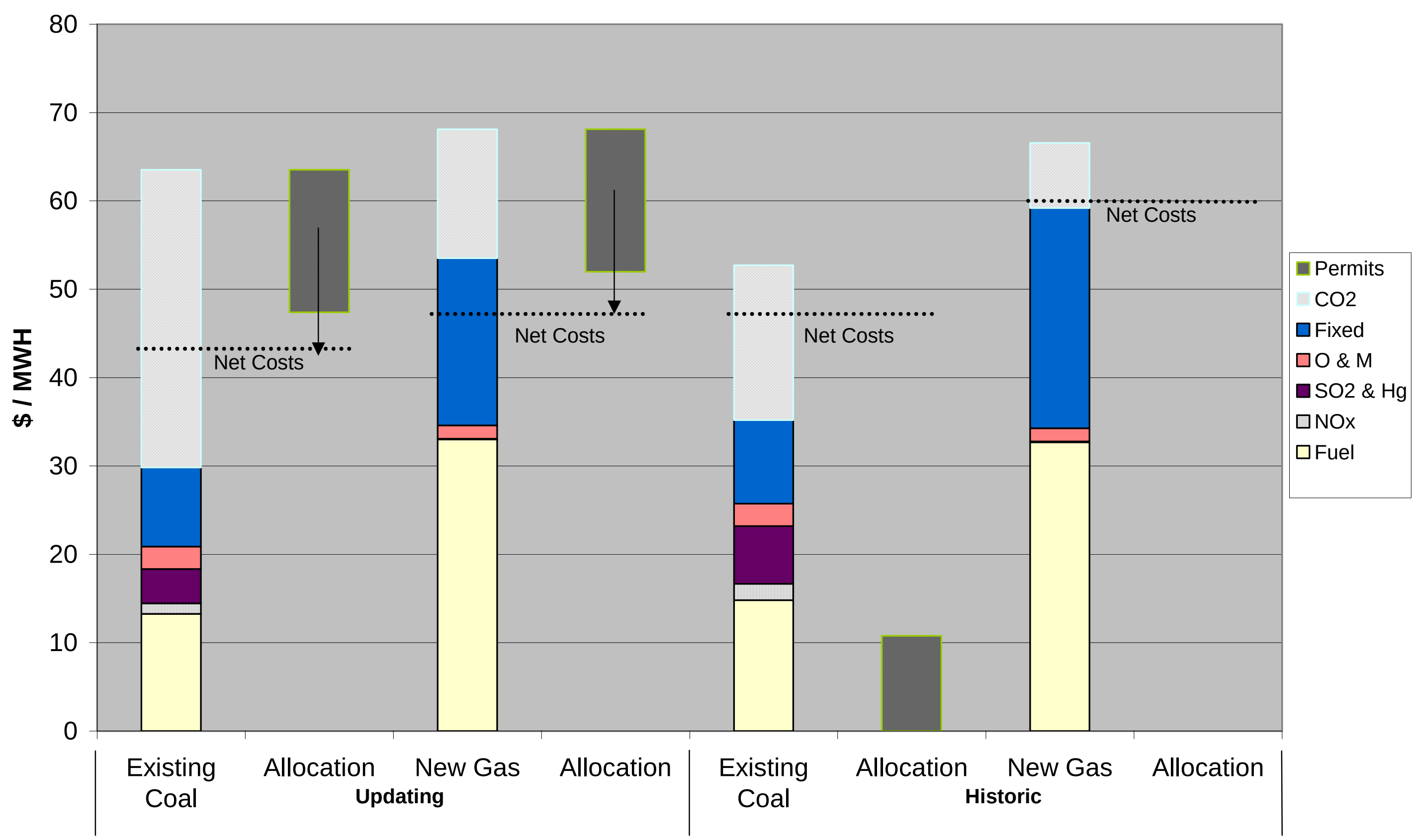
Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:	*None*	*None*	*RPS*	*RPS*
RGGI region	Standard baseline		RPS baseline	
Gas	–273	54	–18	27
Coal	434	8	3	–20
Nuclear	611	67	–17	28
Average ALL[b]	164	60	13	50
MD and PA[a]				
Gas	–255	6	26	7
Coal	364	50	0	26
Nuclear	653	51	–9	26
Average ALL**	229	23	14	20
Model	BL	Heg	RPS_BL	Heg_RPS

[a] Maryland and portion of Pennsylvania within the MAAC region of the NERC and outside the RGGI region.

[b] ALL includes all generation capacity, including types not listed separately.

Figures

Figure 1. Going-Forward Costs for Existing Coal and New Gas Under Dynamic and Historic Allocation, 2025



Notes: Hg = mercury; O&M = operations and maintenance.

Figure 2. Change in Value of Existing and New Generation Assets Compared with Baseline

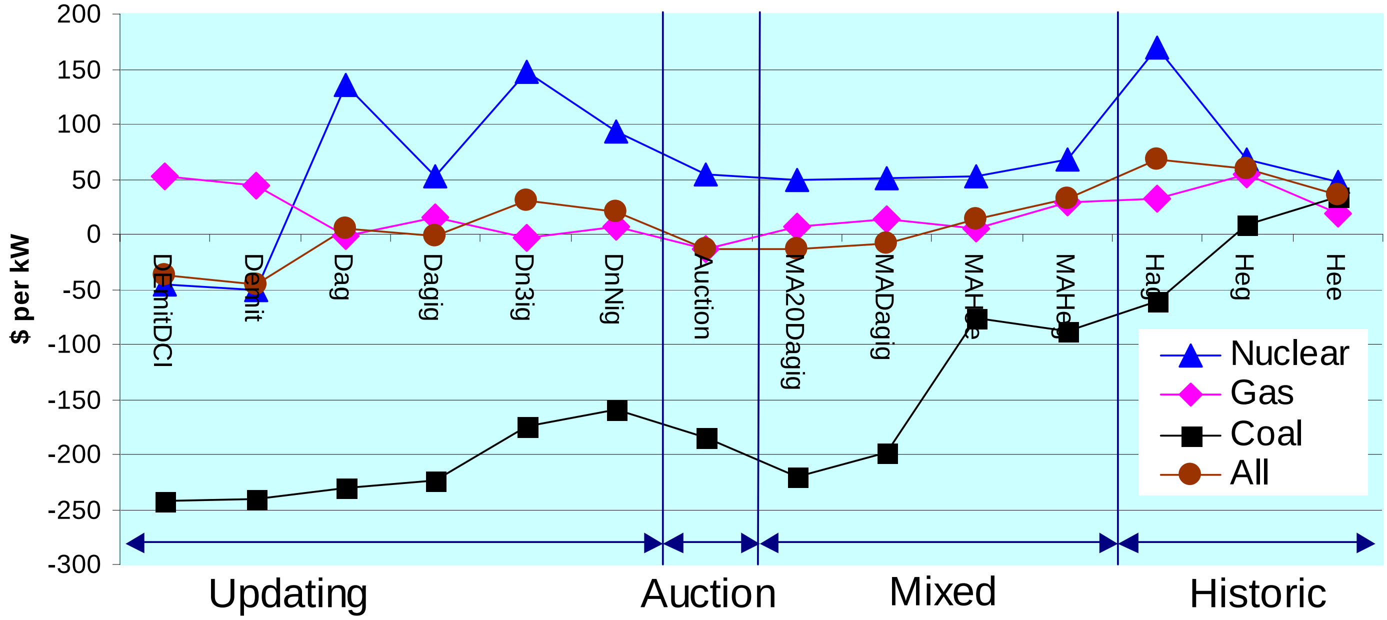
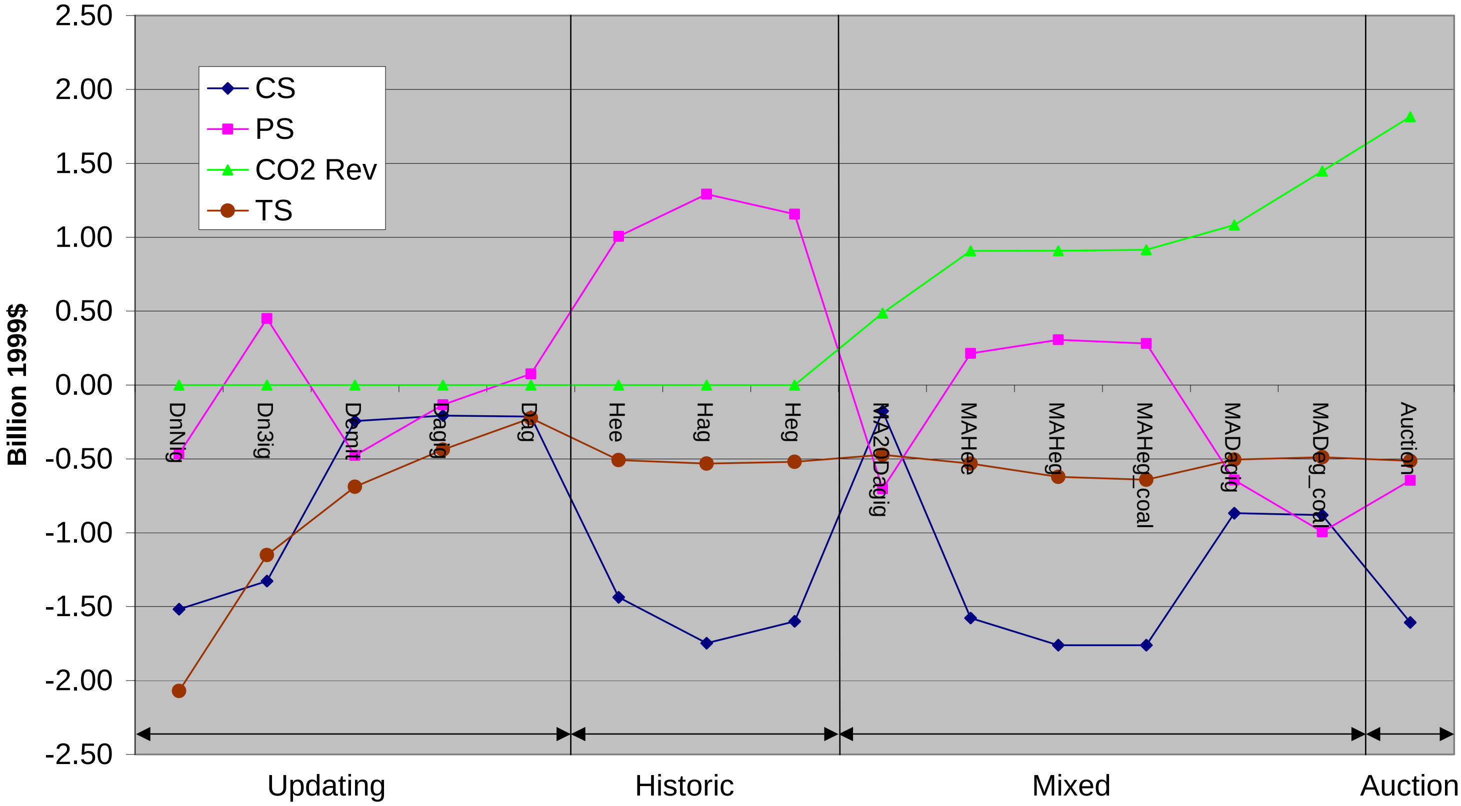


Figure 3. Change in Surplus within RGGI from Baseline, 2025



CS = consumer surplus, PS = producer surplus, CO2 Rev = CO_2 revenue, TS = total surplus.