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

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Summary

The emissions cap and trade approach to controlling air pollution has become widely accepted as the preferred approach to reducing pollution in a cost-effective manner. One of the important design questions in a trading program is how to initially distribute the emission allowances. Under the Acid Rain program created by Title IV of the Clean Air Act, the vast majority of emission allowances were distributed based on a historic measure of electricity generation, known as grandfathering, to current emitters. Recent proposals have suggested alternative approaches. One alternative is allocation according to a formula that is updated over time based on some performance metric in a recent year. The basis for this formula can be the share of electricity generation or something else. Another alternative is auctioning allowances to the highest bidder.

Prior research has shown that the manner in which allowances for carbon dioxide 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 environmental policy. Another concern with a regional cap and trade program like RGGI is the effect of different approaches to allocating emission allowances on the level of CO_2 emissions outside the region, also known as "leakage."

In this research we compare approaches to historic, auction and updating mechanisms that we label as "bookends," and subsequently we vary the design of these approaches. We consider changes in measures such as electricity price, the mix of generation, and 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. Also, we examine the effect of different approaches to distributing allowances on the net present value of generation assets inside and outside the region.

We find that how allowances are allocated has an effect on electricity price and consumption, and on 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 falls under all approaches, but it falls the most under updating. Gas-fired generation falls under

historic and auction approaches, but increases substantially under updating. Renewable generation increases under historic and auction approaches, but falls slightly under updating as a consequence of the expanded generation from gas. Consistent with the change in the composition of generation, the decline in emissions of conventional pollutants including SO_2, NO_x and mercury that was expected as a result of the Clean Air Interstate Rule is accelerated substantially due to the RGGI policy, particularly under the updating mechanism. There is an associated sizeable decline in the cost of complying with SO_2, NO_x and mercury rules.

We find that the social costs of the bookend auction and historic approaches are comparable, and that the social cost of updating is roughly 3 times that of the other approaches. At the same time updating yields greater emission reductions on a national basis because it produces less leakage of emissions and greater cumulative reductions in emissions at the national level than under 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 we mix the approaches to allocation 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 loses from the policy varies across the different approaches to allocation. Producers in the RGGI region gain substantially under a historic approach and in the aggregate they are better off than in the absence of the program. This is not true under an auction or updating approach. Producers in the aggregate also gain 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 due to the higher electricity price in the RGGI region, but they benefit the least under updating because the effect on electricity price is least under updating.

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

Different types of generators fare differently under the various approaches to allocation. Asset values for all types of generators are highest under a historic approach, although the difference between historic and auction is small for nuclear generators. Both nuclear and existing gas generators in RGGI gain under an auction relative to the baseline. Only gas 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 to this is that moving from 50% auction and 50% updating to a 100% auction has a negative effect on the asset values for coal.

Finally we look at a sensitivity analysis with higher natural gas prices or transmission constraints. The social cost of the RGGI program does not appear to be sensitive to the existence of these constraints. Higher gas prices or transmission constraints by themselves impose significant costs that are larger than the effect of adding the RGGI policy. For example, they have a substantial effect on electricity price that is greater than the added effect imposed by the RGGI program. The constraints that are modeled do not appear to have a potent impact on the implementation of the RGGI.

Key Words: emission 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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Allocation of CO_2 Emission Allowances in the Northeast Regional Greenhouse Gas Cap-and-trade Program

Dallas Burtraw, Karen Palmer and Danny Kahn*

1. Introduction

The Regional Greenhouse Gas Initiative (RGGI) is an effort by nine Northeastern and Mid-Atlantic States to develop a regional, mandatory market-based cap-and-trade program to reduce greenhouse gas emissions. The effort was initiated formally in April 2003 when New York Governor George Pataki sent letters to fellow governors in the Northeast and Mid-Atlantic states, and each of the nine participating states has assigned staff to a working group that is charged with developing a proposal in the form of a model rule by April 2005. Initially, the program will address carbon dioxide (CO_2) emissions from the electric power sector. If successful, this program could serve as a model for a future national cap-and-trade program for greenhouse gases (GHGs).

One of the most important and contentious features of an emissions trading program is how allowances are distributed initially. Several different approaches for the distribution of emission allowances have been considered in other regulatory contexts. One such approach is to distribute allowances based on **historic** measures of electricity generation. This approach is often termed “grandfathering” because it distributes allowances without charge to incumbents in the industry.

Another approach is to regularly **update** the calculation underlying the distribution of allowances based on current year or recent year data. Like historic based distribution, an updating approach distributes allowances without charge and could also distribute according to any of a variety of measures such as share of electricity generation, share of emissions, or share of heat input (related to fuel use) at a facility.

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The primary alternative to these free approaches to distribution of allowances is to sell allowances through an **auction**, or alternatively to distribute allowances for free to third parties such as energy consumers or their trustee, who then may distribute 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 they could be used to offset other needs for tax revenue by government.

Each of these approaches has proponents and each has precedent. The most well-known emission cap-and-trade program - the sulfur dioxide (SO_2) emission trading program initiated under the 1990 Clean Air Act Amendments – distributes allowances primarily based on an historic measure of generation (heat input) at electricity generating facilities. The second large trading program in the United States is the NO_x regional cap-and-trade program in nineteen eastern states. In 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 emitters share of electricity generation.[1] An auction also has precedent, for example in the State of Virginia, which distributed a small portion of their NO_x allowances in the regional cap-and-trade program through a revenue raising auction. Recent legislative proposals for 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 the initial distribution of allowances, but several theoretical and policy studies have examined efficiency and distributional issues. These studies have examined a variety of pollutants, and the findings in these studies differ somewhat with respect to 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 region has its own mix of technologies for electricity generation that will have a direct bearing on the evaluation of different 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 a challenge in the enforcement of the policy. Any environmental policy that increases

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

costs in the region is likely to cause some leakage of emissions to outside the region as economic activity or electricity generation moves in order to avoid the regulation. It is noteworthy that the northeast region faces relatively high natural gas prices and electricity prices compared to other parts of the nation.

There are two major types of issues that affect the choice of 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 differing ways through changes in value of generation assets. **Economic efficiency** affects everyone and concerns cost-effectiveness of the program within the electricity sector. 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 a variety of ways.
- What are the distributional consequences? Attention can be focused on the distribution between consumers and producers, and among producers who 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 tradeoffs?
- Are there combinations of auctioning (or “grandfathering to consumers”, a form of auctioning) and no-cost allocation that would compensate companies but still provide for an efficient outcome?

In the progress of the research additional questions surfaced, and these also are discussed below.

1.2. Summary of Findings

In brief, we find:

- ✓ 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 the distribution of allowances offers a potentially important source of compensation.
- ✓ Due to 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 an auction and of a historic approach are similar. However, producers gain substantially under an historic approach and in the aggregate they are better off than in the absence of the program.
- ✓ Updating will yield a higher allowance price, a lower electricity price, more electricity generation in the region than the other approaches.
- ✓ But, the social cost of an updating approach is about three times greater than for an auction or historic approach.
- ✓ Updating is worse for electricity producers than either historic or auction approaches.
- ✓ Coal-fired generation falls under all approaches but it 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 or auction approaches, and is less with updating.
- ✓ Emissions of conventional pollutants in the RGGI region fall substantially under all approaches to allocation, but they fall the most with updating.
- ✓ The cost of complying with SO_2, NO_x and mercury rules falls considerably within the RGGI region due to 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. This comes at the expense of costs imposed outside the region.
- ✓ Combining approaches generally leads to intermediate outcomes.

- ✓ Variations in baseline assumptions such as higher natural gas prices or transmission constraints tend to benefit producers in the aggregate 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 sensitive to the existence of natural gas or transmission constraints.

1.3. Conceptual Background

The distribution of allowances is one of the most contentious issues faced by policy makers when they design a cap-and-trade program. Allowances are a valuable asset, and the distribution of this asset has both equity and efficiency implications. 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 by compensating consumers for high prices, communities that are severely affected, or making investments in energy conservation. Alternatively, the revenues from auctioning allowances may have economy-wide efficiency benefits if they are used for reducing taxes.

On the other hand, companies participating in a cap-and-trade program usually oppose auctions. Companies argue that because they bear the costs of emission reduction obligations they should not also have to bear the cost of acquiring an initial endowment of (tradable) emission allowances. The net cost to producers of the emissions trading program depends on the difference between their change in revenue and their change in cost. Regardless of the way that allowances are distributed, firms are expected to pass through in product prices some of the resource cost associated with reducing emissions and some of the opportunity cost (market value) of emission allowances, causing revenues to increase. The justification for free distribution of emission 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 acquiring allowances.

The degree to which producers pass on in electricity prices the resource costs and allowance costs varies with the presence or absence of regulation of prices, and with the technology that sets marginal cost in competitive regions. In the case of nationwide regulation of CO_2, Burtraw et al. (2002) find that free allocation of emission allowances can dramatically over-compensate the electricity industry in the aggregate, although different parts of the industry will be 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 over compensate industry. A central issue for the RGGI planners is whether the free allocation of CO_2 emission allowances in the northeast region provides a level of compensation that is proximate to the compliance costs, or potentially a level of compensation that could surpass the compliance cost, perhaps by a significant degree.

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 literatures have sprung up with regard to economic costs or efficiency issues in general of emission permit trading programs. One literature explores the role of pre-existing 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). This literature has relied 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. 1999, Goulder et al. 1997 , Parry et al. 1999, Smith et al. 2002). The analysis has examined cap and trade programs for CO_2, SO_2 and NO_x in competitive product markets (electricity regulation is not considered explicitly), and results favor an auction as the most efficient approach to distributing emission allowances initially when the revenues are used to reduce pre-existing taxes. In this paper we do not consider these issues.

A second literature, to which this paper contributes, examines the role of pre-existing 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 emission allowances results in a substantially lower social costs than does either an updating approach based on output or a historic approach (Burtraw et al. 2001, 2002; Beamon et al. 2001). This result is attributable in large part 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 emission allowance given to a firm for free under either an updating or historic approach is not directly reflected in the price of electricity, e.g. 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 amplify or diminish the gap between regulated prices and efficient prices. Typically, though, it tends to close 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 an auction and a historic approach to distributing allowances from an efficiency perspective. In one case the revenues go to government, in the other they go to industry, but investment and compliance behavior is expected to be nearly identical and hence so is the change in electricity prices. In competitive electricity markets an updating approach is expected to have greater social costs than an auction or historic approach because it does not provide the same incentive through higher prices for consumers to improve the 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 (Bluestein, 2003). An updating approach provides generators with an incentive to increase generation by all sources because of the implicit output subsidy, while 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 greater generation with natural gas and less generation with coal.

Another issue of central interest to RGGI is the leakage of electricity generation, CO_2 emissions, and economic activity to outside the RGGI region. For instance, leakage could be the result of a decision by electricity generators to use power plants outside the region to generate more electricity that can be imported into the region over the transmission grid. Leakage could also occur through the decision of electricity customers to self-generate rather than purchase electricity off the grid if electricity prices increase. Previous analysis suggests that the method of distributing emission 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 change 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, producer profits, etc. 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 IPM model 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 simulation model would be expected to track very closely to the more comprehensive effort were both conducted with the same 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 a larger number of 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, and variations among these options, while preserving the important quantitative and qualitative differences among these 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 emission 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 tradeoffs among approaches. Subsequently, we investigate a number of variations on the bookend approaches, a mix of approaches, or changes in the baseline parameters.

The level of aggregation in the model has 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. Moreover the model captures the differentiation among fuels and technologies and the effects that policies have 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 high and low electricity price within a region 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 units. In several states in the RGGI region, when nuclear plants and others 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 marginal cost of electricity sold in shorter term markets. The reason is that the retailer who has purchased power under long-term contract with a generator could turn around and sell that power in the spot market where the RGGI policy could be impacting costs of the marginal generator and thus it is the spot market price that defines the opportunity cost of selling power to retail customers. This means that electricity retailers (not explicitly represented in our model) will profit from the RGGI policy at the expense of those generators who have their power committed for sale under long-term contracts. Thus, the existence of long-term contracts for wholesale power will affect those among the different producers and retail suppliers who profit from the RGGI policy, but it will not affect the cost to consumers in a competitive market. [2]

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

2.1. Modeling Scenarios

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

2.1.1. Central Case Baseline

Throughout this analysis, we make several assumptions about underlying policies, both federal and state environmental policies and market regulatory policies, that affect the performance of electricity generators. In the baseline we assume electricity generators face requirements under the NO_x SIP Call, Title IV of the 1990 Clean Air Act Amendments and the draft Clean Air Interstate Rule (CAIR) for SO_2, NO_x and associated mercury rule of the Bush administration. The seasonal NO_x SIP Call for 19 eastern states is in force for 2008 and then replaced by the annual NO_x constraint for a 28 state region under CAIR for the other simulation

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[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 price is 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 effect during the transition period.

years.[3] The annual emission constraints for SO_2 are drawn from 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 due to 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. The NO_x caps include an adjustment of about 331,000 tons for units outside the CAIR NO_x region but within the MAPP and New England electricity regions in the model.

The national annual allocation of mercury emission allowances is to be capped at 34 tons beginning in 2010 and 15 tons beginning in 2018. We model cap-and-trade for mercury, and we adopt as our Hg emissions cap EPA's prediction of annual emissions in the presence of a $35,000 per 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, emission allowances are distributed on a historic basis.

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 renewable portfolio standards (RPS) and other state-level renewables policies and programs including green pricing on investment in new

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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.

[5] NSR settlements are those that electricity generating companies have reached with the federal government to bring their plants into compliance with New Source Review requirements for emission reductions that the government claims were violated by past investments at specific facilities.

renewables, we incorporate 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 and Pennsylvania in our central baseline case or policy cases. We expect these policies could reduce emissions in the baseline (e.g. in the absence of the RGGI policy), reduce CO_2 allowance price, reduce investment in gas-fired generation, reduce incremental compliance cost and reduce leakage. We conduct a sensitivity analysis of the baseline and historic bookend cases to identify the effects of including the RPS on one of the RGGI policy cases. The emission reductions in our model could therefore be thought of as a more stringent policy on CO_2 because greater emission reductions from the baseline are required. We also include the anticipated effects of state-level multipollutant policies in the following states: Connecticut, Massachusetts, Missouri, New Hampshire, North Carolina, Texas and Wisconsin.[7]

We assume that electricity prices are set competitively in six NERC regions (New York, New England, mid-Atlantic (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 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 out to 2030 for purposes of calculating returns to investment choices.

2.1.2. Policy Scenarios

In all policy cases the annual CO_2 emission target is set by calculating a 20% decline from 2008 baseline emission levels in the RGGI region, with the emission reduction to be phased in on a linear basis over the time period from 2008 until 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 mid-Atlantic electric reliability region (MAAC). Unless otherwise noted we assume all new fossil fuel (e.g. natural

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[6] We also include the effects of state level RPS policies in Arizona, California, Nevada, Texas, and Wisconsin. It includes 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 generators.

gas) plants built in the mid-Atlantic region in the baseline and in all policy cases are built outside the RGGI region – that is, we assume they are built in Maryland and Pennsylvania. Where, in fact, plants are located when they are 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 that we have no constraints on transmission within the mid-Atlantic region then, other things equal, it makes sense that a plant locating in the region would locate where it could escape the constraints of the RGGI program. This model design is one way in which leakage estimated in these model runs are likely to over-estimate the actual leakage that would occur. Hence, we do not focus on the quantitative magnitude of leakage but instead compare the different approaches to allocation in qualitative terms.

Furthermore, when non-emitting renewable plants qualify for allocation of emission allowances, we assume that all new plants built in the mid-Atlantic region qualify. This assumption is for modeling convenience but it also accounts for the expectation that a qualifying facility would be more likely to locate on the RGGI side of a political boundary, other things equal, if it could realize a reduction in costs by doing so. 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 distribution of emission allowances that we analyze are historic (to emitters based on historic generation in 1999), an auction, and updating (to emitters based on recent year generation with two year lag). Variations for each bookend case are listed in Table 1. Two choices characterize each scenario: Who is eligible for emission 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 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$ over the time horizon from 2003 until 2030 and valued according to the usual method used in benefit-cost analysis. This 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 as 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, compensate those who are adversely affected by the program, or put to 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 emission fees is greater than face value when that revenue is used to offset pre-existing 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 just one measure of public policy. Equity and other concerns may override efficiency. An increase in electricity price may be viewed as efficiency enhancing, 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 NPV of producer surplus of electricity generators of different types over the time horizon from 2003 until 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 RFF's electricity market model, Haiku, to analyze the effects of different approaches to allocation under a RGGI GHG cap-and-trade program focused on the electricity sector.[8] The Haiku model looks at the effects of the policies on the behavior of electricity producers and consumers and the resulting implications for costs, prices to consumers and the level and location of emissions. The model 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 a geothermal plant. Factor prices, such as the cost of capital and labor, are held constant, and fuel price forecasts are calibrated to match EIA price forecasts (U.S. 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 3 customer classes, with demand divided across 3 seasons and four time blocks within each season. The quantity of electricity demanded 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 and other sources. Electricity trade between regions is also allowed subject to transmission losses and physical transmission constraints.

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[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, which include coal, natural gas, oil, hydro, and nuclear. There are steam plants that run on oil as well as gas turbine plants that run on oil. The same is true for natural gas. Coal is a little different from the other fuels in that it is divided into 14 subcategories based on the region the coal is from and its level of sulfur content. The users of coal are broken down into demand regions that have different costs associated with each type of coal, which reflect the varying interregional transport costs. Model plants might switch the type of coal they use in order to reduce their SO2 or mercury emissions, which may be more cost effective than installing new pollution controls.

3. Results for "Bookend Scenarios"

In this section results are presented first for a set of "bookend scenarios" that are compared to a baseline that represents a forecast in the absence of the regional greenhouse gas initiative. In the following sections the results are presented for a number of 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 due to the implementation of the Clean Air Interstate Rule (CAIR). State multi-pollutant rules that are not modeled would add to this trend.

However, CO_2 emissions in the baseline are shown to rise by 20% over the same period on a national basis and by nearly the same rate within the RGGI region. The CO_2 emissions in the RGGI region in 2008 form the basis for calculating emission targets. Under the RGGI targets CO_2 emissions are assumed to decline by 20% in a linear manner between 2008 and 2025, leading to an emission target in 2025 of 100 million tons.

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

The policy bookends include 100% allocation through each of three different mechanisms. The historic approach would distribute allowances to emitters of CO_2 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. The updating approach would distribute allowances to emitters based on their share of total generation by emitters two years previously. 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 prices of the three policy scenarios. Similarly, in each case total generation within the region falls relative to the baseline, but it falls the least - by less than one-half as much - under the updating approach compared to the other approaches. This attribute of updating follows from the incentive to increase electricity generation in order to earn a larger award of emission allowances.

Coal-fired generation falls under all approaches, but it 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 it increases substantially under updating. Natural gas has emission rates that are below the average for emitting sources while the emission rates are above average for coal. 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, while under the other approaches gas-fired generation falls by about 12%. The price of CO_2 emission allowances is twice as high in the updating case because of the overwhelming incentive to increase generation from gas, which more than compensates for the decreased average emissions from natural gas sources.

Figure 1 illustrates the going-forward cost of electricity generation for a representative existing coal plant and for a new natural gas combined cycle plant in the RGGI region. “Going-forward costs” are the costs of bringing power from this plant to market in the future. This includes fuel cost, fixed costs and operating and maintenance (O&M) costs. For existing and new plants it includes new capital investments in post-combustion pollution controls, operational costs, and the cost of emission allowances net of the allocation of permits in order to comply with the CAIR rule. For a new plant it also includes capital cost.

The component labeled CO_2 in Figure 1 represents the addition to going-forward cost associated with the opportunity cost of using CO_2 allowances under RGGI policy. The component labeled “permits” represents the value of the allocation of CO_2 permits to the plant. In the (bookend) updating case, emission allowances are earned by generating electricity and their value is subtracted from other costs to arrive at the net costs of generation in the future. Since the change in net cost is less than the change in gross costs, 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 MWh 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 while it is greater than the CO_2 cost at the new natural gas plant. Net costs at the coal plant of about $48/MWh remain slightly below the net costs at the gas plant of about $52/MWh. Nonetheless the difference in costs nearly disappears compared to the difference in the absence of the RGGI CO_2 policy, where the cost of the coal plant of $30/MWh is substantially less than the cost of $53/MWh at the gas plant.

With the bookend historic approach, only the existing coal plant earns an allocation. The plant is endowed with the allowance value whether or not it generates electricity. Hence, the value is not subtracted from going-forward costs. One can also note that the magnitude of the CO_2 costs is much smaller with a historic approach than with an updating approach because the price of emission allowances is less.

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 per MWh of SO_2 and mercury (Hg) control at the existing coal plant is greater under historic allocation of CO_2 emission allowances than under updating. This is due primarily to the cost of acquiring allowances for SO_2 and mercury in excess of 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 generation 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 MWh are greater under the historic approach when the plant is more heavily utilized 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 is even less than under the baseline. 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 emission allowances.

The decline in emissions of conventional pollutants in the northeast is accelerated dramatically under RGGI. Emissions are expected to fall substantially over time in the baseline. However, the RGGI policy dramatically accelerates this trend. Emissions of

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[10] This "representative plant" is a "model plant" in the simulation model that aggregates constituent plants of similar technological characteristics, and 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 to updating, and the amount of wet scrubbers in place is greater in absolute terms but less in proportion to generation capacity. The unscrubbed capacity uses more expensive, lower sulfur fuel.

conventional pollutants fall in all cases, but as a consequence of the shift in generation away from coal to natural gas, the emissions of conventional pollutants are substantially less under an updating approach than under a historic or auction approach. Annual emissions of NO_x are reduced by over 40% and annual emissions of SO_2 are reduced by about 46% under the historic and auction mechanisms. Under updating the annual emissions of NO_x are reduced by over 65% and annual emissions of SO_2 are reduced by 81% from baseline levels. Mercury emissions are reduced by almost as large of a percentage. In every case, however, nationally there is no change in emission of NO_x, SO_2 or mercury due to emissions caps, so that 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 under a historic and auction approach are about $100 million, and under the updating approach they are about $180 million. Also there is a reduction in the use of SO_2, NO_x and mercury emission allowances. In 2025 the reduction in emissions leads to savings on emission allowances of about $80 million under the historic and auction approaches, and savings of about $250 million under the updating approach. Total avoided cost of compliance with SO_2, NO_x and mercury rules is about $180 million under the historic and auction approaches, and about $436 million under updating.

Leakage of CO_2 emissions to outside the RGGI region is the least under an updating approach. In almost all cases the greatest decrease in CO_2 emissions at the national level occurs with updating. We find an increase in generation outside the RGGI region in order to import power into RGGI from plants not subject to the emissions cap. However, the incentive to increase generation within the region under an updating approach offsets this to some degree and causes there to be less leakage of emissions to outside the region.

In all scenarios there is an increase in electricity price for the rest of nation due to the increased demand for electricity to be imported into the RGGI region that is not subject to the emissions cap. The demand for generation from outside the RGGI region drives up marginal cost in the regions supplying power leading to higher prices. Nationally, leakage is least and the reduction in emissions is greatest with the updating approach.

The 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 price 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, which has a big effect on the calculation of leakage for the whole horizon. This highlights the importance of modeling institutions that may be put in effect to mitigate leakage properly, and to focus on the proper metric. One may reasonably question whether forecast changes at the national level in 2025 under a RGGI policy, with the rest of the country pursuing a business-as-usual policy, have meaning. 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 reductions in emissions 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 emission 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) for the year 2025 are reported.

The social cost of the auction and historic approaches are the same, but who bears the cost differs. The auction and historic approaches have virtually identical social cost of about $300 million in 2025. The auction imposes substantial cost on consumers that is offset by government revenue that can be expected to flow back to households through their role as 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 they receive the value of the emission 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 because the lower electricity price means less revenue per unit of electricity generated. The total social cost within the electricity sector in RGGI for the updating approach is $700 million, or 40% greater than that of the other approaches.

Under the historic and auction approaches, there are slight increases in total economic surplus outside the RGGI region due to the allocation of resources to supplying electricity to the region. However, a sizeable redistribution between consumers and producers occurs. Producers outside the RGGI region that supply power back to the 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 region occurs under updating, but the net effect is a drop in total surplus.

In the aggregate producers realize the lowest value of existing generation assets under updating. Table 5 presents a summary of the change in the net present value of generation assets in the baseline and the change in value under each approach. This differs from the change in producer surplus reported in Table 4 because that was a snapshot for 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, although under an auction the change is slightly negative. Existing gas-fired generation benefits under all approaches. There is no new coal or nuclear capacity built in the region, so the change in asset value applies only to existing assets. Coal-fired assets just break even under historic allocation, and they do the worst under updating, losing substantial value relative to the baseline. Existing nuclear assets benefit substantially under a historic or auction approach compared to the baseline. However, they lose value under the updating approach, which has a lower electricity price than under historic and auction approaches, and which leads to lower variable costs for gas units that qualify for allowances, thereby pushing some incremental nuclear out of the dispatch order. In variations of updating discussed below we find that when nuclear units qualify for emission allowances they do substantially better.

When all types of assets are aggregated together, the net present value of generation assets increases by about 35% under historic allocation and decreases slightly under an auction. The fact that industry can benefit or be virtually unaffected from the auction may appear to be a paradox, but it can result due to several factors including the long-lived nature of capital investments, the distribution of capital intensity, emission intensity and fuel intensity of different technologies for generating electricity, and the variation in the electricity demand over time of day. Meanwhile, under the updating approach to free allocation of emission allowances, the value of generation assets in the aggregate declines by about 27%.

In Maryland and that portion of Pennsylvania that constitute the portion of the MAAC region outside the RGGI region, the change in net present value 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 provides an illustration of the change in 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, which are composed of only existing plants since no new plants are built, and gas, which includes both existing and new plants. The aggregate overall generation technologies for the industry is also represented with the label "All." The three bookend cases we have discussed heretofore are indicated by the labels: Heg (Historic), Auction and Demit (Updating). Labels at the bottom of the graph provide a mapping between the label for each scenario and the general type of approach; to identify precise mappings one must compare the label with the titles provided 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 updating bookend, which was discussed above, when natural gas generation expands and there is little change in electricity price. However, in the cases when nuclear earns an allocation it does substantially better, as indicated by the peaks in its line graph.

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

The change in value for the industry in the aggregate is a weighted average of changes in the value of individual plants. Hence, while 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 for most other updating approaches and for the auction the industry experiences little change in value in the aggregate. Under historic allocation, however, the industry in the aggregate gains substantial value. 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 variation distributes to all generators on the basis of historic generation.

There is little difference in price and generation among these variations on the historic approach. The overview of electricity price, generation and emissions in Table 6 shows the main difference is that cumulative national CO_2 emissions are much higher under the scenario where allowances are distributed to all generators on the basis of generation.

The differences that emerge among the historic approaches are due largely to the characterization of stranded asset recovery policies in the model. The term “stranded assets” describe generation assets that lost value due to restructuring of the electricity industry. We assume that 90% of stranded assets (and 0% of stranded benefits) are recovered through a surcharge on electricity prices that is expected to continue for ten years after the transition from regulation to competition. We assume the award of emission allowances is considered in the calculation of the value of existing assets and 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 in Table 6.

There is a large difference in the market value of different types of assets under different 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 generators within the RGGI region are significantly better off when permits are distributed to emitters on the basis of emissions because their share of total emissions is higher relative to their share of total generation. Additionally, nuclear generators are much better off under the scenario in which permits are distributed to all generators on the basis of historic generations.

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 eligibility of incremental nonemitters, which include renewable generation and nuclear generation in excess of 1999 levels. Another variation adds eligibility of consumers for reductions in consumption below baseline levels. The institution that would monitor and achieve these reductions is unspecified.

In another variation allowances are distributed only to nonemitters (renewables and incremental nuclear generation), including nonemitters located anywhere in the nation. This 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 approaches provide incentives to expand generation from nonemitters, somewhat analogous to a renewable portfolio standard. Recall that all renewables in the mid-Atlantic region (MAAC) are always included as part of

RGGI when we characterize qualifying renewable generation. When using the label “nonemitters” we are also including incremental nuclear generation.

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

CO_2 allowance price remains relatively high in most of the updating approaches. Total generation in the RGGI region is relatively high except when only nonemitters qualify. The price of a CO_2 allowance is high in the updating runs whenever electricity generation is relatively great because the allowances have a greater opportunity cost. Allowance price is lower, comparable to the auction and historic approaches, when only non-emitters qualify.

It is noteworthy that electricity price in the rest of the nation actually falls below baseline levels in the case when nonemitters nationwide qualify for allowances. Cumulative emission 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 we examine. 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. Furthermore, within the RGGI region the change in social cost is very small, however 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. Distribution to nonemitters imposes large costs within the RGGI region, while benefits accrue outside the region due to subsidized investments outside of the region.

Updating affects different technologies in different ways. In general this depends directly on whether a technology qualifies for distribution, and the value of the allowances in that case. The larger the number of kWh generated that qualify for a share of the allowances, the lower the value to each individual facility. It is noteworthy that compared to the bookend approach, distribution to generators including incremental generation by nonemitters improves the value of every class of generation asset. We offer the following observations:

- The net present value of gas-fired generation does relatively well in most updating approaches.

- The net present value of coal-fired generation suffers under all updating approaches.
- The net present value of nuclear generation benefits substantially whenever it qualifies for a share of allowances under updating, and it 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, in general 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 have more emission reductions at the national level compared to the scenarios that combine an auction with historic allocation.

Changes in economic surplus measures for the combination of an auction with updating are in between those for the auction bookend approach and for the updating bookend approach. 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 auction/historic mixed scenarios, as with each of these approaches taken individually, producers outside the RGGI region benefit considerably due to the opportunity to supply power at a higher electricity price in RGGI. Modifying the combined auction and historic case to compensate coal-fired generators more than gas generators per kWh of historic generation has no effect on the economic surplus costs of that mixed allocation approach.

The changes in the different components of economic surplus in 2025 under the different mixed approaches are compared to the other scenarios in Figure 3. Changes in consumer surplus (CS), producer surplus (PS), CO_2 revenue, and total surplus (TS) are represented in the graph. The policy scenarios are ordered here in terms of the size of the CO_2 auction revenues associated with each and they are grouped by general category: updating, historic, mixed and auction.

This figure shows that the mixed scenarios all 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 pure auction cases. Combining dynamic and auction approaches in equal proportion has a bigger adverse effect on consumers relative to a pure dynamic approach that rewards incremental generation by non-emitters. 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 cases when we mix an auction and updating is close to the auction bookend, which is less than the updating bookend. The increase is slightly less when coal generators earn twice as many allowances as gas generators per kWh of generation. The decrease in value for coal-fired generation is worse than for the auction but not as bad as for updating. Combining an auction with historic reduces the losses to coal generators from the auction, especially when coal generators earn twice as many allowances as do gas generators per unit of historic generation. Nuclear generation benefits in the mixed cases because the increase in electricity price is greater than with updating. For the industry as a whole, the change in asset values is small in the aggregate because the mixed approaches yields a greater increase in electricity price than does the updating bookend. Increasing the fraction of allowances that are auctioned in combination with updating of the remaining allowances generally has a positive impact on asset values of all types of generators including coal. The one exception is that moving from 50% auction combined with 50% updating to a 100% auction has a negative effect on the asset value of gas generators in the region.

The cases that combine the auction with historic allocation have a positive effect on average asset values across the industry and produce a much smaller drop in the value of coal-fired assets than occurs when the auction is combined with updating. Interestingly, the increase in average asset values for existing units in the RGGI region under the auction combined with historic allocation based on generation is the roughly the same as that for generators outside the region. In the region these assets experience the program costs and receive a share of allowance allocation that is approximately equal, leaving them in a similar financial situation as assets outside the 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 of these constraints are short-run, such as fuel supply contracts that would be renegotiated over time. Other constraints such as requirements to balance load on the grid affect individual facilities but are not expected to have a noticeable effect on behavior of the entire system. However, two types of constraints present in the northeast seem to be potentially important in the long run:

constraints on the ability to supply natural gas to the northeast and constraints on 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 price or gas demand could be important. To address this we ran a scenario with gas prices at the national level 15% above baseline levels. In addition, any increase in demand for gas in the northeast above baseline levels in 2008 resulted in a regional change in price that was twice as sensitive as in the baseline.

The first column in Tables 15 and17 repeats our central case baseline findings. The second column considers the historic bookend approach with higher gas prices.[11] The difference in electricity price and the choice of technology for generation is substantial, but this is due to a significant degree to the change in natural gas price that we assume occurs independent of changes in gas demand due to the RGGI program. Another result is interesting, nonetheless. In Table 17 we find the net present value of all technologies is substantially higher in the constrained gas case relative to the baseline. This follows from the increase in the cost of natural gas generation, which is the technology that determines marginal electricity price in most time blocks. Hence, higher gas price translates into 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. In the baseline model inter-regional transmission capability is represented by quantity constraints and by prices, cost thresholds and line losses in the model. Intra-regional line losses also are represented on average. Intra-regional quantity constraints are not captured directly, although 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 to the right of the vertical line 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 fourth column describes the historic bookend under these constraints.

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[11] This is the second column in table 16, which reports economic surplus as differences from baseline only.

The effect of adding constraints on natural gas supply and electricity transmission is larger than the effect of adding the RGGI policy. The constraints cause substantial changes in the absence of the RGGI policy, which is evident in comparing the first and third columns of Table 15. Moreover, the change in electricity price and other overview measures that occur from the implementation of the RGGI policy are of comparable magnitude when the policy is added to the constrained no-policy baseline (comparing the third and fourth columns of Table 15) as when the policy is added to the central case baseline described in Table 3.

One can also see from Table 15 that the constraint on natural gas is more important than the constraint on inter-regional transmission capability. The model with both constraints operative varies relatively little compared to the model with just the high gas price in effect.

Producers benefit substantially in the face of gas or transmission constraints. Table 16 presents the change in economic surplus reported as the difference relative to the central case baseline. The higher gas price negatively affects consumers and benefits producers. Again one can observe the change in surplus due to the addition of 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 inclusion of higher gas prices.

The constraints that are modeled do not appear to have a potent impact on the implementation of RGGI. Overall, the changes in electricity price or the choice of technology for electricity generation, or the distribution of costs due to the 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 cases, as well as in the auction case and many updating cases, 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. Incorporation of rules governing transmission that are aimed at reducing leakage could have a big role, but modeling of that is saved for subsequent 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 within the RGGI states. To get a sense of how policies to encourage renewables might affect the impact of a RGGI policy we run a baseline and one policy case scenario with an aggregate regional RPS. The RPS policy, which covers the NY, NE, and

MAAC NERC regions, is a scenario developed by RFF to represent at a regional level all of the existing renewables policies for states in the three NERC regions covered or partially covered by RGGI. 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. The policy also includes increased imports from Canada to New York that are largely expected to come from hydro generation. The RPS policy that we model is not intended to be an exact representation of the RPS policies in the included states, but instead a plausible approximation of existing policies within the region that as a result of rounding is likely to be slightly higher than actual renewables requirements.

In the case of the baseline with the RPS, renewable generation increases by 56% relative to the standard baseline within the three NERC regions by 2025, while electricity price remains roughly the same and CO_2 emissions decrease by 14 million tons or 9%. The increase in renewable generation mostly serves as a replacement for gas since coal generation remains nearly the same while gas generation declines by 17%. The price of a renewable credit is $16 per MWh in 2025.

In the policy case with the RPS CO_2 permits are distributed to emitters based on historic generation, a scenario analogous to the bookend historic allocation. The combination of the RPS and CO_2 cap has about the same effect on renewable generation as the RPS alone, which increases by 53% within the three regions by 2025 relative to the standard baseline. The increased renewable generation displaces more coal generation in the policy case, which declines by 25% as does gas. The price of electricity in RGGI rises to $106 per MWh, an increase of about $2.50 per MWh from both baselines, causing generation within the RGGI region to fall by 20 billion kWh compared to the baseline with an RPS. However, electricity price in 2025 with the RPS and the CO_2 cap is $1 per MWh lower than it is in the bookend historic case. Electricity price is lower than under the bookend historic case because the RPS encourages generation by renewables, which have lower variable cost, and thus exerts downward pressure on electricity price.

Having an RPS in place lowers baseline CO_2 emissions and thus lowers the cost of CO_2 permits. The CO_2 permit price in 2025 is $15.6 per ton, about $2.50 per 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 per MWh in 2025 with the RGGI policy.

CO2 emissions leakage to outside the RGGI region resulting from the RGGI policy with historic allocation is about 10% lower with the RPS than it is without it. By lowering the cost of the RGGI policy, the RPS lowers the incentive for generation and emissions to migrate away from the RGGI region.

Regarding economic efficiency, the RPS has the effect of pushing the costs outside of the RGGI region. In the baseline with RPS the consumers in the region are as well off while the producers are slightly better off relative to the standard baseline. The consumers outside the region, however, are considerably worse off, while the producers are also slightly better off.

When the RGGI policy is added, the national surplus results are similar to what they are in the RPS baseline. In RGGI the consumers are considerably worse off because of the increase in electricity price, while the producers gain substantially. The total cost of the RGGI policy in the presence of the RPS inside the region is close to 0. The consumers and producers outside of the region fare similarly to those inside. Compared to the bookend historic case without the RPS the consumers in the region are substantially better off while the producers are only slightly better off. Outside the region the producers are significantly worse off while consumers fare only slightly worse.

The asset value of various types of generation is affected differently by the RPS and CO_2 cap. Within the RGGI region under the RPS gas and nuclear decline slightly in value while coal remains the same and renewables increase substantially. Outside the RGGI region but in MAAC the value of gas generation increases modestly, while renewables decline somewhat. Adding the CO_2 cap causes the value of gas and nuclear generation to increase within the RGGI region, while coal loses value. The effects of the RGGI policy with historic allocation on asset values are typically smaller in the presence of the RPS than in the bookend case. The gain to renewable generation is about the same as with only the RPS.

9. Conclusion

In this research we compare approaches to historic, auction and updating mechanisms that we label as “bookends,” and subsequently we vary the design of these approaches. We find that how allowances are allocated has a substantial effect on electricity price and consumption, on the mix of technologies used to generate electricity, on the emissions of conventional pollutants and on the cost of controlling conventional pollutants.

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. The fact that electricity price changes depend on how emission allowances are distributed initially suggests that the distribution of allowances offers a potentially important source of compensation. We provide an assessment of the effect of different approaches to distribution on the change in the market value of generation assets, and we find substantial variation, depending on how allocation is implemented.

The measure of compensation that is required to preserve asset value will vary if calculated at facility, business unit, firm or state level. Change in shareholder value depends on the portfolio of assets held by the firm. In this paper we have not calculated the change in value at the firm level, but policy makers may be interested in this information when considering how different parties are affected.

A general pattern emerges in looking across the approaches to allocation. The historic or auction approaches are most efficient. Updating has about three times the social cost of historic or auction approaches. Nonetheless, updating has the political advantage of a lower electricity price, and it can be designed to reduce leakage.

In recognition that updating has attracted interest in the RGGI process, we explore a variety of approaches to updating, with a variety of consequences. It is noteworthy that one approach– updating allocation on the basis of all generation – has the lowest social cost within the RGGI region of any approach we modeled, in part because it imposes costs outside the region. Ultimately, however, we note that 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 method of allocation among different sectors of the economy when updating is used. Hence, we suggest that updating may be seen as a useful tool in the initial implementation of RGGI, but in any event it may not be a useful model at the national level.

The approaches vary significantly in their effect on asset values in the aggregate, and for specific types of generation technology. The industry does best with historic allocation, while consumers do the worst. The auction is the intermediate case with respect to the effect on market value, and updating leads to the greatest decline in market value for the industry in the aggregate.

The institution of the auction that we model might take a variety of forms. One form is allocation to consumers, or a public benefit allocation, which endows a trustee with allowances who can sell them to the industry and apply the revenue to a variety of purposes. Some observers have suggested that investments in energy conservation or renewables could be funded through this kind of approach.

There are important limitations to this analysis stemming from the level of aggregation 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 have a bearing on the amount of emission leakage that occurs. Out-of-merit-order-dispatch that may result from long-term fuel contracts or intra-regional transmission constraints is captured in an approximate fashion, based on evidence from recent years. We look at a sensitivity analysis with higher natural gas prices or transmission constraints, and find the social cost of the RGGI program does not appear to be sensitive to the existence of these constraints.

The variation that we discover in measures and performance of various policies suggests policy makers have latitude in providing compensation to industry through the distribution of emission allowances. We suggest a different emphasis could be given to compensation versus efficiency in the short run and long run, and we 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 in the long run efficiency concerns should be a central consideration in the policy design.

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Tables

Table 1. Modeled Scenarios

		Eligibility	Basis for Allocation
	Historic Approaches		
Heg	a. (Bookend)	Emitters	Historic generation
Hag	b.	Generators	Historic generation
Hee	c.	Emitters	Historic emissions
	Auction Approach		
Auc	d. (Bookend)	Emitters	Auction
	Updating Approaches		
Demit	e. (Bookend)	Emitters	Recent generation
Dag	f.	Generators	Recent generation
Dagig	g.	Generators	Generation by emitters and incremental generation for nonemitters
Dn3ig	h.	Nonemitters	Incremental generation for nonemitters
DnNig	i.	Nonemitters nationwide	Incremental generation for nonemitters
	Mixed Approaches		
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 gen. counts double
MADeg_coal	q.	Auction (d) (50%) / Updating (e) (50%)	Auction / recent generation Coal gen. counts double
	Constrained Alternatives		
HegGhi	r. Higher gas price	Emitters (Historic a)	Historic generation
HegT10Ghi	s. Constrained transmission and higher gas price (new baseline)	Emitters (Historic a)	Historic generation

Notes:

Historic generation and historic emissions = 1999.

Recent generation is based on two years previous to allocation.

Incremental generation includes generation beyond 1999 levels.

Constrained transmission assumes inter-regional capability in northeast reduced by 10%.

Higher gas price has national (Henry Hub) prices pegged 15% above baseline and supply price sensitivity for imports into the northeast above baseline levels doubled.

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

	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)**	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)**	1.7	1.2	1.2	1.2
Reduction Target				
CO_2 *(million tons)*	124	114	107	100

* Includes mercury emissions from uncontrolled municipal solid waste facilities that, in fact, have already begun to achieve important emission reductions.

Table 3. Overview for Bookend Cases, 2025

Eligibility: **Basis:**		Emitters Historic generation	Emitters Auction	Emitters Recent generation
RGGI Region	**Baseline**	**Historic**	**Auction**	**Updating**
Average Electricity Price (1999$/MWh)	$103.4	$107.1	$107.2	$103.9
TOTAL Generation (billion kWh)	393	348	348	371
Coal	73	48	48	23
Gas	130	115	116	173
Nuclear	107	108	108	106
Renewable	34	40	40	32
TOTAL New Capacity* (GW)	28	31	31	33
Gas	23	24	24	28
Renewable	5	6	6	5
CO_2price *(1999$ per ton)*	n/a	$18.1	$18.3	$35.3
Emissions				
CO_2 *(million tons)*	147	100	99	98
NO_x *thousand (tons)*	118	70	70	41
SO_2 *(thousand tons)*	193	101	107	36
Mercury *(tons)*	1.2	0.8	0.8	0.3
Rest of Nation**				
Average Electricity Price (1999$/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

* Numbers may not sum due to rounding.
**Includes MD and portion of PA 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*	-0.5	-0.5	-0.7
Rest of Nation**			
Consumers	-1.2	-1.2	-1.3
Producers	1.5	1.5	1.2
SUBTOTAL*	0.2	0.2	-0.2
National Total*	-0.3	-0.3	-0.9
Model	Heg	Auc	Demit

* Numbers may not add because of other categories including change in tax credit costs.

**Includes MD and portion of PA within MAAC outside the RGGI region.

Table 5. Net Present Value 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	164	60	-13	-45
Existing Capacity Only				
Gas	-375	228	17	102
Coal	434	8	-185	-240
Nuclear	611	67	55	-51
Average ALL	300	104	-3	-51
MD and PA*				
Gas	-255	6	12	12
Coal	364	50	-185	24
Nuclear	653	51	51	20
Average ALL	229	23	26	8
Model	BL	Heg	Auc	Demit

* MD and the portion of PA within MAAC outside the RGGI region.

Table 6. Overview of Historic Allocation Cases

Eligibility: **Basis:**	Emitters Historic generation	Emitters Historic emissions	Generators Historic generation
RGGI Region			
Avg. Elec. Price **(1999$/MWh)**	$107.1	$106.8	$107.5
TOTAL Gen. **(billion kWh)**	348	349	348
Coal	48	48	48
Gas	115	116	115
Nuclear	108	108	108
Renewable	40	40	40
New Capacity* **(GW)**	31	31	31
Gas	24	24	24
Renewable	6	6	6
CO_2 price *(1999$ per ton)*	$18.1	$18.2	$18.3
Emissions			
CO_2 *(million tons)*	100	100	100
NO_x *(thou. Tons)*	70	72	71
SO_2 *(thou. Tons)*	101	107	105
Mercury *(tons)*	0.8	0.8	0.8
Rest of Nation**			
Avg. Elec. Price **(1999$/MWh)**	$66.8	$66.8	$66.9
TOTAL Gen. **(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

*Numbers may not sum due to rounding.

**Includes MD and portion of PA 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*	-0.5	-0.5	-0.5
Rest of Nation**			
Consumers	-1.2	-1.1	-1.3
Producers	1.5	1.3	1.4
SUBTOTAL*	0.2	0.1	-0.1
National Total*	-0.3	-0.4	-0.6
Model	Heg	Hee	Hag

*Numbers may not add because of other categories including change in tax credit costs.

**Includes MAAC outside RGGI

Table 8. Change from Baseline of Net Present Value of Existing and New 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
Avg. ALL	60	36	68
MD and PA*			
Gas	6	2	23
Coal	50	55	46
Nuclear	51	51	48
Avg. ALL	23	23	24
Model	Heg	Hee	Hag

*MD and portion of PA within MAAC outside the RGGI region.

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

Eligibility:	Emitters	Generators	Generators	Nationwide nonemitters	Non-emitters in NY, NE, & MAAC
Basis:	Recent generation	Recent generation	Recent gen. by emitters and incremental gen. by nonemitters	Incremental generation	Incremental generation
RGGI Region					
Avg. Elec. Price **(1999$/MWh)**	$103.9	$104.0	$103.9	$107.0	$106.5
TOTAL Gen. **(billion kWh)**	371	374	367	350	356
Coal	23	43	39	48	52
Gas	173	129	137	114	104
Nuclear	106	108	107	108	108
Renewable	32	58	46	43	55
New Capacity* **(GW)**	33	35	33	32	34
Gas	28	25	25	24	23
Renewable	5	10	8	7	11
CO_2price *(1999$ per ton)*	$35.3	$23.7	$26.1	$18.1	$16.4
Emissions					
CO_2 *(million tons)*	98	100	100	100	100
NO_x *(thou. Tons)*	41	65	63	69	73
SO_2 *(thou. Tons)*	36	82	65	104	115
Mercury *(tons)*	0.3	0.7	0.6	0.8	0.8
Rest of Nation**					
Avg. Elec. Price **(1999$/MWh)**	$66.9	$66.7	$66.7	$66.5	$66.8
TOTAL Gen. **(billion kWh)**	4,861	4,862	4,870	4,888	4,878
CO_2 Reduction Nation (2008-2025) *(million tons)*	289	232	282	461	310
Model	Demit	Dag	Dagig	DnNig	Dn3ig

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

Eligibility:	Emitters	Generators	Generators	Nationwide nonemitters	Non-emitters in NY, NE, & MAAC
Basis:	Recent generation	Recent generation	Generation by emitters and incremental generation for nonemitters	Incremental generation	Incremental generation
RGGI Region					
Consumers	-0.2	-0.2	-0.2	-1.5	-1.3
Producers	-0.5	0.1	-0.1	-0.5	0.4
CO_2 Revenue	0.0	0.0	0.0	0.0	0.0
SUBTOTAL*	-0.7	-0.2	-0.4	-2.1	-1.2
Rest of Nation**					
Consumers	-1.3	-0.6	-0.6	0.3	-0.9
Producers	1.2	0.3	0.6	1.5	1.6
SUBTOTAL*	-0.2	-0.3	-0.1	1.3	0.5
National Total*	-0.9	-0.5	-0.6	-0.8	-0.6
Model	Demit	Dag	Dagig	DnNig	Dn3ig

*Numbers may not add because of other categories including change in tax credit costs.

**Includes MAAC outside RGGI

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

Eligibility:	Emitters	Generators	Generators	Nationwide nonemitters	Non-emitters in NY, NE, & MAAC
Basis:	Recent generation	Recent generation	Generation by emitters and incremental generation for nonemitters	Incremental generation	Incremental generation
RGGI Region					
Gas	45	-2	16	7	-3
Coal	-240	-231	-223	-159	-175
Nuclear	-51	136	53	93	147
Avg. ALL	-45	5	-1	20	30
MD and PA*					
Gas	12	-5	10	23	21
Coal	24	35	43	50	48
Nuclear	20	35	37	65	129
Avg. ALL	8	9	14	30	47
Model	Demit	Dag	Dagig	DnNig	Dn3ig

*MD and portion of PA within MAAC outside the RGGI region.

Table 12. Overview for Mixed Approaches

Eligibility:	Generators	Generators	Emitters	Emitters	Emitters	Emitters
Basis:	Auction (20%) / Recent generation (80%)	Auction (50%) / Recent generation (50%)	Auction (50%) / Historic generation (50%)	Auction (50%) / Historic emissions (50%)	Auction (50%) / Historic generation (50%) – coal gen counts twice	Auction (50%) / Recent generation (50%) – coal gen counts twice
RGGI Region						
Avg. Elec. Price **(1999$/MWh)**	$103.9	$105.5	$107.5	$107.1	$107.5	$105.5
TOTAL Gen. **(billion kWh)**	359	354	348	349	348	356
Coal	43	45	48	48	48	42
Gas	130	121	115	115	116	130
Nuclear	108	108	108	108	108	108
Renewable	42	42	40	40	40	40
New Capacity* **(GW)**	32	32	31	31	31	32
Gas	25	25	25	24	24	25
Renewable	7	7	6	6	6	6
CO_2price *(1999$ per ton)*	$24.4	$21.8	$18.3	$18.2	$18.4	$23.8
Emissions						
CO_2 *(million tons)*	100	100	99	100	100	99
NO_x *(thou. Tons)*	64	67	69	69	70	61
SO_2 *(thou. Tons)*	83	99	104	103	105	78
Mercury *(tons)*	0.7	0.8	0.8	0.8	0.8	0.7
Rest of Nation**						
Avg. Elec. Price **(1999$/MWh)**	$66.7	$66.8	$66.8	$66.8	$66.8	66.8
TOTAL Gen. **(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

*Numbers may not sum due to rounding.

**Includes MD and portion of PA 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 generation (80%)	Auction (50%) / Recent generation (50%)	Auction (50%) / Historic generation (50%)	Auction (50%) / Historic emissions (50%)	Auction (50%) / Historic emissions (50%)– coal gen counts twice	Auction (50%) / Recent generation (50%)– coal gen counts twice
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*	-0.5	-0.5	-0.6	-0.5	-0.6	-0.5
Rest of Nation**						
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*	-0.1	-0.1	0.2	0.2	0.3	0.0
National Total*	-0.6	-0.6	-0.4	-0.3	-0.3	-0.5
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

* Numbers may not add because of other categories including change in tax credit costs.

**Includes MAAC outside RGGI.

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

Eligibility:	Generatorrs	Generators	Emitters	Emitters	Emitters	Emitters
Basis:	Auction (20%) / Recent generation (80%)	Auction (50%) / Recent generation (50%)	Auction (50%) / Historic generation (50%)	Auction (50%) / Historic emissions (50%)	Auction (50%) / Historic emissions (50%)– coal gen counts twice	Auction (50%) / Recent generation (50%)– coal gen counts twice
RGGI Region						
Gas	7	14	28	5	11	4
Coal	-221	-198	-88	-77	-50	-222
Nuclear	49	51	68	53	62	40
Avg. ALL	-13	-8	32	14	19	-21
MD and PA*						
Gas	-4	14	27	11	21	6
Coal	39	46	54	50	59	59
Nuclear	35	47	56	48	52	55
Avg. ALL	14	24	33	23	28	25
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

* MD and portion of PA 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	**Baseline**		**Constrained – No Policy**	
Avg. Elec. Price (1999$/MWh)	$103.4	$112.2	$108.4	$112.7
TOTAL Gen. (billion kWh)	393	345	386	347
Coal	73	50	74	49
Gas	130	96	97	97
Nuclear	107	108	108	108
Renewable	34	47	37	47
New Capacity* (GW)	28	30	28	30
Gas	23	22	22	22
Renewable	5	8	6	8
CO2price *(1999$ per ton)*	n/a	$20.6	$0.0	$20.5
Emissions				
CO_2 *(million tons)*	147	99	149	100
NO_x *(thou. tons)*	118	76	115	77
SO_2 *(thou. tons)*	193	127	250	130
Mercury *(tons)*	1.2	0.8	1.2	0.8
Rest of Nation**				
Avg. Elec. Price (1999$/MWh)	$66.6	$67.5	$67.2	$67.5
TOTAL Gen. (billion kWh)	4,847	4,867	4,838	4,864
CO_2 Reduction for Nation Cummulative (2008-2025)	n/a	n/a***	n/a	238****
Model	BL	HegGhi	BLT10Ghi	HegT10Ghi

* Numbers may not sum due to rounding.

**Includes MD and portion of PA within MAAC outside the RGGI region.

***No baseline was run for only high natural gas prices.

****Compared to Constrained-No Policy case.

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

Eligibility:	Emitters		Emitters
Basis:	Historic generation		Historic generation
Constraints:	Higher gas price	Higher gas price & transmission limits	
RGGI Region		**Constrained – No Policy**	
Consumers	-3.8	-2.2	-4.0
Producers	2.4	1.0	2.6
CO_2 Revenue	0.0	0.0	0.0
SUBTOTAL*	-1.5	-1.2	-1.5
Rest of Nation**			
Consumers	-4.1	-2.4	-4.0
Producers	2.8	0.9	2.9
SUBTOTAL*	-1.9	-2.3	-1.7
National Total*	-3.4	-3.5	-3.2
Model	HegGhi	BLT10Ghi	HegT10Ghi

* Numbers may not add because of other categories including change in tax credit costs.
**Includes MAAC outside RGGI.

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

Eligibility:		Emitters		Emitters
Basis:		Historic generation		Historic generation
Constraints:		Higher gas price	Higher gas price & transmission limits	Higher gas price & transmission limits
RGGI Region	**Baseline**		**Constrained – No Policy**	
Gas	-273	47	1	54
Coal	434	147	154	156
Nuclear	611	208	146	206
Avg. ALL	164	125	76	124
MD and PA*				
Gas	-255	-14	-13	-11
Coal	364	161	78	145
Nuclear	653	173	87	157
Avg. ALL	229	94	47	77
Model	BL	HegGhi	BLT10Ghi	HegT10Ghi

***** MD and portion of PA within MAAC outside the RGGI region.

Figures

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

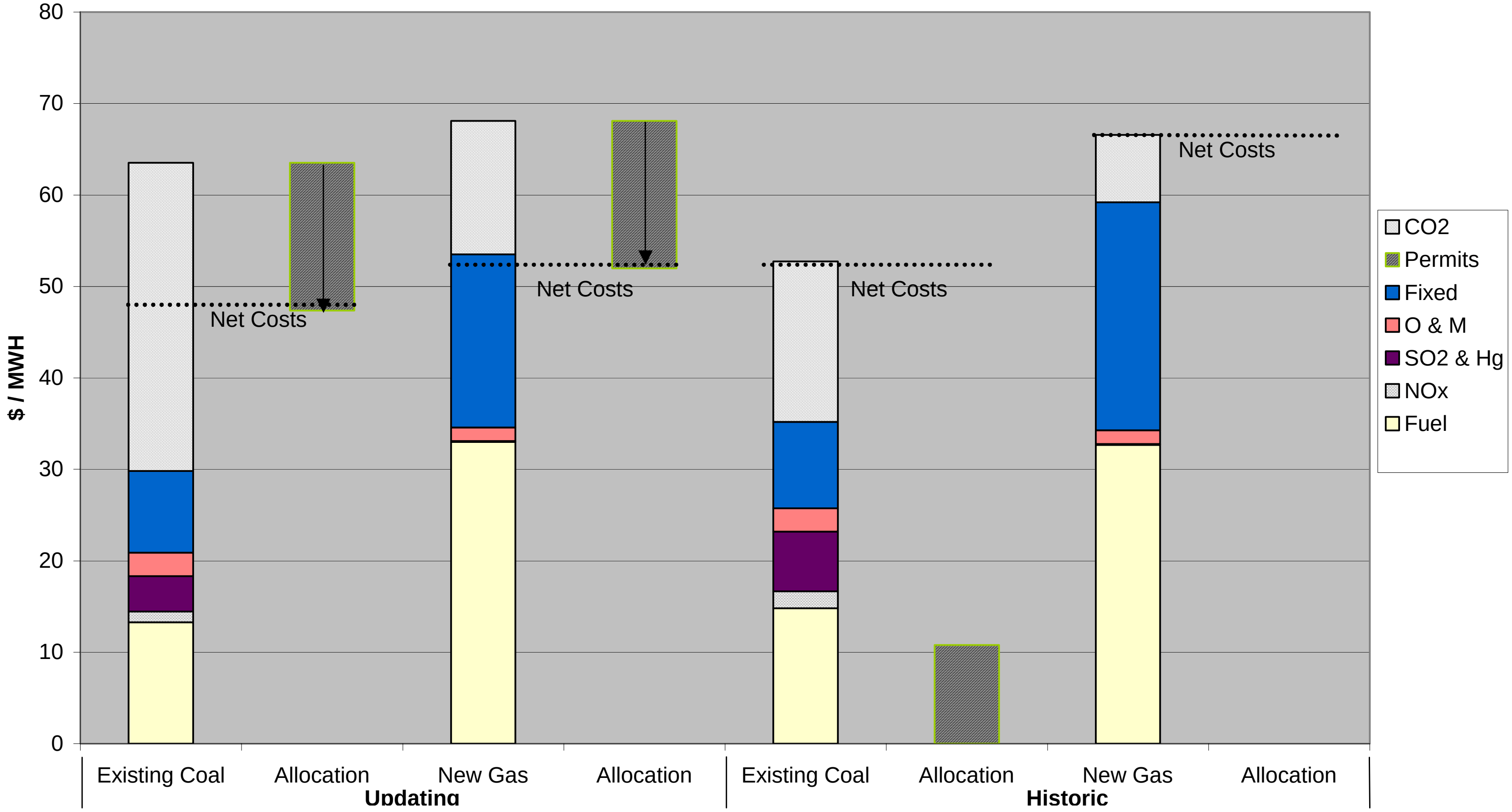

Figure 2. Change in Value of Existing and New Generation Assets Compared to Baseline.

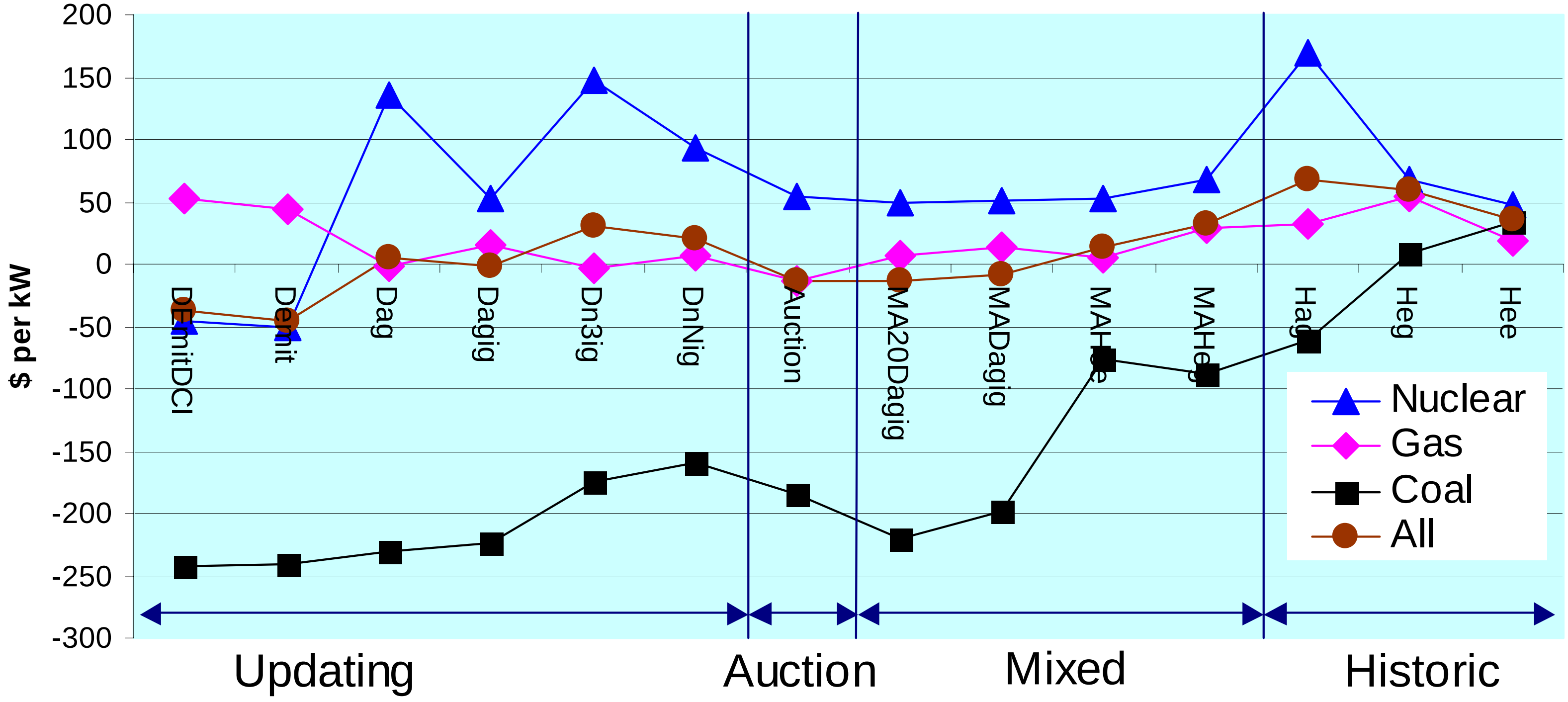

Figure 3. Change in Surplus Within RGGI from Baseline