Evaluation of CO_2 Emission Allocations as Part of the Regional Greenhouse Gas Initiative

Final Report

June 30, 2005

CENTER FOR ENERGY,
ECONOMIC & ENVIRONMENTAL POLICY

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Executive Summary

As part of the Regional Greenhouse Gas Initiative (RGGI), nine Northeastern and Mid-Atlantic states are in the process of drafting a model rule that would implement a carbon dioxide cap-and-trade system covering the generation of electricity. The use of cap-and-trade programs regulating other air emissions have been generally acknowledged as being successful in reducing other emissions in a cost-effective manner.

The economic success of cap-and-trade programs stems from the fact that they allow sources that would incur high costs in reducing their emissions to purchase allowances from those that can curtail their emissions at low costs. Environmental policy objectives are assured because the total amount of emissions is capped; they are achieved efficiently because participants are able to trade, and therefore reductions tend to come from those that can achieve them in the most cost-effective manner.

CO_2 is an ideal emission to be regulated under a cap-and-trade approach. The location and timing of CO_2 emissions do not affect the associated impact those emissions have on global warming, which simplifies design and greatly limits the potential for trading to prove environmentally harmful. Compliance with the cap is assured simply by monitoring emissions and ensuring that each source holds allowances equal to its emissions.

All cap-and-trade policies require the distribution of emission allowances to jump-start the program. Holders of an emission allowance have the right to emit one ton of CO_2. As part of the RGGI process, three types of allocation methods are being discussed: historic, auction, and updating. Historical allocations, which distribute allowances to generators, can be based on emissions (tons of CO_2) or generation (MWH) in a historic year. Under the auction approach, all allowances are sold to CO_2 emitters and other market participants in an open auction. The sale of allowances creates revenue that can be then distributed to satisfy a variety of public purposes, such as fund energy efficiency, renewable resources, reduction of transmission and distribution charges, and payments to generation owners. Similar to the historical approach, the updating approach allocates allowances to generation units based on emissions or generation. Rather than fix allocations based on a single historical year, under an updating approach, allocations would vary based on the most recent generation or emissions levels. It is also possible to combine these approaches.

Whatever allocation method policymakers select, it is a critical decision because it affects the profitability of generation resources, the cost of electricity, and future power plant investment decisions. In addition, those who receive an allocation are in effect receiving the monetary value of the emission allowances. Collectively, the allowances are worth several times more than the social cost of mitigating CO_2 to meet the cap. For example, if CO_2 allowances sell at $10/allowance and 100 million are issued, the value of the allowances is $1 billion, although the social cost of mitigation may be only in the several hundreds of millions of dollars.

In this paper, we examine the implications of each of these three allocation approaches on the cost of CO_2 allowances, wholesale electricity prices, production decisions by different types of generation units, and generation profitability. These interrelationships are illustrated using calculations and examples that may be typical of the types of qualitative impacts such a cap-and-trade program is likely to have. In addition, we discuss several important issues related to the economic impact of the program, including leakage (the production of electricity outside the RGGI region for sale into the region to avoid the cap), and several administrative issues.

Our research leads us to the following conclusions:

Cost of Allowances and Impact on Wholesale Electricity Prices

- Two of the possible three allocation approaches – historic and auction – result in identical outcomes for the cost of allowances, the impact on wholesale electricity prices, and the operational decisions generators make. Identical outcomes for these metrics result from the fact that allocations under these two methods are independent of future decisions made by generators. Because going forward behavior does not affect the amount of allowances received, generators behave in the same manner regardless of differences in how emissions are allocated.

- The updating allocation results in the lowest increase in the cost of wholesale electricity, but is less efficient than the other two allocations. The reason is that the updating allocation in effect subsidizes the production of CO_2 because, as a generation unit produces electricity going forward, it is granted more allowances for an upcoming period. From an economic efficiency perspective, the allocation of allowances should not have any impact on production decisions. In other words, allocations that depend on production provide an inefficient incentive to emit.

- At the same time, updating allocations produces the lowest impact on electricity prices, assuming none of the auction revenue is used to support increased efficiency. Because generator owners earn allowances as a result of production, they will tend to offer their units into the market at a lower price.

Profitability of Generation Units

- In the historic allocation, generation units, both collectively and within each of the 12 fuel-technology subcategories that we examine, have higher profits than without a cap-and-trade program. The reason is that generators make more money due to the increase in wholesale electricity prices as a result of RGGI and they are granted allowances that offset the costs of emitting CO_2.

- Under the updating and auction allocations and assuming none of the auction revenue is distributed to generation owners, generation units are better off collectively with RGGI than without, but certain subcategories with high CO_2 emissions – particularly coal units – are worse off. Generator owners that own different types of generation units, however, may be better off with RGGI than without even if they have some coal units in their portfolio. Our numerical results may overstate the amount by which generators are better off because we do not quantify the effects of leakage.

Use of Auction Revenues

- Increased energy efficiency, due to the use of auction revenues to increase funding for efficiency programs, and due to the increase in wholesale electricity prices, can mitigate the wholesale electricity price impact of RGGI by reducing the demand for electricity and therefore the need to purchase CO_2 allowances. Effective program design, management, and implementation must accompany increased funding for energy efficiency measures if this additional funding is to result in meaningful reductions in electricity consumption.

- Auction revenues may also be used to reduce transmission and distribution charges, which would lower consumers' electricity bills and ensure that consumers obtain some of the value of CO_2 allowances.

Auctions, Leakage, Transaction Costs and Administrative Issues

- Auctions are well understood, have been used in a variety of circumstances similar to RGGI, and are regarded by economists as being an efficient and transparent method of allocating CO_2 allowances. Auctions also provide a clear and transparent price signal to generators and other market participants, and do not adversely affect the elements of cap-and-trade programs that make them cost effective. In particular, auctions do not interfere with the ability to trade allowances, since that does not depend on whether they are auctioned or granted free of charge to generators or other parties.

- Because it results in the cap being circumvented, leakage is an important issue that should and can be addressed with appropriate policies. Any CO_2 cap-and-trade program, unless it applies to all interconnected electricity markets, has the potential for leakage. The larger the relative difference between the price of electricity in the RGGI region and outside it, the more the leakage. When leakage occurs, however, it mitigates the electricity price impact due to RGGI, which lowers the impact on consumers, the additional profit generators earn from higher electricity prices and the overall environmental benefit of the program.

- A variety of transaction costs are associated with any cap-and-trade program, such as working capital requirements, staff, and other expenses, that market participants will incur regardless of which allocation methodology policymakers select. These costs are also likely to be small relative to the value of allowances that are being traded. Building on existing trading experience, efficient trading and marketing mechanisms should develop when RGGI is established.

- There are other important program design and administrative issues that policymakers should consider in designing the RGGI model rule, such as allowing regulated sources to bank allowances (i.e., and use their allowances in a later year), which would help reduce compliance costs with minimal environmental impact.

I. Introduction

The Center for Energy, Economics and Environmental Policy (CEEEP) at the Edward J. Bloustein School of Planning and Public Policy, Rutgers, The State University of New Jersey has been engaged by the Energy Foundation and worked with the Natural Resources Defense Council to evaluate the economic impacts of different methodologies for allocating carbon dioxide (CO2) emission allowances and related issues as part of the Regional Greenhouse Gas Initiative (RGGI).

RGGI was initiated in 2003 as a regional effort among nine Northeastern and Mid-Atlantic States to develop a regional cap-and-trade program initially covering carbon dioxide emissions from power plants in the region.[1] Cap-and-trade programs for environmental emissions already exist in the region and elsewhere for sulfur dioxide (SO_2) and nitrogen oxide (NO_x). These existing programs have been generally well received as being cost-effective in reducing associated emissions.[2]

In short, a cap-and-trade program restricts the total amount of emission of a particular pollutant by issuing a fixed set of emission allowances equal to the cap. Only holders of emission allowances can emit emissions up to the amount of allowances that they hold. Emission allowances can be traded among firms, giving them flexibility in how to respond to the overall emission cap. Firms that can reduce emissions inexpensively can sell any extra allowances to those firms that cannot, resulting in cost-effective compliance by the industry with the emission cap. A critical first step in setting up any cap-and-trade program is determining how to allocate emission allowances.

The purpose of this paper is to identify and discuss the implications of three possible CO_2 allocation approaches: historic, historic with updating (output-based), and auction. We illustrate several specific aspects of how cap and trade programs for CO_2 in the RGGI region might work and highlight the differences between the three allocation methods. Results obtained here should not be interpreted as a forecast of actual, generation patterns, emissions, or prices. Rather, this work is intended as an exercise that will foster a better understanding of the economic impact to consumers and generators under different allocation schemes. A more complete analysis of the economic impacts of different CO_2 emission allocations is available in a study done by Resources for the Future (RFF).[3]

We also briefly discuss some important issues related to the economic impact of the program, including leakage (an increase in production of electricity outside the RGGI region for

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[1] For more information on RGGI, see its webpage at http://www.rggi.org/index.htm .

[2] U.S. Environmental Protection Agency, *Tools of the Trade: A Guide to Designing and Operating a Cap and Trade Program for Pollution Control*, June 2003 available at www.epa.gov/airmarkets and A. Denny Ellerman, Paul L. Joskow, and David Harrison, Jr., *Emissions Trading in the U.S.: Experience, Lessons, and Considerations for Greenhouse Gases*, Pew Center on Global Climate Change, May 2003 available at www.pewclimate.org . These two references are hereafter denoted EPA 2003 and Pew Center 2003, respectively. EPA 2003 is a how-to manual on designing and implementing emission markets.

[3] Dalls Burtraw, Karen Palmer and Danny Kahn, *Allocation of CO2 Emission Allowances in the Regional Greenhouse Gas Cap-and-Trade Program*, Resources for the Future, March 29, 2005 available at http:///www.rff.org , hereafter denoted "RFF 2005".

sale into the RGGI region, and a corresponding decrease in production of electricity within the RGGI region, to avoid the use of allowances), banking (the ability to save allowances for use in future years), administrative issues associated with different allocation methods, and costs incurred by firms trading allowances.

This report is organized into the following Sections. Section II provides background information on the types of generation, their levels of production, and the CO_2 emissions in the RGGI region. Section III investigates the three main allocation methods, and Section IV concludes.

II. Background: Capacity, Generation and CO2 Emissions in the RGGI Region

The RGGI region consists of nine states: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. Maryland, the District of Columbia, Pennsylvania, the Eastern Canadian Provinces and New Brunswick are observing the RGGI process. The participating states span three wholesale electricity markets, New England, New York, and the classic Pennsylvania-New Jersey-Maryland (PJM) region, which includes Delaware among other states. Each of these three wholesale electricity markets have similar market rules and a substantial amount of trading occurs among them, as well as with other regions that are not participating in the RGGI process.

Generators in these three markets sell energy (megawatt-hours or MWH), capacity (megawatts or MW), and other ancillary services, such as operating reserves. The primary market is the energy market, which can be sold forward in the bilateral market, in the day-ahead market, or in the real-time market. Generation units submit bids to the ISOs that stipulate the minimum amount they are willing to be paid to produce electricity. Every hour, each of these markets, which are administered by Independent System Operators or ISOs, set hourly energy prices that vary by the location on the power grid.

In order to maximize profits in competitive electricity markets, generation units bid something close to their variable costs. Generators in these electricity markets earn the market-clearing price, which is based on the cost of the most expensive accepted offer. Thus most units earn a market-clearing price that is above their offer when they are dispatched. The resulting operating profits (market revenue less as-bid variable costs) are used to pay for fixed costs and provide a return of and on capital. The ISOs also ensure the reliable operation of their respective region's bulk power system and, to that end, administer a market for capacity, which helps ensure that sufficient generation capacity exists to meet demand and provides some additional revenue for generation units. Capacity can be sold forward or in monthly capacity auctions.[4]

Capacity in the RGGI region can be grouped into twelve categories shown in Table 1. These categories are based on the different types of fuels used in generation, the major ones are

[4] See Adam Jaffe and Frank A. Felder, "Should Electricity Markets Have a Capacity Requirement? If So, How Should It Be Priced?" *The Electricity Journal*, December 1996, pp. 52-60. Markets for generation capacity are based on the same economic principles as emission cap-and-trade markets, except that instead of mandating a cap on emissions, capacity markets require a floor on capacity to ensure resource adequacy.

coal, nuclear, and natural gas, and on different generation production technologies. For illustrative purposes, we model the entire RGGI region as 12 units corresponding to the 12 categories of Table 1. This simplified representation of capacity in the region illustrates the likely economic impact that alternative approaches to allocating CO_2 allowances will have on different types of sources, which in turn will depend on each unit's emissions, costs, and other characteristics. Simplifying the region into 12 unit types enables us to illustrate these differing impacts while not losing the reader in the complexity of the more than 2,000 units actually located in the region.

Table 1: Aggregated Model of RGGI Region - Capacity and Energy
(Illustrative Model Based on Current Data)

Unit Type	Fuel	Approx. RGGI Region Capacity (MW)	Capacity Factor	Heat Rate (mmBTU/MWH)	Yearly Energy (MWH/Year)
Coal Steam (Older)	Coal	5,000	45%	11.0	19,710,000
Coal Steam (Newer)	Coal	6,000	70%	9.8	36,792,000
Oil Steam (Older)	FO6	6,000	10%	10.5	5,256,000
Oil Steam (Newer)	FO6	10,000	30%	9.0	26,280,000
Gas Steam	Gas	8,000	10%	9.5	7,008,000
Gas Combined Cycle (Older)	Gas	10,000	15%	8.5	13,140,000
Gas Combined Cycle (Newer)	Gas	16,000	55%	7.0	77,088,000
Efficient Gas Turbine	Gas	9,000	3%	10.5	2,365,200
Older Diesel Turbine	FO2	6,000	1%	13.0	525,600
Nuclear	Nuclear	14,000	85%	N/A	104,244,000
Hydro	Water	9,000	40%	N/A	31,536,000
Renewables	N/A	3,000	40%	N/A	10,512,000
Total		102,000			334,456,800

Table 1 lists the twelve categories, the technology, fuel type, aggregated level of capacity, the capacity factor, the heat rate, and the yearly energy production. Large power plants, such as nuclear and large coal facilities, are typically 600 to 1,000 MW in size and have high capacity factors. Smaller units can vary in size from approximately 2 to 500 MW. A generation unit's capacity factor is the percentage of the time that it is producing electricity at its full output. Formally, it is the number of MWHs that a unit produces in a year divided by the total amount of MWH it could have produced if it were to operate at full capacity every hour in the year. A generation unit's heat rate is an inverse measure of its efficiency. It is the number of British Thermal Units (BTUs) that it takes to produce one MWH.[5]

Currently, the RGGI region has about 102,000 megawatts of capacity that produce roughly one-third of a trillion megawatt-hours of electric energy annually. The largest single source of energy is nuclear. Significant additions of gas in recent years have made it the second largest source of energy. Third is coal followed by significant amounts of generation from oil and hydro capacity. While most types of capacity are found in most states, capacity types are not uniformly spread over the RGGI region. For example, a somewhat larger percentage of oil-fired capacity is located in New England. Coal capacity is more common in the Delaware-New Jersey region. Hydro units are most common in New York. Natural gas-fired and nuclear capacity is spread more uniformly.

[5] The "mm" in mmBTU in the heading of Table 1 stands for thousands thousands, or a million BTUs. Heat rates can also be expressed in BTUs/kWh, where a 1,000 kWh equals a MWH.

Typically, larger units have lower variable costs but higher capital costs, which depreciate over time. Table 2 provides approximate variable costs for different unit types. Variable costs are costs borne as a direct result of producing energy. Variable costs are primarily a function of fuel costs and the efficiency with which units convert fuel into electricity (inversely proportional to heat rate found in Table 1), but also include other variable costs such as for waste disposal. For competitive reasons, generation owners keep their variable costs and associated energy offers confidential; however, the variable costs can be estimated based on the type of unit and the cost of fuel, which is publicly available.

Because they are used as a direct result of generation, allowance costs are also considered a variable cost. For example, the cost of "consuming" a sulfur dioxide emission allowance is a variable cost that would be added to a plant's fuel cost and variable operations and maintenance cost. Collectively, these costs are typically reflected in its energy bid submitted to the ISO. Generators in the RGGI region have a lot of experience in incorporating the costs of sulfur dioxide and nitrogen oxide emission allowances into their bids, fuel procurement decisions, and business operations. The same type of processes would occur for CO_2 emission allowances.

Table 2: Aggregated Model of RGGI Region - Variable Cost
(Illustrative Model Based on Current Data)

Unit Type	Fuel	Example Fuel Cost ($/mmBTU)	Other Variable Cost ($/MWH)	Total Variable Cost ($/MWH)
Coal Steam (Older)	Coal	3.50	9.00	47.50
Coal Steam (Newer)	Coal	3.50	6.00	40.30
Oil Steam (Older)	FO6	5.00	4.00	56.50
Oil Steam (Newer)	FO6	5.00	4.00	49.00
Gas Steam	Gas	6.00	2.00	59.00
Gas Combined Cycle (Older)	Gas	6.00	2.00	53.00
Gas Combined Cycle (Newer)	Gas	6.00	2.00	44.00
Efficient Gas Turbine	Gas	6.00	3.00	66.00
Older Diesel Turbine	FO2	10.00	7.00	137.00
Nuclear	Nuclear	N/A	N/A	N/A
Hydro	Water	N/A	N/A	N/A
Renewables	N/A	N/A	N/A	N/A

Units with the lowest variable costs tend to be used most often to produce electricity. For example, a relatively efficient coal unit is shown to have a capacity factor of 70% in Table 1. Thus, such coal units produce about 70% of the energy that they would if they ran at full capacity all the time. This corresponds directly with the relatively low cost of producing energy from coal (estimated at $40.30/MWH) as shown in Table 2. More expensive units run less often. Some capacity, particularly relatively expensive gas or diesel fired turbines, run at very low capacity factors as they produce energy only during peak load conditions.

The ISO establishes the dispatch order based on the energy bids of generation units. Units with the lowest variable costs typically submit lower bids than units with higher variable costs. Subject to several operational parameters (e.g., minimum run times) associated with each unit and transmission constraints, the ISO dispatches units with the lowest bids first and works its way up the dispatch order to ensure that sufficient quantities of electricity are generated to meet the region's electricity demand. The ISO also accounts for imports and exports into and out of its region in a similar manner.

The amount of CO_2 emitted by the 12 aggregated units is shown in Table 3. While this example is constructed for illustrative purposes, the total of 117 million metric tons[6] of CO2 emissions shown for the RGGI region is roughly equal to current (2003) emissions levels. CO2 is emitted by fuel-type and generation technology in roughly the amounts shown.

Table 3: Aggregated Model of RGGI Region - CO2 Emissions
(Illustrative Model Based on Current Data)

Unit Type	Fuel	Pounds CO2 (per mmBTU)	Pounds CO2 (per MWH)	Metric or Long Tons CO2 (per Year)
Coal Steam (Older)	Coal	210	2,310	20,695,500
Coal Steam (Newer)	Coal	210	2,058	34,417,244
Oil Steam (Older)	FO6	165	1,733	4,139,100
Oil Steam (Newer)	FO6	165	1,485	17,739,000
Gas Steam	Gas	118	1,121	3,570,895
Gas Combined Cycle (Older)	Gas	118	1,003	5,990,645
Gas Combined Cycle (Newer)	Gas	118	826	28,943,040
Efficient Gas Turbine	Gas	118	1,239	1,332,038
Older Diesel Turbine	FO2	160	2,080	496,931
Nuclear	Nuclear	0	-	-
Hydro	Water	0	-	-
Renewables	N/A	0	-	-
Total				117,324,392

The amount of CO_2 emitted is highest for coal units. While coal accounts for roughly 17% of generation, it accounts for about 47% of CO2 emissions. Nuclear power, in contrast, accounts for about 31% of generation, but produces no CO2 emissions. Emissions of CO_2 vary greatly even among fossil technologies. For example, gas-fired combined cycles produce half or less of the CO_2 emissions per MWH of energy produced as compared to coal. This lower amount can be attributed both to the higher efficiency of combined cycle units and to the lower carbon content of natural gas.

Reducing CO_2 emissions to satisfy the RGGI cap would be accomplished by a combination of different methods. On the demand side, reductions in electricity use would occur from any increase in electricity prices that result from the additional variable costs associated with the need for allowances and from any increased spending on energy efficiency programs or new energy policies undertaken by the states. On the supply side, reductions in CO_2 emission would occur when more efficient units (facilities that burn less fuel per unit of electricity produced), or those that burn less carbon intensive fuels, displace less efficient units or those that burn more carbon intensive fuels. The displacement of more carbon intensive production with less carbon intensive production requires that the relative cost per MWH of the higher emitting facility is larger than that of the lower emitting facility. For instance, if an efficient natural gas unit, which emits less than one half of the CO_2, were to be used to displace coal, the variable cost

[6] A metric ton is equal to 2,200 pounds.

of a coal plant would have to increase above that of a natural gas plant. As we will illustrate below, CO_2 allowances reorder the dispatch of units and produce reductions in CO_2 emissions in just this manner.

III. Investigation of Three Alternative Allocation Methods

In this section we examine three possible CO_2 allocation methods. To initiate the CO_2 cap-and-trade program, emission allowances have to be distributed so that they can be bought, sold, and used by generation units. The three methods that we examine could be combined in various ways to form other possible allocation schemes and therefore are not mutually exclusive.

Whatever allocation method policymakers select, it is a critical decision because it affects allowance prices, the cost of electricity, power plant investment, and the intensity with which existing generation resources will be utilized. In addition, those who receive an allocation are in effect receiving the monetary value of the emission allowances. Collectively, the allowances are worth several times more than the social costs of mitigating CO_2 to meet the cap.[7] For example, if CO_2 allowances sell at $10/allowance and 100 million are issued, the value of the allowances is $1 billion, although the social costs of mitigation are only in the several hundreds of millions of dollars.

In this section, we first describe the three allocation methods that we investigate. Next, the modeling assumptions that we make are discussed. Then, we examine each of these allocation approaches based on its impact on wholesale electricity prices and costs to different types of generation units, its impact on generation unit dispatch, and generation profitability and its impact on consumers. We close this section with a short discussion of leakage and other allocation related issues.

A. Description of the Three Allocation Methods Investigated

Allocation based on historical generation ("Historical"). Historical allocations can be based on emissions (tons of CO_2) or generation (MWH) in a historic year. Allocation based on historic emissions tends to spread the burden of reduction most evenly as unit owners are allocated allowances based on actual emissions. Allocation based on historic generation, in contrast, tends to reward lower emitting sources, which produce relatively more generation per unit of emissions. For illustrative purposes, we have chosen an allocation based on historic emissions (based roughly on year 2003 and as shown in Table 3, the last year for which complete data was available), as this is comparable to the allocation method used in the acid rain program (which was primarily based on historic fuel input), under which states would allocate allowances

[7] RFF 2005, p. 4. "The CO2 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."

to all fossil fuel-fired units based on historic emission levels.[8] This corresponds to an allocation of roughly 0.85 allowances per ton of CO_2 emitted in the baseline year.

Allocation using an auction ("Auction"). Under this approach, all allowances are sold to CO_2 emitters and other market participants subject to the program in an open auction. The sale of allowances creates revenue that can be used for other purposes. For example, some or all of the revenue raised in selling 100 million metric tons of allowances can be used to fund energy efficiency and renewable energy programs in order to reduce the demand for, and therefore the cost of allowances. In addition, some or all of the auction proceeds may be used to reduce other portions of consumers' electric bills (e.g., transmission and distribution charges).

We consider an auction to allocate emission allowances, even though its application has not been widespread at least with respect to emission markets, although the State of Virginia has distributed a small portion of its nitrogen oxide allowances using an auction.[9] In addition, in England, the House of Commons recently concluded that the British Government should take greater steps to auction CO_2 allowances due to the substantial windfall generators made under the United Kingdom National Allocation Plan.[10] In addition, "[t]here is considerable research in the economic literature that supports the view that auctions are more economically efficient than allocations."[11] Auctions would also provide an immediate and clear price signal of the value of a CO_2 allowance, which is important in establishing a new market.

Allocation based on continuously updated generation ("Updating"). As with the historical approach, states using an updating methodology may allocate allowances based on emissions or generation. Rather than fix allocations based on a single historical year, under an updating approach, states would allocate allowances according to the most recent generation or emissions levels. To illustrate this approach here, we have chosen to allocate based on recent generation. Allowances would be received by all generators except for non-emitting technologies (nuclear, hydro, and renewable) units.

After the initial distribution of allowances by whatever allocation method, generation owners, traders, and speculators will buy and sell allowances based on their CO_2 emission needs and business strategies.[12] Each of these allocation methods launches the bilateral market for CO2 allowances, which will further develop as changing market conditions result in some generators purchasing additional allowances, others selling excess allowances, and generators as

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[8] We recognize that an allocation based on historic emissions may not be exactly how RGGI decides to allocate emission allowances if it chooses a historical approach nor is it exactly how the acid rain program allocated allowances.

[9] RFF 2005, p. 2.

[10] House of Commons, Environmental Audit Committee, *The International Challenge of Climate Change: UK Leadership in the G8 & EU, Fourth Report of Session 2004-05*, March 27, 2005, p. 4.

[11] EPA 2003, p. 3-16, which cites Peter Cramton and Suzi Kerr, *Trade Carbon Permit Auctions: How and Why to Auction Not Grandfather*, Resources for the Future, Discussion Paper 98-34, May 1998. "An auction of carbon permits [allowances] is the best way to achieve carbon caps set by international negotiation to limit climate change….An auction is preferred to grandfathering (giving polluters permits in proportion to past pollution), because it allows reduce tax distortions, provides more flexibility in distribution of costs, provides greater incentives for innovation, and reduces the need for potentially contentious arguments over the allocation of rents." (p. ii..)

[12] However CO_2 emission allowances are allocated or auctioned, policymakers need to consider how the distribution affects the potential for the exercise of market power both in the allowance and electricity markets.

well as third parties buying and selling allowances on the basis of price speculation. Regardless of whether generation owners are allocated allowances or must purchase them from the market, they will have to have some capability to buy and sell allowances to best meet their needs. Emission allowance markets are well established for nitrogen oxide and sulfur dioxide and are similar to natural gas, oil, and coal markets. Many, if not most, generation owners are already active in these markets. The extension of these capabilities to CO_2 allowance markets should not prove difficult or particularly expensive. Transaction costs associated with buying and selling allowances, particularly any difference in these costs due to different allocation methods, are likely to be small compared to the value of the allowances and the overall economic impacts to generators and consumers under the different methodologies.

B. Modeling Assumptions and Results

We modeled the RGGI region using our simplified 12-unit model. It is essential to understand that this model is not intended to predict the specific impact that RGGI will have on wholesale electricity prices or generator profits. Rather, it is intended to illustrate the impact that different allocation methodologies will have on prices and profitability, and to explain whether and why different allocation schemes will affect these things differently. To simplify the illustration and our calculations, we assume a cap that reduces emissions by 15% from current (2003) levels in a single year, although we expect states would gradually reduce emissions over many years. We also ignore the impact of at least three important factors that are likely to affect operation of the program, although the impact of each of these three factors is discussed in more detail following the presentation of the simplified modeling results.

1. Leakage. Programs that only cover a portion of an interconnected area may achieve local reductions by reducing in-region generation and increasing imports from other areas. We held local generation constant ignoring the importance of leakage. However, when leakage occurs, it mitigates the electricity price impact due to RGGI, which lowers the impact on consumers, the additional profit generators earn from higher electricity prices and the overall environmental benefit of the program.

2. New Capacity. We assume a fixed set of capacity resources in illustrating emission reductions; however, investment in new generation capacity provides an important means of reducing CO_2 emissions in response to the program. Depending on the price (and expected future prices) of CO_2 allowances, programs will tend to incent investment toward lower or zero emitting technologies. In addition, many RGGI states have RPSs that will ensure the development of new zero-emitting sources in the region. However, new capacity is also likely to mitigate the electricity price impact due to RGGI, lowering the impact on consumers and the additional profit generators earn from higher electricity prices.

3. Load Growth. For this illustration, we ignore the affects of load growth. Any real program would have to account for the fact that, absent other changes in the electricity markets, load tends to increase with the expanding economy. Load growth in the RGGI region has typically run at about 1.2% per year. Unless mitigated by additional policies to increase energy efficiency, load growth is likely to drive an

increase in generation, particularly new gas plants, which would increase the demand for, and price of, allowances, and consequently increase the impact to wholesale electricity prices.

Existing energy efficiency programs and increased wholesale electricity prices are expected to reduce demand below ISO projections. Roughly speaking, every 1% increase in the price of electricity results in about a 1 to 1.5% long-term reduction in demand for electricity.[13] In our simplified example, we illustrate the impact of this conservation by reducing generation levels by 2.5% when introducing the cap-and- trade program.

In modeling emission reductions, we reduced emissions of CO2 throughout the RGGI region from the levels shown in Table 3 to 100 million metric tons, a reduction of about 17 million metric tons, or 15%. Relative to business as usual, the actual reductions sought by the program are likely to be larger as CO_2 emissions will grow from current levels absent CO_2 control programs.

1. Impact on Unit Costs and Electricity Prices

For any cap that is lower than current levels of emissions, cap-and-trade allowance programs increase electricity prices because they generally increase the cost to generation unit owners of producing electricity. As previously explained, to produce electricity, owners of generating units that emit CO_2 must use or "spend" an allowance. In other words, like fuel, allowances become part of the variable cost of producing electricity. Logically, when unit owners offer their energy into the market, they will increase their offer by the value of the allowances that they must use. This effect occurs regardless of whether a generation owner is allocated an allowance free of charge or has to purchase an allowance. If allocated an allowance, when a generation owner decides to use it in order to produce electricity, the owner does not have to purchase an allowance. It does, however, forego the opportunity of selling that allowance in the market.[14] That lost opportunity cost would be internalized into the generator's variable costs and energy offer in the same manner as if the allowance were purchased at auction.

Table 4 presents the added cost of producing electricity resulting from allowance use for three different possible prices of allowances ($5, $10 and $20 per metric ton CO_2). These values can be calculated directly using the emission rates presented in Table 3. For example, an older coal unit produces slightly more than one metric ton of CO_2 for every megawatt hour that it produces. Thus, if allowances cost $10 per ton, then the added variable cost of producing a megawatt hour is slightly more than $10. This cost is shown in Table 4 as $10.50. Less carbon

[13] In the short-term, electricity is very price inelastic, meaning that a 1% increase in its price would only result in a fraction of a 1% decrease in demand. Over the long-term, which is applicable for the analysis conducted here, electricity is slightly price elastic, meaning that the price elasticity of demand is slightly greater than 1.

[14] "Emission allowances include an opportunity cost independent of whether allowances are received free of charge or are purchased from the market. This leads to a situation where the opportunity cost increases the marginal production cost of fossil-fuelled power production." Energy Business Group, *Emission trading and European Electricity Markets: Conceptual Solution to Minimize the Impact of the EU Emissions Trading Scheme on Electricity Prices*, March 17, 2004, p. 3.

intensive technologies have lower costs. A new gas-fired combined cycle has CO_2 emission costs as little as one third as large as coal due its much lower emission rate.

Table 4: CO2 Allowance Costs per Unit Generation ($/MWH)
(Auctioning and Historic Allocations)

	Cost of Allowance ($/Metric Ton CO2)		
Unit Type	5	10	20
Coal Steam (Older)	$ 5.25	$ 10.50	$ 21.00
Coal Steam (Newer)	$ 4.68	$ 9.35	$ 18.71
Oil Steam (Older)	$ 3.94	$ 7.88	$ 15.75
Oil Steam (Newer)	$ 3.38	$ 6.75	$ 13.50
Gas Steam	$ 2.55	$ 5.10	$ 10.19
Gas Combined Cycle (Older)	$ 2.28	$ 4.56	$ 9.12
Gas Combined Cycle (Newer)	$ 1.88	$ 3.75	$ 7.51
Efficient Gas Turbine	$ 2.82	$ 5.63	$ 11.26
Older Diesel Turbine	$ 4.73	$ 9.45	$ 18.91
Nuclear	$ -	$ -	$ -
Hydro	$ -	$ -	$ -
Renewables	$ -	$ -	$ -

In the RGGI region, wholesale electricity prices are set by the most expensive bid accepted to meet demand for electricity. Thus, how much electricity prices increase at any given time depends on the type of unit operating at the marginal offer price. This offer frequently comes from a gas-fired unit, but it may also be set by coal, oil, or another type of unit depending on the season, type of day (workday versus holiday), and time of day. In all three wholesale markets in the RGGI region, the price of electricity also can vary by location due to transmission constraints.

The wholesale electricity price increase above the level that would have occurred without RGGI will first occur in the spot market for electricity. Buyers and sellers of electricity that have long-term contracts that are not affected by this increase will not be affected until their contract terminates. Consumers who have electricity purchased on their behalf via long-term contracts will not be exposed to any electricity price increase associated with the implementation of the RGGI model rule until those contracts expire, although many are expected to do so before RGGI goes into effect.

The overall increase in wholesale electricity prices should be calculated as the weighted average increase in all periods less the impact of conservation programs and the impact of higher prices on demand. This calculation is beyond the scope of the modeling conducted for this exercise, but appears likely to fall in a range intermediate to the values presented in Table 4. For the purpose of this illustration, we assume that allowances are valued at $10 per ton. Examining Table 4 at a $10 allowance price, increases in wholesale electricity offers would likely be in the $5 to $9 per megawatt–hour range. Taking into account our assumed decrease in electric consumption (2.5%), we expect that price increases would tend toward the lower end of this range.

Table 4 illustrates the extent to which electricity prices are likely to increase under either a historic or auction-based allocation. Under both of these allocation schemes, allowances must be used in order to produce electricity and allowance allocations are unaffected by the current amount of electricity being produced. To restate, in both a historic an auction-based allocation, the going forward decision by a generator whether to produce electricity is identical whether it is allocated allowances free of charge or must purchase them via an auction.[15] Of course, how much money a generator makes is different between these two allocation approaches.

The impact of an allocation that is updated based on current or recent generation is somewhat more complicated. Not only do generation owners "spend" allowances when they produce electricity, they also "earn" them. This is, in effect, a subsidy to produce fossil fuel fired electricity because the more MWH a fossil generator produces, the more emission allowances it is allocated in the future.[16] In this example, we have 100 million tons of allowances to allocate over all fossil generation. This results in an allocation of roughly 0.56 allowances per megawatt hour of electricity produced by fossil sources (100,000,000 tons spread over roughly 180,000,000 megawatt hours). The economic incentives produced by this allocation method are shown in Table 5.

Table 5: Value of Allowance Allocation* per Megawatthour Generation
(Updating Allocation Only, Illustrative Example Based on Recent Data)

	Cost of Allowance ($/Metric Ton CO2)		
Unit Type	5	10	20
Coal Steam (Older)	$ 2.80	$ 5.60	$ 11.19
Coal Steam (Newer)	$ 2.80	$ 5.60	$ 11.19
Oil Steam (Older)	$ 2.80	$ 5.60	$ 11.19
Oil Steam (Newer)	$ 2.80	$ 5.60	$ 11.19
Gas Steam	$ 2.80	$ 5.60	$ 11.19
Gas Combined Cycle (Older)	$ 2.80	$ 5.60	$ 11.19
Gas Combined Cycle (Newer)	$ 2.80	$ 5.60	$ 11.19
Efficient Gas Turbine	$ 2.80	$ 5.60	$ 11.19
Older Diesel Turbine	$ 2.80	$ 5.60	$ 11.19
Nuclear	$ -	$ -	$ -
Hydro	$ -	$ -	$ -
Renewables	$ -	$ -	$ -

* - Assumes 100 Million Ton Cap

In Table 5 allowances are allocated to resources based only on their electrical output, the benefit is the same for all units. Non-emitting units are the exception to this statement as we have assumed that they will not receive an allocation.

For the purpose of illustrating the electricity price impact of an updating approach, we assume a CO_2 allowance value of $10 per ton. Thus, units receive a benefit worth about $5.60 for every megawatt hour they produce. Table 6 shows the net cost of allowances per unit of

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15 Pew Center 2003, p. 39. The authors make this observation with respect to a historic allocation, which "…provides no incentive to alter production or abatement behavior in order to obtain more allowances in present or future periods and thus does not create distortions."

16 Another way to think about the updating approach is that it is similar to a frequent flier mileage program. "Because updating systems change allowance allocations at periodic intervals, entities may have an incentive to do more of the activity that will earn them more allowances. Therefore, updating allocations can influence future behavior." EPA 2003, pp. 3-15 to 3-16.

generation under an Updating type allocation. The values shown in Table 6 are the same as those found in Table 4 except that the values in Table 5 have been subtracted to reflect the benefit of receiving an allowance allocation when producing.

Table 6: Net CO2 Allowance Costs per Megawatthour Generation
(Updating Allocation Only, Illustrative Example Based on Recent Data)

	Cost of Allowance ($/Metric Ton CO2)		
Unit Type	5	10	20
Coal Steam (Older)	$ 2.45	$ 4.90	$ 9.81
Coal Steam (Newer)	$ 1.88	$ 3.76	$ 7.52
Oil Steam (Older)	$ 1.14	$ 2.28	$ 4.56
Oil Steam (Newer)	$ 0.58	$ 1.15	$ 2.31
Gas Steam	$ (0.25)	$ (0.50)	$ (1.00)
Gas Combined Cycle (Older)	$ (0.52)	$ (1.04)	$ (2.07)
Gas Combined Cycle (Newer)	$ (0.92)	$ (1.84)	$ (3.68)
Efficient Gas Turbine	$ 0.02	$ 0.04	$ 0.07
Older Diesel Turbine	$ 1.93	$ 3.86	$ 7.72
Nuclear	$ -	$ -	$ -
Hydro	$ -	$ -	$ -
Renewables	$ -	$ -	$ -

Note that for the lowest emitting technologies, an allocation that updates based on current generation is likely to result in a reduction in costs, increasing revenues for owners of such units with each MWH they generate. These units would receive this subsidy even though they have no compliance costs and are already expected to increase market share (and profits) under any allocation scheme. In this example, a newer combined cycle unit emits CO_2 at a rate per megawatt-hour that is less than the allocation rate. Thus, under the Updating allocation, a new gas-fired combined cycle unit would receive more allowances than it needs as a result of producing electricity. For $10 allowances, this benefit is worth $1.84 per megawatt-hour.

As with Table 4 for a historic or auction allocation, the expected impact on average wholesale electricity prices would be the weighted average increase in the marginal unit's offer. With an updating approach, we can see that the average increase in price would be in the range of $0 to $3 per megawatt hour at an allowance price of $10 per ton, significantly less than the $5 to $9 discussed for a Historic or Auction approach.

Although the updating approach results in a lower increase in the price of electricity than the historic and auction methods, it does have a major drawback. From an efficiency perspective, the updating approach is substantially worse than the other two methods.[17] To maximize efficiency, the link between the allocation method and future production of CO_2 should be completely severed, which the historic and auction approaches accomplish but the updating approach does not. The reason is that the updating approach provides an incentive to produce electricity and therefore to emit CO_2, which undercuts the efficient (higher) price signal to producers and consumers to avoid activities that produce CO_2.

[17] RFF 2005.

Two major conclusions regarding the impact different allocation methods have on the price of electricity:

- The initial impact on wholesale electricity prices is identical under historical allocation and auction, but with auction states may be able to lower substantially the impact on prices by using auction revenues to increase energy efficiency, provide consumer rebates or reduce transmission and distribution costs.

- Without considering the reduction in electricity prices if auction revenues are used to fund energy efficiency programs or reduce transmission and distribution charges, updating has the smallest initial impact on wholesale electricity prices, but it creates the most economically inefficient system.

2. Impact on Generation and Emission Levels

How emission allowances are allocated will not affect the environmental integrity of RGGI if it is properly enforced.[18] In order to reduce emissions of CO_2 to the 100 million ton target level, we altered generation from each of the 12 types of units comprising the RGGI region. In the cap-and-trade model, reductions are achieved through decreases in generation among higher emitting resources and increases among lower emitting resources. As discussed above, total levels of generation are reduced by 2.5% to simulate the reduction in demand due to energy efficiency activities. The results are shown in Tables 7 through 9.

Table 7 describes the new dispatch given the 100 million ton assumed cap. It should be contrasted to Table 1, which provides the same information but under existing conditions without a cap-and-trade program. Table 8 calculates the total variable costs under the historic and auction approaches and should be compared to Table 2. Table 8 shows the impact of allowance costs on total variable costs for each of the 12 unit types assuming $10 allowance costs. It is important to note that these costs would be reduced by $5.60 per megawatt-hour under an updating allocation as detailed in Tables 5 and 6. Finally, Table 9 calculates the CO_2 emissions given the changes in dispatch costs, resulting in CO_2 emissions meeting the 100 million ton limit.

[18] EPA 2005, p. 3-14.

Table 7: Cap-and-Trade Model of RGGI Region - Capacity and Energy
(Illustrative Model @ 100 Million Tons CO2)

Unit Type	Fuel	Approx. RGGI Region Capacity (MW)	Capacity Factor	Heat Rate (mmBTU/MWH)	Yearly Energy (MWH/Year)
Coal Steam (Older)	Coal	5,000	19%	11.0	8,431,500
Coal Steam (Newer)	Coal	6,000	51%	9.8	26,726,760
Oil Steam (Older)	FO6	6,000	7%	10.5	3,784,320
Oil Steam (Newer)	FO6	10,000	27%	9.0	23,476,800
Gas Steam	Gas	8,000	15%	9.5	10,512,000
Gas Combined Cycle (Older)	Gas	10,000	20%	8.5	17,344,800
Gas Combined Cycle (Newer)	Gas	16,000	61%	7.0	84,936,960
Efficient Gas Turbine	Gas	9,000	4%	10.5	2,995,920
Older Diesel Turbine	FO2	6,000	1%	13.0	473,040
Nuclear	Nuclear	14,000	85%	N/A	104,244,000
Hydro	Water	9,000	40%	N/A	31,536,000
Renewables	N/A	3,000	45%	N/A	11,747,160
Total		102,000			326,209,260

Table 8: Cap-and-Trade Model of RGGI Region - Variable Cost Under Historical and Auction Allocations
(Illustrative Model @ 100 Million Tons CO2)

Unit Type	Fuel	Example Fuel Cost ($/mmBTU)	Allowance Cost* ($/MWH)	Other Variable Cost ($/MWH)	Total* Variable Cost ($/MWH)
Coal Steam (Older)	Coal	3.50	10.50	9.00	58.00
Coal Steam (Newer)	Coal	3.50	9.35	6.00	49.65
Oil Steam (Older)	FO6	5.00	7.88	4.00	64.38
Oil Steam (Newer)	FO6	5.00	6.75	4.00	55.75
Gas Steam	Gas	6.00	5.10	2.00	64.10
Gas Combined Cycle (Older)	Gas	6.00	4.56	2.00	57.56
Gas Combined Cycle (Newer)	Gas	6.00	3.75	2.00	47.75
Efficient Gas Turbine	Gas	6.00	5.63	3.00	71.63
Older Diesel Turbine	FO2	10.00	9.45	7.00	146.45
Nuclear	Nuclear	N/A	-	N/A	N/A
Hydro	Water	N/A	-	N/A	N/A
Renewables	N/A	N/A	-	N/A	N/A

* - Based on $10/Metric Ton CO2 Allowance Cost. Allowance and Total Costs would be reduced by $5.60 per megawatt-hour using Updating-type allocation.

Table 9: Cap-and-Trade Model of RGGI Region - CO2 Emissions
(Illustrative Model @ 100 Million Tons CO2)

Unit Type	Fuel	Pounds CO2 (per mmBTU)	Pounds CO2 (per MWH)	Metric or Long Tons CO2 (per Year)
Coal Steam (Older)	Coal	210	2,310	8,853,075
Coal Steam (Newer)	Coal	210	2,058	25,001,669
Oil Steam (Older)	FO6	165	1,733	2,980,152
Oil Steam (Newer)	FO6	165	1,485	15,846,840
Gas Steam	Gas	118	1,121	5,356,342
Gas Combined Cycle (Older)	Gas	118	1,003	7,907,652
Gas Combined Cycle (Newer)	Gas	118	826	31,889,968
Efficient Gas Turbine	Gas	118	1,239	1,687,248
Older Diesel Turbine	FO2	160	2,080	447,238
Nuclear	Nuclear	0	-	-
Hydro	Water	0	-	-
Renewables	N/A	0	-	-
Total				99,970,183

Reductions are driven by changes in variable costs resulting from allowances costs. While, under the historical and auction allocations, all unit types become more expensive, higher emitting (or carbon intensive) technologies are more greatly affected. Because of these differences, dispatch order (as determined by variable cost) among units change.

Table 10 presents the variable cost for selected types of units. When the cost of a $10 per ton allowance is factored in, a new coal unit falls from being the least expensive technology to the second least expensive. A new combined cycle gas unit, in contrast, goes from being the 2nd least expensive to being the least expensive. Capacity factors change accordingly. New coal, used at 70% of its maximum capacity in the baseline case without allowance costs is used at only 49% of capacity in the cap-and-trade model. New gas increases from 55% to 61% utilization. New oil steam units are less affected as their emissions fall in the middle of the pack. Utilization of these units falls slightly, though their rank goes from 4th to 3rd.

Table 10: Comparison of Cost and Utilization of Selected Unit Types
(Historical and Auction Allocations)

	Base Model			Cap-and-Trade Model		
	Variable Cost* ($/MWH)	Capacity Factor	Rank (Lowest Cost = 1)	Variable Cost* ($/MWH)	Capacity Factor	Rank (Lowest Cost = 1)
Coal Steam (Newer)	40.30	70%	1st	49.65	49%	2nd
Gas Combined Cycle (Newer)	44.00	55%	2nd	47.75	61%	1st
Oil Steam (Newer)	49.00	30%	4th	55.75	27%	3rd

* - Assumes a $10 per ton allowance cost

Greater or lesser changes in uses among the various unit types would occur as allowance costs vary. In this example, a $10 allowance cost is sufficient to make a new combined cycle plant less expensive than a new coal plant, but the difference is not large. As shown in Table 10, the new gas unit enjoys a $1.90 per megawatt-hour advantage over new coal with $10 allowances in the cap-and-trade model, but is $3.70 more expensive than coal in the base model.

At a $5 allowance cost, the dispatch order of these technologies would not be reversed and considerably less CO_2 reductions would result. In this manner, the lower the emissions cap and thus greater amount of reductions required, the greater the allowance price and the greater the impact on electricity prices. Allowance prices also depend greatly on the cost differences between technologies and the gap that allowance costs must bridge in order to produce significant changes in the dispatch order. For example, if the difference in costs per MWH to produce electricity from coal compared to natural gas increases, then for a given CO_2 cap, a larger CO_2 allowance price is needed to switch the dispatch order between coal and natural gas to achieve the desired reduction in CO_2 emissions.

Figure 1 summarizes the change in fuel use necessary to lower emissions from current levels of 117 million tons to 100 million tons in the cap-and-trade model. Assuming a fixed set of capacity resources, significant reductions in the use of coal capacity is required to achieve the reduction. A relatively small reduction in oil use is observed. The difference is made up largely by natural gas.[19]

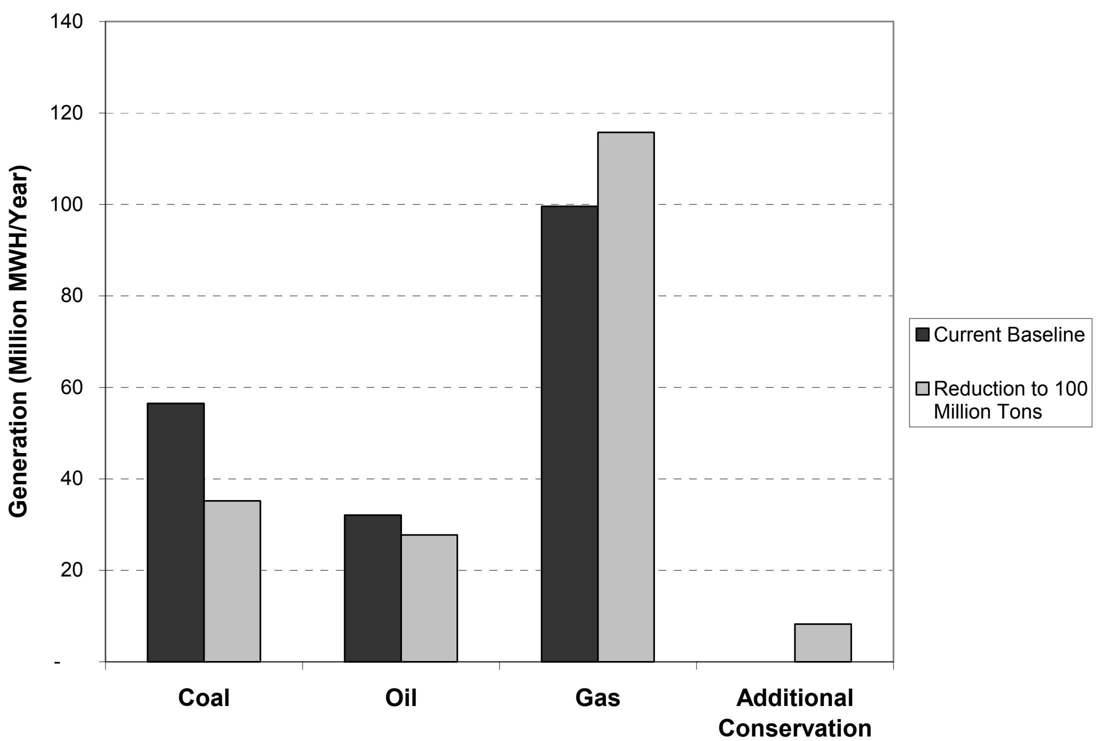

Figure 1: Change in Fuel Use Necessary to Lower Emissions From Current Levels of 117 Million Tons to 100 Million Tons in the Cap-And-Trade Model

[19] Other existing capacity resources once built, including nuclear, hydro, and renewable resources, are much less able to expand production. Nuclear units, for example, tend to run whenever they are available and cannot expand output do to economic conditions. Hydro and renewable resources produce as much as possible given that their variable costs tend to be well below the going price for electricity. Of course, with respect to the capacity addition decision, less CO_2 intensive technologies are more likely to be built with a cap than would otherwise occur without a cap.

As discussed above, much lower increases in price occur under an updating allocation. Table 11 presents the same data as presented in Table 10, but with variable costs adjusted downward to reflect the value of the variable allowance allocation ($5.60 per megawatt hour as discussed above).

Table 11: Comparison of Cost and Utilization of Selected Unit Types
(Updating Allocation)

	Base Model			Cap-and-Trade Model		
	Variable Cost* ($/MWH)	Capacity Factor	Rank (Lowest Cost = 1)	Variable Cost* ($/MWH)	Capacity Factor	Rank (Lowest Cost = 1)
Coal Steam (Newer)	40.30	70%	1st	44.05	49%	2nd
Gas Combined Cycle (Newer)	44.00	55%	2nd	42.15	61%	1st
Oil Steam (Newer)	49.00	30%	4th	50.15	27%	3rd

* - Assumes a $10 per ton allowance cost

Because it affects the variable costs of all three unit types equally (each receives the same value in allowances per megawatt hour produced), the rank order of the unit types does not change as a result of the Updating allocation. Thus, in this simplified model, the same changes in generation and reductions in emissions occur under all three allocation approaches. The primary difference lies in the resulting electricity prices.

In these examples, conservation plays a small, but important role in meeting the emissions cap. If generation had not been reduced by 2.5%, larger reductions in coal use (driven by higher allowance prices) would have been required in order to achieve a reduction to 100 million tons.

Limits exist to the level of reduction that can be achieved simply by altering levels of generation among existing resources using today's commercially available technologies. For example, even if we use the resources with the lowest CO_2 emissions to the greatest extent possible, it would be extremely difficult to drop CO_2 emissions below about 80 million metric tons in the RGGI region. This is because, unlike other pollutants, no technologies are currently available to lower CO_2 emissions from individual units. CO_2 emission levels are more or less a fixed function of the fuel used and efficiency of any given plant. Further reductions would require additional energy efficiency, renewable resources, and technological innovation and investment to reduce the use of carbon-based fuels.[20]

3. Impact on Generator Profitability

Whether fossil-fueled generators benefit or are harmed by the introduction of a cap-and-trade program depends greatly on their emissions characteristics and the manner in which allowances are allocated. All generators benefit from higher electricity prices, but fossil-fueled generators must possess and use allowances in order to produce electricity.

[20] Coal integrated gas combined cycle (IGCC) combined with carbon capture and sequestration is currently technically feasible but not commercially viable at this time.

Table 12 presents the value of allowances allocated under the historic, updating, and auction approaches. Allocation under the historic approach is based on current emissions patterns. Accordingly, the allocation does not reflect the changes in generation that are likely to occur as a result of the program itself. The updating approach assumes that allocations will be updated regularly. Thus, unit types that are likely to produce less electricity under the program receive a smaller allocation. Coal units in particular receive more allowances under the historic approach than the updating approach. Natural gas units, in contrast, receive a greater share of allowances under the updating approach both because they are expected to be used more intensively and because they produce more megawatts per ton of CO_2 emitted. We assume that non-emitters (nuclear, hydro, and renewable) units will receive no allocation under any approach. Under the auction approach, all fossil fueled units must purchase their allowances and the value of all allowances becomes available as public funds, which could be used in a variety of ways. In Table 12, we assume that none of the revenue raised by an auction is distributed to generators, although this does not necessarily have to be the case.

Table 12: Value of Allowance Allocation* Under Alternative Allocation Approaches

	Historic		Updating		Auction	
	($Million/Yr)	($/kw-yr)	($Million/Yr)	($/kw-yr)	($Million/Yr)	($/kw-yr)
Coal Steam (Older)	176	35	47	9	-	-
Coal Steam (Newer)	293	49	150	25	-	-
Oil Steam (Older)	35	6	21	4	-	-
Oil Steam (Newer)	151	15	131	13	-	-
Gas Steam	30	4	59	7	-	-
Gas Combined Cycle (Older)	51	5	97	10	-	-
Gas Combined Cycle (Newer)	247	15	475	30	-	-
Efficient Gas Turbine	11	1	17	2	-	-
Older Diesel Turbine	4	1	3	0	-	-
Nuclear	-	-	-	-	-	-
Hydro	-	-	-	-	-	-
Renewables	-	-	-	-	-	-
Public Funds	-	N/A	-	N/A	1,000	N/A
Total	1,000		1,000		1,000	

* - Assumes allowances are worth $10 per ton and a 100 million ton cap.

Table 13 shows the cost of allowances experienced by each of the 12 unit types when CO_2 emissions are reduced to 100 million tons. These costs are a function of both units' emission rates and how intensively units are used to produce electricity. For example, the cost per kilowatt of older coal capacity ($18) is actually less than the allowance cost experienced by a new combined cycle unit ($20). Even though older coal plants have nearly triple the emissions rate of a new combined cycle, they are used one third as intensively in the cap-and-trade model.

Table 13: Allowance Costs* for 12 Unit Types

	Allowance Costs ($Million/Yr)	($/kw-yr)
Coal Steam (Older)	89	18
Coal Steam (Newer)	250	42
Oil Steam (Older)	30	5
Oil Steam (Newer)	158	16
Gas Steam	54	7
Gas Combined Cycle (Older)	79	8
Gas Combined Cycle (Newer)	319	20
Efficient Gas Turbine	17	2
Older Diesel Turbine	4	1
Nuclear	-	-
Hydro	-	-
Renewables	-	-
Total	1,000	

* - Assumes allowances are worth $10 per ton and a 100 million ton cap.

Generators benefit from increased wholesale electricity prices. We assume that electricity prices increase by a value in the lower end of the range discussed previously to account for the impact of reduced demand on price. Thus, we assume that electricity prices increase by $5.00 under the historic and auction allocations and $1.00 under the updating allocation. Table 14 presents estimated increases in generator revenue for the 12 unit types.

Table 14: Increased Generator Revenue* Due to Increase In Electricity Prices

	Historic ($Million/Yr)	($/kw-yr)	Updating ($Million/Yr)	($/kw-yr)	Auction ($Million/Yr)	($/kw-yr)
Coal Steam (Older)	11	2	(14)	(3)	11	2
Coal Steam (Newer)	112	19	13	2	112	19
Oil Steam (Older)	17	3	3	0	17	3
Oil Steam (Newer)	115	11	23	2	115	11
Gas Steam	52	7	8	1	52	7
Gas Combined Cycle (Older)	86	9	13	1	86	9
Gas Combined Cycle (Newer)	420	26	74	5	420	26
Efficient Gas Turbine	15	2	3	0	15	2
Older Diesel Turbine	2	0	0	0	2	0
Nuclear	521	37	104	-	521	37
Hydro	158	18	32	-	158	18
Renewables	56	19	11	4	56	19
Total	1,564		270		1,564	

* - Assumes $5.00/MWH increase in electricity prices under Historic and Auction, $1.00 under Updating

These estimates further account for the fact that, because most generators will operate for a differing number of hours, the profit opportunities available to resources will change under a cap-and-trade program. Thus, coal units, which will operate less, experience a much smaller benefit than gas units, which will tend to operate more. In this example, older coal units actually lose money under an updating allocation because the comparatively small increases in price that occur when such units operate do not make up for the lost operating profits resulting from decreased operation. Benefits under updating are much smaller due to the smaller price increase expected under this allocation method.

The combined result of the impacts shown in the previous three tables is presented in Table 15. The total impact across all 12-unit types is found in the bottom of the table. Overall, nearly all unit types fare best under a historic allocation. Such an approach both awards allowance values to generators and produces a larger increase in electricity prices than the updating approach. The exception is non-emitting units, which receive no allocation in the historic approach and thus, because historic and auction approaches produce the same price increase, non-emitting units are indifferent between these two allocations. Non-emitting units prefer either historic or an auction to the updating approach because it results in a larger increase in electricity prices, and these resources do not have to purchase CO_2 allowances.

Table 15: Net Impact of Program for 12 Unit Types

	Historic		Updating		Auction	
	($Million/Yr)	($/kw-yr)	($Million/Yr)	($/kw-yr)	($Million/Yr)	($/kw-yr)
Coal Steam (Older)	99	20	(55)	(11)	(77)	(15)
Coal Steam (Newer)	155	26	(88)	(15)	(138)	(23)
Oil Steam (Older)	22	4	(6)	(1)	(13)	(2)
Oil Steam (Newer)	108	11	(4)	(0)	(44)	(4)
Gas Steam	29	4	13	2	(1)	(0)
Gas Combined Cycle (Older)	58	6	31	3	7	1
Gas Combined Cycle (Newer)	348	22	230	14	101	6
Efficient Gas Turbine	9	1	3	0	(2)	(0)
Older Diesel Turbine	2	0	(1)	(0)	(2)	(0)
Nuclear	521	37	104	7	521	37
Hydro	158	18	32	4	158	18
Renewables	56	19	11	4	56	19
Total	1,564		270		564	

On balance, most unit types fare better under the updating approach than the auction approach. The increased market revenues produced by the auction approach is somewhat less than the value of the allowance allocation that units receive under updating. The three exceptions are nuclear, hydro, and renewable. The non-emitting units do not receive allowances under updating and thus, would much prefer the historic or auction approaches and the larger associated increases in electricity price. The total benefits to generators are significantly greater under the auction approach than the updating approach due to the greater benefits that flow to non-emitting units. In the aggregate, industry margins increase under all three scenarios.

Companies selling into the electricity markets in the RGGI region typically own a portfolio of units. Like individual units, the impact on the profitability of a portfolio of generation resources can vary greatly depending on the type of resources owned. The impact on a portfolio, however, tends to be somewhat less dramatic than individual units as the impacts on different unit types in the portfolio tend to offset each other.

Table 16 presents the impact of the program based on this simplified example on typical individual units of each of the 12 unit types. The financial impacts of the three allocations are shown in $1,000's of dollars. While the actual impacts experienced by unit owners will vary greatly depending on actual conditions (e.g., allowance prices, fuel costs, etc.), the table provides a sense of the magnitude of impacts that may be possible, and the relative differences among portfolios.

Table 16: Net Impact of Program on Typical Units of Each Type

	Typical Unit Capacity (MW)	Historic	Updating ($1,000/Yr)	Auction
Coal Steam (Older)	150	2,970	(1,648)	(2,322)
Coal Steam (Newer)	400	10,337	(5,840)	(9,220)
Oil Steam (Older)	150	557	(144)	(325)
Oil Steam (Newer)	400	4,306	(153)	(1,741)
Gas Steam	400	1,463	657	(59)
Gas Combined Cycle (Older)	150	867	466	101
Gas Combined Cycle (Newer)	400	8,690	5,756	2,522
Efficient Gas Turbine	50	51	14	(12)
Older Diesel Turbine	20	7	(5)	(7)
Nuclear	1,000	37,230	7,446	37,230
Hydro	20	350	70	350
Renewables	20	371	74	371

Tables 17 through 19 present the cumulative impact of the program on three different 3,000 MW portfolios of generation resources. As we might expect based on the cumulative unit results presented previously, all three portfolio's fare best under a historic allocation. Of the three portfolios, the second portfolio does the best under the historic allocation due primarily to the increase in profitability of nuclear capacity it contains. The first portfolio (fossil only) fares the worst of the three, but still sees significant increases in profitability across all of its units including a relatively large portion of coal-fired capacity.

Table 17: Net Impact of Program on Example Portfolio 1 (Fossil Only)

	Units (#)	Capacity (MW)	Historic	Updating ($1,000/Yr)	Auction
Coal Steam (Older)	2	300	5,940	(3,295)	(4,643)
Coal Steam (Newer)	1	400	10,337	(5,840)	(9,220)
Oil Steam (Older)	2	300	1,114	(289)	(650)
Oil Steam (Newer)	1	400	4,306	(153)	(1,741)
Gas Steam	1	400	1,463	657	(59)
Gas Combined Cycle (Older)	2	300	1,733	932	202
Gas Combined Cycle (Newer)	1	400	8,690	5,756	2,522
Efficient Gas Turbine	4	200	206	57	(46)
Older Diesel Turbine	15	300	101	(71)	(111)
Nuclear	0	-	-	-	-
Hydro	0	-	-	-	-
Renewables	0	-	-	-	-
Total	29	3,000	33,891	(2,246)	(13,747)

Table 18: Net Impact of Program on Example Portfolio 2 (Nuclear Heavy)

	Units (#)	Capacity (MW)	Historic	Updating ($1,000/Yr)	Auction
Coal Steam (Older)	1	150	2,970	(1,648)	(2,322)
Coal Steam (Newer)	1	400	10,337	(5,840)	(9,220)
Oil Steam (Older)	1	150	557	(144)	(325)
Oil Steam (Newer)	1	400	4,306	(153)	(1,741)
Gas Steam	0	-	-	-	-
Gas Combined Cycle (Older)	1	150	867	466	101
Gas Combined Cycle (Newer)	1	400	8,690	5,756	2,522
Efficient Gas Turbine	3	150	154	43	(35)
Older Diesel Turbine	5	100	34	(24)	(37)
Nuclear	1	1,000	37,230	7,446	37,230
Hydro	5	100	1,752	350	1,752
Renewables	0	-	-	-	-
Total	20	3,000	66,897	6,253	27,925

Table 19: Net Impact of Program on Example Portfolio 3 (Large Developer)

	Units (#)	Capacity (MW)	Historic ($1,000/Yr)	Updating ($1,000/Yr)	Auction ($1,000/Yr)
Coal Steam (Older)	0	-	-	-	-
Coal Steam (Newer)	0	-	-	-	-
Oil Steam (Older)	0	-	-	-	-
Oil Steam (Newer)	1	400	4,306	(153)	(1,741)
Gas Steam	0	-	-	-	-
Gas Combined Cycle (Older)	0	-	-	-	-
Gas Combined Cycle (Newer)	4	1,600	34,759	23,024	10,090
Efficient Gas Turbine	10	500	515	144	(116)
Older Diesel Turbine	0	-	-	-	-
Nuclear	0	-	-	-	-
Hydro	10	200	3,504	701	3,504
Renewables	15	300	5,565	1,113	5,565
Total	40	3,000	48,649	24,828	17,301

The updating and auction allocations produce mixed results. The first (fossil only) portfolio is made worse off by the presence of the cap-and-trade program. Note that the net deficit resulting from the program is less than it might have been had this portfolio not included a moderate fraction of natural gas-fired units. This offset is more significant in the Updating allocation due to the better performance of gas-fired units and lower losses for coal. In this example, the new combined cycle unit, in particular, offsets much of the losses experienced by coal-fired capacity under the updating allocation. A smaller but significant offset occurs under the auction allocation.

Both the second (nuclear heavy) portfolio, and the third (large developer's) portfolio fare well under either an updating or an auction approach. The nuclear heavy portfolio fares better under the auctioning allocation due to the increase in electricity prices that results. The advantage of auctioning is much less significant for the large developer's portfolio than the portfolio with significant nuclear capacity. Under the updating allocation, in contrast, the natural-gas fired units in the large developer's portfolio receive an allocation of allowances whereas nuclear capacity does not. Thus, the gas-heavy portfolio of the developer fares better than the other portfolios under updating.

Both hydro and other renewable resources contribute significantly to the bottom line of portfolios that contain them. Because most of the increases in value for these resources are seen through increases in electricity prices, this contribution is more significant in the historic and auction allocations than the updating allocation.

4. Importance of Leakage and Other Issues

Leakage refers to unintentional local reductions in CO_2 emissions that occur due to reduced local generation that is made up through imports from other areas. Because overall generation is not actually reduced and no CO_2 cap is in place in the area from which generation is imported, local CO_2 reductions are likely to be offset by increases in other areas, thus undermining the CO_2 reduction goals of cap-and-trade programs.[21]

Leakage can have a large impact on efficacy of programs. Significant leakage is most likely to occur in programs where large price increases result, thus providing incentives for importation of lower cost power from neighboring regions. Because it tends to have a lower impact on price, the least amount of leakage is likely to occur under an updating type allocation, or under an auction if revenues are used to reduce demand and thereby lower price impacts.

Leakage also tends to limit the extent to which price increases can occur. Thus, local generation resources are likely to fare more poorly when leakage occurs than depicted in the examples presented in this paper. Generation resources in neighboring regions, in contrast, have a comparative advantage because they are not required to use allowances to produce energy and can take advantage of higher prices in affected regions to the extent that transmission is available.

Policymakers should consider and implement policy measures that minimize leakage. One such measure for consideration is the investment in additional energy efficiency and renewable resources, which could mitigate the electricity price increase due to RGGI. If allowances are granted to promote a particular type of energy efficiency or renewable investment or to maintain system reliability, then policymakers should make sure that the granting of the allowance is conditional on the performance by those receiving the monetary value of the allowance.[22] In addition, policymakers, if they choose to use some of the allowances to fund energy efficiency or renewable programs should ensure that these programs are well managed, cost effective, and capable of being ramped up commensurate to their new funding levels. Another option is to develop a policy to regulate CO_2 emissions associated with imports from outside the RGGI region, although it is beyond the scope of this paper to evaluate such a proposal.

There are numerous specific issues related to designing a comprehensive and effective CO_2 cap-and-trade program, the discussion of which is beyond the scope of this paper.[23] Policymakers should consider how specific issues of program design could also help mitigate leakage and reduce the program's cost impact. For example, banking is an important way to reduce compliance costs. It allows holders of emission allowances to "bank" some or all of their allowances for use in future years, perhaps in anticipation of higher CO_2 allowance prices. Banking is especially appropriate for CO_2 when the specific timing of emissions is unimportant.

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[21] Another type of "leakage" is economic activity shifting from the RGGI to outside the region due to higher electricity prices. RFF 2005, p. 3.

[22] The same applies if allowances are used to ensure reliability by allocating some of them to generation units to ensure that they do not retire due to the additional costs imposed upon them by RGGI. There are, however, many other existing measures in the RGGI region to address the issue adequately funding generation units needed for reliability, such as locational marginal prices for electric energy, installed capacity markets (some with locational requirements), uplift payments, and reliability must run contracts. Whether these policies are sufficient and whether CO2 emission allowances should be used as a reliability tool are important questions for policymakers to consider.

[23] See EPA 2003 for a complete discussion of these issues.

Numerous other administrative and rulemaking issues come into play under different allocation methods. For example, rules for historic allocations are often complicated by such factors as new entry and retirement among generators. Allocations in a "pure" historic allocation should be unaffected by generation additions and retirements. Many policy makers will point out, however, that it makes little sense to continue allocating to a generation unit long since retired. Nevertheless, rules that end allocations in such circumstances create an inefficient incentive to keep older units from retiring in order to maintain their allowance stream.

IV. Conclusion

The allocation of CO_2 allowances is critical because it involves distributing, in effect, a large amount of money. The total value of the allowances is far greater than the compliance cost to meet the cap. The allocation scheme also has critical implications on the cost of electricity, the profitability of generation units, and the amount of leakage, and each allocation approach affects these issues differently.

When confronting this decision, policymakers have a variety of choices that can be combined to satisfy their goals of RGGI effectiveness, cost impacts, equity considerations, and administrative issues. An auction of some or all allowances may enable policy makers to achieve these public policy objectives by the raising of money through the auction process. Finding ways to mitigate the cost impacts of a RGGI program, such as increasing investment in energy efficiency and renewable technologies and reducing transmission and distribution charges, should be part of policymakers' calculus in designing a model RGGI rule.