Evaluation of Impact of Regional Greenhouse Gas Initiative CO_2 Cap on the New England Power System

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Executive Summary

In December 2005, seven northeastern states signed a Memorandum of Understanding (MOU) to implement a carbon dioxide (CO_2) cap-and-trade program, called the Regional Greenhouse Gas Initiative (RGGI), to reduce CO_2 emissions from power plants in those states. RGGI developed a draft Model Rule in early 2006 as a framework to guide the states to implement their share of the cap starting in 2009. Four New England states (Connecticut, Maine, New Hampshire and Vermont) were signatories to the RGGI MOU[1]. The RGGI CO_2 cap for these four states would be 26.5 million tons[2] per year through 2014 applicable to 50 fossil-fueled generators. For comparison, in 2004 the CO_2 emissions from these generators totaled 25.1 million tons.

The RGGI cap-and-trade program would create CO_2 emission allowances needed by generators, which would have a market value. This value would be reflected in the generator bid prices, similar to how SO_2 and NO_x allowances are reflected today. This additional generator cost could shift the dispatch of the generators and their CO_2 emissions, and potentially affect electric system operation and reliability in New England.

The System Planning Department of ISO New England Inc. (ISO) has conducted a study to evaluate the impact that RGGI could have on CO_2 emissions from New England's affected power plants and the likelihood of these generators, collectively, to comply with the RGGI cap. This report documents the study assumptions, analysis method, results and conclusions.

Study Method and Assumptions

The ISO study performed energy production simulations of New England generators, using the Inter-Regional Electric Market Model (IREMM)[3] model. The model estimated the RGGI units' annual CO_2 emissions over the study period of 2006-2015 used in the ISO's *2006 Regional System Plan* (RSP06). The study's reference case is based on the RSP06 assumptions for load forecast, resources, transmission, and imports, and assumes no new generators or demand response resources are added to the system. Other key assumptions of the study related to RGGI are:

- The RGGI CO_2 allowance price is modeled as a cost adder on the RGGI generators over the study period;
- RGGI generators would be allocated a share of allowances and could purchase the remainder in the market to obtain 100% of their share of the individual state allowance caps;
- No use of offsets[4] is assumed;
- No other new air regulations are modeled;
- Annual compliance with the RGGI cap is used as a proxy for the three-year RGGI compliance period;
- The Massachusetts regulations for CO_2 (310 CMR 7.29) are modeled.

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[1] The other RGGI participating states are Delaware, New Jersey, and New York. Maryland will join in 2007.

[2] All figures in short tons: short ton = 2,000 lbs.

[3] IREMM is a multi-area computer simulation program that simulates electric generation production using transmission transportation representation.

[4] Offsets are emission reductions from sources outside the states that participate in RGGI.

To investigate the possibility of the New England generators' CO_2 emissions collectively complying with the New England RGGI cap, various scenarios and cases were studied. These examined two main issues under the RGGI cap: 1) the effect of CO_2 allowance prices on compliance by the RGGI generators collectively, and 2) the impact on compliance of alternative new resource additions to the electric system. Other results produced by this evaluation included estimates of CO_2 emission leakage, the effect of decreasing imports, or increasing exports, and the effect of the relative price of natural gas versus residual oil on RGGI compliance in New England. The effects of the RGGI cap on fuel usage and natural gas dependency were also estimated. The study also investigated the RGGI compliance issues related to the CO_2 allowance price and potential new resource additions for a New England six-state RGGI cap if Massachusetts and Rhode Island were to join RGGI.

CO_2 emission leakage refers to any increase in CO_2 emissions outside of the RGGI cap region, resulting from the cap, which would offset the CO_2 reductions occurring within the RGGI region. For this study, leakage from Massachusetts and Rhode Island for the four New England state RGGI was calculated, but leakage from Canadian imports was not[5]. For a six New England state RGGI, the emission leakage would be only from Canadian imports and was not calculated.

No attempt was made to compare the results of this evaluation with the RGGI group's modeling results. That modeling effort focused principally on identifying an appropriate emission cap for the RGGI region, while ISO's study focused on New England's ability to meet the cap. In addition, the regions modeled, the assumptions and the scenarios in the two studies were different.

All references to the RGGI cap in this report refer to the New England portion of the RGGI cap.

Results for RGGI Cap in Four New England States

RGGI Compliance vs. CO_2 Allowance Price

The study examined how uncertainty in CO_2 allowance price might affect the four New England states' compliance with the RGGI cap. CO_2 allowance prices of \$5, \$10 and \$20/ton were simulated for the New England RGGI generators' CO_2 emission adders. Assuming no resource additions in New England over the next ten years, and without accounting for leakage, the 50 New England RGGI units would appear able collectively to meet the New England RGGI cap through 2015, if the CO_2 allowance price were \$5/ton or higher. A higher CO_2 allowance price would reduce CO_2 emissions from the RGGI units even more, but would also increase the CO_2 emission leakage from non-RGGI units. Thus, due to the RGGI cap, the net reduction in total CO_2 emissions in all of New England, including Massachusetts and Rhode Island, would be less. In the reference case, by 2015, the New England RGGI units' CO_2 emissions would decrease by 1.6 million tons at a CO_2 allowance price of \$5 per ton. However, the CO_2 emission leakage would offset this by 1.6 million tons, resulting in no reduction in the total New England CO_2 emissions. Similarly, if the CO_2 allowance price were increased to \$10/ton, the New England RGGI units' CO_2 emissions would decrease by 4.5 million tons and CO_2 emission leakage would be 3.4 million tons resulting in a net reduction in CO_2 emissions in New England of 1.1 million tons. Similarly, a CO_2 allowance price of \$20/ton would reduce the RGGI CO_2 emissions by 8.8 million tons and the CO_2 emission leakage would be 5.2 million tons, yielding a net reduction in the total New England CO_2 emissions of 3.6 million tons.

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[5] Canadian imports would be largely hydro from Hydro Quebec and possibly energy banking with Hydro Quebec and include some fossil from New Brunswick. The study did not attempt to calculate Canada's potential contribution to RGGI leakage.

The study assumption of not using offsets makes the study results conservative in terms of compliance. The use of offsets (the maximum is 3.3% unless price triggers are reached) would provide about 0.9 million tons of additional compliance flexibility annually, or help replace any set-aside allowances unavailable from the market.

RGGI Compliance vs. New Resource Additions

The ISO study examined the impact of adding alternative resources to the system to reduce CO_2 emissions for the four-state RGGI scenario. These alternative cases included 1,000 MW of nuclear, coal and natural gas combined cycle capacity. The coal alternative assumed the use of Integrated Coal Gasification Combined Cycle (IGCC) with 90% of carbon capture and sequestration (CCS) and, alternatively, without CCS. A mix of resource additions (1,651 MW) representing the resources in the ISO Generator Interconnection Queue (Queue)[6] was also examined.

As compared to the results of the base case, if 1,000 MW of new resources with zero or low emission characteristics were added, the New England RGGI units' CO_2 emissions would decrease in 2015 by about 1.8 million tons if these additions were nuclear units and, similarly, by 1.0 million tons if the additions were IGCC units with 90% CCS. If the additions were IGCC units without CCS, the New England RGGI units' CO_2 emissions would increase and exceed the cap of 25.8 million tons[7] by 5.0 million tons in 2015. Alternatively, if 1,000 MW of natural gas combined cycle units were added to the system, the New England RGGI CO_2 emissions would increase by almost one million tons in 2015 as compared to the base case (no resource additions). If a representative mix of proposed new resources in the ISO Queue were added, the 2015 New England RGGI units' CO_2 emissions would be reduced by about 0.7 million tons compared to the base case. These results suggest that low or zero CO_2-emitting resources would be more desirable additions for maintaining the region's CO_2 emissions at or below the RGGI cap as New England energy demand grows.

Effect of Varying Imports and Exports on RGGI Compliance

The evaluation compared a case of zero imports into New England to the reference case, which assumed market-based imports. Alternatively, a case of increased exports was examined for its impact on RGGI compliance versus the reference case. At an assumed CO_2 allowance price of $10/ton, the results show zero imports would increase the RGGI CO_2 emissions by 3.7 million tons compared with the base case, and by 2015, would exceed the RGGI cap. With an assumed CO_2 allowance price of $10/ton, a 200 MW increase in exports would increase the RGGI CO_2 emissions by 1.5 million tons, but the RGGI CO_2 emissions would remain below the RGGI cap during the study period through 2015.

Effect of Relative Price of Natural Gas vs. Residual Oil on RGGI Compliance

The assessment analyzed the impact of changes in the relative price of natural gas versus residual oil on CO_2 emissions from the RGGI generators at a CO_2 allowance price of $10/ton. The results show that if the natural gas price were about 1.6 times the price of residual oil, the New England RGGI CO_2 emissions would equal the RGGI cap in 2015.

Effect on Fuel Usage

The New England RGGI cap would not significantly affect the energy mix or natural gas use in New England, since this is largely driven by energy demand and natural gas is the marginal fuel most of the time.

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[6] http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html

[7] Starting in 2015, the CO_2 emissions cap would be reduced at a rate of 2.5% per year until 2018.

Results for RGGI Cap in Six New England States

RGGI Compliance vs. CO_2 Allowance Price

The ISO study examined the impact on CO_2 emissions if Massachusetts and Rhode Island were to join RGGI in the future. In this scenario, the number of RGGI units in New England would increase to 106 and the six New England states' annual RGGI cap would increase to 55.8 million tons. The New England six-state RGGI cap was assumed to supersede the Massachusetts 310 CMR 7.29 regulations.

In the reference case (no resource additions), the CO_2 emissions would exceed the six-state RGGI cap by 2011 at an assumed CO_2 allowance price of $5/ton, and by 2014 at a CO_2 allowance price of $20/ton. At a $5/ton CO_2 allowance price, the RGGI units' emissions would exceed the cap by 6.8 million tons in 2015.

RGGI Compliance vs. New Resource Additions

Similar to the four-state RGGI cap, the study examined the impact of alternative new resource additions in the six-state RGGI scenario. The results show that at a CO_2 allowance price of $5/ton, even if 1,000 MW of low or zero CO_2-emitting resources were installed in the system, the New England RGGI units' CO_2 emissions would still exceed the six-state cap starting in 2012 and result in 2.6 million tons of excess CO_2 emissions above the cap by 2015. The other resource additions show even higher CO_2 emissions by 2015, i.e. greater non-compliance with the six-state RGGI cap.

Conclusions

The ISO RGGI study was based on the assumption that 100% of the state caps would be available to the RGGI generators, including all set-asides through allocation, auctions and a liquid allowance market. However, no use of offsets was assumed. The evaluation shows that based on these assumptions, the RGGI generators in the four New England RGGI states would be able to comply with the New England RGGI CO_2 cap through 2015 if CO_2 allowance prices were $5/ton or higher and there were no new resource additions. But because of CO_2 leakage, any CO_2 reductions resulting from the RGGI cap would be offset to some degree by increases in non-RGGI units' CO_2 emissions. The RGGI organization is developing strategies that will minimize the effects of leakage. To meet energy growth over the next ten years, the addition of low or zero CO_2-emitting resources is essential to maintain compliance with the RGGI cap, offsetting CO_2 emission growth resulting from the growth of energy use.

Decreasing imports, or increasing exports, would increase the New England CO_2 emissions and make RGGI compliance more difficult. Similarly, if natural gas were more expensive than residual oil, the New England CO_2 emissions would increase, making it more of a challenge for the New England generators to meet the RGGI cap. The New England energy mix would not be significantly affected by the RGGI cap.

If Massachusetts and Rhode Island were to join RGGI, compliance with the cap would be difficult by 2011 without any new zero or low CO_2-emitting resources added to serve energy growth. Any new resources added over the next ten years would need to have zero or low CO_2 emission characteristics to comply with the New England RGGI cap, especially after 2011.

1.0 - Introduction

1.1 Purpose of Report

This report describes a study by ISO New England of the potential impact that the proposed Regional Greenhouse Gas Initiative (RGGI) would have on the New England bulk power system's CO_2 emissions during the period of 2006-2015. RGGI will impose a CO_2 emission cap of 26.5 million tons on 50 generators in four participating New England states (Connecticut, Maine, New Hampshire and Vermont) starting in 2009. In 2015, the cap will decline 2.5% per year until 2018, and be fixed thereafter at 23.9 million tons. For comparison, in 2004, the CO_2 emissions from these 50 generators totaled 25.1 million tons.

The study focused on simulating the New England RGGI generators' total CO_2 emissions and comparing them annually to the RGGI cap; it did not focus on individual unit's CO_2 emissions. The RGGI generators were assumed to have 100% access to the allowances created under the state caps, including all set-asides, through allocation, auctions, and a liquid allowance market. No dependency on use of offsets was assumed in the study.

1.2 Background on RGGI

On December 20, 2005, Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont, signed an agreement to implement RGGI, as outlined in a Memorandum of Understanding (MOU).[8] Maryland signed legislation in April, 2006, that requires it to become a full participant in the process by June 30, 2007. In addition, the District of Columbia, Massachusetts, Pennsylvania, Rhode Island, and the Eastern Canadian Provinces were observers in the RGGI process. The purpose of this initiative is to design and implement a flexible, market-based, cap-and-trade program to stabilize and then reduce CO_2 emissions from major power plants in the Northeast United States. RGGI will apply to electric generating units that have a nameplate capacity equal to or greater than 25 MW and that burn more than 50% fossil fuel.

The RGGI cap-and-trade program will create through the RGGI states a CO_2 emission allowance budget for the RGGI generators. Like SO_2 and NO_x allowances, these allowances will have a value (dollars per ton). Therefore, the effect of RGGI will be to increase a generator's energy cost by requiring the value of a CO_2 allowance to be reflected in addition to the environmental costs currently reflected for SO_2 and NO_x allowances. The resulting system dispatch would cause a shift to lower CO_2-emitting generators to serve the region's energy needs. Depending on the energy price, the resulting dispatch may or may not result in the New England RGGI generators meeting the regional cap.

The RGGI cap will start in 2009 and stabilize CO_2 emissions from the affected power plants at approximately their current levels through 2014. From 2015, the overall CO_2 cap will decline 2.5% per year, achieving a 10% reduction by 2018. The total cap of 121.3 million tons of CO_2 for all of the RGGI MOU states has been distributed among the seven participating states. The CO_2 cap for the four New England states is 26.5 million tons as shown in Table 1.1. Although Massachusetts and Rhode Island participated in the development of RGGI, they did not sign the RGGI MOU. However, RGGI made provisions for Massachusetts and Rhode Island to join by 2008. Their CO_2 emission budgets are also listed in Table 1.1.

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[8] http://www.rggi.org/agreement.htm

Table 1.1 – RGGI States CO_2 Emission Budgets

Regions	States	Annual CO_2 Budget (tons)
	Connecticut	10,695,036
	Maine	5,948,902
	New Hampshire	8,620,460
	Vermont	1,225,830
Total New England (4 States)		**26,490,228**
	Delaware	7,559,787
	New Jersey	22,892,730
	New York	64,310,805
TOTAL RGGI (7 States)		**121,253,550**
	Massachusetts	26,660,204
	Rhode Island	2,659,239
Total New England (6 States)		**55,809,671**
TOTAL RGGI (9 States)		**150,572,993**

On March 23, 2006, the RGGI Staff Working Group released a draft Model Rule for public comment with proposed model regulations for states to implement the cap-and-trade program. In May, the ISO, along with many others, submitted comments on the Model Rule[9]. The final Model Rule was issued on August 16th, 2006 and forms the basis for individual states to implement the program through their own state-promulgated regulations or legislation. The ISO RGGI evaluation documented in this report was based on the draft Model Rule. The changes in the final model rule do not change the results of this study.

In 2001, Massachusetts issued regulations imposing a cap on the CO_2 emissions from six fossil plants (15 units) in the state starting in 2006[10]. In addition, starting in 2008, the regulations also cap the CO_2 emission rates of these plants at 1,800 lbs per MWh. In 2004, the six plants emitted CO_2 below their annual tonnage cap[11], but most of them emitted at a rate above the CO_2 rate cap. To comply with both caps, the regulations allow the purchase of greenhouse gas (GHG) offsets from non-electric sector GHG reductions up to a ceiling price of $10 per ton. While these regulations are less severe than the RGGI cap, they will increase the energy costs of the plants with CO_2 rates above the 1,800 lbs per MWh limit. The tonnage cap was not modeled in the study since the projected emissions of the six plants as calculated in the emissions analysis of RSP06 are below their caps. The rate cap was modeled in this study.

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[9] http://www.rggi.org/modelrule.htm

[10] 310 CMR 7.29 affects Brayton Point, Canal, Mt. Tom, Mystic, Salem Harbor and Somerset plants. The total annual tonnage cap of these plants is 27.8 million tons.

[11] http://www.rggi.org/docs/MA-2000-2004-rev081105.xls

1.3 Purpose of ISO RGGI Evaluation

The RGGI cap-and-trade program would impact the bidding and operational behavior of the generators in the power markets since it would create CO_2 emission allowances which have a market value. This value will need to be reflected in a unit's bid price for cost recovery similar to how SO_2 and NO_x allowances are reflected currently. To evaluate the potential impact of RGGI on the New England power system, ISO's System Planning Department conducted two studies: 1) identify the likely compliance methods to be implemented by generators and the potential risks which may present for maintaining system reliability[12]; and 2) estimate the impacts of the RGGI cap on the New England RGGI generators' total CO_2 emissions and their ability collectively to comply with the cap. The latter study simulated the energy production and corresponding CO_2 emissions from the New England generators for various cases, and the results are presented and discussed in this report. It did not analyze the issues related to the compliance of individual RGGI generators in New England.

1.4 Study Method

The simulations were performed over the period of 2006-2015 consistent with the ISO's *2006 Regional System Plan* (RSP06). The study reference case was based on the RSP06 assumptions. Scenarios and cases were simulated to examine the effect of the CO_2 cap on the RGGI generators' dispatch and their CO_2 emissions and to compare these projected emissions to the New England RGGI cap for compliance. Under the current New England four-state RGGI structure, two main issues were studied: 1) the effect of CO_2 allowance prices on meeting the cap, and 2) the impact of alternative new resource additions on complying with the cap. The evaluation also calculated CO_2 emission leakage, the effect of decreasing imports and increasing exports, the effect of the relative price of natural gas versus residual oil, and the effect on fuel usage in New England. In addition, the ISO RGGI study investigated the RGGI compliance issues related to CO_2 allowance prices and alternative new resource additions under a possible New England six-state RGGI structure, assuming Massachusetts and Rhode Island were to join RGGI in the future.

The RGGI generators collectively were assumed to be able to acquire 100% of their state allowance caps (Table 1.1) through direct allocation, auctions and purchase in a liquid market. No use of offsets was considered.

1.5 Structure of the Report and Review of Study Results

This report has three remaining sections. Section 2 presents the modeling and assumptions used in the evaluation. Section 3 presents the simulation results from this analysis and Section 4 provides the major observations and conclusions. The Appendix provides a more detailed discussion of the modeling and assumptions used in the study.

The results from the evaluation were presented to Planning Advisory Committee (PAC) on June 6th, 2006[13]. A participant submitted questions on the evaluation and ISO has responded to these[14]. This report also addresses the majority of the concerns from that participant.

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[12] http://www.iso-ne.com/genrtion_resrcs/reports/emission/levitan_rggi_memo04142006.pdf

[13] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2006/jun62006/regional_greenhouse_gas_initiative.pdf

[14] http://www.iso-ne.com/genrtion_resrcs/reports/emission/rggi_study_q_and_a.pdf

2.0 Modeling and Assumptions

This section presents the modeling and main assumptions, and describes the cases simulated in the study. More detailed information on the modeling and assumptions can be found in the Appendix. This study was conducted based on the RSP06 assumptions. Although the RGGI cap will not go into effect until 2009, the study period covers ten years from 2006 to 2015.

2.1 Inter-Regional Electric Market Model (IREMM)

The ISO RGGI study was performed using the Inter-Regional Electric Market Model (IREMM). This is an engineering-based production simulation model that has the flexibility of modeling the market infrastructure and transmission interface constraints. The model represents individual unit characteristics and performs a chronological energy production simulation based on the input hourly load shape and load forecast profile. It models unit forced outages by derating the unit capacities. CO_2 emissions are calculated based on an average unit CO_2 emission characteristic. A more detailed description of IREMM is provided in the Appendix.

2.2 Loads and Generation

The study used the 13 RSP06 subarea chronological hourly loads and annual energies consistent with RSP06 assumptions, based on the New England reference load forecast. Load forecast uncertainty was not modeled in this study.

The characteristics of the generators, i.e. summer and winter ratings, forced outage rates, maintenance rates and emission rates, were consistent with the RSP06 assumptions. For all the fossil units in New England larger than 25 MW, the costs of SO_2 and NO_x emissions were modeled as dispatch cost adders calculated from the unit emission rates and the recent regional SO_2 and NO_x allowance prices. CO_2 emission cost adders were modeled as discussed in the Appendix for the RGGI units, and for the six plants (15 units) in Massachusetts affected by the Massachusetts 310 CMR 7.29 regulations.

Table 2.1 illustrates the impact of CO_2 allowance cost adders on three typical generators by unit and fuel type. The CO_2 allowance price makes the bids/dispatch costs of the generators in the New England RGGI states more expensive compared with lower-cost imports and the generators in non-RGGI states where there is no CO_2 cap. Table 2.1 shows that the CO_2 allowance cost adder for a typical coal unit does not change its relatively low cost, maintaining it as a base load unit. Based on the table, the total energy cost ($/MWh) of a typical base load coal unit would become comparable with that of a typical combined cycle gas turbine if the CO_2 allowance prices reached $36/ton.

In the study, the economic dispatch of the generators was based on their full load heat rate and fuel costs, plus SO_2, NO_x, and CO_2 emission cost adders. For the RGGI units and six Massachusetts plants affected by the Massachusetts 310 CMR 7.29 regulations, SO_2, NO_x and CO_2 cost adders were modeled; while for the rest of Massachusetts and Rhode Island units, only SO_2 and NO_x cost adders were modeled. No plant O&M costs were included in the simulation.

Table 2.1 – Example of Impact of CO_2 Allowance Costs on Three Typical Fossil Plants

Fuel prices (\$/MBtu): Gas and Oil = 7; Coal = 2.25;

Emission allowance prices (\$/ton): SO_2 = 1,085; NO_x = 2,800; CO_2 = 5

Typical Plant	Fuel Price (\$/MBtu)	Heat Rate (Btu/kWh)	CO_2 Content (lb/Btu)	CO_2 Allowance Price (\$/ton)	Fuel Cost (\$/MWh)	SO_2 Cost Adder (\$/MWh)	NO_x Cost Adder (\$/MWh)	CO_2 Cost Adder (\$/MWh)	Total Energy Cost (\$/MWh)
Combined Cycle – Gas	7	7,000	120	5	49.0	0.0	0.1	2.1	51.2
Peaking Steam – Oil	7	10,500	160	5	73.5	11.5	4.4	4.2	93.6
Base Load Steam – Coal	2.25	8,900	210	5	20.0	4.7	4.4	4.7	33.8

2.3 Fuel Prices

The fuel price assumption is the same as those used in RSP06, i.e. from the EIA Annual Energy Outlook 2006 and the January 2006 Short-term Energy Outlook. Figure 2.1 shows the 10-year fuel prices assumed in the simulation, in constant 2004 dollars.

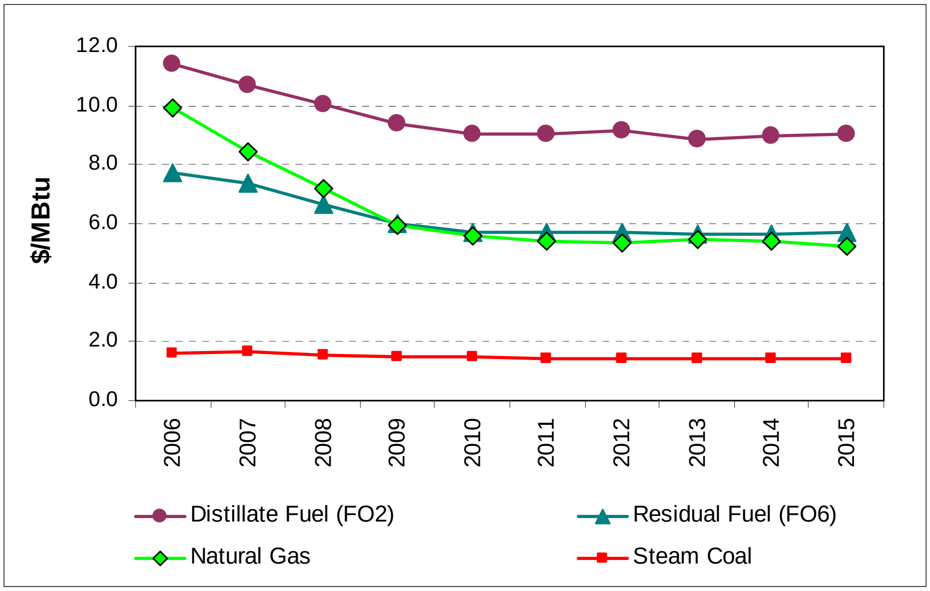

Figure 2.1: Fuel Price Assumption

2.4 Transmission

An approximation of the New England bulk transmission system using 13 subareas consistent with RSP06 was modeled in IREMM. The transmission interface constraints among subareas were also the same as the RSP06 assumptions (See Table A.5 in the Appendix). Only major transmission interfaces were modeled, i.e. no detailed transmission line flows were calculated.

2.5 Exports and Imports

Power transfers between New England and neighboring systems were modeled using two types of transactions: a fixed and a price responsive transaction. These reflected an approximation of a reasonable supply curve for typical market transactions between control areas. The fixed transaction was a 24-hour energy transfer, and price responsive transactions were modeled with proxy generators of different technologies: combined cycle, steam turbine, and gas turbine. The fuel prices in Figure 2.1 were used for these proxy generators.

2.6 Scenarios and Cases

Table 2.2 shows the scenarios and cases studied in this analysis. Six scenarios were studied and grouped as follows. These can be described as: 1) the RGGI cap as proposed for the four New England RGGI states (Table 2.2 (a)); 2) some sensitivity cases to evaluate the effect of imports and exports, and the impact of the relative price of natural gas versus residual oil (Table 2.2 (b)); and 3) a six-state New England RGGI cap if Massachusetts and Rhode Island were to join RGGI (Table 2.2 (c)). In these scenarios, the study assumed that the RGGI generators could have access to 100% of the state cap allowances through allocation, auctions and trading in a liquid market. Because of uncertainty in their availability, no use of offsets was assumed.

Table 2.2 – Scenarios and Cases Simulated

(a) New England Four States in RGGI – Reference and New Resource Additions

Scenario	Case ID	Description	CO_2 Price ($/ton)	Resource Additions
Reference	Base	RSP06 Base Case with CO_2 Allowance Price of $0/ton	0	None
	Base_5	Same as Base but with CO_2 Allowance Price of $5/ton	5	None
	Base_10	Same as Base but with CO_2 Allowance Price of $10/ton	10	None
	Base_20	Same as Base but with CO_2 Allowance Price of $20/ton	20	None
Resource Additions	NUC_5	Assume addition of 1,000 MW of Nuclear, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of Nuclear
	IGCC90_5	Assume addition of 1,000 MW of IGCC with 90% CCS, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of IGCC
	IGCC0_5	Assume addition of 1,000 MW of IGCC without CCS, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of IGCC
	NGCC_5	Assume addition of 1,000 MW of NGCC, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of NGCC
	QUEUE_5	Assume additional 1,651 MW of a representative mix of resources in the ISO Queue are located in the proposed states and with the proposed in-service dates.	5	Nuclear: 170 MW, Wind: 497 MW, Landfill Gas 15 MW, Natural Gas/Oil 969 MW

(b) New England Four States in RGGI - Sensitivity Scenarios

Scenario	Case ID	Description	CO_2 Price ($/ton)	Resource Additions
Import and Export Sensitivity	Base_0IMP_10	Assume 0 MW from HQ and NB	10	None
	Base_NBExport_10	Assume 200 MW fixed energy export to New Brunswick	10	None
Natural Gas Price Sensitivity	Natural Gas Price Sensitivity Cases	Same as Base but with 10 times lower Gas/Oil fuel price ratio	10	None

(c) New England Six States in RGGI

Scenario Set	Case ID	Description	CO_2 Price ($/ton)	Resource Additions
RGGI Six States	Base_six	Assume Massachusetts/Rhode Island join RGGI with CO_2 allowance price of $0/ton	0	None
	Base_six_5	Same as Base_six but with CO_2 allowance price of $5/ton	5	None
	Base_six_10	Same as Base_six but with CO_2 allowance price of $10/ton	10	None
	Base_six_20	Same as Base_six but with CO_2 allowance price of $20/ton	20	None
Resource Additions - RGGI Six States	NUC_six_5	Assume addition of 1,000 MW of Nuclear, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of Nuclear
	IGCC90_ six_5	Assume addition of 1,000 MW of IGCC with 90% CCS, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of IGCC
	IGCC0_ six_5	Assume addition of 1,000 MW of IGCC without CCS, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of IGCC
	NGCC_ six_5	Assume addition of 1,000 MW of NGCC, 500 MW in Connecticut and 500 MW in New Hampshire; 500 MW in 2012 and 500 MW in 2015	5	1,000 MW of NGCC
	QUEUE_ six_5	Assume additional 1,651 MW of a representative mix of resources in the ISO Queue are located in the proposed states and with the proposed in-service dates	5	Nuclear: 170 MW, Wind: 497 MW, Landfill Gas 15 MW, Natural Gas/Oil 969 MW

The reference scenario studied the impact of a CO_2 allowance price on the New England RGGI generators' CO_2 emissions and the four-state RGGI cap compliance assuming no resource additions over the ten-year period. The base case in this reference scenario assumed no RGGI cap, i.e. no CO_2 allowance adder. The other three cases in this scenario assumed the CO_2 allowance price was $5/ton, $10/ton and $20/ton, respectively. The study didn't try to predict allowance prices in the future allowance market. These values were simply assumptions for the study to see their effect on the RGGI generators' CO_2 emissions versus the RGGI cap.

The scenario of resource additions investigated how the RGGI units' CO_2 emissions would affect compliance with the RGGI cap if alternative new resources were installed in the future. This scenario did not add all the capacity needed to meet resource adequacy criteria since the purpose was only to determine the relative impacts on CO_2 emissions of alternative types of resource additions.

Five cases were studied in this scenario. Four cases added 1,000 MW of nuclear, coal and natural gas combined cycle resources, respectively. The coal alternative consisted of two cases: one assuming Integrated Coal Gasification Combined Cycle (IGCC) with 90% of CO_2 capture and sequestration (CCS), and alternatively without CCS. In these four cases, the new resources were assumed to be installed in two of the RGGI states, Connecticut and New Hampshire, with 500 MW each. In each of these two states, 250 MW was assumed to be added into the system in 2012 and 250 MW in 2015. A fifth resource addition case represented a mix of resources (1,651 MW) in the ISO Generator Interconnection Queue ('Queue') in the first quarter of 2006. We assumed these resources would be built in the proposed states by the proposed in-service date. A \$5/ton CO_2 allowance price was assumed for all these cases. ISO recognizes that energy conservation and efficiency programs could also be helpful in reducing CO_2 emissions in New England. However, the ISO does not have sufficient information to model these programs.

Two sets of sensitivity scenarios were also simulated to study the effect of imports and exports and the effect of the relative price of natural gas and residual oil on compliance with the New England four-state RGGI cap. In the imports and exports sensitivity scenarios, the CO_2 allowance price was assumed to be \$10/ton and two cases were studied: 1) assuming zero MW imports from Canada, i.e. Hydro Quebec and New Brunswick; and 2) assuming 200 MW of fixed energy export to New Brunswick at all hours in a year.

The natural gas price sensitivity scenario evaluated the impact on New England CO_2 emissions of changes in the relative price of natural gas versus residual oil. Specifically, the price of natural gas was modeled from 50% of the reference forecast price (as shown in Figure 2.1) up to 200% of the reference forecast price. While changing the natural gas price, all other fuel price assumptions were held constant. In this scenario, the CO_2 allowance price was assumed to be \$10/ton.

The New England six-state RGGI scenarios examined the effect on the RGGI CO_2 emissions if Massachusetts and Rhode Island were to join RGGI. Two scenarios were studied for their impact on compliance with the six-state RGGI cap: 1) a set of cases assuming various CO_2 allowance prices, and 2) a set of cases with alternative new resource additions. The assumptions of CO_2 allowance prices and the new resources added were the same as the similar cases in the four-state RGGI scenarios.

2.7 CO_2 Emission Leakage

Since the RGGI cap is regional and part of New England is not under the cap, CO_2 emission leakage is an important issue. CO_2 emission leakage in this study refers to the increase in CO_2 emissions from CO_2 emitting units not under the New England RGGI cap, which offsets to some degree the CO_2 reduction produced by the New England portion of the RGGI cap. Therefore, CO_2 emission leakage can come from the non-RGGI units in New England and Canadian imports. The CO_2 emissions associated with any increase in imports from New York are not counted as leakage, since New York is a RGGI state.

The imports from Hydro Quebec would be hydro energy to a large degree since Hydro Quebec's energy is over 95% hydroelectric[15]. This energy would be largely free of CO_2 emissions. But some energy banking may occur from New England fossil generation off-peak, in exchange for banked hydro energy on peak. Therefore, the percentage of hydro energy imported from Hydro Quebec is likely to be less than 95%, but the actual value would be difficult to determinate.

The energy imported from New Brunswick is produced by a combination of hydro, nuclear and fossil resources and was not estimated for this study. Until the treatment of leakage is fully developed by RGGI[16], any adjustment for leakage cannot be estimated. Therefore, the leakage quantified in this report is only the increase in CO_2 emissions from the non-RGGI units in New England. This includes all the units in Massachusetts and Rhode Island and the units less than 25 MW in the four RGGI states, which are excluded from the RGGI cap

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[15] http://www.canelect.ca/en/Pdfs/HandBook.pdf

[16] A draft report is planned before the end of 2006.

3.0 Results

This section presents the results of the study in two parts: 1) for the four New England states currently in RGGI; and 2) with Massachusetts and Rhode Island as part of RGGI (six-state RGGI).

3.1 Four-State RGGI Scenarios

This section presents the four New England RGGI states' CO_2 emissions as function of the CO_2 allowance price for the base case with no resource additions. It also presents the CO_2 emissions for the five alternative resource addition cases. Other results presented from these scenarios under the four New England state RGGI cap, include the CO_2 leakage, the effect of changing imports and exports, the effect of the relative price of natural gas versus residual oil, and the effect on the energy mix and natural gas consumption.

3.1.1 CO_2 Allowance Prices

This section presents the simulated CO_2 emissions from the RGGI generators and all the New England generators for CO_2 allowance prices of $5, $10 and $20/ton compared with the base case with no RGGI cap. The results show the impact of the CO_2 allowance prices on the New England RGGI generators' ability to comply with the RGGI cap.

3.1.1.1 Base Case – No RGGI Cap

The base case for these simulations was the RSP06 base case that had no new resource additions or retirements, no RGGI CO_2 emission cap, and SO_2 and NO_x emission cost adders on all fossil units 25 MW and larger. Table 3.1 shows by state the CO_2 emissions from the RGGI and other generators in the RGGI states, as well as the generators in Massachusetts and Rhode Island, as calculated by IREMM for this base case. Figure 3.1 shows the total emissions from the RGGI generators and the total emissions from all the generators in New England assuming no RGGI cap. The RGGI cap is shown for information only.

Table 3.1 – Ten Year CO_2 Emissions from RGGI and Other New England Generators (Million Tons) - Base Case: No RGGI Cap

Year	CT		ME		NH		VT		MA	RI	RGGI Units Total	New England Total
	RGGI	Other	RGGI	Other	RGGI	Other	RGGI	Other				
2006	13.73	1.00	6.68	0.85	7.55	0.51	0.69	0.13	26.41	2.15	**28.65**	**59.70**
2007	10.22	1.00	6.65	0.85	7.95	0.51	0.69	0.13	25.92	2.77	**25.51**	**56.69**
2008	9.29	1.00	6.78	0.85	8.08	0.52	0.69	0.13	26.39	3.05	**24.84**	**56.78**
2009	9.30	1.00	6.82	0.84	8.12	0.51	0.69	0.13	26.58	3.35	**24.93**	**57.34**
2010	9.60	1.01	6.89	0.85	8.23	0.52	0.69	0.13	27.17	3.60	**25.41**	**58.69**
2011	9.82	1.02	6.95	0.85	8.31	0.52	0.69	0.13	27.93	3.81	**25.77**	**60.03**
2012	10.38	1.03	6.99	0.85	8.42	0.52	0.69	0.13	28.76	4.02	**26.48**	**61.79**
2013	10.80	1.03	7.03	0.85	8.48	0.52	0.69	0.13	29.34	4.12	**27.00**	**62.99**
2014	11.07	1.03	7.06	0.85	8.60	0.53	0.69	0.13	29.84	4.30	**27.42**	**64.10**
2015	11.26	1.04	7.10	0.85	8.64	0.53	0.69	0.13	30.34	4.48	**27.69**	**65.06**

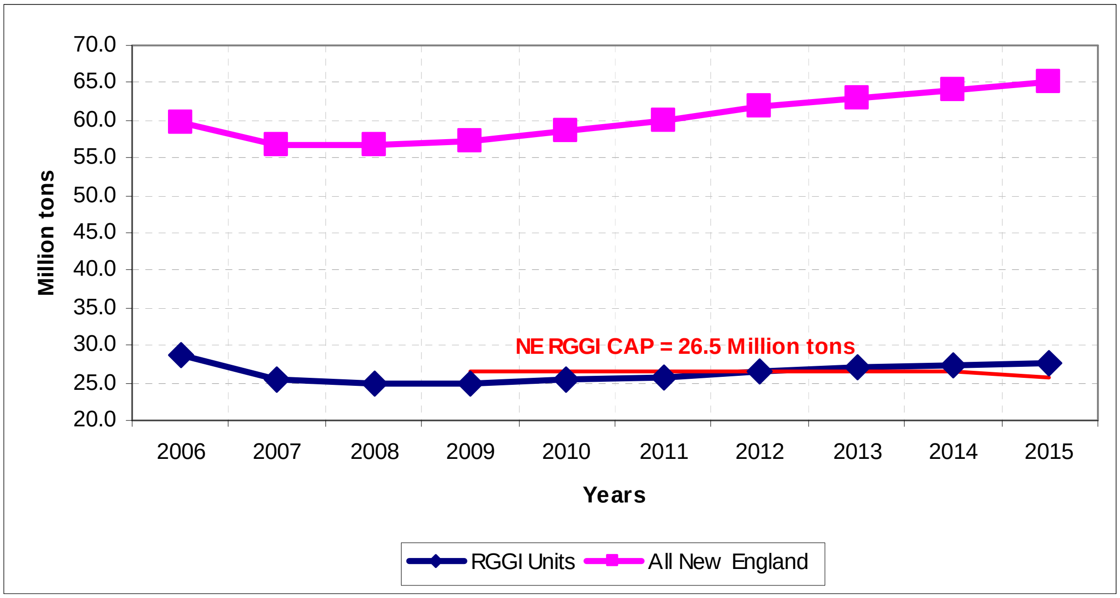

Figure 3.1: **Total CO_2 Emissions from RGGI generators and All New England generators – Base Case: No RGGI Cap**

As Figure 3.1 shows, for the base case, the RGGI generator CO_2 emissions would be less than the RGGI cap of 26.5 million tons through 2012, and from year 2013 to year 2015, they would exceed the cap. Total New England CO_2 emissions would increase from 60 to 65 million tons from 2006 to 2015. The years 2006 and 2007 show a drop in CO_2 emissions. This is due to the forecast natural gas price which decreases until it is on par with the residual oil price by 2009.

From 2010 on, the New England control area would be deficient in capacity to serve all the loads since no resources were assumed added in the base case over the study period. In IREMM, when the capacity available is not enough to meet the system load, a "pseudo" peaker generator with zero emissions is dispatched to serve the load. Therefore, the emissions shown in the base case would underestimate the total emissions, but this underestimation is not significant in the context of this RGGI study[17].

3.1.1.2 Base Case with RGGI Cap - Vary CO_2 Allowance Prices

With a RGGI cap, three cases were simulated using an assumed CO_2 allowance price of $5/ton, $10/ton, and $20/ton, respectively. These price assumptions correspond well with a recent forecast for regional CO_2 allowance prices for 2015[18]. The CO_2 allowance price reflected in a RGGI generator's dispatch price increases the cost of the generators in New England RGGI states compared with the generators in the non-RGGI states, and with lower cost imports. Therefore, this shift in generator costs tends to reduce the amount of RGGI generation and consequently the RGGI CO_2 emissions. Correspondingly, the non-RGGI generation would tend to increase, as would imports.

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[17] The simulation results show the unserved energy is 130 GWh in 2015, less than 0.1% of total New England energy. The CO_2 emissions related to this unserved energy is about 72,000 tons, amounting to 0.1% of total New England emissions of 65 million tons. Therefore, these emissions have been ignored for this evaluation.

[18] http://www.synapse-energy.com/Downloads/SynapsePresentation.2006-01.Forecasting-and-Using-Carbon-Prices-in-a-World-of-Uncertainty.pdf

Figure 3.2 shows the annual simulated CO_2 emissions from the RGGI generators for the three CO_2 allowance price cases compared to the Base Case with no cap ($0/ton). The RGGI cap for New England's four RGGI states is 26.5 million tons from 2009 to 2014, and then is reduced to 25.8 million tons in 2015. From 2009 to 2015, the RGGI units' emissions would decrease with an increase in CO_2 allowance price. With no cap, the RGGI generators' CO_2 emissions would exceed the 26.5 million ton cap starting in 2013. With a CO_2 allowance price at $5/ton, the annual emissions from the RGGI generators would not exceed the New England RGGI cap until 2015. If the CO_2 price were equal to or greater than $10/ton, the RGGI emissions would be below the RGGI cap throughout the study period.

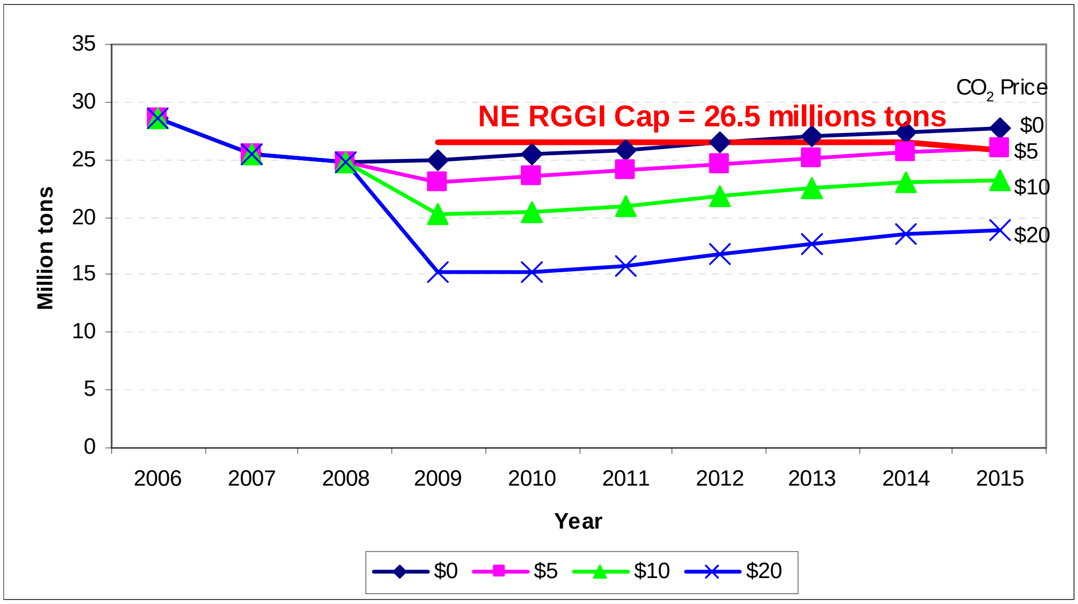


Figure 3.2: **Annual CO_2 Emissions from New England RGGI Generators for Assumed CO_2 Allowance Prices**

Figure 3.3 shows how the total emissions from the generators in Massachusetts and Rhode Island would change with the increase of CO_2 allowance prices. Higher CO_2 allowance prices for the RGGI generators make the lower-cost generators in these non-RGGI states economic to operate and, therefore, produce more emissions. The increase in CO_2 emissions from the non-RGGI generators due to the RGGI cap, is called CO_2 emission leakage. This results in more power flowing into the RGGI states as the RGGI generators produce less power due to their higher costs. In the context of this study, CO_2 emission leakage refers to the CO_2 emissions from 1) generators in Massachusetts and Rhode Island, 2) the units less than 25 MW in the four RGGI states, and 3) Canadian imports. Section 3.1.3 discusses the results related to CO_2 emission leakage in more detail.

The simulation shows that the total CO_2 emissions from the six plants affected by the Massachusetts CMR 7.29 caps would have a compliance margin of about 10 million tons below their total cap of 27,833,570 tons. Individually, five of the plants would be also below their individual caps, but one unit would exceed its cap by about 0.08 million tons per year. This amount is negligible given the accuracy of the simulation results. In addition, the generator could buy offsets to comply with its tonnage cap when necessary.

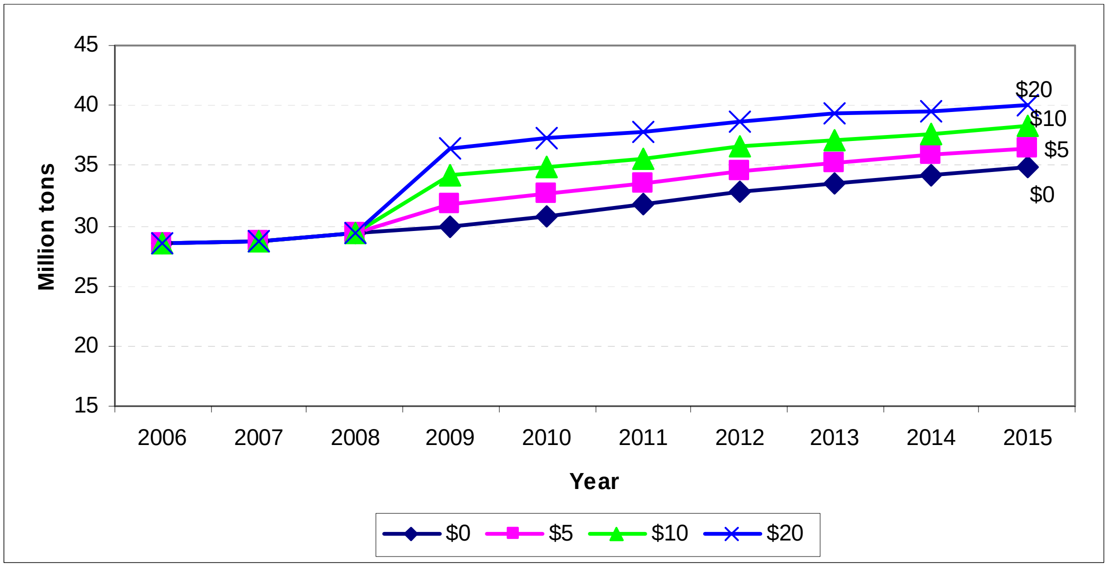


Figure 3.3: **Projected CO_2 Emissions from the Massachusetts and Rhode Island Generators vs. Assumed CO_2 Allowance Prices**

Figure 3.4 shows the total emissions from all the generators in New England for varying CO_2 allowance prices. If the CO_2 allowance price were \$5/ton, the impact on total New England CO_2 emissions would be negligible. At higher CO_2 allowance prices, the CO_2 emissions from all the units in New England would decrease due to more energy being imported from the external control areas.

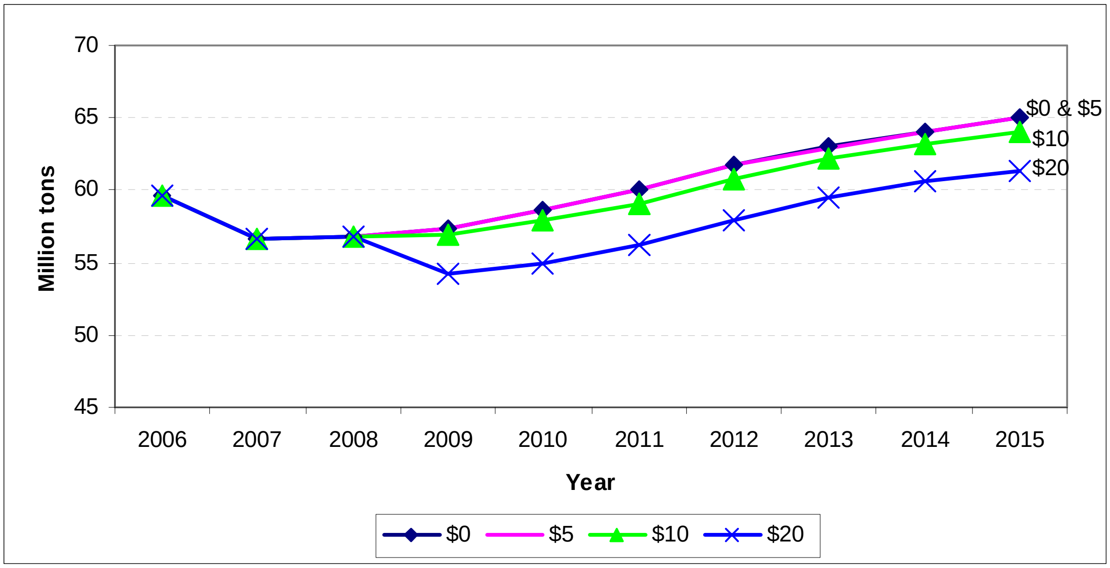


Figure 3.4: **Projected CO_2 Emissions from All the Generators in New England vs. Assumed CO_2 Allowance Prices**

3.1.2 New Resource Additions

This section presents the results of the five cases simulating alternative resource additions. Since new resources will likely be added over the next ten years, the study examined the effect of adding new resources on reducing CO_2 emissions. Given the uncertainty of what these new resources might be, four different cases were simulated by alternatively adding 1,000 MW of various types of new resources in the New England RGGI states. The types of resources added were nuclear, coal (IGCC) both with 90% CO_2 capture and sequestration (CCS) and without CCS, and natural gas combined cycle (NGCC). The 1,000 MW additions were composed of 500 MW added in 2012 and 500 MW in 2015. A fifth case simulated a mix of projects representative of those in the ISO Queue.

Figure 3.2 showed that $10/ton and $20/ton CO_2 allowance prices cause the RGGI units' CO_2 emissions to drop dramatically. If a relatively high CO_2 allowance price were used in these resource addition cases, the impact of the CO_2 allowance prices on emissions would overshadow the effect of the different resource additions on CO_2 emissions. Therefore, a CO_2 allowance price of $5/ton was used.

Figure 3.5 and Figure 3.6 show simulated CO_2 emissions from RGGI generators, and also the total New England CO_2 emissions in the new resource additions cases, respectively.

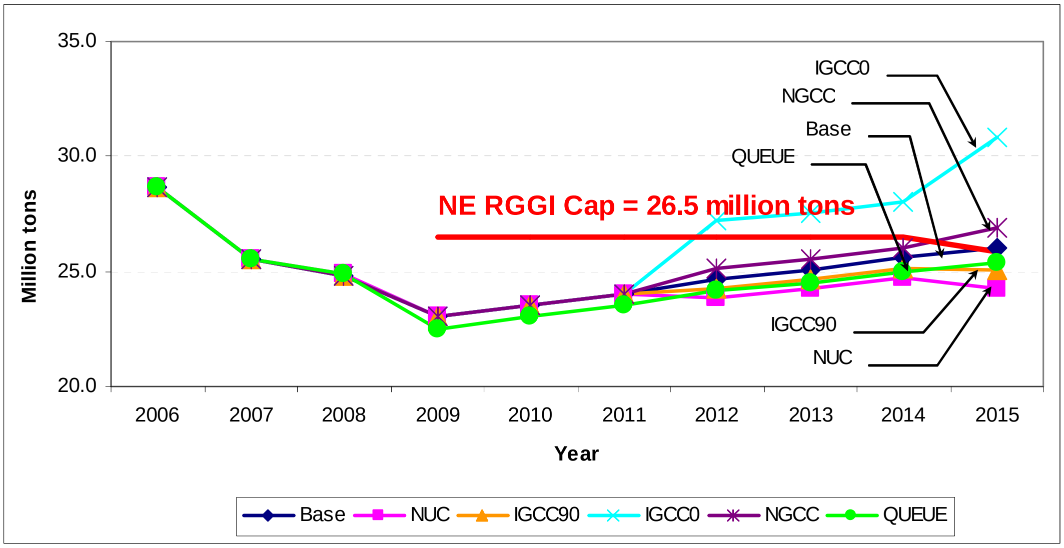


Figure 3.5: **New England RGGI Units CO_2 Emissions vs. RGGI Cap with 1,000 MW New Resources in RGGI States (CO_2 Allowance Price – $5/ton)**

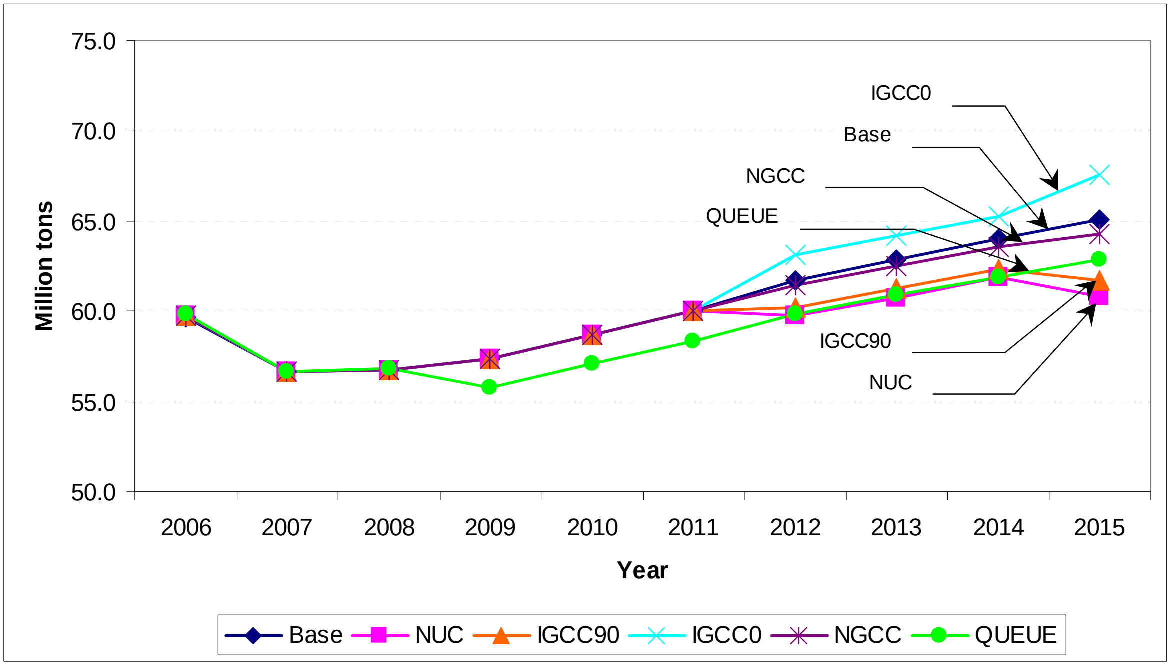


Figure 3.6**: New England Total Emissions with 1,000 MW New Resources in RGGI States (CO_2 Allowance Price – \$5/ton)**

By 2015, adding 1,000 MW of nuclear generators would reduce both the RGGI emissions and the New England emissions the most of all five cases. This result is as expected since the new nuclear generators have low dispatch costs and no CO_2 emissions, and the capacity factor simulated in IREMM was over 90%. In 2015, the reduction in CO_2 emissions for the RGGI generators would be 1.8 million tons and for all the New England generators, 4.3 million tons.

The case of adding IGCC assuming 90% CCS would reduce both RGGI emissions and New England emissions similar to the nuclear case, but not as much. These advanced coal plants would have lower dispatch costs than existing fossil fuel generators and are dispatched as base load units running at a capacity factor of 84%. This would reduce the output of the other generators in New England and decrease the total New England CO_2 emissions. However, adding IGCC without any CCS increases by 2015 the RGGI CO_2 emissions by 20% and total New England CO_2 emissions by 10% compared to the base case. The IGCC capacity without CCS adds 6.7 million tons of CO_2 emissions in 2015. However, since the new IGCC without CCS would replace other fossil units to serve the load, the CO_2 emissions from other fossil units would be reduced. Thus, the RGGI generator CO_2 emissions would increase by about 4.8 million tons and total CO_2 emissions in New England by 2.5 million tons in 2015, compared to the base case.

In the NGCC case, the emissions from the RGGI generators compared to the base case increase by 0.8 million tons in 2015 while the emissions in New England decrease by 0.8 million tons. This results from the new NGCC generators having a lower CO_2 emission rate compared to the existing NGCC fleet in New England (860 lbs/MWh versus 900 lbs/MWh), and replacing other higher CO_2-emitting oil-burn units.

In the ISO Queue case, a representative mix (984 MW oil/gas units, 497 MW wind generators, and 170 MW nuclear uprates) was modeled based on projects in the ISO Queue in the first quarter of 2006.

Compared with the base case results, the RGGI CO_2 emissions and the total New England CO_2 emissions would decrease since about 40% of the new generators have zero or low CO_2 emission rates, i.e. nuclear and wind.

In summary, these results show that by adding 1,000 MW of new resources with zero or low CO_2 emission characteristics in RGGI states, i.e. nuclear, IGCC with 90% CCS or the Queue mix, the RGGI emissions would be below the cap over the study period. However adding 1,000 MW of NGCC or IGCC without CCS would push the RGGI emissions in 2015 over the cap.

The numerical reductions in CO_2 emissions in 2015 versus the base case with $5/ton CO_2 allowance price are shown in Table 3.2.

Table 3.2 – CO_2 Emission Decreases/Increases (-/+) in 2015 for New England Additions vs. the Base Case （CO_2 Allowance Price – $5/ton)

	RGGI Units (Million tons)	New England Units (Million tons)
NUC	-1.8	-4.3
IGCC90	-1.0	-3.3
QUEUE	-0.7	-2.2
NGCC	0.8	-0.8
IGCC0	4.8	2.5

3.1.3 CO_2 Emission Leakage

CO_2 emission leakage refers to any increase in CO_2 emissions outside of the RGGI cap region which offsets the CO_2 reductions in the RGGI region with the cap imposed. Since the total RGGI region was not modeled in this study, this section summarizes the leakage that is caused by the RGGI cap in New England (four states), but not the total RGGI cap leakage (for seven states).

Table 3.3 (a), (b) and (c) list the annual CO_2 emissions for different groups of generators in New England for the base case scenario with no cap and the case with a RGGI cap at different CO_2 allowance prices. Table 3.4 shows the RGGI CO_2 emission leakage due to the New England portion of the RGGI cap at $5/ton, $10/ton and $20/ton allowance prices, respectively. The results show clearly that the New England RGGI cap reduces the RGGI units' CO_2 emissions, but increases the CO_2 emission leakage from the non-RGGI generators. The higher the CO_2 allowance price, the more the CO_2 emission leakage. By 2015, if the CO_2 allowance price were $5/ton, the RGGI units' CO_2 emissions would decrease by 1.6 million tons, but the CO_2 emission leakage would increase by 1.6 million tons. This would lead to a zero net reduction in the total New England CO_2 emissions. Similarly, at a CO_2 allowance price of $10/ton, the RGGI cap would reduce the RGGI units' CO_2 emissions by 4.5 million tons, but cause CO_2 emission leakage of 3.4 million tons, yielding a net CO_2 reduction in New England of 1.1 million tons. If the CO_2 allowance price increased to $20/ton, the cap would reduce the RGGI units' CO_2 emissions by 8.8 million tons, but cause CO_2 emission leakage of 5.2 million tons and a net CO_2 reduction in New England of 3.6 million tons. If leakage from Canadian imports were accounted for, total leakage would likely increase and the total New England CO_2 reductions from the RGGI cap would be less than the estimates in Table 3.3.

Table 3.3 – Emissions from RGGI Generators and Non-RGGI Generators:
(a) Base Case (no RGGI Cap) vs. RGGI Cap (CO$_2$ Allowance Price – $5/ton)

	Without RGGI Cap					With a RGGI Cap at $5/ton Allowance Price				
		Non-RGGI Units					Non-RGGI Units			
Year	**RGGI Units**	**Units <25MW in the RGGI States**	**MA/RI Units**	**Total non-RGGI Emissions**	**New England Total Emissions**	**RGGI Units**	**Units <25MW in the RGGI States**	**MA/RI Units**	**Total non-RGGI Emissions**	**New England Total Emissions**
2006	28.7	2.5	28.6	**31.1**	**59.7**	28.7	2.5	28.6	**31.1**	**59.7**
2007	25.5	2.5	28.7	**31.2**	**56.7**	25.5	2.5	28.7	**31.2**	**56.7**
2008	24.8	2.5	29.4	**31.9**	**56.8**	24.8	2.5	29.4	**31.9**	**56.8**
2009	24.9	2.5	29.9	**32.4**	**57.3**	23.0	2.5	31.8	**34.3**	**57.4**
2010	25.4	2.5	30.8	**33.3**	**58.7**	23.5	2.5	32.6	**35.1**	**58.7**
2011	25.8	2.5	31.7	**34.3**	**60.0**	24.0	2.5	33.5	**36.0**	**60.0**
2012	26.5	2.5	32.8	**35.3**	**61.8**	24.7	2.5	34.5	**37.1**	**61.7**
2013	27.0	2.5	33.5	**36.0**	**63.0**	25.1	2.5	35.3	**37.8**	**62.9**
2014	27.4	2.5	34.1	**36.7**	**64.1**	25.6	2.6	35.9	**38.4**	**64.0**
2015	27.7	2.6	34.8	**37.4**	**65.1**	26.1	2.6	36.4	**39.0**	**65.0**

(b) Base Case (no RGGI Cap) vs. RGGI Cap (CO$_2$ Allowance Price – $10/ton)

	Without RGGI Cap					With a RGGI Cap at $10/ton Allowance Price				
		Non-RGGI Units					Non-RGGI Units			
Year	**RGGI Units**	**Units <25MW in the RGGI States**	**MA/RI Units**	**Total non-RGGI Emissions**	**New England Total Emissions**	**RGGI Units**	**Units <25MW in the RGGI States**	**MA/RI Units**	**Total non-RGGI Emissions**	**New England Total Emissions**
2006	28.7	2.5	28.6	**31.1**	**59.7**	28.7	2.5	28.6	**31.1**	**59.7**
2007	25.5	2.5	28.7	**31.2**	**56.7**	25.5	2.5	28.7	**31.2**	**56.7**
2008	24.8	2.5	29.4	**31.9**	**56.8**	24.8	2.5	29.4	**31.9**	**56.8**
2009	24.9	2.5	29.9	**32.4**	**57.3**	20.3	2.5	34.1	**36.6**	**56.9**
2010	25.4	2.5	30.8	**33.3**	**58.7**	20.5	2.5	34.9	**37.4**	**57.9**
2011	25.8	2.5	31.7	**34.3**	**60.0**	20.9	2.5	35.6	**38.1**	**59.0**
2012	26.5	2.5	32.8	**35.3**	**61.8**	21.8	2.5	36.5	**39.1**	**60.8**
2013	27.0	2.5	33.5	**36.0**	**63.0**	22.4	2.5	37.2	**39.7**	**62.2**
2014	27.4	2.5	34.1	**36.7**	**64.1**	23.0	2.5	37.7	**40.2**	**63.2**
2015	27.7	2.6	34.8	**37.4**	**65.1**	23.2	2.5	38.2	**40.8**	**64.0**

(c) Base Case (no RGGI Cap) vs. RGGI Cap (CO_2 Allowance Price – $20/ton)

	Without RGGI Cap					With a RGGI Cap at $20/ton Allowance Price				
		Non-RGGI Units					Non-RGGI Units			
Year	RGGI Units	Units <25MW in the RGGI States	MA/RI Units	Total non-RGGI Emissions	New England Total Emissions	RGGI Units	Units <25MW in the RGGI States	MA/RI Units	Total non-RGGI Emissions	New England Total Emissions
2006	28.7	2.5	28.6	**31.1**	**59.7**	28.7	2.5	28.6	**31.1**	**59.7**
2007	25.5	2.5	28.7	**31.2**	**56.7**	25.5	2.5	28.7	**31.2**	**56.7**
2008	24.8	2.5	29.4	**31.9**	**56.8**	24.8	2.5	29.4	**31.9**	**56.8**
2009	24.9	2.5	29.9	**32.4**	**57.3**	15.3	2.5	36.5	**38.9**	**54.2**
2010	25.4	2.5	30.8	**33.3**	**58.7**	15.3	2.5	37.2	**39.7**	**55.0**
2011	25.8	2.5	31.7	**34.3**	**60.0**	15.9	2.5	37.8	**40.3**	**56.2**
2012	26.5	2.5	32.8	**35.3**	**61.8**	16.8	2.5	38.6	**41.2**	**58.0**
2013	27.0	2.5	33.5	**36.0**	**63.0**	17.6	2.5	39.3	**41.8**	**59.4**
2014	27.4	2.5	34.1	**36.7**	**64.1**	18.5	2.6	39.6	**42.1**	**60.7**
2015	27.7	2.6	34.8	**37.4**	**65.1**	18.9	2.5	40.0	**42.5**	**61.4**

Table 3.4 – CO_2 Emission Leakage Due to New England RGGI Cap at Different CO_2 Allowance Prices ($5/ton, $10/ton and $20/ton)

Year	$0/ton (No Cap)	$5/ton	$10/ton	$20/ton
2006	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0
2009	0.0	1.9	4.2	6.5
2010	0.0	1.9	4.1	6.5
2011	0.0	1.7	3.9	6.1
2012	0.0	1.8	3.7	5.8
2013	0.0	1.8	3.7	5.8
2014	0.0	1.7	3.5	5.5
2015	0.0	1.6	3.4	5.2

3.1.4 Effect of Imports and Exports

These cases examined the impact on the CO_2 emissions of the RGGI generators and all the New England generators of zero imports and, alternatively, increased exports. Figures 3.7 shows the effects of these import and export cases on the CO_2 emissions from the RGGI generators and, similarly, Figure 3.8 on the total New England generators' CO_2 emissions.

With the RGGI cap and a CO_2 allowance price of $10/ton, the case of zero imports would increase the RGGI CO_2 emissions by 3.7 million tons and the total New England CO_2 emissions by 8.5 million tons compared to the base case with the RGGI cap and a $10/ton CO_2 allowance price. In 2015, the CO_2 emissions from the New England RGGI generators would exceed the New England RGGI cap for this case.

A 200 MW increase in exports would increase the RGGI CO_2 emissions by 1.5 million tons and the New England CO_2 emissions by 3.9 million tons. In this case, the CO_2 emissions from the New England RGGI generators would remain below the cap during the study period from 2009 to 2015.

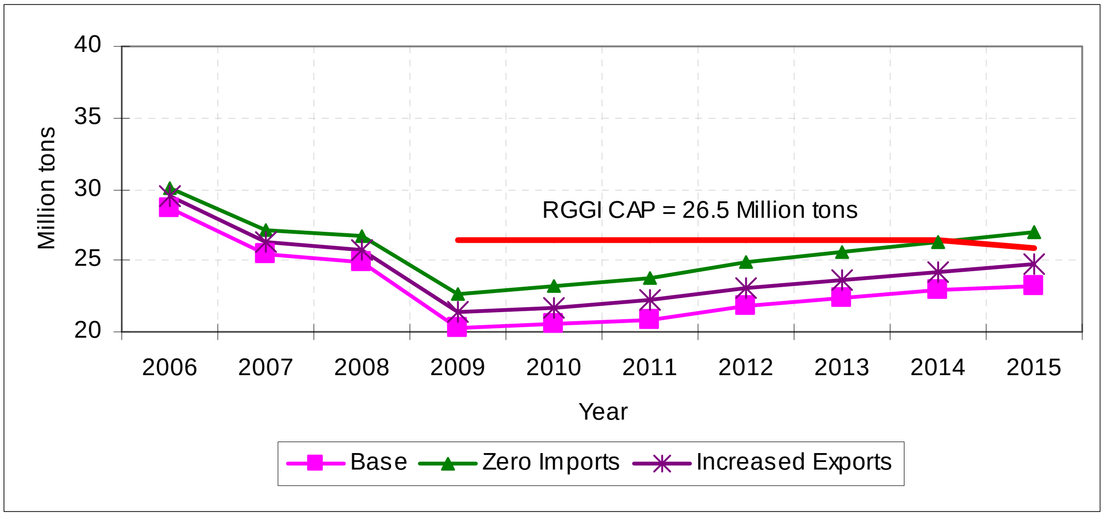


Figure 3.7: **Effect of Zero Imports and Increased Exports on the RGGI CO_2 Emissions (CO_2 Allowance Price – $10/ton)**

Figure 3.8: **Effect of Zero Imports and Increased Exports on Total New England CO_2 Emissions (CO_2 Allowance Price – $10/ton)**

3.1.5 Impact of Natural Gas Price on RGGI CO_2 Emissions

The relative price of natural gas versus residual oil can have a large impact on the generator dispatch, and thus would affect the CO_2 emissions from the generators. Cases were simulated to investigate how a change in the natural gas price relative to the residual oil price impacts the CO_2 emissions. In these cases, the natural gas price was scaled up and down by different percentages based on the base case scenario's fuel price assumptions shown in Figure 2.1.

Natural gas has a lower CO_2 content compared with oil. If two generators were assumed to have the same heat rate of 10,000 Btu/kWh, the gas-fired unit would produce 600 pounds less of CO_2 emissions than the oil-fired unit to serve one MWh of load. Therefore, if natural gas is relatively cheaper than residual oil, more gas-fired generators would be dispatched to serve load, which would reduce the CO_2 emissions from the RGGI generators. Alternatively, if natural gas is relatively more expensive than residual oil, more oil-fired generators would be dispatched and the emissions from RGGI generators would increase.

The results of these cases (Figure 3.9) show that if natural gas were relatively cheaper than residual oil, New England RGGI generators would have a greater margin to comply with the RGGI cap. If the natural gas price were half of the residual oil price, in 2015, the CO_2 emissions from New England RGGI generators would be 10 million tons below the cap. However, if the natural gas price would be relatively higher than the residual oil price, compliance with the RGGI cap would be difficult. The New England RGGI CO_2 emissions would reach the RGGI cap in 2015 if the natural gas price is 1.6 times the residual oil price.

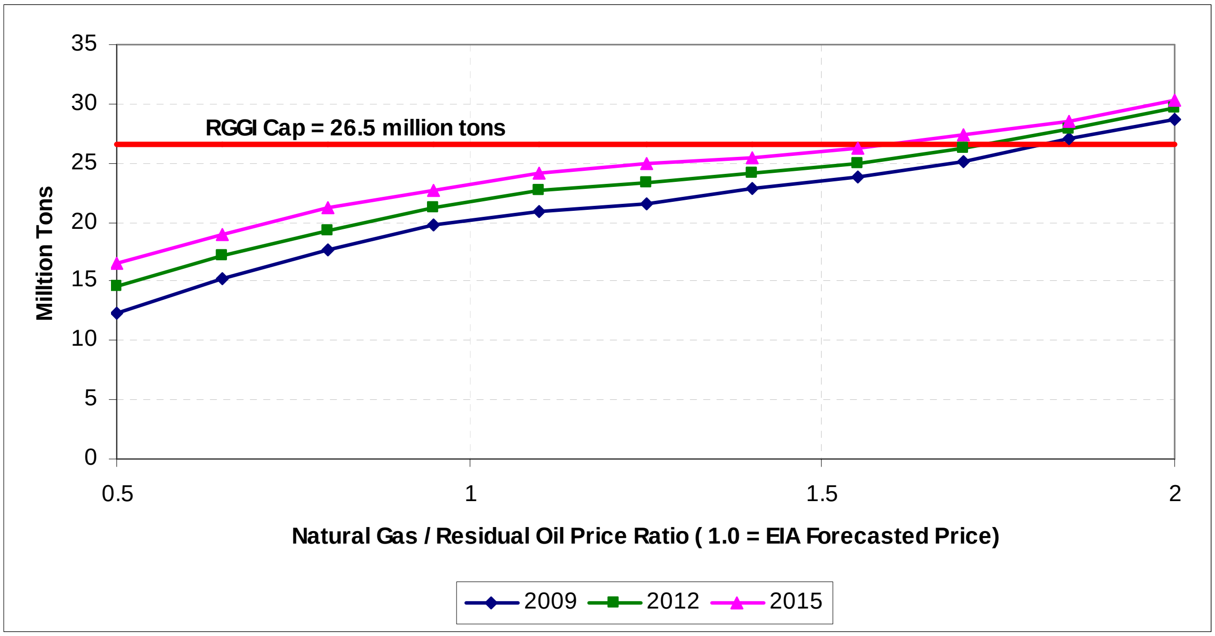
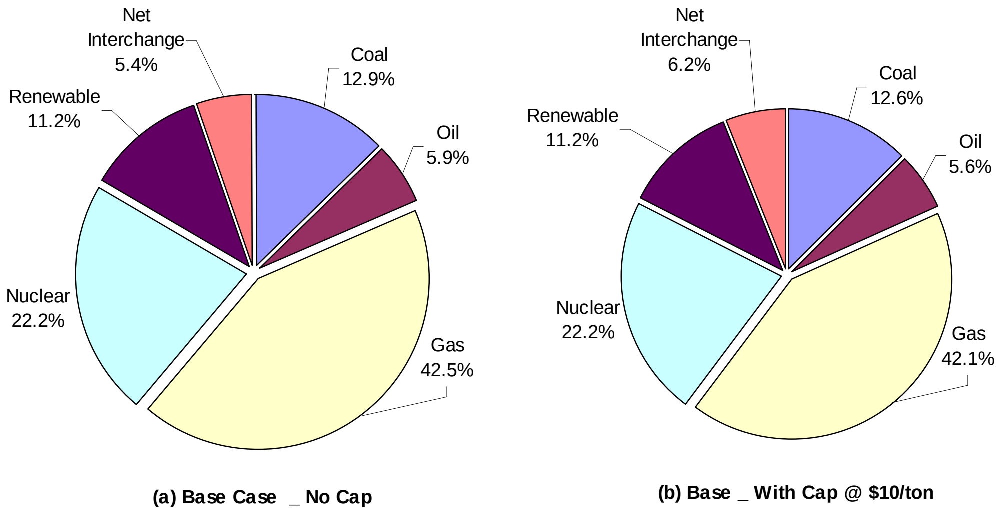


Figure 3.9: **Change of New England RGGI Generator CO_2 Emissions for Relative Prices of Natural Gas vs. Residual Oil (CO_2 Allowance Price – $10/ton)**

3.1.6 Effect on Fuel Usage

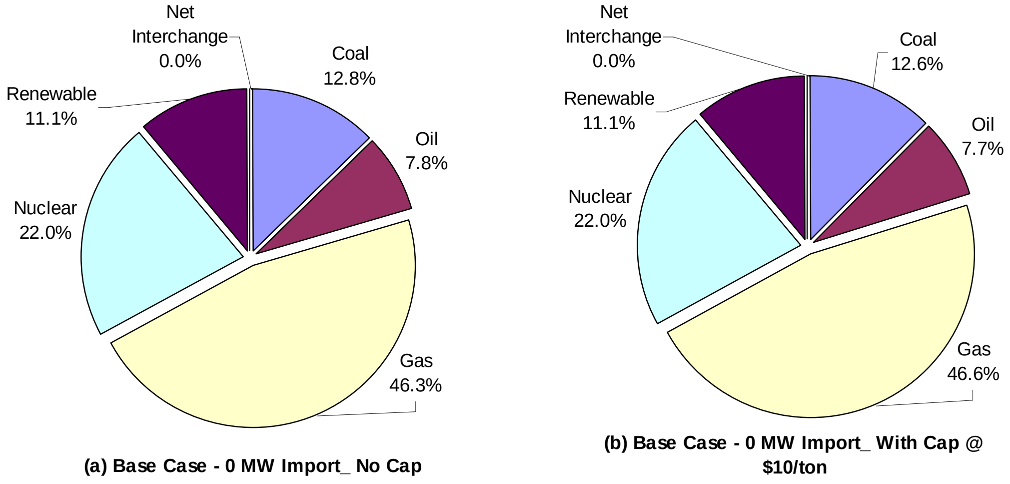
The effect of the RGGI cap on fuel usage in New England has been summarized in Figures 3.10 (a) and (b) for the base case (no new resource additions). They show the percentage of New England's sources of energy in 2015 for the base cases with no cap and with a RGGI cap and a CO_2 allowance price of $10/ton. The two pie charts show that the RGGI cap would increase the percentage of net imports from neighboring systems by 0.8% and decrease slightly the percentage of coal, distillate oil and natural gas by 0.3%, 0.3% and 0.4%, respectively. The total percentage of fossil fuel use would decrease from 61.3% to 60.3%, while imports pick up the increase in energy use.



(a) Base Case _ No Cap **(b) Base _ With Cap @ $10/ton**

Figure 3.10: **New England Projected Sources of Energy in 2015 With and Without the RGGI Cap: Base Case with Imports**

Figure 3.11 (a) and (b) show the sources of energy for cases with zero energy imports from Hydro Quebec and New Brunswick with no cap versus with the RGGI cap (at a $10/ton allowance price). The results show that with zero MW imports, the RGGI cap would decrease slightly the percent usage of higher CO_2 content fuel, such as coal and oil, and this would be replaced by natural gas, since it has a relatively lower CO_2 content (lb/MBtu) compared to oil and coal.



(a) Base Case - 0 MW Import_ No Cap **(b) Base Case - 0 MW Import_ With Cap @ $10/ton**

Figure 3.11: **New England Projected Sources of Energy in 2015 With and Without the RGGI Cap: Base Case with 0 MW Imports**

Figure 3.12 shows the percentage increase after 2006 of natural gas consumption when different CO_2 allowance price assumptions are applied after 2009. The base case (no cap) shows that natural gas consumption would increase to serve the increasing load over the study period by 35%. With a higher CO_2 allowance price, natural gas consumption would increase less than without a CO_2 cap. In 2015, if the CO_2 allowance price were $10/ton, the percentage increase in natural gas consumption would be about 1% lower than in the base case; or if the CO_2 allowance price were $20/ton, the increase in natural gas consumption would be about 3% less than the base case.

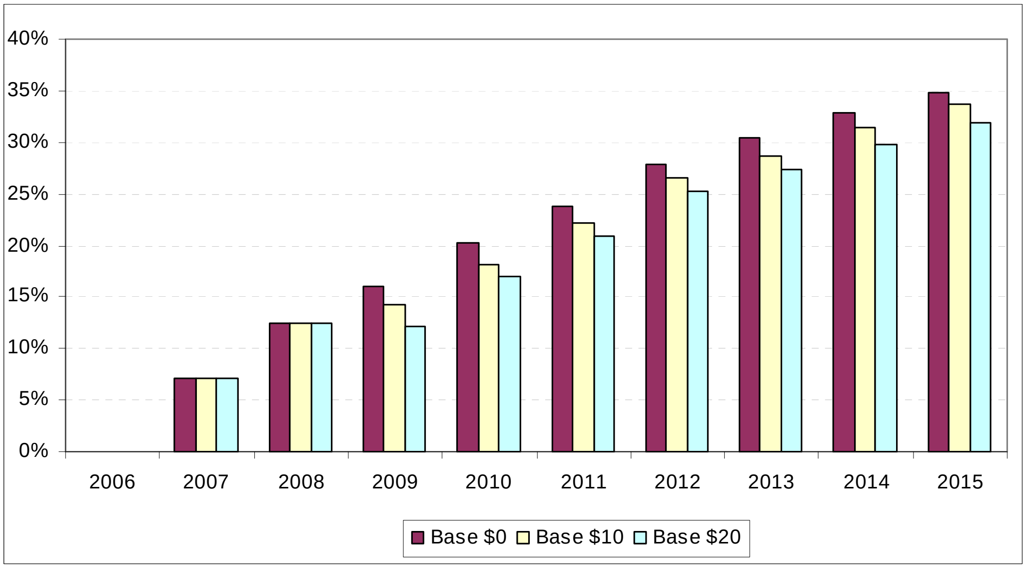


Figure 3.12: **Percentage Increase in New England Generators' Natural Gas Consumption from 2006 vs. CO_2 Allowance Prices**

Figure 3.13 shows similarly the percentage increase of gas consumption from today for the different new resource addition cases. Adding 1,000 MW of nuclear or IGCC units would decrease the increase in gas usage significantly by 2015, i.e. from 35% to 25% versus the base case. For the case with the Queue mix of projects, the natural gas consumption increase would be less (32%) than the base case (35%), since these projects comprise energy from oil/gas, wind and nuclear uprates. Adding 1,000 MW of natural gas combined cycle units would increase the gas consumption the most of these cases over the base case to 39%. This case added new NGCC which replaced the less efficient oil-burning units.

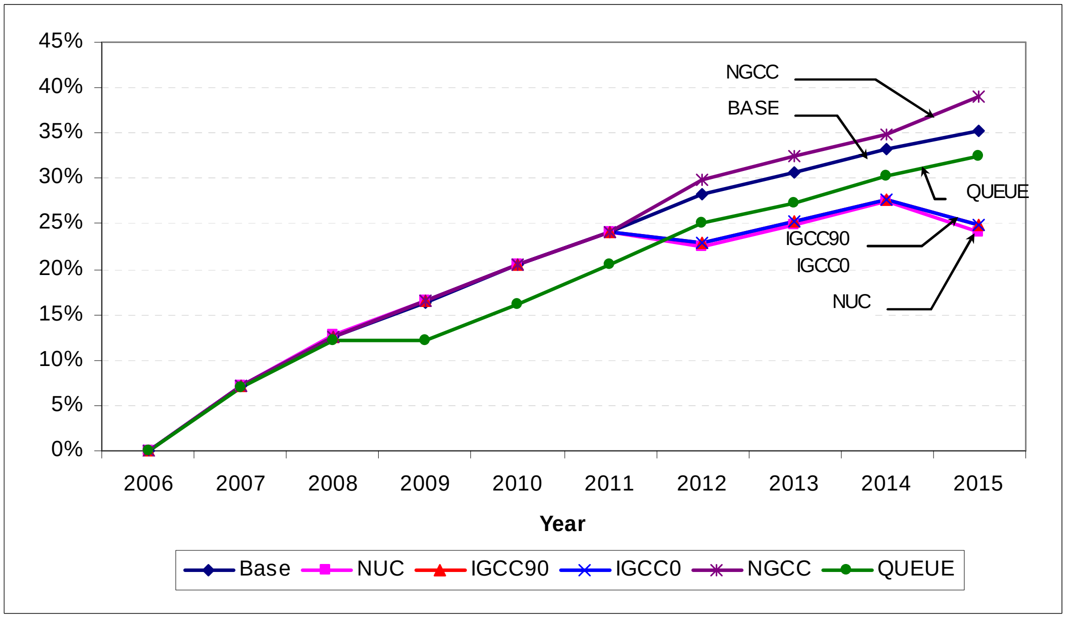


Figure 3.13: **Percentage Increase in New England Generators' Natural Gas Consumption from 2006 vs. New Resource Additions**

3.2 Six-State RGGI – Massachusetts/Rhode Island Join RGGI

This section presents the scenario results assuming a six-state New England RGGI cap. It examined the New England CO_2 emissions as a function of the CO_2 allowance price for the base case (no resource additions), and for the five alternative resource addition cases, similar to the four-state cap. The CO_2 emissions summarized are for the New England generators 25 MW and larger.

If Massachusetts and Rhode Island would join RGGI by 2008[19], it would create a six-state RGGI cap in New England of 55.8 million tons. In this case, the CO_2 emission allowance price would be applied to the Massachusetts and Rhode Island units larger than 25 MW (as listed in the RGGI website). This would add 56 units under the New England RGGI cap, for a total of 106 New England RGGI units. In this case, RGGI was assumed to supersede the Massachusetts CO_2 regulations (310 CMR 7.29) affecting 15 units.

3.2.1 CO_2 Allowance Prices

Figure 3.14 shows the RGGI CO_2 emission results from the cases assuming six New England states in RGGI. For the base case with no cap or with a \$5/ton CO_2 allowance price, the total emissions would exceed the cap starting in 2011. Similarly, at \$10/ton the CO_2 emissions would exceed the cap in 2012 and at \$20/ton, in 2015.

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[19] Since Massachusetts and Rhode Island participated in the development of the RGGI MOU, but did not sign it, the RGGI model rule has made provisions for Massachusetts and Rhode Island to join by 2008 and determined their CO_2 emission caps would be 26,660,204 tons and 2,659,239 tons, respectively.

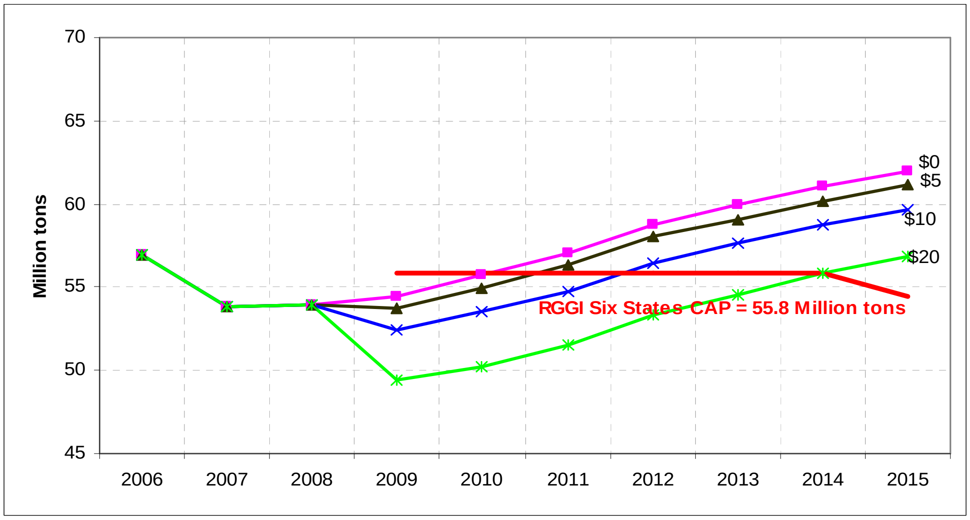

Figure 3.14: New England RGGI Units CO_2 Emissions vs. Six-State RGGI Cap (Assumes Massachusetts/Rhode Island join RGGI)

3.2.2 New Resource Additions

Similar to the new resource addition cases for the four-state RGGI cap, five new resource addition cases were simulated under the six-state RGGI cap. Figure 3.15 shows the CO_2 emissions for the RGGI generators in the six states assuming these various new resources would be installed in New England. In these cases, a CO_2 allowance price of $5/ton was assumed in order to be consistent with the new resource addition cases for the four RGGI states. Similar to the four-state RGGI cases, adding zero or low CO_2 emitting resources will reduce the CO_2 emissions in New England. However, the New England's RGGI units would not meet the cap starting in 2012 even if 1,000 MW of nuclear units with zero emissions were added to the system that year. The Queue mix of resources would delay exceeding the RGGI cap by one year (to 2012) as compared to the base case since wind and nuclear uprates, which have no CO_2 emissions, were assumed to be in service earlier than the resources in the other four cases.

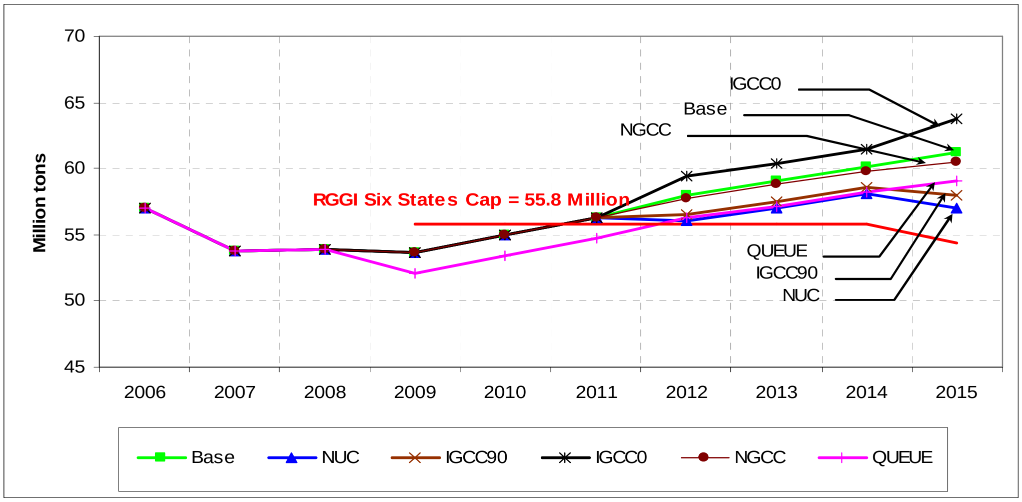

Figure 3.15: Impact of New Resources on New England Generators CO_2 Emissions with a Six-State RGGI Cap (CO_2 Allowance Price − $5/ton)

4.0 Observations and Conclusions

The following are the observations and conclusions drawn from this ISO study of the impact of the RGGI CO_2 cap on New England generators.

4.1 Observations

Under a four-state New England RGGI cap, the evaluation results show that:

- RGGI Compliance vs. CO_2 Allowance Price
  For the base case assumptions (no new capacity additions), the New England RGGI units' total CO_2 emissions would stay under the cap through 2015 at an assumed CO_2 allowance prices of \$5 per ton. Higher CO_2 allowance prices would provide greater margins for RGGI compliance.

  However, without any assumed leakage "controls", the study results show that the RGGI cap would result in a significant increase in the CO_2 emission leakage from non-RGGI units within New England, mainly from the units in Massachusetts and Rhode Island. The higher the CO_2 allowance price, the greater the CO_2 emission leakage. By 2015, with a \$5, \$10, and \$20 per ton CO_2 allowance price, the CO_2 emission leakage would offset the decrease in the New England CO_2 emissions by 1.6, 3.4, and 5.2 million tons, yielding a net reduction in the total New England generator CO_2 emissions of 0, 1.1, and 3.6 million tons, respectively.

- New Resource Additions
  If during the study period, new zero or low CO_2 emitting resources were added in the New England control area, e.g., nuclear, IGCC with 90% CO_2 capture and storage, or a representative mix of projects in the ISO Queue, the emissions of the RGGI generators would stay below the cap. Adding natural gas combined cycle generation would cause the New England RGGI CO_2 emissions to exceed the cap. The results show the importance of adding resources that have zero or low rates of CO_2 emissions per MWh to meet the RGGI cap, especially in 2015 and later years when the cap will be declining.

- Effect of Varying Imports and Exports
  The study confirmed that when the energy imported from external control areas decreases, or exports to external areas increase, the RGGI units' CO_2 emissions would increase. With the RGGI cap at an assumed CO_2 allowance price of \$10/ton, zero imports would increase the RGGI CO_2 emissions by 3.7 million tons compared with the base case with market-based imports, and by 2015, would exceed the four-state RGGI cap. A 200 MW increase in exports compared to the base case would increase the RGGI CO_2 emissions by 1.5 million tons, but these emissions would remain below the RGGI cap during the study period through 2015.

- Effect of Relative Price of Natural Gas vs. Residual Oil
  When natural gas is relatively more expensive than residual oil, the RGGI CO_2 emissions would increase and result in exceeding the RGGI cap. The New England four-state RGGI CO_2 emissions would exceed the RGGI cap in 2015 if the natural gas price were more than 1.6 times the residual oil price.

- Effect on Fuel Usage
  The New England RGGI cap would not significantly affect the fuel mix of energy and gas consumption in New England.

Under a New England six-state RGGI cap, the results show:

- RGGI Compliance vs. CO_2 Allowance Price
  If Massachusetts and Rhode Island were to join RGGI, the six-state RGGI CO_2 emission cap would be 55.8 million tons. For the base case with no resource additions and a CO_2 allowance price of $5 per ton, New England RGGI CO_2 emissions would exceed the cap in 2011, and in 2014 at a CO_2 allowance price of $20 per ton.

- New Resource Additions
  Adding new resources would delay exceeding the cap, but the New England CO_2 emissions would exceed the six-state RGGI cap by 2011 in all the cases simulated.

4.2 Conclusions

This RGGI analysis shows that the proposed New England four-state RGGI cap of 26.5 million tons would reduce the CO_2 emissions from the RGGI generators. Assuming all RGGI generators can have 100% market access to the states' allowance allocations, the allowance market is liquid, and no offsets are used for compliance, the RGGI generators in the four New England states would collectively comply with the RGGI cap with a CO_2 allowance price higher than $5 per ton through 2015. As energy demand increases, adding resources with zero or low CO_2 emission characteristics would help New England generators to maintain compliance with the RGGI cap.

The RGGI cap would increase the CO_2 emission leakage from the non-RGGI generators and the imports from Hydro Quebec and New Brunswick. The leakage from non-RGGI New England generators was quantified as significant, but leakage related to Canadian imports was not estimated. RGGI is developing measures to control the CO_2 emission leakage resulting from the cap. The study shows that reductions from RGGI units would be partially offset with leakage in Massachusetts and Rhode Island, so net reductions occur in New England only at CO_2 allowance prices greater than $5/ton.

Decreasing imports, increasing exports, and a higher natural gas price compared to a residual oil price, all tend to increase New England CO_2 emissions and make New England RGGI compliance more challenging than shown by this study's results.

If Massachusetts and Rhode Island were to join RGGI, it could be difficult for the New England RGGI generators to comply with the new six-state RGGI cap of 55.8 million tons after 2011. With energy growth causing an increase in CO_2 emissions, significant new resources with zero or low CO_2 emission characteristics are required to be added over the next ten years to keep New England RGGI emissions below the cap. This is especially true after 2015 when the cap value will be declining.

4.3 Potential Future Work

There are several potential areas for further study. The ISO RGGI study showed that the impact of the CO_2 emission leakage is significant when the RGGI cap is applied. When the RGGI organization proposes its method to control CO_2 emission leakage, further examination of leakage may be useful. Also, future efforts to quantify the CO_2 emission leakage related to Canadian imports can help refine compliance expectations. Finally, since RGGI is only one of a number of new clean air emission regulations and policies that will impact the region's generators, a more comprehensive study of these regulations together with RGGI would be prudent to assess the generators' potential compliance problems and options from a regional perspective.

5.0 Appendix − Modeling and Assumptions

This appendix documents in more detail the modeling and assumptions used in this study.

5.1 Inter-Regional Electric Market Model (IREMM)

The Inter-Regional Electric Market Model (IREMM)[20] was used to simulate future New England energy production from the region's generators in this study. IREMM is a computer model that provides a chronological simulation of energy market behavior based on both game theory and the traditional, engineering-based least cost production simulation model. The model can represent numerous subarea loads and transmission interfaces as an approximation of the more detailed transmission system.

In the beginning of the simulation process, IREMM calculates the hourly load data for each subarea, based on the subarea hourly load shape and load forecast profile provided input. The transmission system is modeled in terms of transfer limits on interfaces between interconnected Subareas. Power transfer distribution factors are developed from a DC-type network configuration based on relative impedances between subareas.

In IREMM, thermal units are represented by seasonal capacity ratings, full load heat rate, equivalent forced outage rate, and equivalent availability factor. Unit forced outages are handled as permanent deratings to unit capacity. Detailed generator parameters such as low operating limits, dispatch blocks, minimum up time and downtime, ramp rate, unit start-up cost, and O&M cost can not be represented. Pumped storage resources are represented as a load modifier with a ten percent monthly capacity factor. Conventional and run-of-river hydro resources are assumed to have a monthly generation profile that reflects historical stream flows.

For each hour, IREMM initially dispatches generating units to meet each individual area's loads, starting with the least expensive unit. Once these loads are served from available resources, the amount of surplus energy available for sale and the amount of economically displaceable energy may be calculated for various price levels. IREMM then employs a unique methodology to auction relatively low-cost energy resources to the highest bidders. The subareas with relatively higher cost units will survey all the potential sellers to determine the prices at which surplus energy is available. A transaction will then be made with the market area having the lowest delivered price of this surplus energy. In each energy transaction, the flow on each transmission interface is computed, based on power transfer distribution factors, to ensure that none of the interfaces are overloaded. The energy transactions continue until supply and demand are satisfied simultaneously. For any subarea short of energy, a very expensive proxy unit is dispatched to provide the necessary energy and a price spike is assigned for that hour. Once the dispatch and purchase/sale transactions are simulated, the results are then accumulated for developing statistics for reporting purposes. The program then proceeds to the next hour and repeats the same process until the last hour of the study period.

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[20] IREMM is a proprietary model.(www.iremm.com)

5.2 Load

Subarea chronological hourly loads and annual energy were used consistent with the 50/50 load forecast in the RSP06 study[21]. Load forecast uncertainty was not modeled. The subarea peak loads are listed in Table A.1.

Table A.1 – Subarea Peak Load Forecast (2006-2015) (MW)

Subarea	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BHE	310	310	315	320	320	325	330	330	335	335
BOSTON	5470	5495	5595	5715	5830	5960	6070	6160	6245	6325
CMA/NEMA	1750	1755	1785	1825	1860	1900	1940	1970	1995	2020
CT	3580	3630	3695	3780	3865	3955	4050	4115	4175	4230
ME	1085	1100	1120	1140	1160	1185	1215	1240	1260	1280
NH	1910	1970	2030	2105	2185	2265	2335	2400	2460	2510
NOR	1260	1270	1290	1315	1340	1365	1395	1415	1435	1455
RI	2465	2505	2540	2585	2640	2700	2755	2795	2830	2870
SEMA	2960	2985	3045	3115	3180	3260	3330	3390	3450	3500
SME	665	685	700	720	735	750	770	785	800	810
SWCT	2340	2380	2430	2490	2555	2625	2675	2710	2740	2770
VT	1210	1235	1260	1290	1310	1340	1365	1390	1410	1420
WMA	2075	2085	2120	2170	2210	2260	2300	2330	2360	2380

5.3 Generation

Data for existing generators, summer and winter ratings, EFOR information, and maintenance are the same as RSP06. No unit retirements were modeled. The energy costs of the thermal units included the fuel cost plus the emission cost adders. The fuel costs were calculated based on the full-load heat rates and the fuel price assumptions. The full-load heat rates of the thermal units were based on generic and/or publicly available historical heat rate performance.

The impacts of the air emission cap-and-trade programs on the generators were modeled as emission cost adders. The emission rates for all the units were the same as the emission rates used in the RSP06 base case, which were calculated based on the emission data from the EPA Emission Scorecard and ISO New England generation data. The calculated emission rates were adjusted based on CT Executive Order 19 and MA 310 CMR 7.29. In the following section, the assumptions on modeling NO_x, SO_2 and CO_2 emission rates for these units are discussed in detail.

5.3.1 SO2 Emissions

SO_2 emission rates were simulated only for thermal units 25 MW and larger in the RSP06 base case

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[21] http://www.iso-ne.com/trans/rsp/index.html

since SO_2 allowances were not required for units smaller than 25 MW. The allowance price assumed for SO_2 was $860/ton, based on a forward price for 2008 shown on the Evolution Markets website on February 21, 2006[22].

5.3.2 NO_x Emissions

For all thermal units 25 MW and larger in the RSP06 database, NO_x emission cost adders were calculated using the RSP06 NO_x emission rates and the assumed allowance price of $2000/ton. This was based on a forward price for 2008 as shown on the Evolution Markets website on February 21, 2006. For all thermal units smaller than 25 MW, NO_x emission rates were not modeled.

5.3.3 CO_2 Emission Rates

Historical CO_2 emission rates, as described above, were used for existing units in the simulation. For the new resource addition cases, the CO_2 emission rates in lb/MBtu shown in Table A.2 (Item D) were used based on fuel-types of fossil units. These rates were converted from the carbon factors in Table 6 in the DOE GG94 report - Chapter 2: Carbon Dioxide Emissions[23].

Table A.2 – Calculation of CO_2 Emission Rates

Item	Description	Coal	Gas	Distillate	Residual	Wood
A	Carbon Weight/ CO_2 Weight	0.27	0.27	0.27	0.27	0.27
B	Carbon Coefficient Factors (Million Metric Tons Carbon per Quadrillion Btu)	26	14.5	20	22	21
C	CO_2 Emission Rate (lb/MBtu) =B*2200/A/1000	210	117	161	177	171
D	Values used in IREMM (lb/MBtu)	210	120	160	180	170

5.3.4 Modeling of Massachusetts Plants under 310 CMR 7.29 Regulations

The 7.29 regulations establish a cap in tons for CO_2 starting on January 1, 2006 for six plants as shown in Table A.3 and a rate cap of 1,800 lb/MWh for the same plants starting on January 1, 2008. Because the simulated emissions in IREMM from these units were well below the caps over the period studied, the compliance with the tonnage cap could be ignored[24]. If a unit's CO_2 emission rate was at or below the 1,800 lb/MWh rate cap, no modeling of allowance price would be needed. For the units in Massachusetts which could exceed the rate cap, a dispatch cost adder was calculated based on the $10/ton price cap and the increment by which their CO_2 emission rates exceeded the 7.29 CO_2 emission rate cap of 1,800 lb/MWh.

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[22] http://www.evomarkets.com/

[23] http://www.eia.doe.gov/oiaf/1605/87-92rpt/chap2.html

[24] The historical emissions data from the six plants and the projected emissions from RSP06 show the CO_2 emissions from five plants are below the tonnage cap by a large margin. Only one unit exceeds its tonnage cap by a small amount. Considering the accuracy of modeling and the fact the plant can use offsets to meet the cap, this study didn't model the tonnage caps.

Table A.3 – Total Tonnage Cap for Six Plants in Massachusetts affected by 310 CMR 7.29[25]

Generating Plant	Annual Cap (tons)
Brayton Point	8,585,152
Canal Station	5,331,820
Mt. Tom	1,117,569
Mystic	7,596,390
Salem Harbor	4,286,053
Somerset	916,586
Total	27,833,570

5.4 Fuel Price

The fuel price assumptions were from the EIA 2006 Annual Energy Outlook and the January 2006 Short-term Energy Outlook. They were the same as those used in RSP06. The 10-year forecast prices in constant 2004 dollars for coal, distillate oil, residual oil and natural gas are listed in Table A.4.

Table A.4 – 2006 RSP Fuel Cost Forecast (2004 $/MBtu)

Fuel Category	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Distillate Oil	10.68	11.39	10.72	10.05	9.38	9.04	9.04	9.16	8.85	8.98	9.02
Residual Oil	6.92	7.73	7.34	6.66	5.99	5.70	5.72	5.71	5.65	5.67	5.72
Natural Gas	8.40	9.90	8.45	7.19	5.92	5.60	5.40	5.38	5.49	5.41	5.21
Steam Coal	1.54	1.62	1.66	1.57	1.47	1.48	1.45	1.44	1.43	1.41	1.40

5.5 Transmission Systems

In IREMM, the New England transmission system was approximated using 13 load subareas connected by transmission interfaces. The transfer limits for the main transmission interfaces among subareas in the study are listed in Table A.5.

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[25] http://www.mass.gov/dep/air/laws/ghgregjc.pdf.

Table A.5 – Transfer Limits of Transmission Interface (MW)

Interfaces	Interface Limit	
New Brunswick– New England	2006: 700	2007-2015: 1,000
Maine–New Hampshire	2006: 1200	2011: 1300
	2007: 1200	2012: 1275
	2008: 1375	2013: 1250
	2009: 1350	2014: 1225
	2010: 1325	2015: 1200
Orrington South Export	2006:1050	2007-2015: 1200
Surowiec South	2006:1150	2007-2015: 1250
North–South	2,700	
HQ–NE (Highgate)	200	
HQ–NE (Phase II)	1,500	
Boston Import	4,600	
SE Mass/ RI Export	3,000	
East–West	2,400	
Connecticut Import	2,500	
Southwest Connecticut Import	2006: 2,300	2007-2009: 2,340
	2010-2015: 3,650	
Norwalk/Stamford	2006:1,100	2007-2009: 1,300
	2010-2015: 1,650	
New York–New England	1,400	
Cross Sound Cable	330	

5.6 Exports and Imports

Exports and imports were modeled using the RSP06 base case assumptions, as shown in Table A.6. Two types of interchanges were adopted to simulate the power transfers between New England and Hydro Quebec and New Brunswick: fixed and price responsive transactions. The fixed transaction was an all-hours energy transfer modeled as a price taker[26] to represent some of the existing transactions. Price responsive transactions were modeled using proxy generators with different heat rates to represent a reasonable market-based supply curve to simulate transactions. The fuel prices in New England were used for these proxy generators. The existing NYPA transaction between New York and New England was also modeled. The Cross Sound Cable was modeled as a fixed export from New England to New York.

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[26] The unit will accept the market clearing price under any condition.

Table A.6 – Exports and Imports Modeling

Control Area	Modeling	Imports (MW)	Exports (MW)
HQ(Phase II)	Fixed Transaction	300	0
	Natural Gas Combined Cycle (NGCC)	400	0
	Steam Turbine (ST)	300	0
	Gas Turbine (GT)	200	0
HQ(Highgate)	Fixed Transaction	200	0
NB	Fixed Transaction	200	0
	Natural Gas Combined Cycle (NGCC)	500/800(12/2007)	0
NY	Fixed Transaction (NYPA)	85	0
	Fixed Transaction (Cross Sound Cable)	0	330

5.7 Resource Addition Cases

The resource addition cases were simulated to investigate the impact of adding various types of resources on reducing the CO_2 emissions of future RGGI generators and New England generators. The assumptions used in these cases are described below.

Four 250 MW units totaling 1,000 MW were used for the nuclear, IGCC and NGCC cases. In each case, the units were added in two New England RGGI states. In 2012, one unit was added in Connecticut and one in New Hampshire. In 2015, another two units (one each) were added in those same states.

Nuclear: In the simulation of adding nuclear capacity, the nuclear unit had a full load heat rate of 10,089 Btu/kWh based on generic and publicly available historical heat rate performance. The unit had an assumed Equivalent Forced Outage Rate (EFOR) of 0.0161 and 4 weeks maintenance based on the New England nuclear unit average outage information.

Integrated Coal Gasification Combined Cycle (IGCC): Each new IGCC unit had a full load heat rate of 8,600 Btu/kWh, an EFOR of 0.068 and 5 weeks maintenance. The following emission rates were used: 0.15 lbs/MWh for SO_2, 0.206 lbs/MWh for NO_x, and 1,806 lbs/MWh for CO_2. The heat rate assumption was based on an EPRI IGCC estimate[27]. The SO_2 and NO_x emission rates came from an IGCC study[28]. The CO_2 emission rate came from the DOE GG94 report discussed previously. A case was studied that assumed that 90% of the CO_2 emitted from new IGCC was captured and stored. In this case only 10% of the average CO_2 emission rate was used, resulting in a CO_2 emission rate to the atmosphere of 181 lbs/MWh.

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[27] www.climatevision.gov/pdfs/coal_roundtable/dalton.pdf

[28] William G. Rosenberg, “Gasification as a Strategic Energy and Environmental Option”, Harvard University, 2005. http://www.usaee.org/pdf/NE_Gasification.pdf

Natural Gas Combined Cycle (NGCC): The assumed characteristics for NGCC were a heat rate of 7,200 Btu/kWh, an EFOR of 0.061, and 5 weeks maintenance. The following emission rates were used for NGCC: 0.0 lbs/MWh of SO_2, 0.172 lbs/MWh for NO_x, and 864 lbs/MWh for CO_2 emission rate. The heat rate and emission rate assumptions came from the same source as the IGCC case.

Representative Resource Mix in the ISO Queue: A representative mix of resources from the recent ISO Queue was simulated to reflect a potentially more realistic portfolio of future generation additions from the market. The total capacity from these projects was 1,651 MW.

The ISO Queue mix had 497 MW of wind power projects, which included the 462 MW Cape Wind project. Two types of units were used to simulate these wind projects: off-shore and on-shore wind plants. In the IREMM simulation, both units were modeled as load modifiers. Monthly energy provided from Cape Wind estimates was used for the off-shore unit’s monthly energy profile reflecting an annual capacity factor of 38% projected by Cape Wind. For the on-shore wind projects, five years of historical monthly energy data from the Searsburg, Vermont wind project (Year 2000 to Year 2004) was used as the model for the monthly energy profile. This energy represents an annual capacity factor of 22%.

Other new oil/gas generation projects were also modeled. The typical unit parameters, such as heat rates, and SO_2 and NO_x emission rates, came from generic and/or publicly available data. The CO_2 emission rates were based on the DOE GG94 report.