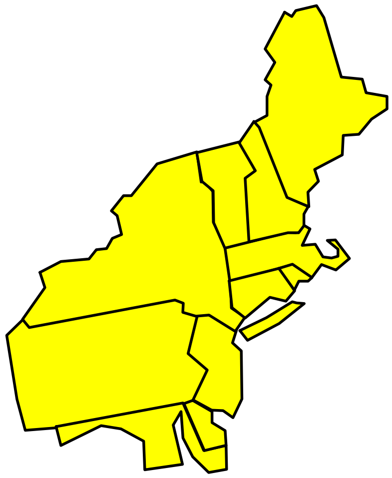
Setting a Northeastern CO2 Emissions Cap on the Electric Power Industry-- Compliance Options, Costs and Market Impacts



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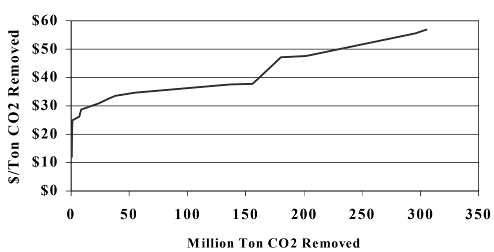
Executive Summary

This study examines the potential costs of reducing carbon dioxide (CO2) emissions by electric generating facilities in an 11-state region of the Northeast. It assumes alternative reduction targets of stabilization of emissions at 1990 levels, and a much more aggressive reduction of 25% below 1990 emissions. Costs were estimated based on replacing or reducing current high-emitting sources of CO2 with lower or zero-emitting sources (including natural gas combined cycle plants, environmental dispatch, biomass cofiring, wind power and nuclear energy.)

The analysis explicitly precluded purchases of emission allowances and additional power imports from Canada or other regions as compliance options. These assumptions were made in order to develop realistic estimates of the costs of reducing carbon through changes in the region's electric supply. As shown in Exhibit 1, the estimated costs of these supply-side reductions range from \$20 to \$60 per ton of CO2 reduced. Given these high direct CO2 reduction costs, emission allowance purchasing on national or international markets and increased power imports represent much more cost-effective means to reduce CO2 emissions from the Northeast power sector. Carbon dioxide allowances trade on the international market at costs of \$5 to \$15 per ton, well below the costs of achieving emission reductions within the Northeast power sector.

Exhibit 1
Northeastern Direct CO2 Reduction Costs



Our methodology provides for emissions trading among sources within each of three subregions selected for analysis: New York State, the six New England states, and four Mid-Atlantic states (Delaware, New Jersey, Maryland and Pennsylvania). Interregional trading between and among these subregions also was evaluated.

Given different generation mixes across the region, the power market impacts from adopting a regional program would not be evenly distributed across the broad 11-Northeast state area. Market effects and costs are likely to be significantly higher in the Mid-Atlantic States than in New York.

As shown in Exhibit 2, most of the compliance costs associated with meeting a range of carbon reductions would be incurred in the mid-Atlantic region south of New York. This region is far more dependent upon coal generation than New York or New England. These results demonstrate the concentration of control costs in states south of New York, and the relative ease of achieving stabilization of emissions at 1990 levels in New York State. This reflects the fact that New York already has reduced its emissions below 1990 levels for independent reasons, including a shift away from oil towards natural gas and increased in nuclear generation and power imports.

Exhibit 2
Compliance Costs for Alternative 11-State Northeast CO2 Caps, 2015

Region	1990 Cap	1990 –25%	1990 Cap	1990 –25%
	Mil. $/Year	Mil. $/Year	$/Ton CO2	$/Ton CO2
New York	$0	$343	$0	$30.93
New England	$349	$767	$29.73	$32.15
NY & N. Eng.*	$109	$1,101	$26.25	$31.15
Mid-Atlantic	$1,592	$3,089	$35.79	$36.56
11-States*	$1,556	$4,144	$31.96	$31.84

*With inter-regional emissions trading.

The analysis also calculates the extent of dislocation of coal utilization in each subregion, based on least-cost substitution of alternative, lower-carbon energy supplies. As shown in Exhibit 3, the largest impacts would occur in the four Mid-Atlantic States, reflecting this subregion's traditional dependence on coal for more than 50% of its electric supply:

Exhibit 3
Reduction of Coal Use in 11-State Region to Meet Alternative CO2 Caps, 2015

Region	1990 Cap	1990 –25%	1990 Cap	1990 –25%
	Mil.tons coal displaced/yr	Mil.tons coal displaced/yr	% of coal-based generation reduced	% of coal-based generation reduced
New York	0.0	5.6	0%	46%
New England	1.1	2.9	18%	45%
NY & N. Eng.*	2.6	3.5	14%	19%
Mid-Atlantic	16.7	24.8	34%	51%
11-States*	20.6	31.8	25%	39%

*With inter-regional emissions trading.

The significant reduction of coal use in the Mid-Atlantic states would have additional cost impacts in the mining and coal transportation sectors that are beyond the scope of this study. Pennsylvania is both a major producer and consumer of coal, and Pennsylvania electric customers are the largest source of demand for the Pennsylvania mining industry.

In sum, we find that a regional CO2 reduction program based on changes in the Northeast electric supply sector is not cost-effective compared to alternative options such as allowance purchasing and increased power importation. If an aggressive emission cap such as 25% below 1990 levels were selected, regional costs could exceed $4 billion annually by 2015. The likely pass-through of these additional costs to industry and other electric consumers would have additional negative economic ramifications for the region that merit further research.

Background

Congress and several state legislatures are debating measures to control the growth of greenhouse gas emissions. Proponents argue that action must be taken to cap national CO2 emissions in order to protect the earth from the adverse effects of greenhouse gas build-up. Opponents counter that the costs for taking action are extremely high and would have significant negative impacts on energy prices and national economic growth.

Given the uncertain outcome of the national policy debate, seven Northeastern states[1] have taken independent action by establishing non-binding emission targets, adopting legislation, or in one case, passing enforceable regulations to control greenhouse gases. Targets range from capping emissions at historic levels by 2006/08 (Massachusetts) to returning to 1990 levels by 2010 (Maine) to lowering emissions to as low as 25 percent below 1990 levels (Vermont Executive Order 11-02; New York Pataki Commission on Global Warming/Center for Clean Air Policy; Rhode Island Climate Action Plan).

In most cases, which sources will be targeted, how much they must reduce their emissions, and what type of trading (if any) would be permitted to achieve these broad goals have yet to be defined. Northeastern state actions have triggered New York Governor Pataki's April 25, 2003 call to develop a comprehensive region-wide program to promote greater efficiency and reduce compliance costs.

Study Approach

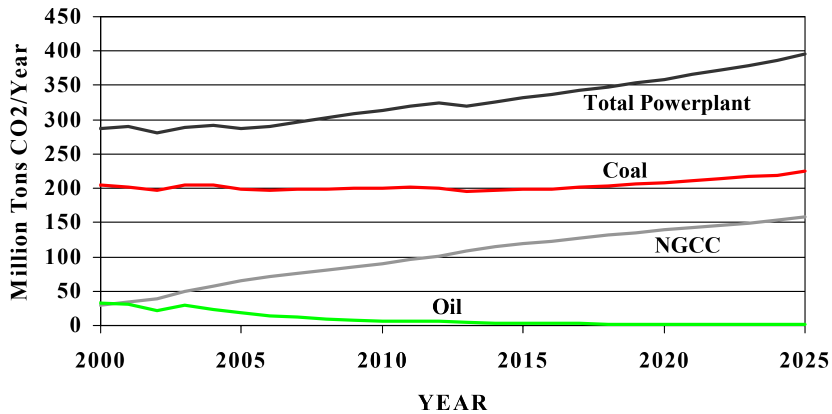
This study assesses the reduction options, compliance costs and electric market impacts of establishing a regional Northeastern CO2 control program that would regulate emissions from the electric power industry beginning in 2013. This Northeastern region includes the 6 New England States, New York and 4 remaining Mid-Atlantic States (DE, MD, NJ and PA). Two different annual CO2 emission cap levels are examined—return to 1990 emission levels (283 million tons/year) and a stricter 25 percent reduction from 1990 levels (212 million tons/year).

Despite the recent decline of Northeastern power emissions to near 1990 levels (from greater imports, nuclear generation and lower residual oil use), significant shifts in the regional generation mix and future capacity choice will be required to achieve the proposed CO2 emission caps. Under the current regional generation outlook, the

[1] In 1999, **New Jersey** established a state goal of reducing greenhouse gas emissions to 3.5 percent below 1990 levels by 2005. In 2001, **Massachusetts** adopted enforceable rules requiring 6 powerplants to cap their CO2 emissions at historic levels (average 1997-99) and also achieve an emission rate average of 1,800 #CO2/MWh by 2006/08. **Vermont** Governor Howard Dean signed an executive order establishing a state-wide goal of reducing state emissions by 25% below 1990 levels by 2012, 50% by 2028 and if practicable 75% by 2050. In 2002, **New Hampshire** passed legislation to cap CO2 emissions at 3 powerplants at 1990 levels by 2007. **Rhode Island** published its Climate Action Plan in 2002 to reduce its emissions by 25% below 1990 levels by 2012. This year, **Maine** passed legislation to develop a climate action plan that reduces CO2 emissions to 1990 levels by 2010 and 10% below 1990 levels by 2020. **New York** Climate Change Task Force recommended a statewide reduction of 5% below 1990 levels by 2010, and a 10% reduction by 2020.

Northeast is expected to rely heavily upon new natural gas combined cycle capacity to meet its estimated 1.7 percent per year electricity demand growth. Without any new nuclear plant construction or further expansion of import transmission capacity, Northeastern powerplant CO2 emissions should climb from 280 million tons in 2002 to 320 million tons by 2013 and 396 million tons by 2025 (Exhibit 4).

Exhibit 4
Northeastern Powerplant CO2 Emissions



Uneven Regional Impacts

Given the generation mix outlook within the region, the market impacts from adopting a regional program would not be evenly distributed across the broad 11-Northeast state area. Market effects and costs are likely to be significantly higher in the Mid-Atlantic States than in New York.

As shown in Exhibit 5, most of the compliance costs associated with meeting a range of carbon reductions (from stabilization at 1990 levels to a 25% reduction below 1990 emissions) would be incurred in the mid-Atlantic region south of New York. This region is far more dependent upon coal generation than New York or New England.

Exhibit 5: Compliance Costs and Emission Reductions For Alternative 11-State Northeast CO2 Caps, 2015

Region	1990 Cap	1990 –25%	1990 Cap	1990 –25%
	Mil. $/Year	Mil. $/Year	Mil. Tons CO2 Reduced	Mil. Tons CO2 Reduced
New York	$0	$343	0 (0%)	11 (-16%)
New England	$349	$767	12 (-20%)	24 (-40%)
NY & N. Eng.*	$109	$1,101	4 (-3%)	34 (-28%)
Mid-Atlantic	$1,592	$3,089	44 (-22%)	84 (-42%)
11-States*	$1,556	$4,144	49 (-15%)	119 (-36%)

*With inter-regional emissions trading.

Overview of Methodology

To reduce emissions to meet stricter CO2 caps, the power industry has the following alternatives:

- Increase power imports from outside the affected region to displace native load generation
- Purchase CO2 emission credits (if permitted)
- Switch fossil fuel fired units to lower carbon-containing fuels (coal->oil->natural gas) though environmental dispatching or direct fuel substitution.
- Increase generation from renewable and nuclear power sources
- Reduce power demand though improved energy efficiency programs

In general, the method for estimating costs of achieving alternative CO2 emission caps uses a stepwise approach, finding the least-cost alternative source of generation with lower carbon emissions

Power imports have played an important role in recent declines in Northeastern powerplant CO2 emissions[2] (and associated increases in other regions). The baseline forecast assumes that regional power imports will increase by an additional 7 TWh[3] and will reduce Northeastern powerplant CO2 emissions by roughly 5-7 million tons/year (and increase emissions in Midwest, Southeast and Canada).

However, to obtain additional emission reductions by increasing power imports further would likely require significant new transmission capacity expansions and upgrades. Evaluation of the cost and potential reductions from these transmission expansions is outside the scope of this study. Given that power imports are unlikely to provide any additional reductions in total US emissions, additional power imports were not permitted as a compliance strategy in this study.

Purchasing emission reduction credits is another potential compliance option. The economic attractiveness of this option depends upon the trading program adopted (if any) and the type of credits allowed. Current voluntary CO2 trading programs offering credits from carbon sequestration projects (e.g. afforestation, reforestation, etc.) have market prices typically ranging between \$1-\$8/ton of CO2.

These carbon sink project costs have been consistently less than the direct carbon reduction costs from fuel switching or increasing renewable/nuclear generation, typically in the range of \$15/ton (in Europe) to \$25-60/ton (in US). Given that carbon sinks are a cheaper alternative to direct emission reduction alternatives, the handling of carbon sink

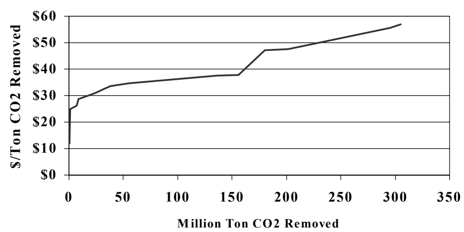
[2] Between 1998-2002, increasing power imports have reduced Northeastern CO2 emissions by roughly 17 million tons/year.
[3] Power imports are expected to increase into the New York and Mid-Atlantic areas and decline slightly into New England over the forecast period (2002-2025).

credits and trading rules would have a profound impact on overall regional compliance costs and market impacts.

If a Northeast regional program allowed carbon sink credits, sources would comply by purchasing these credits for their entire reduction obligation. Annual compliance costs for a cap set at 25% below 1990 levels would likely range from $0.5-1.1 billion in 2013 and steadily increase to 0.9-$1.8 billion by 2025 as electricity demand grows. If the carbon-sink credits were expanded to include more controversial ocean iron fertilization projects, credit prices would drop to only $0.50/ton and Northeastern regional compliance costs could be as low as $50 million/year in 2013 and $100 million in 2025.

If carbon sinks do not qualify for CO_2 credits, Northeastern powerplants would be left to pursue fuel switching and increased renewable/nuclear generation as their only remaining compliance options. The cost of these emission reduction alternatives in the Northeast are shown in Exhibit 6.

Exhibit 6
Northeastern Direct CO2 Reduction Costs



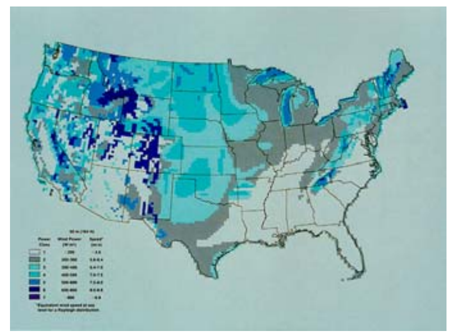
As shown previously in Exhibit-5, the compliance cost for these direct compliance options under the stricter 212 million ton/year emissions cap requirement (25% below 1990 levels) would start at $3.7 billion in 2013 and grow to $6.3 billion/year by 2025. If the target were set to return to 1990 levels (283 million tons/year), the compliance costs would be much less--- $1.1 billion in 2013 and growing to $3.9 billion/year by 2025. These direct carbon reduction options for the Northeastern utilities are described below.

- *Switching from remaining oil/gas steam capacity from residual oil to natural gas*—The Northeast has over 28 GW of oil and/or gas fired steam generating capacity of which more than half is expected to retire during the next 15-20 years. If the suppliers were to switch from residual oil to 100 percent natural gas in these units, suppliers could reduce CO_2 emissions by 0.6-1.2 million tons/year. Delivered fuel cost differentials between the fuel types is the dominant switching cost. Based upon EVA's delivered fuel cost forecasts (Appendix A), most Northeastern oil switching reductions would cost between $15-20/ton CO_2 reduced. The loss of the residual oil generation would further weaken the industry's ability to cap natural gas costs through threatened demand losses from fuel switching.

- *Co-fire biomass in existing coal-fired boilers*—Most regulators and control program rules consider biomass as a fuel offering no net carbon emissions since biomass absorbs the same amount of carbon dioxide during its growing cycle as it emits when it is burned. Under these rules, biomass can gain full credit for the full carbon content of any coal it displaces when it is co-fired in existing coal-fired boilers. This full carbon credit can make it an attractive control option versus other fuel switching/dispatching options[4]. Since suppliers have only a small capital investment for additional fuel handling equipment to become capable of co-firing up to 10 percent biomass with coal[5], the difference in delivered coal and biomass fuel costs is the dominant compliance cost component.

Another major cost element is the market price effect from higher biomass demand. In New York, newly created biomass demand could push supply costs higher by \$0.30-0.50/MMBtu. In the Mid Atlantic area, biomass costs could increase by nearly \$1.00/MMBtu. These supply cost increases would be passed onto existing customers and raise their production costs higher. Even if biomass were expanded to reach DOE's Northeastern maximum resource potential (415 trillion Btu/yr), co-firing biomass in remaining Northeastern coal-fired boilers would reduce CO2 emissions by only 3-5 million tons/year at a cost ranging between \$28-36/ton CO2 removed. To support this incremental biomass generation would require 600-1,200 square miles more dedicated land to grow the needed biomass energy crops.

- *Expand wind capacity and generation*—Wind power offers a zero CO2 emitting generation alternative that can displace limited amounts of coal and gas fired fossil fuel capacity. However, only limited areas within the Northeast have sufficient wind conditions to support wind farm projects. The maximum wind capacity potential in the Northeast[6] has been estimated to be 20,629 MW, of which over 1,000 MW will be built by 2013 in response to existing Northeastern State renewable portfolio standards, regional green pricing programs and state public benefit subsidy funding. **If this maximum wind capacity were built, the wind capacity could lower CO2 emissions by only 30 million tons per year.** The cost of expanding wind capacity to its maximum capacity level is heavily dependent upon the future of the wind production tax credit (slated to expire at the end of this year) and the potential capacity factor for incremental wind projects placed in poorer wind resource areas. If the production tax credit is extended, **compliance costs from expanding wind generation to displace fossil fuel generation would cost \$28-32/ton CO2 removed**. If the production tax incentive is not extended, the wind capacity expansion cost would increase to over \$60/ton CO2 removed and this alternative would become clearly uneconomic.



Source: National Renewable Energy Laboratory

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[4] Without full biomass reduction credit, biomass emissions would count against the carbon emission target. Under these conditions, the biomass carbon reduction potential would be reduced by 70 percent and the carbon reduction cost would triple and it would no longer be a cost-effective CO2 reduction option.

[5] Higher biomass blends are often not used due to biomass resource constraints limitations and the higher cost of boiler modifications. Since a 10% biomass co-firing in existing coal boilers exceeds the EIA biomass supply contained in DOE's National Energy Model, this study has not evaluated higher biomass blends.

[6] Outside New York, wind resources were estimated from *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, Pacific Northwest Laboratory, 1991. New York wind resources were estimated from NYSERDA study.

Overall, if a regional CO2 reduction program were developed, wind tax incentives were extended, and transmission lines were upgraded to handle the variable wind capacity output, an estimated 14-15 GW of additional new wind capacity could be built. This new capacity would cover over 900 square miles of area in the Appalachian Mountain ranges and along the shorelines.

- *Displace coal-fired generation with existing natural gas combined cycle generation*—Another CO2 reduction option would be to displace coal fired generation with power from natural gas combined cycle units. The first increment of these coal displacement reductions could come from environmentally dispatching existing generating units. By placing the combined cycle capacity earlier in the economic dispatch, suppliers could shift roughly 50 TWh of Northeastern fossil fuel generation from coal to natural gas. Roughly 75 percent of this shift would occur in the Mid-Atlantic states. This shift could potentially lower regional CO2 emissions by 25-27 million tons/year. The cost for these reductions would range from $26-31/ton of CO2 in New York to $34-43/ton in the Mid-Atlantic states.

  The second increment would be to build new gas combined cycle plants to displace and retire existing coal-fired power powerplants. This option could reduce powerplant emissions by an additional 120 million tons of carbon dioxide per year. However, because of the large capital investment required, these reductions would cost between $48-55/ton of CO2 and would likely not be implemented since more competitive options exist.

- *Build new nuclear capacity*- Even after maximizing wind and biomass generation and after displacing 50TWh of coal capacity through environmental dispatching, regional power suppliers would still require more emission reductions to achieve emission cap limitations. The next cheapest increment of CO2 reductions would come from building additional nuclear powerplant capacity. This option is highly controversial and extremely difficult to permit. However, compliance costs for the nuclear option range from $35-43/ton CO2 removed, far less expensive than the cost of remaining options such as building additional new gas combined cycle capacity to back out additional remaining coal capacity (@$48-55/ton CO2 removed)

  Nuclear power would back-out a mix of coal and natural gas generation. **To achieve a 25% reduction below 1990 emissions cap, the region would need to build 11,800 MW of nuclear capacity by 2013—a 53 percent increase over the region's existing nuclear capacity. To maintain this emissions cap, the industry would need to add an additional 1,550 MW of new nuclear capacity each year.**

  If the emissions cap were set at 1990 levels, the region would need to build less new nuclear capacity. The region would need to start adding new nuclear capacity in 2017. To maintain this emission level, the region would need to add an additional 1600 MW per year—an equivalent of two new nuclear units each year.

The regional impact from these compliance costs would be significant. First, these price increases likely would be passed onto ratepayers that already pay 33 percent more than the national average electric rate. Average retail power rate increases would range from \$5-7/MWh for the tighter limit (25 percent below 1990levels) and between \$1.50-4.40/MWh for the stabilization of emissions at 1990 levels. Industries dependent upon electricity for a significant portion of their output would confront stiffer competitive challenges from firms in states with lower energy costs.

Second, fossil fuel markets would be adversely impacted. Coal generation market share would decrease to 15 percent, with more than 40 percent of the regional coal demand lost under the stricter emission cap limit. These market impacts would result from switching to natural gas combined cycle, nuclear, biomass and wind power. Coal losses from returning to 1990 levels would be less, but could still reach more than 30 million tons by 2025. The coal demand losses would trigger large job employment losses in Northern and Central Appalachia.

Natural gas demand would decrease as higher renewable generation and nuclear power would more than offset natural gas gains from coal and oil switching. Overall natural gas demand losses could reach 0.6-1.5 TCF/year.

Conclusions

Reducing Northeastern powerplant CO2 emissions to levels 25 percent below 1990 emissions would require a significant shift in generation mix and trigger large electric rate increases of roughly \$5-7/MWh. To reduce emissions, the power industry would need to virtually eliminate use of residual oil. This would reduce fuel diversity and make the industry more vulnerable to natural gas price volatility.

Renewable energy resources would be pushed to their limits as suppliers maximized their use of biomass and wind power. Roughly 600-1,200 square miles of land (beyond the 7,000-9,000 square miles already being required to meet future basecase biomass crop demand) would need to be dedicated to growing biomass energy crops. Wind capacity would also need to increase by 14-15 GW above basecase levels (1,013 MW) by 2013. These wind farms would need to be constructed on an additional 900-925 square miles of land along the Appalachian Mountains and offshore the Eastern seaboard.

Outside the rapid expansion of renewable energy, the economic dispatch of electric utility units would need to be altered to place combined cycle units ahead of coal units in the regional dispatch in order to further reduce CO2 emission. Roughly 50 TWh of coal generation would be displaced.

Even with all of the above actions, additional emission reductions would be required to reach a 25% below 1990 emission reduction target. The final reductions would require building additional nuclear powerplants. By 2013, the Northeast would need to expand its existing nuclear capacity by 11,800 MW—a 53 percent increase over the region's existing nuclear capacity. To remain under the emissions cap, the industry would need to add 1,550 MW each year to help meet the growing electricity needs.

All these efforts would cost $3.7 billion in higher production costs in the first compliance year (2013) and continue growing as electricity demand grows. By 2025, compliance costs would reach $6.3 billion/year.

The increased electricity costs would likely have significant region economic impacts that are outside the scope of this project. Coal demand losses could reach 30-40 million tons/year under the stricter CO2 emission cap and would trigger job losses in the coal mining and supporting industries. Higher electric power rates would likely slow state economic growth. With Northeast power rates are already among the highest in the nation, the CO2 related power price increases would likely push future manufacturing growth into areas with lower energy costs.

Major Assumptions:

Most assumptions that significantly impact the study results have been addressed earlier in this report. These major assumptions included (1) no carbon credits for carbon sinks or purchased carbon credits, (2) no increase in existing import transmission capacity, (3) no incremental emissions assumed for biomass burning (consistent with US DOE assumptions), and (4) Northeastern wind capacity resources limited to 20,629 MW. However, additional input assumptions were also made to estimate alternative Northeastern carbon reduction scenarios but have a lesser affect on study conclusions. These include: (1) baseline electricity forecast and generation mix, (2) generation technology costs, (3) fuel cost, and (4) biomass supply limitations and cost. These additional assumptions are discussed below.

Baseline regional electricity demand and generation mix: The baseline regional electricity demand, generation mix and fuel burn for the Northeastern states was extracted from EVA's *Long Term Outlook-2003 Volume 2* (August 2003). The projections for Northeastern generation and capacity are shown in the Appendix. These projections incorporate state specific assumptions on economic growth, delivered fuel prices, and retail electricity prices. In addition, these projections incorporate EVA's outlook on future environmental regulations and technology cost. In comparison to DOE's *Annual Energy Outlook-2003*, this forecast projects a higher national electricity growth (1.96%/yr vs 1.80%/yr), with more natural gas combined cycle and nuclear power generation and less coal and renewable power generation. As is shown in the Appendix, the projected Northeastern growth rate of 1.72%/year is far below the national average. Some input assumptions are discussed below.

Under the two scenarios, retail electricity prices would rise from \$5-7/MWh under the tighter carbon cap (25% below 1990 levels) and by \$1.50-\$4.40/MWh under the lesser case of returning to 1990 carbon levels. These price increases should lower power demand in some power intensive industries that would shift some projected manufacturing growth into areas outside the Northeast with lower energy costs. Higher electricity prices may also make some energy conservation measures more economic further reducing future electricity demand growth. The demand losses from these price elasticity effects were not evaluated in this analysis. The baseline power demand load was not changed.

New Generation Technology Cost: New generation technology costs are shown in Exhibit 7. These assumptions are in line with most assumptions contained in the DOE's *Annual Energy Outlook-2003* and New York State Public Service Commission's *New York Renewable Portfolio Standard Cost Study Report* (July 2003). The largest difference is the capital cost assumption for new wind capacity. EVA assumes the Northeastern wind capacity capital costs of \$1,128/kW versus \$948/kW in the July 2003 New York report. The largest difference between the two estimates is the assumed capital cost for connecting wind farms into the transmission system.

Exhibit 7

Major Technology & Fuel Assumptions

Economic Assumptions

Debt to Equity Ratio	60%
Debt Cost	9%
Return on Equity	15%
Inflation	2.5%

Technology	Capital	O& M Costs Fixed	Variable-Non Fuel	CF%	
	$/kW	$/kW-Yr	$/MWh		
Nuclear	$ 2,500	$ 67.15	$ 0.43	92%	
Wind	$ 1,128	$ 26.10	$ (18.00)	30%	Assumes PTC extension
Dedicated Biomass	$ 1,870	$ 28.60	$ 7.25	70%	Assumes closed biomass credit
Co-Fire Biomass	$ 20	Same as coal		80%	Assumes 10% co-fire
New Gas CC	$ 500	$ 30.83	$ 1.23	75%	Includes allowance cost
Coal	$ 1,050	$ 27.45	$ 4.95	80%	Includes allowance cost

Delivered Northeastern Powerplant Fuel Cost

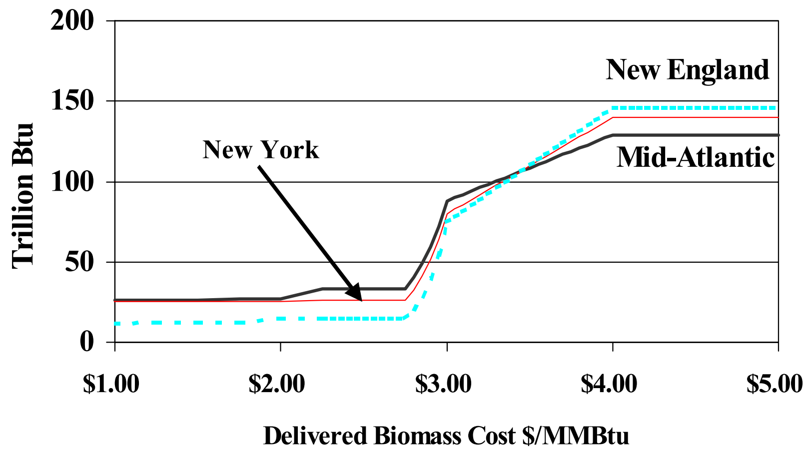
Year		Delivered Natural Gas Prices			Avg Delivered Coal Prices			Avg Delivered Biomass Costs		
	Henry Hub	New York	New England	Mid Atlantic	New York	New England	Mid Atlantic	New York	New England	Mid Atlantic
	$/MCF	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2005	$ 4.60	$ 5.35	$ 5.67	$ 5.51						
2010	$ 3.30	$ 4.00	$ 4.26	$ 4.10	$ 1.32	$ 1.46	$ 1.30	$ 2.90	$ 5.00	$ 3.00
2015	$ 3.46	$ 4.22	$ 4.49	$ 4.33	$ 1.35	$ 1.49	$ 1.33	$ 3.40	$ 5.00	$ 3.20
2020	$ 3.59	$ 4.46	$ 4.73	$ 4.57	$ 1.39	$ 1.52	$ 1.36	$ 3.50	$ 5.00	$ 3.55
2025	$ 3.68	$ 4.66	$ 4.94	$ 4.78	$ 1.40	$ 1.53	$ 1.38	$ 3.55	$ 5.00	$ 3.90

Year	Delivered Oil Prices		
	New York	New England	Mid Atlantic
	$/MMBtu	$/MMBtu	$/MMBtu
2005	$ 3.38	$ 3.66	$ 3.29
2010	$ 3.30	$ 3.41	$ 3.21
2015	$ 3.26	$ 3.38	$ 3.17
2020	$ 3.40	$ 3.52	$ 3.31
2025	$ 3.57	$ 3.70	$ 3.48

Fuel Cost: The delivered fuel cost assumptions for natural gas, coal, oil and biomass are also contained in Exhibit 7 above. These forecasts are taken from EVA's *Long Term Outlook-2003 Volume 2* (August 2003) and DOE's biomass supply model (see below).

Biomass Supply Limitations and Cost: As a result of renewable energy portfolio requirements in seven Northeastern states, public benefit funding subsidies for new renewable capacity and green pricing programs, Northeastern biomass generation is expected to expand from 20 TWh (2002) to 42 TWh by 2025 without any regional CO2 control program. This expansion will place large demand pressures on a limited biomass supply that will likely trigger significant biomass price increases. More than 9,100 square miles of land would be required to be dedicated to these biomass energy crops to just meet this baseline demand.

Exhibit 8
Northeastern Biomass Supply Costs



Source: DOE National Energy Model Biomass Supply Curves

To estimate the delivered biomass prices and biomass resource constraints, the biomass supply cost curves from the DOE National Energy Model were used. These supply curves for the Northeastern states are shown in Exhibit 8. As is shown, the DOE model shows that Northeastern biomass resources are limited to 415 TBtu. This resource limitation reduces the amount that biomass production can be expanded under the carbon dioxide cap limitations.

Appendices

APPENDIX A
Northeastern Generation Mix-Baseline and CO2 Cap Scenarios

APPENDIX B
Study Scenario Results—
Powerplant Cap Set at 25% Reduction from 1990 Levels-212 Million Tons CO2/Year

APPENDIX C
Study Scenario Results—
Return to 1990 Powerplant Emission Levels- 283 Million Tons CO2/Year