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Resource and Environmental Strategies

An Approach for Better Aligning the Nation's Clean Air and Clean Energy Goals

Final Report

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1. Objectives and Summary Findings

The combustion of fossil fuel for electricity production in the US is a major source of sulfur oxides, nitrogen oxides, carbon dioxide, mercury, and hazardous air pollutant emissions in the United States. Various technical means are available to reduce these emissions, including diffusion of more energy-efficient technologies in building and industrial electricity use, emissions control equipment on power plants, greater use of renewable energy resources, and switching to "cleaner" fossil fuels, each affecting the various pollutants in different ways and degrees. Similarly, there are a number of policy approaches, including standards, incentive systems and combinations of standards and incentive systems, which would induce adoption of these technical means. Renewable energy resources and associated electricity generating technologies could play a vital role in reducing these pollutant emissions and thereby helping meet the nation's air quality goals. Policies to spur increased investment in renewable electricity generation can offer a host of public benefits including economic development and energy security, as well as improved public health and environmental quality owing to air pollution reductions. Renewable energy technologies could also play an essential role in reducing greenhouse gas emissions, which contribute to climate change.

Congress has attempted to formally recognize these benefits by creating the Conservation and Renewable Energy Reserve (CRER) in the 1990 Clean Air Act Amendments, which set aside a portion of the national SO_2 allowance budget for renewable energy and energy efficiency. However, the CRER was severely underutilized, and has expired (with only 10% of the 300,000 allowances awarded). The current law did not anticipate the move to restructuring in the electric sector, restricted participation to vertically integrated utilities, and thus discouraged direct participation in emission trading by developers of renewables and energy efficiency service providers. Congress could correct this situation by making several changes in the current law.

This study considers modifications to CAA that would increase the number of emission allowances allocated to renewable energy generation to enable renewables to compete fairly in emission trading and clean air compliance markets, and estimates the economic and environmental benefits of these changes. This analysis provides better understanding of the benefits that would derive from a renewables role in CAA compliance regimes. The estimated impacts of these CAA modifications are compared with those of other policies, including national renewable portfolio standards (RPS), a tighter cap for sulfur dioxide (SO_2) emissions and trading, modifications to the State Implementation Plans (SIP) for (nitrogen oxides (NOx) trading), multi-pollutant cap/trade and a combination of multi-pollutant cap/trade and RPS.

The quantitative analysis for this study is based on output from Tellus-NEMS, a revised version of the National Energy Modeling System (NEMS). Tellus uses the version of NEMS that was used to create the Annual Energy Outlook 2002 (Energy Information Administration, 2001) with some adjustments.[1]

[1] Review by various experts – from National Renewable Energy Laboratories, Union of Concerned Scientists, Oakridge National Laboratories, Lawrence Berkeley Laboratories, Michael Brower and Associates and Princeton Economic Research Institute – noted that several of the parameters used in NEMS to characterize the availability and cost of renewable energy resources are overly conservative. Based on these inputs, Tellus worked with NREL to determine and apply a revised set of parameters, described in Appendix A.

Broadly, we find that:

- Increasing the number of emission allowances allocated to renewables through the set-aside policies of Title IV of the Clean Air Act could induce some increases in renewable generation, along with small GHG and mercury reductions, and no changes in SO_2 and NO_x emissions. However, this approach would achieve minimal emission reductions, little renewable energy generation increases unless the number of allowances allocated per gigawatt hour of generation is prohibitively high. A tighter SO_2 cap alone will reduce SO_2 and mercury emissions but will have little effect on renewables, carbon and NO_x. Combining a tighter SO_2 cap with increased renewables set asides helps somewhat, but is inherently limited owing to the limited number of allowances that can realistically be set aside for renewables. Adding renewable set-asides to the existing NO_x cap system has the same limitations as increasing the renewable set-asides for the SO_2 system plus is more limited in scope since the existing NOx cap system only exists in 19 states and operates only 5 months of the year. Thus, while attractive owing to its limited departure from existing legislation, these modest policy approaches do not offer large clean air and clean energy impacts.

- A national RPS is a more direct way to meet clean energy goals and achieve some associated clean air benefits. A national RPS is not constrained by limitations inherent in the emission allowance allocation system, and could thus be designed to lead to far greater increases in renewables and greater reductions in carbon emissions. Nonetheless, the RPS is, at least contingently, limited so long as natural gas combined cycle plants dominate the national capacity expansion as expected with current technology costs and fuel price projections. The RPS alone will tend to displace mostly gas generation, which is far less carbon and mercury intensive than coal generation, although it will tend to induce natural gas demand reductions and reap large economy-wide benefits from natural gas price decreases. Moreover, the RPS by itself will not help to reduce SO_2 and NO_x emissions in regions with caps on these pollutants.

- Multi-pollutant cap and trade policies are the most direct way to achieve clean air goals. However, since much of the emission reductions can be achieved through control equipment or fossil fuel switching, by itself this approach provides only minimal encouragement for renewable energy. Indeed, to the degree that the caps are met by shifts to natural gas, demand for this fuel will likely rise, which could put pressure on its availability, price and price stability.

- Combining multi-pollutant cap and trade policies with a national RPS achieves the clean air and clean energy objectives. Its two key design components – emissions reductions and renewables development -- complement and reinforce one another, while achieving fuel diversity and moderating potential stresses on natural gas supply and prices.

2. Business as usual

Several types of program currently exist to promote renewable energy; federal programs include provisions in the Clean Air Act, and various programs exist in the states – including awareness programs, financial incentives and renewable portfolio standards.

Production Tax Credit (PTC) – The PTC provides a financial benefit of 1.5 cents per kWh (adjusted annually for inflation) for wind and closed-loop biomass sources.[2] The PTC, which began in 1999 has been extended to December 31, 2003 (H.R. 3090, approved by both the House and Senate) – plants built before this date qualify for the credit for the first 10 years of their operation.

Clean Air Act (CAA) – Phase II of Title IV of the 1990 CAA Amendments establishes a cap and trade program for SO_2 emissions from units with 25 MW or greater electricity output. Nationally, total electric sector SO_2 emissions are capped at 8.9 million tons, beginning in January 1, 2000, with allowances under this cap allocated to existing coal and oil fired plants based on an emissions rate of 1.2 SO_2 lbs/MMBTU and the plant's 1985-1987 average heat input. Affected units are required to acquire (through direct allocation from EPS, from auction, or purchases from other entities) and retire a number of allowances equal to their annual SO_2 emissions (in tons). Allowances may be traded among plants so that plants with more allowances than emissions can sell excess allowances to plants that exceed their initial allocation of allowances. The Environmental Protection Agency, which administers this program, withholds 2.8% of the allowances each year. These allowances can be purchased by new sources or by existing units that require additional allowances through an auction. This policy design alone theoretically benefits renewable generation sources since they have clean air compliance obligations and do not need to hold or retire any SO_2 allowances. However, the cost to fossil fuel generators of reducing SO_2 (and the subsequent cost of SO_2 allowances) has been lower than the incremental cost of renewables over conventional generation. Thus, there has been little stimulation of renewables by Title IV.

The Clean Air Act (CAA) amendments of 1990 attempted to encourage more directly encourage renewable energy and energy efficiency through the Conservation and Renewable Energy Reserve (CRER). The CRER consists of a total of 300,000 SO_2 allowances that have been set aside for renewable energy and energy efficiency projects implemented between 1992 and 1999. The CRER allowances were obtained by removing a portion of the allowance withheld for allocation and auctioning to fossil fuel generations, equal to 0.3% per year from 2000 to 2010. Renewable energy sources are guaranteed 60,000 allowances through this program. Utilities[3] that qualify for these allowances are awarded 1 allowance for every 500 MWh of electricity saved through energy efficiency or generated by renewable energy. These allowances can be used by the utilities for compliance with their obligations under the SO_2 cap (and thus avoid having to purchase allowances or emission control retrofits) or sold on the market to other fossil generators.

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[2] Closed-loop biomass: Plant matter that is grown for the sole purpose of being used to generate electricity. Due to the cost of developing a closed-loop facility to generate electricity, this tax credit has not been used to date.

[3] Only utilities can qualify for SO_2 allowances under the CRER. This has been a major criticism of the policy.

This method of allocating allowances to renewables theoretically creates a new stream of revenue for renewable energy generators who could sell the allowances to fossil generators that need them for CAA compliance purposes or to support sales of "green power" to consumers willing to pay a premium for electricity generated by emission free technologies. The financial benefit to renewables depends on the trading price of the allowances. Note that the CRER program does not reduce emissions relative to a cap-and-trade system without set-asides. The renewable generators only gain the financial incentive by selling the allowances to fossil generators in the market. Thus, the net result is more renewable generation in the mix but fossil fuel plants can still purchase the allowances from renewable generators rather than switching to low-sulfur coal or installing scrubbers. Unfortunately, the policy was a failure in practice. For a number of reasons, few allowances were allocated to renewable generators and the program expired, for all practical purposes in 2000.

NOx SIP call – In March 2000, the D.C. Circuit upheld EPA rules to limit NO_x emissions from electric power generators in the Northeastern and midwestern states, for the purpose of achieving he national ambient air quality standard for ozone. The NO_x SIP (State Implementation Plan) call is summer season a cap and trade program for NO_x emissions that has been implemented in 19 States. Similar to the SO_2 cap and trade program, this program sets caps on NO_x emissions in the summer (May to September) for each state. The EPA administers the program but it allows each state to choose its method of allocating emission allowances among existing and new sources. Wind, solar and hydro generators theoretically gain because they do not have clean air compliance obligations and are not required to hold or retire allowances, but the effect is minor give the differential between renewable energy generation costs and competing fossil generation and fossil emission control options. EPA has encouraged but not required states to adopt set-aside programs for energy efficiency and distributed renewable energy sources. The set-aside programs would be similar to the CRER, with a portion of the allowances reserved for awarding to qualified sources based on the amount of electricity saved or generated. The program will start in 2004 with the states listed in Table 1.

Currently, only a few states (Massachusetts, New Hampshire, Indiana, Maryland, New Jersey, and New York) have adopted NO_x allowance set-asides for renewables in their NO_x control programs.

Table 1 SIP call, States with NO_x emission caps

State	
Alabama	New Jersey
Connecticut	New York
Delaware	North Carolina
District of Columbia	Ohio
Illinois	Pennsylvania
Indiana	Rhode Island
Kentucky	South Carolina
Maryland	Tennessee
Massachusetts	Virginia
Michigan	West Virginia

Renewable Portfolio Standards (RPS) – An RPS is a flexible, market-oriented policy for accelerating the introduction of renewable resources and technologies into the electric sector. A national RPS would set a schedule for the acquisition of a certain percentage of renewable energy as a fraction of each retail electricity provider's total annual energy sales. Each retail electricity supplier must meet the requirement either by producing that amount of renewable electricity in its own mix or by purchasing tradeable renewable credits (or "certificates") from renewable energy generators. The RPS program design and resulting market would determine the portfolio of technologies and geographic distribution of facilities that meet the target at least net cost – the difference between the cost of renewable generation and that of the fossil generation that it avoids. This is achieved by a trading system that awards credits to generators for producing renewable electricity and allows them to sell or purchase these credits.

The RPS provides strong incentives for suppliers to design the lowest cost, most reliable renewable electricity projects, and to identify those applications for which the projects will have the greatest value for utility consumers or shareholders. It also provides assurance and stability to renewable technology vendors, by guaranteeing markets for renewable power, allowing them to capture the financial and administrative advantages that come with planning in a more stable market environment. Yet it still maintains a competitive environment that encourages developers to innovate.

The following states have an operational RPS, established by regulation or legislation.

- Arizona
- Connecticut
- Iowa
- Maine
- Massachusetts
- Minnesota
- Nevada
- New Jersey
- New Mexico
- Pennsylvania
- Texas
- Wisconsin

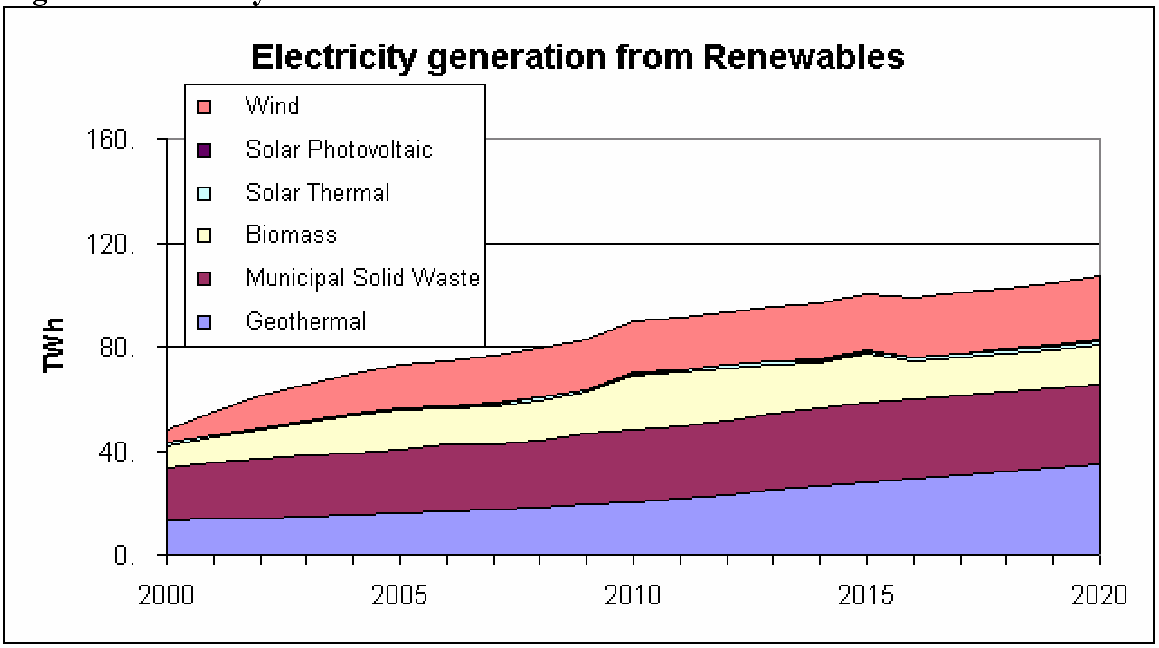
California is currently developing rules to implement a legislatively created RPS, though the future potential effect of the legislation is unclear due to limitations in the program structure. New York is currently developing an RPS through administrative action of the state Public Service Commission. Connecticut and Maine have RPS legislation that has proved to be dysfunctional. National RPS legislation has been proposed by several bills in Congress. The proposed Renewable Energy and Energy Efficiency Act of 2001 (S. 1333) included a national RPS that reaches 20% by 2020. In 2002 Senate passed a national RPS starting at 1% in 2005 and increasing to 10% by 2020 in the recent Senate Energy Bill (S. 517). However, currently a national RPS policy does not exist.

Results of the policies

The Energy Information Administration (EIA) projects low growth in renewable energy generation through 2020. The following chart indicates renewable generation in the Reference Case of the Annual Energy Outlook 2002. Although electricity generation from non-hydro renewable sources increases by 75% from 2002 to 2020 (increasing from 61 TWh to 107 TWh), the generation from these sources only accounts for 2.1% of total national annual generation by 2020. Growth in coal generation is 25% while natural gas generation grows by 186%.

According the EIA, about 75% of the growth in renewable capacity is due to state mandates (EIA 2001).

Figure 1 Electricity Generation from Renewables in AEO2002 Reference Case



(Source: detailed output tables from AEO2002)

3. Alternative Policy Approaches

The structure of the Clean Air Act has evolved, since its initial enactment in 1970, to incorporate a combination of market mechanisms and emission control standards to reduce pollutant emissions. The CRER was included as a provision in the Title IV of the 1990 CAAA as a way of encouraging SO_2 reductions prior to 2000 when the full scale SO_2 trading started. However, due to several factors – including restricted acquisition of allowances from the Reserve and changes within electricity industry – the CRER never became a strong incentive system for renewable energy investment. The CRER has now expired, although projects installed between 1992 and 1999 can still apply, with only 12% of the allowances used (by June 2000). Only about 6,700 of the allowances were obtained by renewable energy sources (Wooley 2000).

Several policy approaches have been developed to better integrate renewable energy with the emission control objectives of the Clean Air Act. This study has analyzed adjustments to the 1990 Clean Air Act Amendments that would: (1) strengthen its renewable energy set-aside option; (2) progressively tighten its SO_2 cap; or 3) combine strengthened renewable set-asides with tighter SO_2 caps. We have chosen to focus initially on adjustments to existing legislation, which avoids the effort to take wholly new legislative action in a controversial area. These adjustments to SO_2 control policies could simultaneously help to modestly reduce emissions of other pollutants (particularly mercury and CO_2).

For comparison, this study has also analyzed four other policies aimed at achieving clean energy and/or clean air, (1) establish renewable energy set-asides in the cap-and-trade programs for

NO_x, (2) adopt a national Renewable Portfolio Standard (RPS), (3) enact a multipollutant cap and trade program for SO_2, NO_x, Mercury and CO_2, and (4) adopt a mulipollutant cap and trade system in combination with an RPS. The policies are compared in terms of emissions reductions, incremental renewable energy generation and total resource costs.

Strengthened Renewable Energy set-asides in the CAAA

The CAA Amendments of 1990 created a Conservation and Renewable Energy Reserve set-aside of 60,000 allowances to promote renewable energy. Renewable energy generators can qualify for one allowance (1 ton SO_2) for every 500 MWh of electricity. Based on 10,000 Btu of energy for 1 kWh of electricity, the allowance allocation is equivalent to 0.4 lbs of SO_2 per MMBtu. For comparison, average emission rates for existing coal plants has been estimated to range from 1.2 lbs/ MMBTU (Phase II plants) to 2.5 lbs/MMBTU (Wooley, Morss and Fang 2000). The New Source Performance Standard for coal is 0.3 to 0.4 lb/MMBtu.

However estimates of avoided emissions might not be most appropriate values to determine the number of set-aside allowances. In any SO_2 cap and trade program, the renewable sources theoretically benefit from the emissions that they avoid since they do not require the SO_2 allowances that the avoided fossil plants would have needed. If the avoided emissions are high then the fossil generators are penalized by high emission costs and renewable generators gain. This relationship is captured with the cap and trade programs without any set-asides, but only if the cost of renewables is less than the cost of emission control technology or alternative fossil generation. To date that has not been the case, and the system has not materially benefited renewable generation

The use of set asides has similarly failed to stimulate renewable generation for several reasons. First the structure of the program effectively precluded non-utility generator participation and put conditions on utility renewable generators that were unrealistic. Second, the Act's methodology allocated emission allowances using estimates of emissions avoided by renewable generation. The allocation metric chosen underestimated the emission reduction value of renewables. Moreover, the approach was not the most appropriate way to value the benefit of renewable energy.

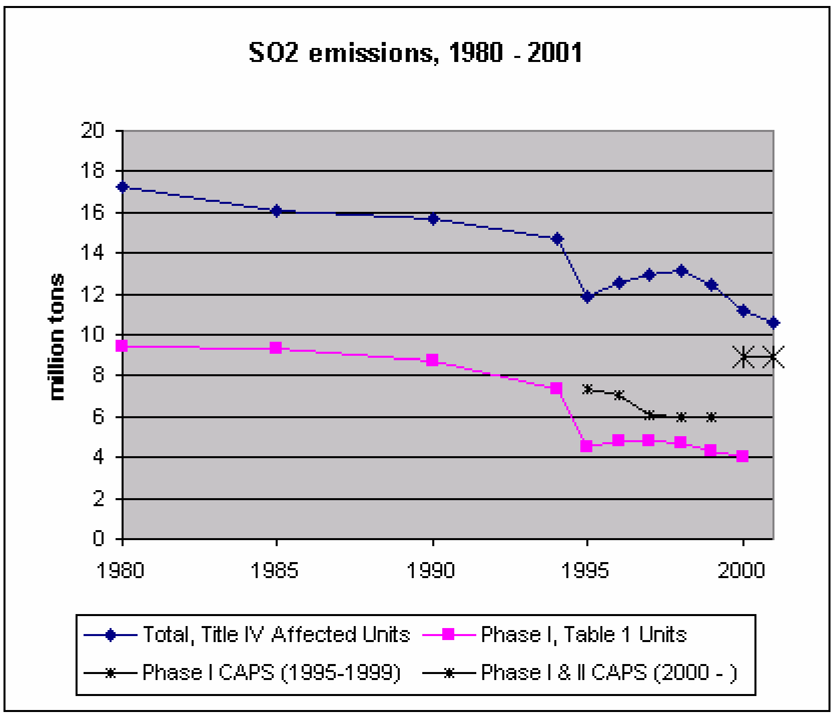
The set-aside mechanisms should acknowledge additional benefits provided by renewables or energy efficiency, that differ from the benefits of reducing SO_2 emissions through low-sulfur coal, installing scrubbers or switching to natural gas. These benefits could encompass several co-benefits: a) reduction of other emissions including carbon dioxide; b) increased diversification of electricity system; c) lower reliance on fossil fuels such as natural gas, and thus mitigation of price volatility; and d) use of local resources and enhancement of local expertise in new, high growth industry (renewable energy). The value of these co-benefits could be far greater than the value of SO_2 emission allowances based on solely on estimates of avoided SO_2 emissions. This analysis considers the impacts of legislative action that increases the number of CRER allowances allocated to renewable generation in order to capture some of these additional benefits.

Tightening the SO_2 caps

As an alternative policy, we analyzed the effects of progressively tighter SO_2 caps in the Title IV cap/trade system. Heretofore, as shown in Figure 2, Title IV affected power plants have demonstrated an ability to reduce their aggregate SO_2 emissions by an average of 2.5% per year for the period 1980 to 1995, including rapid 5.5% per year decrease between 1990 and 1995. In 1995, Phase 1 designated plants[4] were required to comply with the Acid Rain Program. From 1995 to 1998, SO_2 emissions from all plants increased by about 2.6% per year then decreased by 5.2% from 1998 to 1999. In 2000, when Phase II units were required to comply with the Acid Rain Program, total SO_2 emissions decreased by 10% from 1999 levels. Preliminary data for 2001 indicate emissions fell a further 5.4% to 10.6 million tons (emissions for Phase I units were not available). (USEPA 2002. *2000 Emissions Scorecard.*) From website, http://www.epa.gov/airmarkt/emissions/score00/text00.pdf)

While the above results indicate the ability of plants to decrease emissions, especially in anticipation of or because of emissions caps, the Clean Air Act keeps the cap of SO_2 emissions constant after 2000. The downward pressure of a declining cap could create additional incentives for clean sources of electricity because the pool of available SO_2 emission allowances will steadily shrink. We applied caps that decline annually to consider the impacts on encouraging cleaner sources.

Figure 2 SO_2 emissions from Title IV Affected Units



Source: USEPA 2000, Emissions Scorecard and National Air Pollutant Emission Trends 1900-1998

[4] 263 units were required to participate in Phase 1 of the Acid Rain Program. Phase II units, virtually all units above 25 MW, are not required to comply until 2000; emissions for these units increased each year from 1996 to 1998 then decreased in 1999 and decreased strongly in 2000.

Renewable set-asides in the NOx cap-and-trade program

For comparison, we also analyzed policies with renewables set-asides in the NOx cap-and-trade program. Following the same principles as the CRER, NO_x allowances would be allocated to renewable electricity generators based on a pre-determined number of allowances per MWh. Renewable generators could gain financial incentives by selling the allowances in the market. We considered several cases, each with a different number of allowances allocated per MWh of renewable energy generation. We assumed that generators could sell into the regional market including all 19 states in the SIP call.

Applying a National Renewable Portfolio Standard (RPS)

As described in section 2, RPS programs specify a minimum level of electricity generation from renewable sources by requiring electricity suppliers to hold renewable energy credits equal to a specified fraction of total generation. Renewable energy credits are granted to generators of electricity from renewable sources and these credits can be held or sold to suppliers with insufficient generation of renewable electricity to meet the required level.

We analyzed the impacts of expanding the current state RPS programs to a national level RPS with different cases representing different requirements for the minimum level of renewables. Suppliers would be required to hold the minimum renewable energy credits but these credits can be bought and sold on a national market. The national RPS can work in conjunction with a state RPS that is specified at a different level but requires renewable energy credits from the state market.

Multipollutant Policy

Multipollutant policies seek to achieve co-control synergies (in technology choice and cost of control) and avoid the problem where focus on controlling one pollutant increases emissions of other pollutants.

We analyzed a policy that used national emission caps for each of SO_2, NO_x, carbon and mercury. Generators would be required to hold allowances for their emissions but would be able to buy and sell allowances in a national market. Any existing regional or state regulations of these emissions would still be valid.

Multipollutant Policy combined with RPS

Combining a national RPS with a national multipollutant policy could achieve both multiple pollutant and clean energy co-control benefits. Several advantages of renewable energy will not be captured by individual generators – for example, reducing the capital costs of emerging technologies by increased installations (learning by doing), reducing natural gas prices by reducing overall demand for natural gas. This policy attempts to capture these societal benefits directly and to capture synergies between renewable energy and emission reductions.

We combined the multipollutant policy described above with one of the levels of RPS considered in the RPS cases.

Policy comparisons

The policies can be compared on several levels. For this study, comparisons included the extent to which pollutant emissions are reduced (cleaner air) and renewable generation is increased (cleaner energy), as well as the cost, fuel use and technology impacts:

- emissions reductions,
- renewable generation increases,
- economy-wide costs
- cost per ton of emission reductions and cost per megawatt hour increase in renewable generation.

4. Analytical Approach

The quantitative analysis for this study is based on output from Tellus-NEMS, a revised version of the National Energy Modeling System (NEMS). NEMS was developed and is maintained by the US Department of Energy, Energy Information Administration (EIA). EIA uses NEMS to create 20-year projections of energy supply and demand for a Reference Case and for a variety of scenarios. Tellus uses the same version of NEMS as was used to create the Annual Energy Outlook 2002 ("AEO2002"), with some adjustments. Review by various experts – from National Renewable Energy Laboratories, Union of Concerned Scientists, Oakridge National Laboratories, Lawrence Berkeley Laboratories, Michael Brower and Associates and Princeton Economic Research Institute – noted that several of the parameters used to characterize the availability and cost of renewable energy resources in NEMS are overly conservative. Based on these judgments, Tellus worked with NREL to develop a revised set of parameters, described in Appendix A (Renewable Energy Characteristics in Tellus-NEMS).

Base Case – the Base Case scenario relies on the AEO2002 Reference Case, with the changes to renewable energy characteristics. As expected, the Base Case only shows minor changes from the AEO2002 Reference Case since, with no further constraints on emissions, or representation of external costs or incentives for renewables, renewable electricity does not become widely competitive with new fossil generation. The changes made to renewable energy parameters in the model are more likely to affect model results in scenarios that embody policies designed to achieve higher penetration of these generation resources. The Table 2 shows compares predicted electricity generation in the Base Case for 2020, with changes predicted to occur from theses modifications to the model. Note that only wind, which is already near competitive in certain regions of the country, does better with the modified NEMS.

Table 2 Electricity generation in 2020, national (TWh)

	AEO2002 Reference Case	Tellus-NEMS Base Case
Coal	2423	2416
Petroleum	38	36
Natural Gas	1414	1389
Nuclear	702	702
Conventional Hydropower	300	300
Geothermal	35	35
Municipal Solid Waste	31	31
Biomass	15	16
Solar Thermal	1	1
Solar Photovoltaic	1	1
Wind	**24**	**62**
Total	4984	4989

The analysis considers five sets of cases, each based on a different type of policy. The first set is based on the SO_2 cases defined by NREL, that is an expansion of renewable set-asides in the CAAA. The second set is based renewable set-asides through the NO_x SIP call. The third set considers the effect of a national renewable portfolio standard (RPS). The fourth set assesses the effects of a multi-pollutant cap/trade. The fifth set combines RPS with multi-pollutant cap/trade. The cases are summarized in Table 3

Table 3 Description of Cases

Scenario	Policy	Comments
Base case	None	Includes changes to renewable energy characteristics in NEMS based on discussion with various experts.
SO_2 cases	CAAA set-asides for renewables with enrichment levels (SO_2 credit cases)	modeled as a financial incentive. (\$7/MWh to \$34/MWh for renewable generation)
	Tightened SO_2 cap	Cap decreased by 3%/year and 5%/year
NO_x cases	NO_x SIP call set-asides for renewables	provides incentives for renewables only in the 19 NE states. (\$7/MWh to \$34/MWh for renewable generation)
RPS cases	Renewable portfolio standards	Renewable requirement matches results of SO_2 cases, extends incentive to biomass cofiring
Multipollutant case	National cap and trade levels set for SO_2, NO_x, carbon and mercury	Tightened SO_2 cap, extended NO_x cap to national annual requirement, added national carbon and mercury caps
Multipollutant plus RPS case	Multipollutant case as above plus national RPS	RPS levels match one of the RPS cases, 8.5% renewables in 2010 and 23.5% in 2020

***SO_2 Credit cases* -** To explore the relationship between the number of CRER allowances allocated per MWh of renewable generation and the level of electricity generation from renewables, we ran a series of cases in NE MS with different financial incentives provided to new renewable generation. These incentives represent the value that the renewable generators would gain from selling the SO_2 credits on the market. We set up seven cases with different financial incentives to mimic different numbers of allowances allocated per MWh. The financial incentives ranges from $1.4/MWh to $34/MWh (the values was held constant for all years of each case) and were provided to new geothermal, wind, solar (thermal and PV), biomass (dedicated plants) and landfill gas plants.

We also analyzed effects of tighter SO_2 caps in two cases; the first case decreases the cap by 3% per year starting in 2003 and the second case decreases the cap by 5% per year starting in 2003 and continuing to 2020. These cases excluded the financial incentives described above.

RPS cases – these cases were run to allow a direct comparison between the effect of increased SO_2 allowance allocation ("Credit cases") with the effect of RPS policies. To determine the renewable requirements for the RPS cases, we used the annual renewable generation from each of the SO_2 Credit cases as input for the renewable generation requirements for an RPS run. For example, we took the outcomes of the $7/MWh case to determine the percent of national electricity generation supplied by renewables in each year from 2003 to 2020. These annual levels were used as input for one RPS case – thus giving us a case that is directly comparable to a SO2 case in terms of renewable generation. The different RPS cases are identified by the SO_2 Credit case that was used to determine the level of renewables (e.g., the run in the example is identified as the $7/MWh RPS even though no financial incentives are applied). Qualifying renewables for the RPS are the same as in the SO_2 cases but with the addition of biomass co-firing in coal plants. Co-firing does not qualify for incentives under the current CAAA requirements for renewables.

NO_x *cases* – these cases are based on the same idea as SO_2 cases, with renewables gaining incentives by being awarded emission credits that can be sold into the emission credit market. The main difference between these cases and the SO_2 cases is that the current NO_x cap and trade market only covers 19 states in the northeastern U.S. rather than all states. For this set of cases, renewable plants must be located in one of the 19 states to qualify for the incentive.

Multipollutant case – Emissions targets are set for each pollutant and generators would be required to hold sufficient allowances to cover their emissions. The emission limits are shown in table 2. The SO_2 targets are the same as the 5% per year from 2003 to 2020; NO_x levels are annual, national emission limitation with the target decreasing 7% per year from 2003 to 2015; mercury emissions decrease 11% per year from 2003 to 2015, and carbon emissions decrease 3% per year from 2006 to 2015. The NO_x, carbon and mercury targets remain at 2015 levels from 2016 to 2020.

Table 4 Cap and Trade Emission Levels for Multipollutant Case

	mercury	NOx	SO2	carbon
		thousand	thousand	
units	tons	tons	tons	MMTCE
2003	38	4.03	9.01	
2005	30	3.48	8.13	636
2010	17	2.42	6.29	546
2015	9	1.69	4.87	469
2020	9	1.69	3.77	469
target in 2020 as % of 2001 levels	21%	39%	34%	79%

Multipollutant plus RPS case - For the case with multipollutant cap and trade policies combined with a national RPS, we used the above multipollutant targets plus RPS levels that match the \$34/MWh SO_2 case. These levels require national renewable generation to be 8.5% of electricity sales in 2010 and 21% in 2020.

5. Results from modeling

5.1 Highlights of Results

The results are summarized in the following table and described in greater detail below. The table compares the results of the different policy types to each other, showing impacts on Clean Energy (represented by the fraction of electricity generation supplied by renewables), Clean Air (by comparing the emission levels in the policy cases to the base case levels) and costs (by comparing the costs of the policy cases with the costs for the SO_2 Credit cases). The results below are generally qualitative with the detailed quantitative results following in the subsections below.

Table 5 Summary of results

	Renewables in 2020 (fraction of total generation)	Changes in Air Pollution emissions compared to base case emission levels	Costs
Base case	3%		
SO_2 Credit cases set-asides	6% to 22%	zero or small change (SO_2, NO_x) some carbon and mercury reductions (almost 20% carbon reduction in 2020 for \$34/MWh case)	Generally low cost (under 1 billion net present value for 2000-2020), net benefits in several cases.
Tightened SO_2 caps	4%	Large reduction in SO_2, some early reduction in carbon but small reduction by 2020	Total costs are higher than all but the \$34/MWh SO_2 Credit cases (but achieve greater SO_2 and mercury reductions)
NO_x cases	Less than SO_2 Credit cases 4% to 13%	Less reduction of SO_2, NO_x, carbon and mercury than in equivalent SO_2 Credit cases	Total costs are lower but cost/ MWh and cost/tonneC are higher, relative to equivalent SO_2 Credit cases
RPS cases	Similar to SO_2 Credit cases by design	Slightly larger carbon reductions than SO_2 Credit cases; other pollutants same as SO_2 cases	Total costs, cost/MWh and cost/tonneC are all lower than similar SO_2 Credit cases
Multipollutant case	12.5%	Strong emission reduction in SO_2, NO_x, carbon and mercury by policy design	Higher total cost and cost /MWh, cost/tonneC than any of the other cases but policy also achieves reductions in other emissions
Multipollutant plus RPS case	21%, by policy design	Same emission reductions as multipollutant case, by policy design	Lower total cost than multipollutant case

For all the cases, we report the same output from Tellus-NEMS. The outputs are defined in the box below.

Key to Results

Tables 1-3 and charts 1-3 provide basic output from Tellus-NEMS for each of the cases. The variables are defined below; the tables show results in 2010 and 2020 while the cost curves are for 2020, as described below.

Incremental electricity generation from renewables (TWh) – the increased renewable generation in each year is compared with estimated levels from the base case in that year. Renewables exclude conventional hydroelectricity but include landfill gas.

Emission reductions (million tons of carbon, SO_2, NO_x and mercury). These are the national reductions from the base case in that year by emission.

Resource Cost – the net costs (compared to the base case) of fuel, O&M, and capital for the electric sector (with capital costs for plants annualized over 20 year plant-life). Also included is the net change in fuel costs for the residential, commercial and industrial sectors – the policies tend to lead to reduced natural gas demand by the electric sector resulting in lowered natural gas prices for all sectors. Costs shown are the net present value (NPV) of the annual net costs from 2000 to the relevant year, using a 5% discount rate.

SO_2 allowance prices – Tellus-NEMS provides estimates of average annual SO_2 allowance prices. We report these prices based on a 5-year running average to smooth the large variations in this output variable.

Charts of Cost Curves

We also show the costs in charts. The costs (y-axis) are in $/tonne carbon or $/MWh of renewable generation where both costs and carbon reductions/renewable generation are expressed in NPV (2000 to 2020 using 5% discount rate). The x-axis is the carbon reduction/renewable generation in 2020. Each point represents a different case as indicated by the labels.

5.2 SO_2 Credit cases

Table 6 summarizes the results of the SO_2 Credit cases in terms of penetration of renewable electricity, emission reductions and total resource costs. Details on the mix of electricity generation for the cases are reported in Appendix B.

Electricity generation from renewables increases with increasing levels of financial incentives, as shown in Figure 2. Note that the change in the incremental amount of renewables is not linearly related to the change in the financial incentive. For example, considering the results in 2020, doubling the financial incentive from $7/MWh to $14/MWh results in almost a doubling of incremental renewables (92% increase). Doubling the incentive again from $14/MWh to $28/MWh results in a 75% increase of renewable electricity. However, increasing from $28/MWh to $34/MWh (only a 25% increase) leads to an 80% increase in renewable electricity. Renewables reach about 21 percent of national generation by 2020 at $34/MWh financial incentive. These asymmetries are linked to effects of decreased capital costs associated with increased capacity (learning by doing) countering increased costs associated with resource depletion.

Figure 4 shows the mix of renewable generation for the $28/MWh and $34/MWh cases. Wind generation plays a significant role in the $28/MWh case (38% of renewable generation in 2020) but contributes a lower fraction in the $34/MWh case (26% of renewable generation in 2020). Many of the best wind sites have been used in the $28/MWh case, leading to lower potential for additional wind generation in the $34/MWh case. Biomass generation is dominant in the $34/MWh case, where learning-by-doing leads to a 30% decrease in the capital cost of biomass plants, compared with the costs in the base case. Generation by type information is available for the other cases in Appendix B.

Figure 3 Total Renewable Generation for SO_2 credit cases

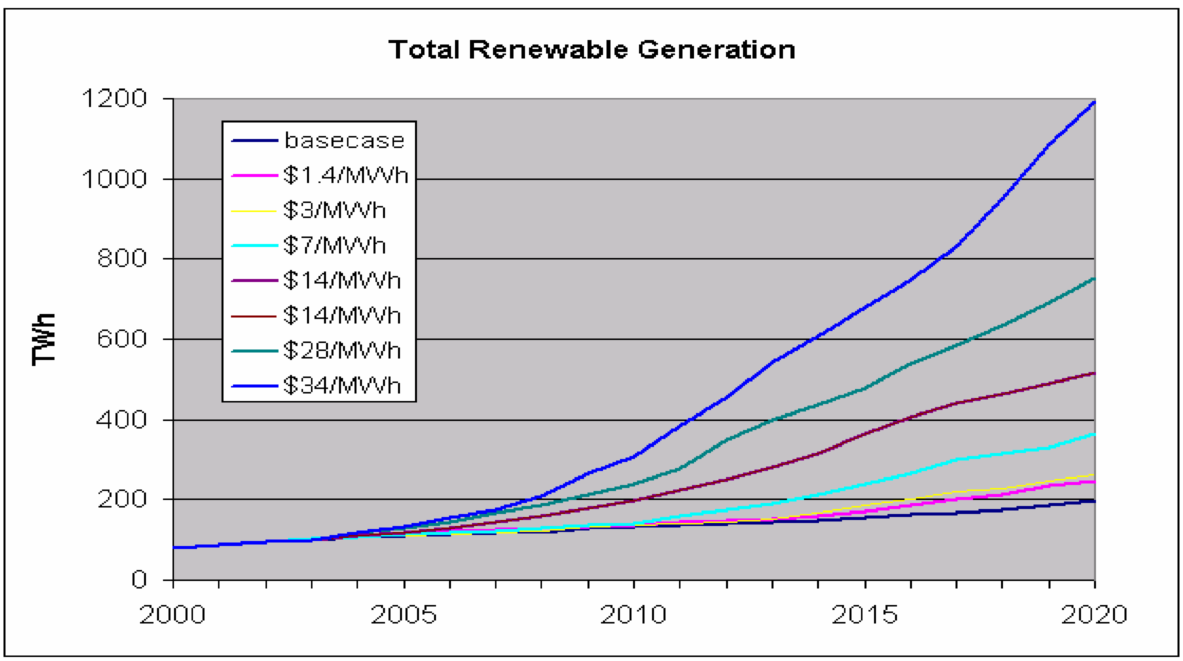
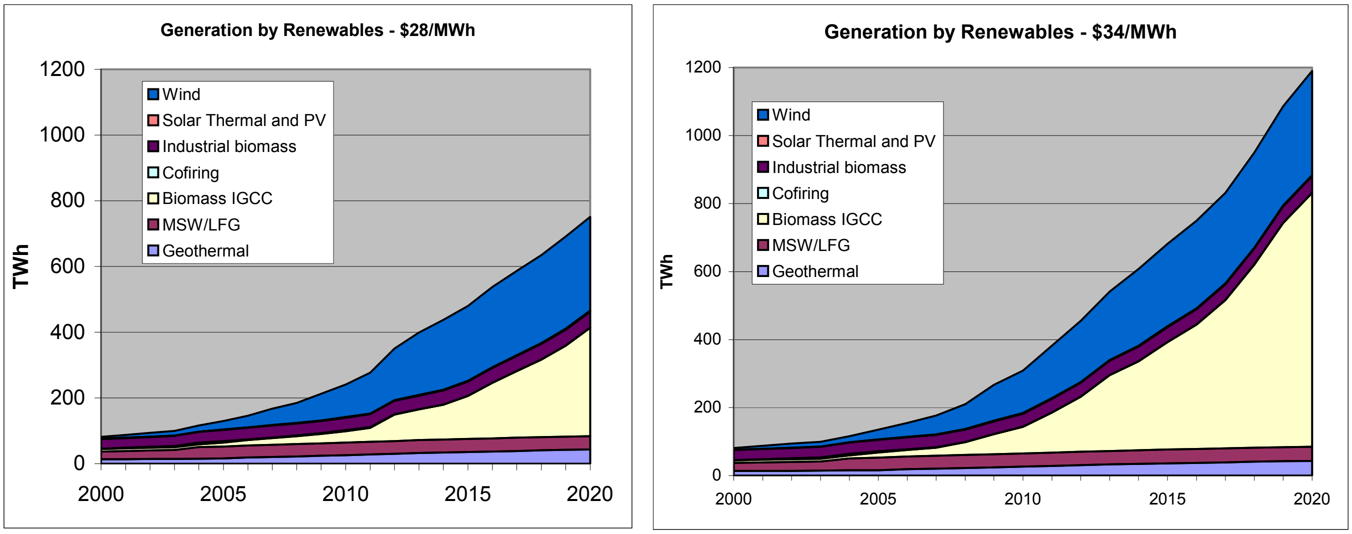


Figure 4 Generation by Type of Renewable for $28/MWh case and $34/MWh case

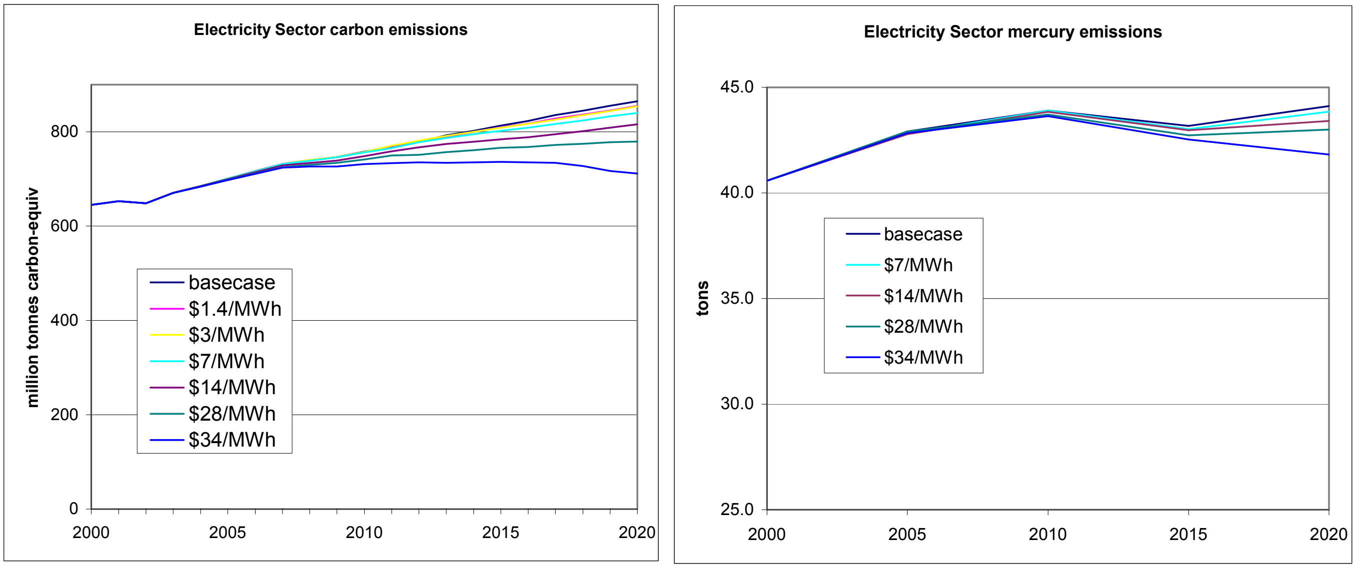


As reported in Table 6, emission reductions for **SO_2 and NO_x** are zero or very small with this program. The SO_2 emissions are limited by the overall Title IV cap, with this policy changing the initial allocation of the allowances. The total level of SO_2 does not change when the renewable generators gain credits - rather the credit reallocation results in a transfer from the fossil generators to the renewable generators. Any SO_2 reductions due to increased renewable generation is countered by increased use of high-sulfur coal, decreased investment in control equipment or decreased investments in natural gas plants. Regional emissions reductions may occur under the constant national cap, depending upon the geographic distribution of renewables.

NO_x emissions are capped in 19 states by the SIP call, so the summer NO_x levels in these states will not be affected by increased renewables. As with the SO_2 emissions, the cap means that more renewable generation can result in less investment in NO_x emission control technology.

Carbon and mercury reductions do occur, though they are somewhat limited because this program affects new generation; so the avoided generation is mostly from new, efficient natural gas plants, which have relatively low carbon and virtually zero mercury emissions. As shown in Figure 4, the carbon emissions in 2020 are reduced by only 0.5% to 10% by 2020, compared with base case emissions in that year, for the incentives of $1.4/MWh to $28/MWh. The $34/MWh case results in emission reductions of 18% in 2020 but as described in section 8, this level of incentive will be impossible to achieve through this policy alone. The mercury emissions show much smaller reductions than the carbon emissions (0.3% to 2.5% in 2020 for the $1.4 to $28/MWh cases).

Figure 5 Electric Sector carbon and mercury emissions, SO_2 credit cases



Note: Due to lack of space, the chart for mercury emissions does not include all cases and has 25 tons rather than 0 tons for the x-intercept; relative emission reductions may appear over-stated.

Costs – Net benefits occur for the lower levels of incentive factors due to capital cost decreases caused by increased renewable builds (effects of learning by doing) and the benefit of natural gas price decreases. Increased renewable generation leads to lower natural gas generation, thus lower natural gas demand and lower natural gas prices. Although the decreased price of natural gas is relatively small (8% reduction from base case in 2020 for $34/MWh case), this price change multiplied by natural gas consumption across all sectors leads to large benefits. The benefits from natural gas price decreases range from $1.5 billion for the $1.4/MWh run to $54 billion for the $34/MWh run (NPV 2000-2020). Section 7 describes the effects of changes to natural gas prices for all the cases.

Table 6 Results from SO_2 cases in 2010 and 2020

	2010							
	generation by renewables[1]	SO2 price	Emission Reduction (million short tons)				incremental elec gen from renew	Resource Cost
	% of total gen.	$/ton	Carbon	SO2	NOx	Mercury (tons)	TWh	billion $
Runs								
EIA basecase	2.5%							
Base case	2.5%	$207						
SO2 credit cases								
$0.7 / MWh	2.5%	$206	0.95	-	(0.00)	0.09	2.31	-$0.5
$1.4 / MWh	2.6%	$205	3.25	-	(0.01)	(0.04)	6.25	-$0.3
$3 / MWh	2.6%	$200	1.33	-	(0.01)	0.02	4.02	-$0.4
$7 / MWh	2.7%	$203	1.06	-	(0.00)	0.00	9.99	-$0.7
$14 / MWh	3.9%	$204	9.21	-	0.01	0.07	65.36	-$0.8
$28 / MWh	4.8%	$200	16.17	-	0.02	0.19	109.51	-$0.7
$34 / MWh	6.3%	$198	26.08	-	0.05	0.26	177.46	$0.9
Tightened SO2 cap								
3% per year[2]	2.5%	$290	0.69	1.96	0.00	4.96	1.22	$8.9
5% per year[3]	2.6%	$889	13.11	2.97	0.06	7.62	5.01	$26.5

	2020							
	generation by renewables	SO2 price	Emission Reduction (million short tons)				incremental elec gen from renew	Resource Cost
	% of total gen.	$/ton	Carbon	SO2	NOx	Mercury (tons)	TWh	billion $
Runs								
EIA basecase	2.7%							
Base case	3.4%	$153						
SO2 credit cases								
$0.7 / MWh	3.8%	$150	4	-	0.01	0.11	24	$0.5
$1.4 / MWh	4.2%	$213	10	-	0.01	0.02	48	-$1.0
$3 / MWh	4.5%	$160	11	-	0.02	0.04	63	$0.4
$7 / MWh	6.4%	$139	25	-	0.04	0.26	164	-$0.9
$14 / MWh	9.1%	$145	49	-	0.08	0.70	316	-$2.9
$28 / MWh	13.5%	$158	86	-	0.15	1.11	552	$4.8
$34 / MWh	21.5%	$135	154	-	0.31	2.29	992	$55.3
Tightened SO2 cap								
3% per year	3.7%	$629	5	3.79	0.00	8.15	16	$16.3
5% per year	3.6%	$1,113	11	5.18	0.00	11.27	11	$19.3

1. Renewables exclude hydro but include landfill gas and industrial cogeneration
2. Reductions starting in 2003 - targets are 6.99 million tons in 2010, 5.16 million tons in 2020
3. Reductions starting in 2003 - targets are 6.29 million tons in 2010, 3.77 million tons in 2020

The relatively high cost of the $34/MWh case is in part due to high demand for biomass, leading to higher biomass prices and higher costs to all plants using biomass (Such price feedbacks do not occur with wind, geothermal or solar resources).

Cost curves. Figure 6 and Figure 7 indicate steadily increasing costs per tonne carbon or TWh of renewables, except for the $3/MWh case. The charts indicate that with net economic benefits, the policy could reduce about 65 tonnes of carbon by 2020 (7.5% reduction from the Base Case) and generate about 450 additional TWh of renewable electricity (9% of total sales). The cost curve for carbon shows that the $34/MWh case leads to carbon emission reductions of about 140 million tons of carbon in 2020 at a cost of $150/tonne carbon. For comparison, a recent study by the Tellus Institute reported that a combined set of electricity sector policies (renewable portfolio standards plus cap and trade programs for NOx, SO_2, and carbon) lead to 190 million tonnes of carbon reduced in 2020 at a cost of $188/tonne. The cost curve for renewable generation shows that cost per MWh of renewable generation is significantly lower than the financial incentive applied in each case. This result is partly expected (the marginal cost should exceed the average cost) but also reflects the feedback of lower natural gas prices (discussed in section 7).

Figure 6 Cost Curve for Carbon, SO_2 cases

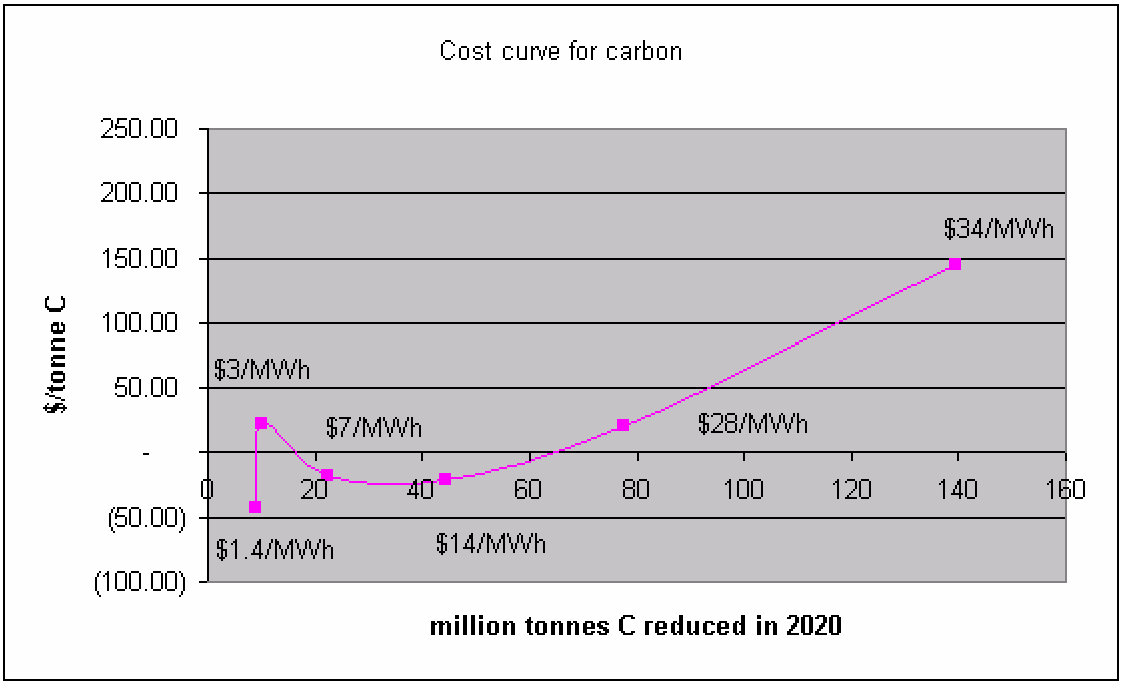
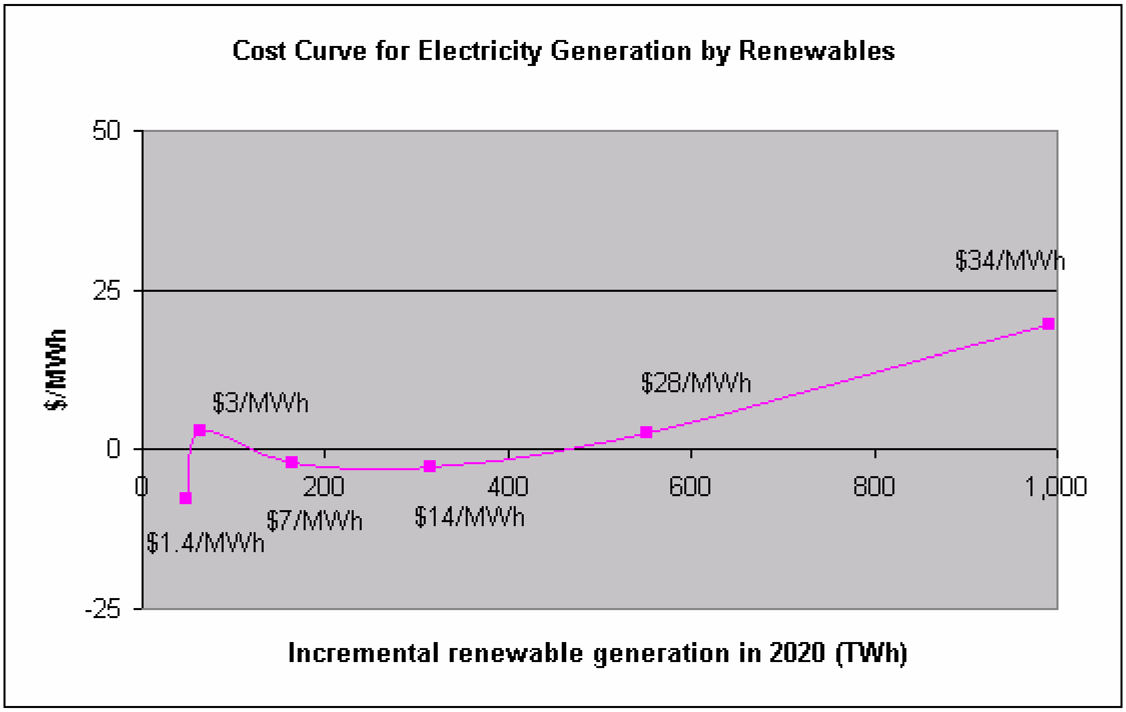
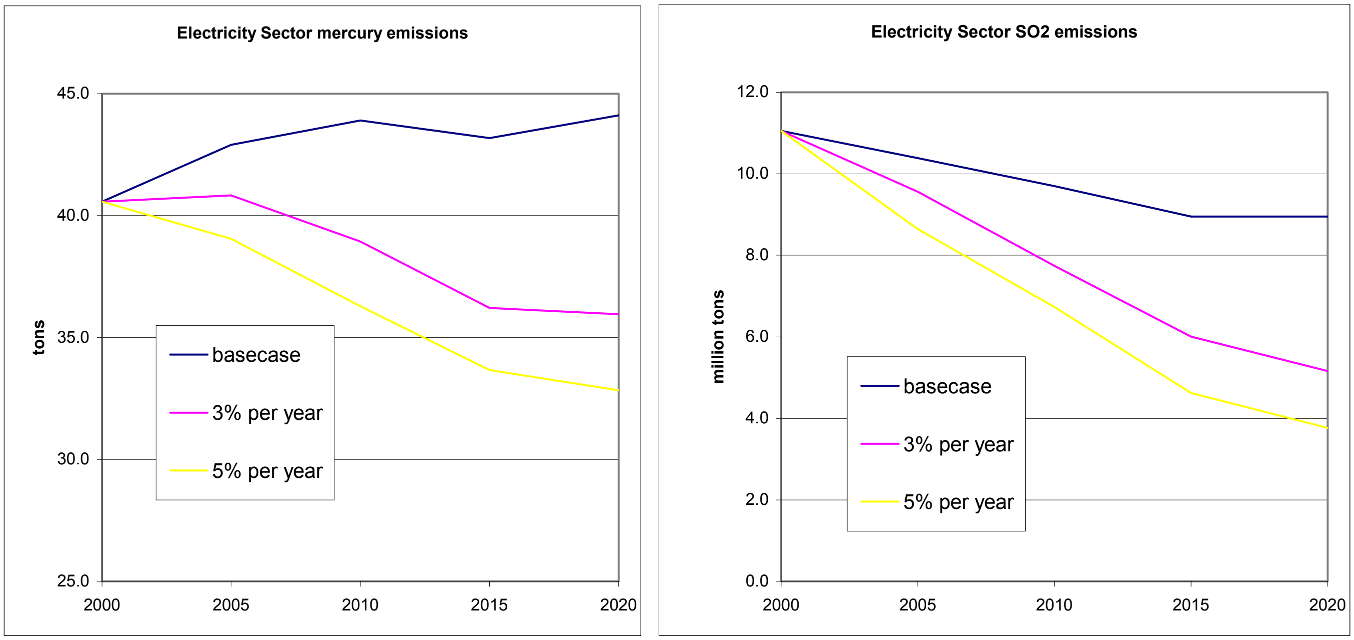


Figure 7 Cost Curve for Electricity Generation by Renewables, SO_2 cases



Tighter SO_2 caps. These cases result in significant increases in the price of the allowances but only small changes in the levels of renewables. The cases do not include financial incentives for renewables, so the renewables seeking to enter the market compete directly with low-sulfur coal, natural gas and control technologies (scrubbers). In general, the results indicate that generators favor increased use of scrubbers on coal plants and more natural gas generation for SO_2 reductions, rather than increased use of renewables. As shown in figure 7, these cases result in significant decreases in SO_2 (by design) and in mercury – some of the control technologies for SO_2 also decrease mercury emissions (EIA 2001). Minor or no emission reductions occur for carbon and NO_x, as shown in table 6.

Figure 8 Mercury and SO_2 emissions for Tightened SO_2 cap cases



Note: Due to lack of space, the chart for mercury emissions has 25 tons rather than 0 tons for the x-intercept; relative emission reductions may appear over-stated.

The Tighter SO_2 caps show relatively high costs, compared to the SO_2 credit cases, though direct comparisons are difficult due to different impacts of the policies (renewables/carbon reductions for the SO2 credit cases vs. mercury/SO_2 reductions in the tightened SO_2 caps cases). The natural gas feedback leads to increased costs for these cases as the electric sector reacts to the decreased caps by increasing natural gas generation, leading to increased prices and increased costs for all natural gas users. As further described in section 7, the natural gas price feedback accounts for $7 billion incremental cost (cumulative present value, 2000-2020) for the 3% decline per year case and $9.5 billion for the 5% decline per year case.

5.4 NO_x cases

The NO_x cases are based on the same type of policy as the SO2 cases – emission allowances are allocated to renewable generators who can then sell these allowances in the emissions credit market. These emission allowances provide financial incentives to the renewable generators. We used the same ragne of financial incentives for the NOx cases (in $/MWh) as the SO_2 credit cases but only apply this incentive to renewables in the 19 states with the NO_x cap and trade policies. As expected this leads to lower levels of renewables, lower emission reductions and lower overall costs, as shown in Table 7.

The incremental renewable generation in 2020 for the $34/MWh NO_x case is similar to the $28/MWh SO_2 credit case. However, the mix of generation differs leading to different impacts. Figure 9 shows that in the $34/MWh NO_x case, the renewable generation is dominated by biomass (accounting for 66% in 2020, compared with 44% in the $28/MWh SO_2 credit case). The Northeast states that have the NO_x cap and trade policy have lower potential for wind than the western states that are included in the SO_2 credit cases. As noted previously, higher demand for biomass leads to higher biomass prices, which causes higher costs to all biomass generators and increases overall costs. The NO_x case also shows slightly lower changes in natural gas prices; thus the natural gas prices feedbacks are lower (the natural gas price feedbacks for the $34/MWh NO_x case are about $23 billion, compared with $31 billion for the $28/MWh SO_2 credit case).

Figures 10 and 11 show that the costs per tonneC are greater than the SO_2 credit cases – except for the $7/MWh cases where the small carbon reduction leads to a large net benefit per tonne. The costs per MWh of renewables are similar for both sets, but the SO_2 credit cases achieve much greater levels of renewable generation.

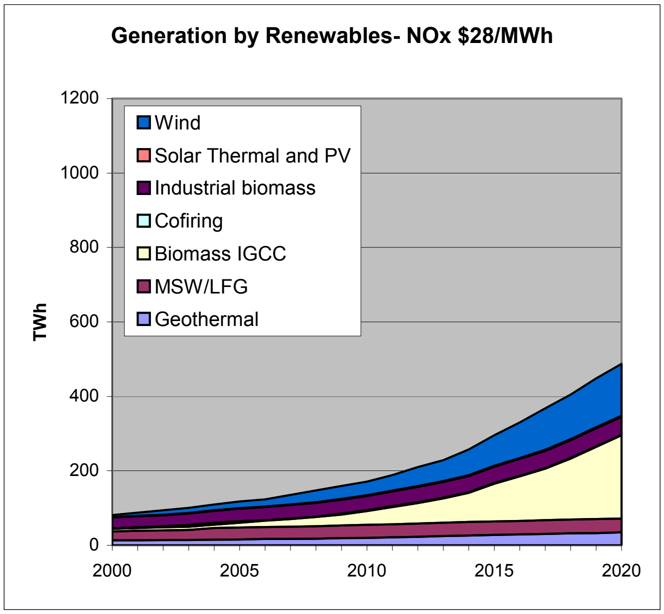
Table 7 Results from NOx cases in 2010 and 2020

	2010							
	generation by renewables[1]	**SO2 price**	**Emission Reduction (million short tons)**				**incremental elec gen from renew**	**Resource Cost**
	% of total gen.	$/ton	CO2	SO2	NOx	Mercury (tons)	TWh	billion $
Runs								
Base case	2.5%	$207						
NOx credit cases								
$1.4 / MWh	2.5%	$197	1	0.00	0.00	0.03	53	-$0.4
$3 / MWh	2.5%	$198	0	0.00	0.00	-0.07	54	-$0.3
$7 / MWh	2.6%	$206	1	0.00	0.00	0.01	4	-$0.9
$14 / MWh	2.8%	$205	5	0.00	0.00	-0.04	13	$0.2
$28 / MWh	3.3%	$208	19	0.00	0.01	-0.08	40	$0.2
$34 / MWh	3.6%	$204	27	0.00	0.02	0.08	55	$0.6

	2020							
	generation by renewables	**SO2 price**	**Emission Reduction (million short tons)**				**incremental elec gen from renew**	**Resource Cost**
	% of total gen.	$/ton	CO2	SO2	NOx	Mercury (tons)	TWh	billion $
Runs								
Base case	3.4%	$163						
NOx credit cases								
$1.4 / MWh	3.5%	$174	9	0.00	0.00	0.14	130	$0.1
$3 / MWh	3.7%	$172	11	0.00	0.00	0.03	136	-$0.2
$7 / MWh	4.3%	$159	26	0.00	0.01	0.18	50	$0.5
$14 / MWh	5.9%	$217	78	0.00	0.04	0.09	138	$0.9
$28 / MWh	8.6%	$162	160	0.00	0.07	0.53	288	$4.7
$34 / MWh	13.8%	$146	316	0.00	0.20	1.70	575	$41.8

1. Renewables exclude hydro and co-firing but include landfill gas and industrial cogeneration

Figure 9 Generation by Type of Renewables for \$28/MWh and \$34/MWh NO_x cases



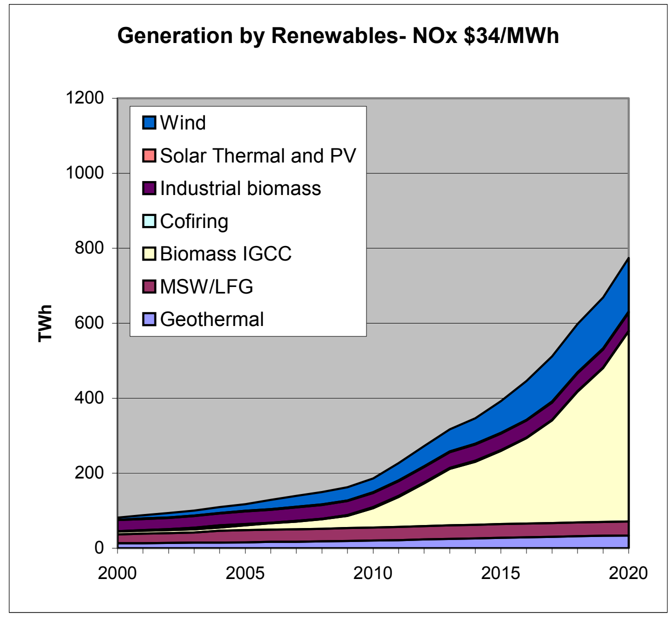


Figure 10 Cost Curve for Carbon, NO_x cases

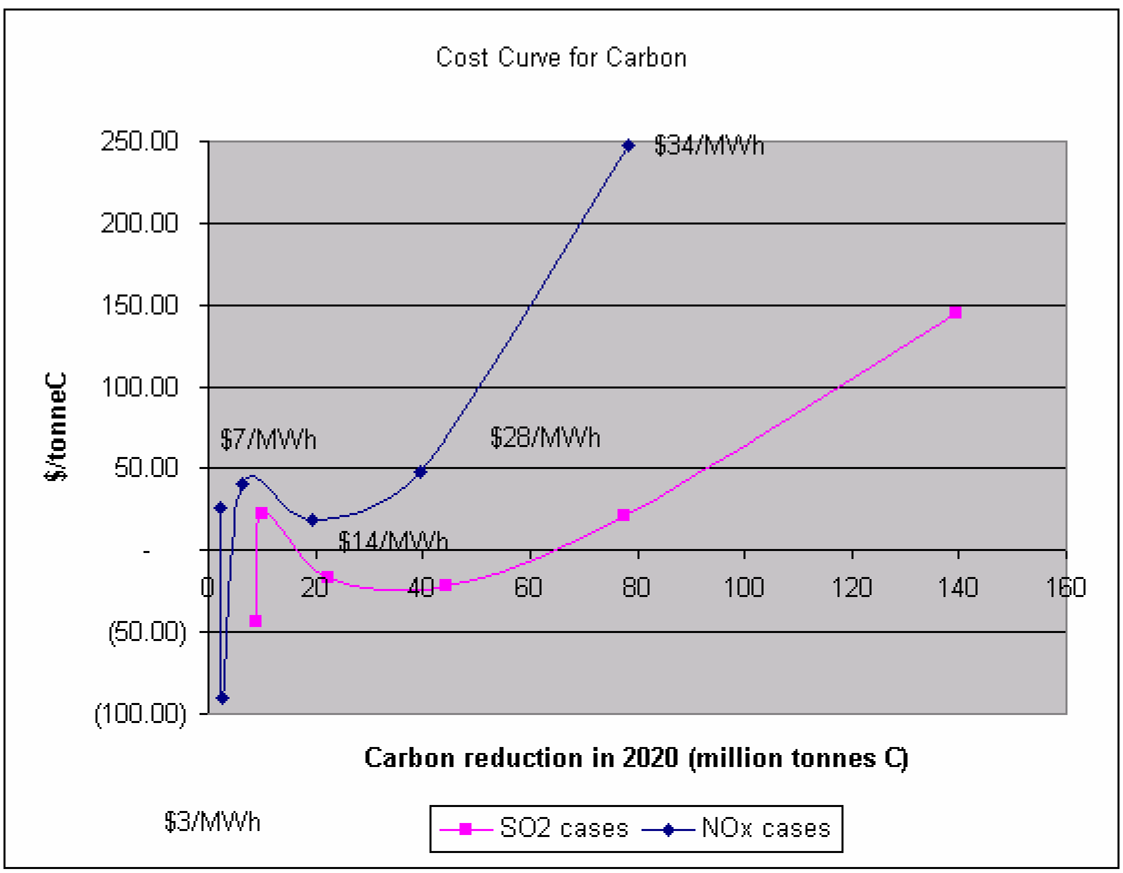
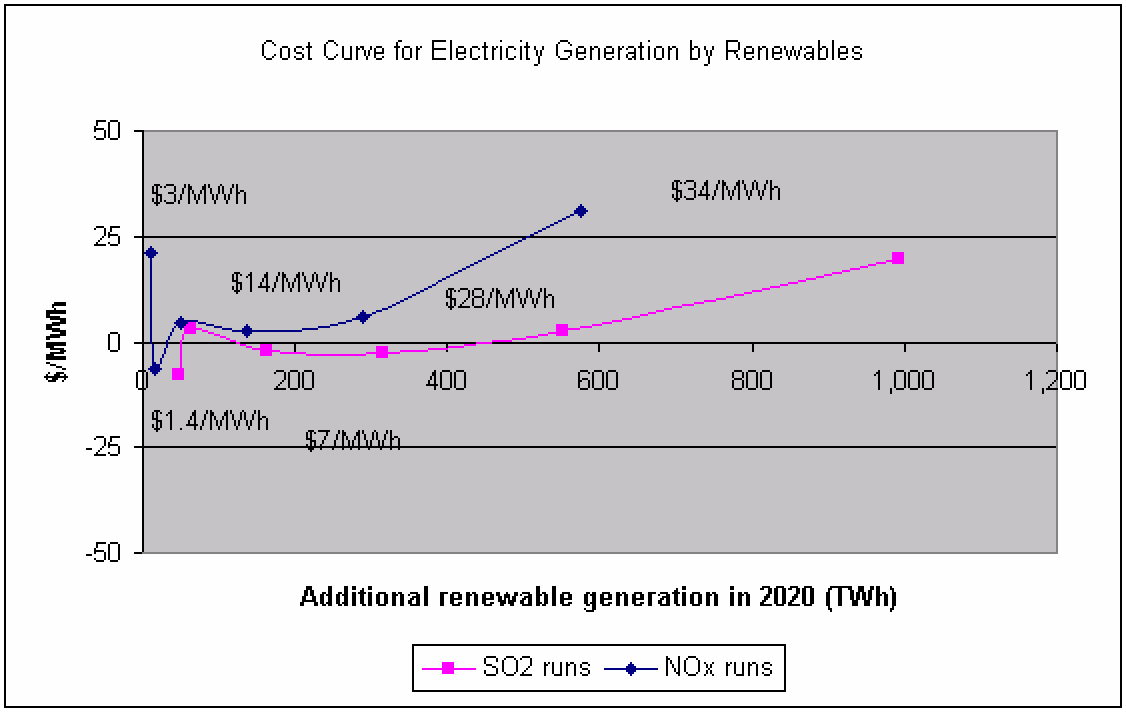


Figure 11 Cost Curve for Electricity Generation by Renewables, NO_x cases



5.3 RPS cases

Table 7 includes the results of the RPS cases (the output are defined in the text box at the start of section 5). By construction, the RPS cases closely match the levels of renewable generation in the SO_2 cases. These cases show greater reductions in carbon, NOx and mercury, than any of the SO_2 cases. The costs for the RPS cases are also lower than the costs for matching SO_2 cases.

The differences between the SO_2 Credit cases and RPS cases highlight the impacts of policy design on total costs and emission reductions. For this analysis, the SO_2 Credit cases have low impact on electricity prices[5] (the policy changes the allocation of allowances rather than introducing new requirements to the electric sector) and biomass co-firing does not qualify for the SO_2 credits. For the RPS cases, electricity prices will be impacted directly by the cost of the renewable energy credits and biomass co-firing does qualify as renewable generation. These elements lead to differences in the type of renewable generation stimulated and in the cost of the cases.

[5] This may not hold for the $34/MWh case since, as described in section 7, allocation of SO_2 allowances to renewable generators will not be sufficient to provide this level of financial incentive. In that case, the financial incentive may need to be provided in part by electricity consumers.

Table 8 Results from RPS cases in 2010 and 2020

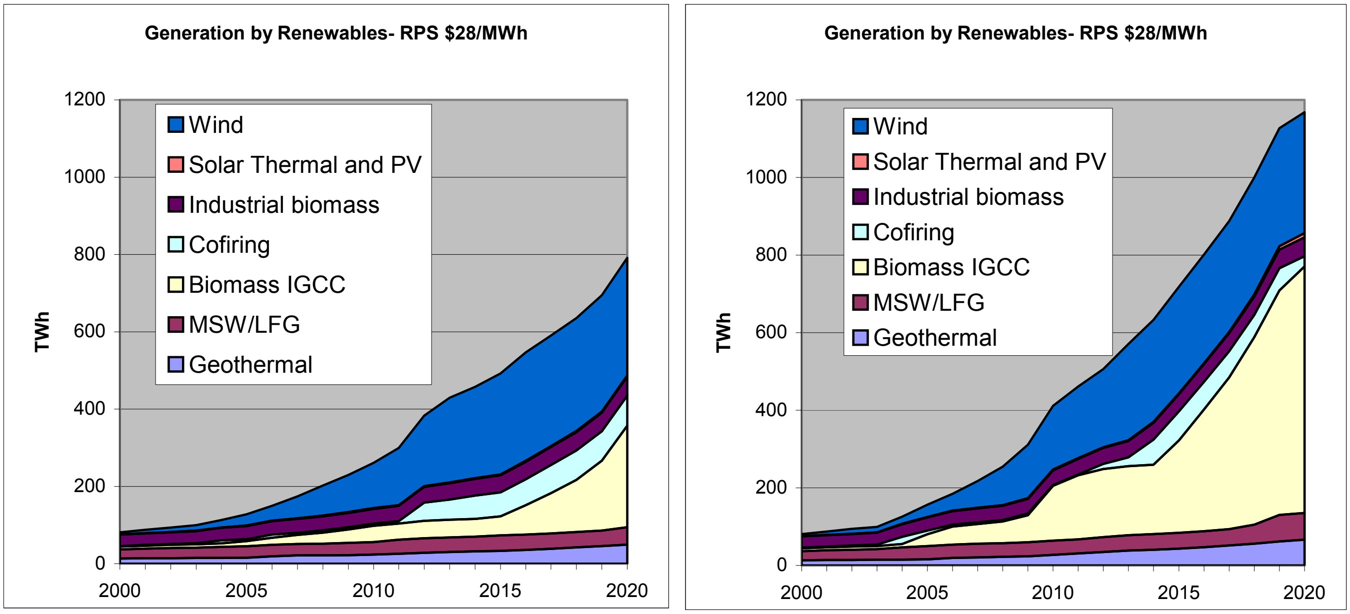
	2010						incremental elec gen from renew	Resource Cost
	generation by renewables[1]	SO2 price	Emission Reduction (million short tons)					
	% of total gen.	$/ton	CO2	SO2	NOx	Mercury (tons)	TWh	billion $
Base case	2.5%	$207						
RPS runs to match SO_2 credit cases[2]								
$3 / MWh	3.2%	$201	20	-	0.01	0.06	33	-$1.7
$7 / MWh	3.4%	$199	31	-	0.01	0.16	45	-$1.8
$14 / MWh	4.2%	$195	52	-	0.02	0.00	79	-$3.1
$28 / MWh	5.3%	$196	79	-	0.04	0.14	130	-$3.3
$34 / MWh	8.5%	$187	170	-	0.11	0.44	280	-$0.5

	2020						incremental elec gen from renew	Resource Cost
	generation by renewables	SO2 price	Emission Reduction (million short tons)					
	% of total gen.	$/ton	CO2	SO2	NOx	Mercury (tons)	TWh	billion $
Base case	3.4%	$163						
RPS runs to match SO_2 credit cases[2]								
$3 / MWh	4.6%	$177	54	-	0.02	0.05	65	-$2.1
$7 / MWh	6.0%	$149	111	-	0.04	0.47	144	-$5.8
$14 / MWh	9.3%	$140	231	-	0.07	1.18	322	-$10.4
$28 / MWh	14.2%	$166	396	-	0.16	1.57	592	-$13.9
$34 / MWh	21.5%	$143	675	-	0.38	3.09	969	$12.7

1. Renewables exclude hydro and co-firing but include landfill gas and industrial cogeneration
2. The minimum level of generation by renewables was set to match the renewable generation achieved by the corresponding SO_2 credit case

Figure 12 shows the type of renewable generation in the RPS cases that match the renewable levels attained in the $28/MWh and $34/MWh SO_2 credit cases. The RPS cases show a large amount of co-firing especially at the end of the modeling period. This reflects both that co-firing receives renewable energy credits under the RPS cases and the impact of the RPS sunset in 2020 – since generators are not guaranteed the extra incentive for renewable generation after 2020, the lowest cost solution to meeting the renewable energy targets in later years is through co-firing rather than building new plants that will only be able to gain credits for a portion of their lifetimes.

Figure 12 Generation by Renewable for RPS cases matching $28/MWh and $34/MWh



As shown in figures 13 and 14, the RPS cases have lower costs and greater emission reductions compared with the SO_2 cases. The reasons for these differences are discussed above, relating to differences in policy implementation.

Figure 13 Cost Curve for Carbon, RPS cases

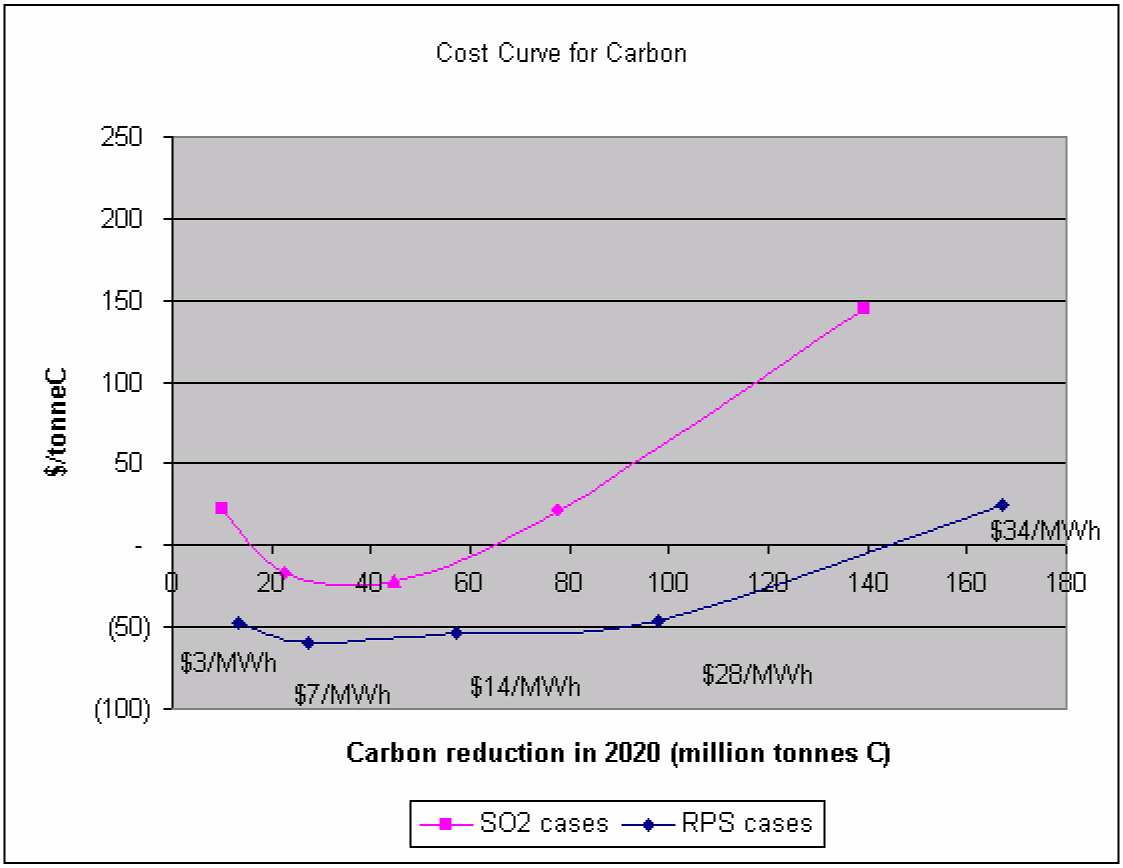
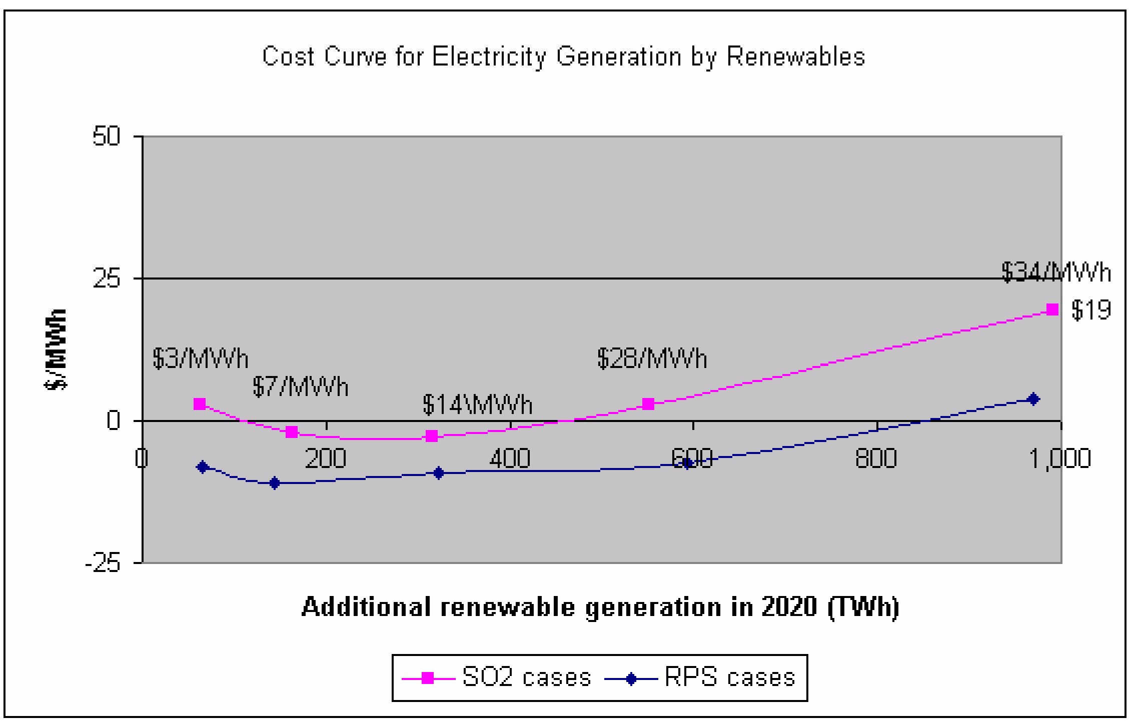


Figure 14 Cost Curve for Electricity Generation by Renewables, RPS cases



6. Multipollutant and Multipollutant with RPS Cases

This section discusses the results from the Multipollutant and Multipollutant with RPS cases. For comparison and to better consider the synergies of combined policies we also include the results of three other cases, which have pollutant reduction or renewable energy generation levels that are the same as in the multipollutant cases:

1. Tightened SO_2 caps – 5% per year case
2. RPS case – RPS levels set to match the $34/MWh SO_2 Credit case
3. RPS + 5% case – a combination of the tightened SO_2 cap and the RPS case described above.

The requirements for the emission reductions for the multipollutant case are described in section 4 and summarized below:

Carbon – 3% reduction per year starting in 2006, continuing to 2015 then stable at 2015 levels to 2020 (469 MMTCe)

SO_2 – 5% reduction per year starting in 2003, continuing to 2020 (3.77 million tons in 2020)

NO_x - 7% reduction per year starting in 2003, continuing to 2015 then stable at 2015 levels to 2020 (1.69 million tons in 2020)

mercury - 11% reduction per year starting in 2003, continuing to 2015 then stable at 2015 levels to 2020 (9 tons in 2020)

RPS – set to match levels achieved by the run with financial incentive of $34/MWh

Table 9 summarizes the results of the multipollutant cases and the comparison cases. The multipollutant case leads to a significant increase in renewable generation (12.5% of total generation in 2020) but it is only about half of the multipollutant plus RPS case (as shown in Figure 15). Figure 16 shows the multipollutant cases achieve large reductions in emissions, following the policy design.

Figure 15 Total Generation by Renewables, Multipollutant cases

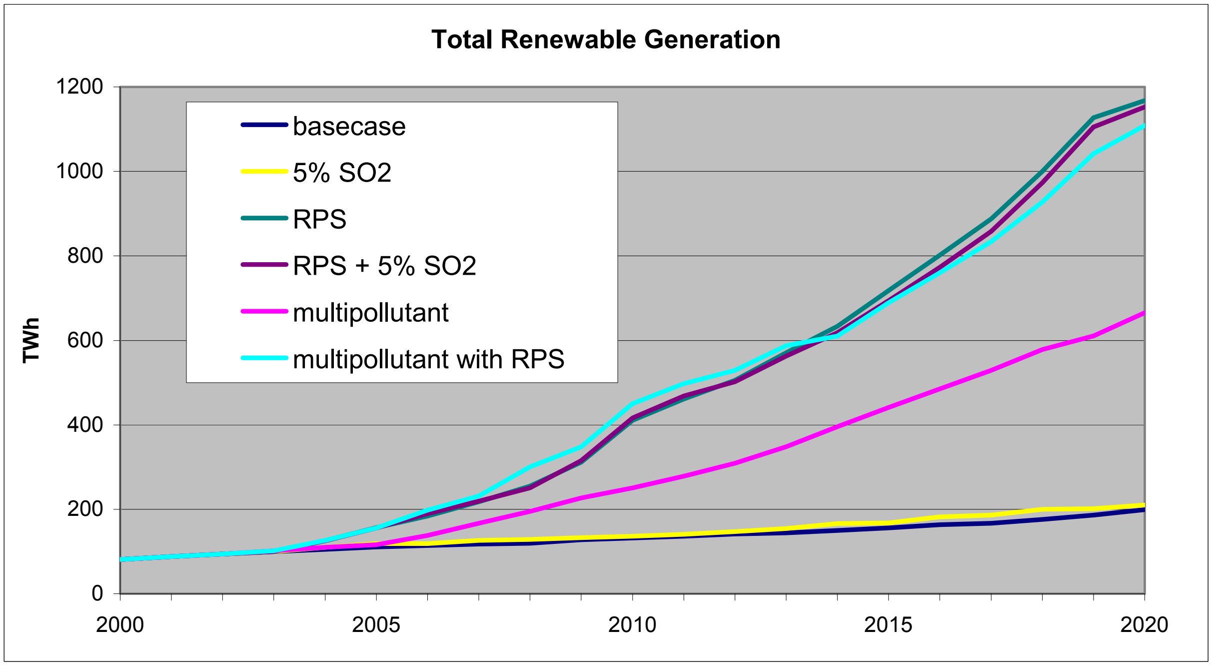
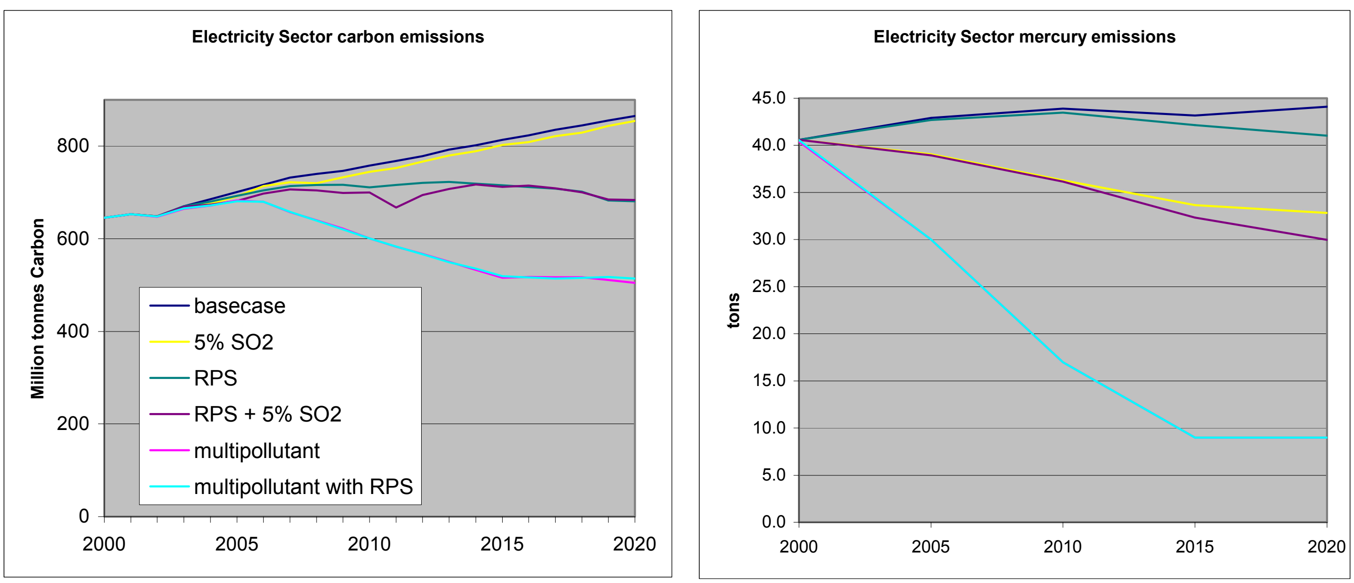
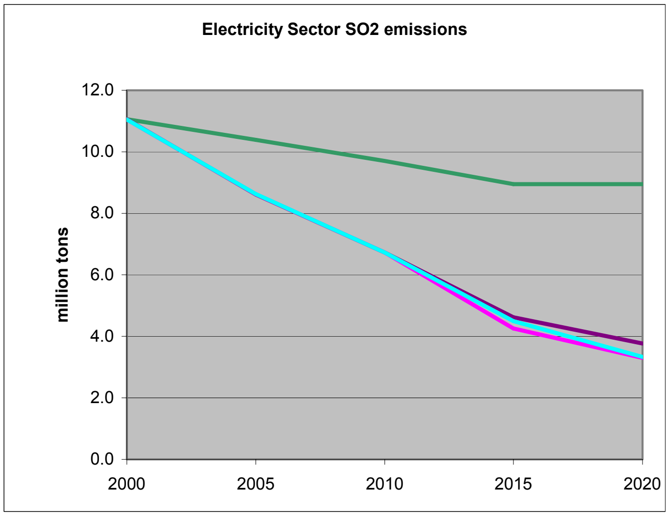


Figure 16 Carbon, Mercury, SO_2 and NO_x emissions for Multipollutant cases





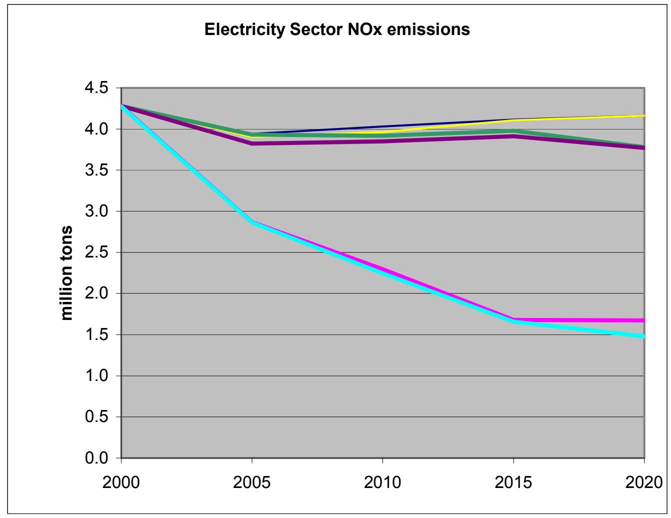


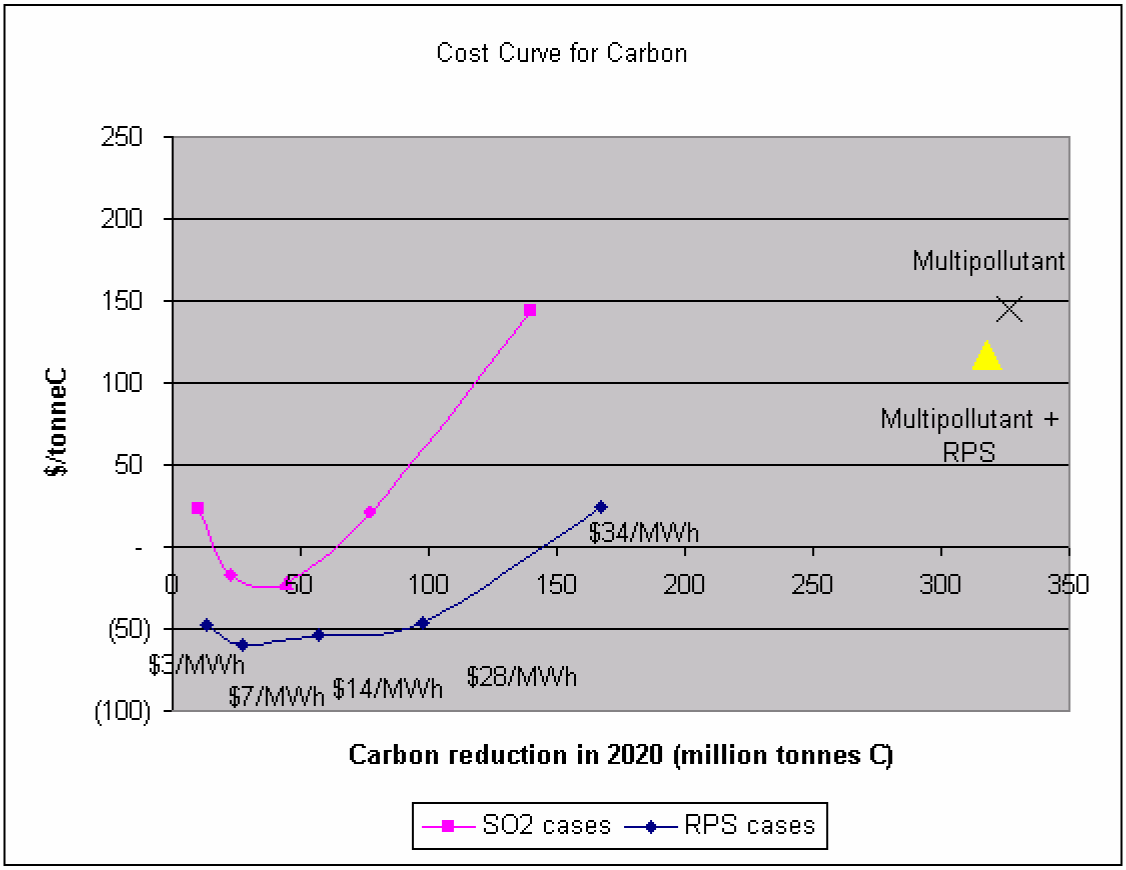
Table 9 Impacts of Multipollutant and Multipollutant with RPS cases

	2010						incremental elec gen from renew	Resource Cost
	generation by renewables[1]	SO2 price	Emission Reduction (million short tons)					
	% of total gen.	$/ton	Carbon	SO2	NOx	Mercury (tons)	TWh	billion $
Base case	2.5%	$207						
multipollutant with RPS	9.6%	$121	575.06	2.97	1.78	26.90	318.47	$52.6
multipollutant	5.2%	$33	575.06	2.97	1.73	26.90	119.48	$51.5
RPS + 5% SO2	8.7%	$763	57.77	2.97	0.18	7.76	284.81	$2.7
RPS	8.5%	$187	46.41	-	0.11	0.44	279.50	-$0.3
Tightened SO2 cap 5% per year[3]	2.6%	$889	13.11	2.97	0.06	7.62	5.01	$26.5

	2020							
	generation by renewables	SO2 price	Emission Reduction (million short tons)				incremental elec gen from renew	Resource Cost
	% of total gen.	$/ton	Carbon	SO2	NOx	Mercury (tons)	TWh	billion $
Runs								
EIA basecase	2.7%							
Base case	3.4%	$153						
multipollutant with RPS	20.8%	$4	351	5.18	2.68	35.11	910	$169.6
multipollutant	12.5%	$180	360	5.18	2.49	35.11	467	$213.3
RPS + 5% SO2	21.2%	$823	182	5.18	0.39	14.14	954	$40.4
RPS	21.5%	$130	184	-	0.38	3.09	969	$12.7
Tightened SO2 cap 5% per year	3.6%	$1,113	11	5.18	0.00	11.27	11	$19.3

The costs of the multipollutant cases are high compared to the other cases but also lead to greater emission reductions and renewable energy generation. As shown in figure 16, the cost of saved carbon is $145/tonneC for the multipollutant case and $117/tonneC for the multipollutant plus RPS case.

Figure 17 Cost Curve for Carbon, including SO_2 credit cases, RPS cases and Multipollutant cases



However, the multipollutant cases also reduce significant levels of other pollutants while the cost of saved carbon calculation attributes the full cost of the electric sector changes to carbon reductions.

For the purpose of comparing the different policy approaches to one another, it is possible to share the costs across all emission reductions by first weighting all emission reductions to a common unit.We chose to use carbon reductions as a common metric and estimated the total emission reductions as:

$$\textit{Emission Reductions} = \textit{carbon reductions} + \textit{ratio } SO_2/C * SO_2 \textit{ reductions} + \textit{ratio } NO_x/C * NO_x \textit{ reductions} + \textit{ratio } Hg/C * Hg \textit{ reductions} \quad [1]$$

Ratio SO_2/C is the ratio of the value of reducing one ton of SO_2 to the ratio of reducing one tonne of carbon. Ideally this quantity would reflect a value of the avoided health impacts or avoided environmental damage. However such "values" are difficult to calculate and necessarily encompass a variety of biases. For our calculations we calculated the ratio of the values by the cost of saving one ton of each emission individually, at approximately the same reduction level as achieved by the multipollutant cases in question. Thus we weight the reduction of each emission by the relative cost of reduction compared to the cost of reducing carbon. For cost of emission reduction we used the allowance prices associated with cap and trade policies applied to each emission individually. These allowance prices were obtained from a recent EIA analysis, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard* (EIA 2001). Table 10 presents the allowance prices in 2020 for each emission and the associated emission level in that year. The allowance prices were used to calculate the ratios of each emission to carbon for the required weights in the above equation.

Table 10 Weights for value of emission reduction, SO_2, NO_x, and mercury compared to carbon

Emissions	Allowance Price in 2020 ($/unit)	unit	Reduction in 2020	Unit for reductions	ratio of allowance price to carbon allowance price	
Carbon	150	tonneCe	420	MMTCe	1	
SO2	1000	ton	5.7	million ton	6.67	Ratio SO_2/C
NOx	3000	Ton	2.6	million ton	20	Ratio NO_x/C
Mercury	400,000,000	Ton	39	ton	2,666,667	Ratio Hg/C

Source: EIA 2001 with Tellus calculations

The costs of emission reduction is then calculated in the same way as for cost of saved carbon,

$$\text{Cost of emission reductions} = \frac{CPV of \cos ts}{CPV of Emission \operatorname{Re} ductions}$$

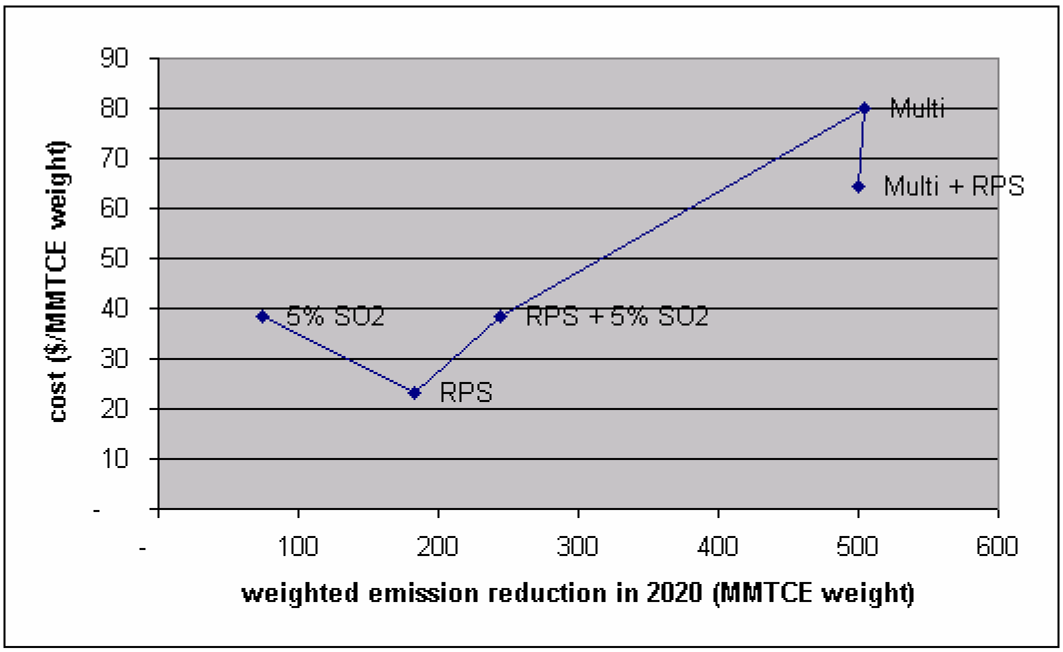
where CPV is the cumulative present values of the quantity (e.g $ or tons reduced) from 2000 to 2020 using a 5% discount rate and *EmissionReductions* follow equation [1] with ratios from table 10. Ideally the ratios would reflect any changes in the values of the allowance prices over time but this information was not available from the EIA report.

Table 11 and Figure 18 report the weighted emission reductions in 2020 and calculated cost of saved emissions over the full time period.

Table 11 Cost of Saved Emissions for Multipollutant cases

	Multipollutant + RPS	Multipoll-utant	RPS + 5% SO2	RPS	SO2 5%
Costs, cumulative present value 2000-2020 (billion 2000$)	$170	$213	$40	$13	$19
Emission Reduction in 2020					
Carbon (MMTCE)	318	327	165	167	10
SO2 (Million ton)	5	5	5	0	5
NOx (million ton)	3	2	0	0	0
Mercury (ton)	35	35	14	3	11
Weighted Reductions (MMTCe weight)	500	505	245	183	74
cost of saved emissions ($/tonne C weight)	$64	$80	$38	$23	$38

Figure 18 Cost of Saved Emissions, Multipollutant Cases



7. Policy Implications

Table 8 presents the results for the SO_2 cases. A key restriction on the policies is the annual credits required. This policy is based on a re-allocation of allowances from fossil fuel generators to renewable generators. The trading price of the SO2 credits can be used to estimatethe number of allowances that would need to be allocated to renewable generators in order to provide the

Key to Results

As an aid in interpreting these results in the context of the NREL project, we calculated several indicators for the SO_2 cases.

Required enrichment factors is the factor necessary to achieve the same level of incentive (in $/MWh) as the negative externality in each run. This enrichment factor was calculated as a multiplier to the basecase allowance provision of 1 ton SO_2 allowances per 500 MWh of renewable generation, using the estimated SO_2 allowance price from Tellus-NEMS runs.
(calculated from the negative externality)
*enrichment factor = negative externality * 500 / SO_2 allowances*

Equivalent emission factor (lbs SO_2/MWh) – represents the amount of "displaced SO_2" for which the renewable generators get credit. This value is the **required enrichment factor** converted to lbs SO_2/MWh. *(calculated from incentive factor)*

Annual credits (tons) – this is the *annual* amount of credits that would need to be transferred to renewables and could be used to estimate the required size of the set-asides. *(calculated from incentive factor and level of renewables)*

financial incentive used as input to the case. For example, providing a -$7/MWh incentive to renewable generators is equivalent to providing 17 SO_2 allowances (valued at $203 each) for each 500 MWh of renewable generation in 2010. Based on the amount of renewable generation in that case, the policy would need to allocate 300,000 allowances to renewable generators in that year and 8.1 million allowances in 2020. However, only 9 million tons of SO_2 allowances are available in any year leading to a limit on the potential for this policy. The higher enrichment cases (at $14, $28 and $34/MWh) would need impossibly high numbers of allowances. In order to achieve the results shown in the cases the allocation policy would need to be supplemented with other types of funding or with policies that do not rely exclusively on financial incentives (e.g., combining carrots and sticks).

Table 12 Policy Implications for SO_2 cases

	2010				
	generation by renewables[1]	SO2 price	required enrichment factor	equivalent emission factor	Annual credits
	% of total gen.	$/ton	X 1 ton SO2 /500 MWh	lbs SO2 /MWh	million tons
$1.4 / MWh	2.6%	$205	3	13	0.0
$3 / MWh	2.6%	$200	7	28	0.1
$7 / MWh	2.7%	$203	17	68	0.3
$14 / MWh	3.9%	$204	34	135	4.4
$28 / MWh	4.8%	$200	69	275	15.1
$34 / MWh	6.3%	$198	87	348	30.9
Tightened SO2 cap					
3% per year	2.5%	$290			
5% per year	2.6%	$889			

	2020		in 2020		
	generation by renewables	SO2 price	required enrichment factor	equivalent emission factor	Annual credits
	% of total gen.	$/ton	X 1 ton SO2 /500 MWh	lbs SO2 /MWh	million tons
$1.4 / MWh	4.2%	$213	3	13	0.3
$3 / MWh	4.5%	$160	9	34	1.1
$7 / MWh	6.4%	$139	25	99	8.1
$14 / MWh	9.1%	$145	48	190	30.0
$28 / MWh	13.5%	$158	87	349	96.2
$34 / MWh	21.5%	$135	127	510	252.7
Tightened SO2 cap					
3% per year	3.7%	$629			
5% per year	3.6%	$1,113			

Combined Cases

To investigate alternatives to the allowance limitation confronted by the straight set-aside policy, we considered combining tighter SO_2 caps with SO_2 allowance set-asides. In the cases with tighter SO_2 caps, the allowance prices are significantly higher, so it seems beneficial to combine the tighter SO_2 caps with renewable energy set-asides and get substantial benefits for achievable numbers of seta-asides. Fewer allowances would be needed by renewable sources to provide the equivalent financial incentive. We combined the results of various cases to estimate the impacts of policies that include tighter caps and set-asides.[6] The cases considered were:

- tightened SO_2 cap of 3% per year plus set-asides of 3 SO_2 allowances per 500 MWh of renewable generation (3 times the number of allowances as would have been provided by the CRER),
- tightened SO_2 cap of 5% per year plus set-asides of 3 SO_2 allowances per 500 MWh of renewable generation, and
- tightened SO_2 cap of 5% per year plus set-asides of 5 SO_2 allowances per 500 MWh of renewable generation.

The results of these combined cases are presented in Table 13 (see section 5.1 for definition of output variables). For comparison, Table 13 also includes results from runs with tightened SO_2 caps and with increased number of set-asides considered separately.

[6] Because this analysis showed little interaction between incentives for renewables and tighter SO_2 caps, we did not re-run NEMS to estimate these impacts. Instead we combined the results from the tighter SO_2 caps with values interpolated from the cases with negative externalities.

Table 13 Results from Combined Cases

	2010							
	generation by renewables[1]	SO2 price	Emission Reduction (million short tons)				incremental elec gen from renew	Resource Cost
	% of total gen.	$/ton	Carbon	SO2	NOx	Mercury (tons)	TWh	billion $
Base case	2.5%	$207						
Tightened SO_2 cap								
3% per year[2]	2.5%	$290	1	1.96	0.00	4.96	1	$8.9
5% per year[3]	2.6%	$889	13	2.97	0.06	7.62	5	$26.5
SO_2 credit cases								
3X ($1.4/MWh)	2.6%	$205	3	0.00	-0.01	-0.04	6	-$0.3
5X ($2/MWh, estimated)	2.6%	$203	3	0.00	-0.01	-0.01	5	-$0.3
Combinations								
3%[2] plus 3X	2.6%	$290	3	1.96	-0.01	4.97	6	$8.5
5%[3] plus 3X	2.7%	$889	14	2.97	0.06	7.63	13	$26.0
5%[3] plus 5X	3.1%	$889	16	2.97	0.07	7.64	30	$25.8

	2020							
	generation by renewables	SO2 price	Emission Reduction (million short tons)				incremental elec gen from renew	Resource Cost
	% of total gen.	$/ton	Carbon	SO2	NOx	Mercury (tons)	TWh	billion $
Base case	3.4%	$153						
Tightened SO_2 cap								
3% per year	3.7%	$629	5	3.79	0.00	8.15	16	$16.3
5% per year	3.6%	$1,113	11	5.18	0.00	11.27	11	$19.3
SO_2 credit cases								
3X ($1.4/MWh)	4.2%	$213	10	0.00	0.01	0.02	48	-$1.0
5X ($2/MWh, estimated)	4.3%	$193	10	0.00	0.02	0.02	54	-$0.4
Combinations								
3%[2] plus 3X	4.8%	$629	16	3.79	0.02	8.19	77	$16.4
5%[3] plus 3X	6.4%	$1,113	15	3.79	0.02	8.18	167	$18.5
5%[3] plus 5X	8.2%	$1,113	50	5.18	0.07	11.79	265	$17.3

1. Renewables exclude hydro but include landfill gas and industrial cogeneration
2. Reductions starting in 2003 - targets are 6.99 million tons in 2010, 5.16 million tons in 2020
3. Reductions starting in 2003 - targets are 6.29 million tons in 2010, 3.77 million tons in 2020

As expected, the combined cases achieve similar SO_2 and mercury reductions as the cases with tightened SO_2 caps – significant reductions in SO_2 (58% reduction from base case in 2020 for 5% plus 5X case) and some mercury reductions (25% reduction in 2020 for 5% plus 5X case). These pollutant reductions strongly surpass the SO_2 credit cases. In addition, generation from renewables increases, surpassing both the tightened SO_2 caps and SO_2 credit cases. Renewable generation in the combined cases exceeds the SO_2 credit cases because the higher prices for SO_2 credits provides greater incentive for the renewables. However, carbon reductions are limited in the combined cases – only 6% reduction from base case in 2020 for the 5% plus 5X case – since the renewables will primarily replace natural gas generation, rather than coal generation.

These impacts would occur with much lower requirements for SO_2 allowance set-asides. Table 14 indicates the required numbers of SO_2 allowances for each case in 2010 and 2020. To achieve 8.2% renewable generation in 2020 requires a transfer of about 2.65 million SO_2 credits in the combined case, while in the uncombined SO_2 credit cases 9.1% renewables required transferring an unreasonable 30 million SO_2 credits.

Table 14 Policy Implications of Combined Cases

	2010		
	generation by renewables[1]	SO2 price	Annual credits
	% of total gen.	$/ton	million tons
Base case	2.5%	$207	
Tightened SO_2 cap			
3% per year[2]	2.5%	$290	
5% per year[3]	2.6%	$889	
SO_2 credit cases			
3X ($1.4/MWh)	2.6%	$205	0.04
5X ($2/MWh, estimated)	2.6%	$203	0.05
Combinations			
3%[2] plus 3X	2.6%	$290	0.04
5%[3] plus 3X	2.7%	$889	0.08
5%[3] plus 5X	3.1%	$889	0.30

	2020		
	generation by renewables	SO2 price	Annual credits
	% of total gen.	$/ton	million tons
Base case	3.4%	$153	
Tightened SO_2 cap			
3% per year	3.7%	$629	
5% per year	3.6%	$1,113	
SO_2 credit cases			
3X ($1.4/MWh)	4.2%	$213	0.31
5X ($2/MWh, estimated)	4.3%	$193	0.60
Combinations			
3%[2] plus 3X	4.8%	$629	0.46
5%[3] plus 3X	6.4%	$1,113	1.00
5%[3] plus 5X	8.2%	$1,113	2.65

1. Renewables exclude hydro but include landfill gas and industrial cogeneration
2. Reductions starting in 2003 - targets are 6.99 million tons in 2010, 5.16 million tons in 2020
3. Reductions starting in 2003 - targets are 6.29 million tons in 2010, 3.77 million tons in 2020

8. Impacts of natural gas price feedbacks

Increasing renewable generation, leads to decreased fossil fuel demand, particularly decreased natural gas demand. The decreased demand leads to lower natural gas prices. This section presents the impacts of the decreased natural gas prices to the economy. Although Tellus-NEMS includes a response to the lower price (i.e., natural gas demand increases), in the cases in this study the impact of this response on overall costs is smaller than the effect of lower prices. Table 11 decomposes the resources cost into three categories. Natural gas feedback to the rest of the economy indicates the effects of the changes in prices to the industrial, residential and commercial sectors (including both price and minor changes in demand due to the change in fuel price). Natural gas feedback to the electricity sector is the effect of the change in natural gas price in the electric sector (only includes the effect of price changes, not the effect of changed demand). All other costs (the cost of new renewable plants, additional fuel expenditure for biomass, decreased fuel expenditure due to lower natural gas and coal demand) are contained in the final term.

Most of the cases indicate that the natural gas price feedbacks are as significant as all other costs (note however that the remainder costs are *net costs* including both increased costs from capital expenditures and some fuel savings due to decreased fossil demand). In the cases with tightened SO_2 caps, the price feedbacks lead to increased resource costs. The tighter caps result in increased natural gas consumption, as a means of meeting the SO_2 caps, which leads to higher natural gas prices for all sectors.

Table 15 Resource cost decomposition (net present value, 2002 to 2020)

		resource cost decomposition		
Cases	Resource Cost	NG feedback from rest of economy	NG price feedback in electricity	remainder (electric sector capital, fuel, O&M)
	billion $	billion $	billion $	billion $
SO2 cases				
$1.4 / MWh	-0.96	-0.96	-0.69	0.69
$3 / MWh	0.42	-0.50	-0.47	1.39
$7 / MWh	-0.87	-4.10	-2.68	5.91
$14 / MWh	-2.89	-12.42	-6.67	16.21
$28 / MWh	4.80	-20.06	-11.11	35.97
$34 / MWh	55.28	-34.66	-19.48	109.42
Tightened SO2 cap				
3% per year	16.25	4.20	2.97	9.08
5% per year	19.32	6.23	3.28	9.82
RPS cases				
$3 / MWh	-2.12	-2.31	-1.24	1.43
$7 / MWh	-5.76	-4.18	-2.41	0.83
$14 / MWh	-10.43	-10.28	-5.43	5.28
$28 / MWh	-13.93	-21.64	-11.48	19.18
$34 / MWh	12.66	-38.95	-22.00	73.61
NOx cases				
$1.4 / MWh	0.08	-0.05	-0.07	0.20
$3 / MWh	-0.17	-0.27	-0.17	0.26
$7 / MWh	0.53	-0.76	-0.64	1.93
$14 / MWh	0.85	-3.85	-2.23	6.94
$28 / MWh	4.67	-8.97	-5.02	18.67
$34 / MWh	41.81	-15.19	-7.92	64.91

The following charts present the carbon cost curves with the decomposition of the natural gas price feedbacks. In all charts the lowest line represents the costs with all feedbacks (same as the line shown in previous charts). The middle line represents the costs without the economy-wide price feedback effect in the demand sectors and the top line represents the costs without any natural gas price feedback. Thus, going from top to middle incorporates the economy-wide feedbacks and going from middle to bottom adds the electricity sector feedbacks.

Without natural gas price feedbacks, none of the cases show net economic benefits since, as expected these cases incur costs to reduce emissions by generally higher cost supply-side options.[7]

[7] A countervailing factor is the technology learning or scale economies, which can result in policy-induced the cost reductions of renewable electricity over time.

Figure 19 SO_2 cases showing impacts of natural gas feedback

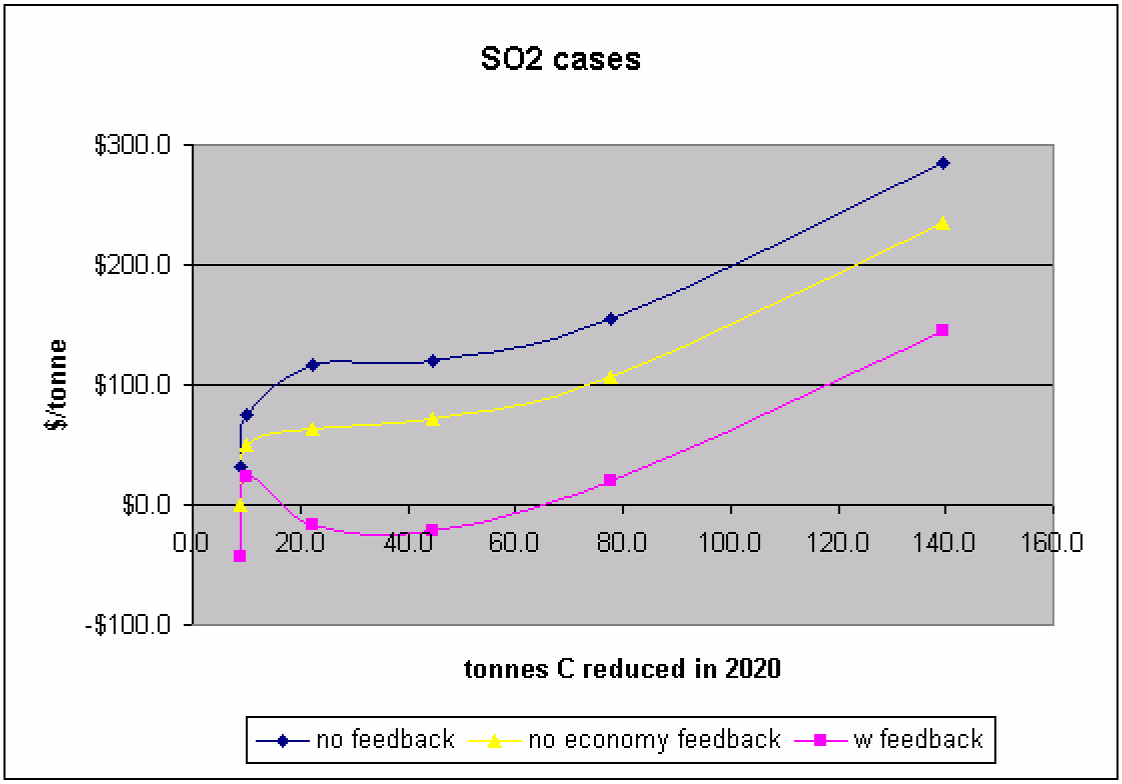


Figure 20 RPS cases showing impacts of natural gas feedback

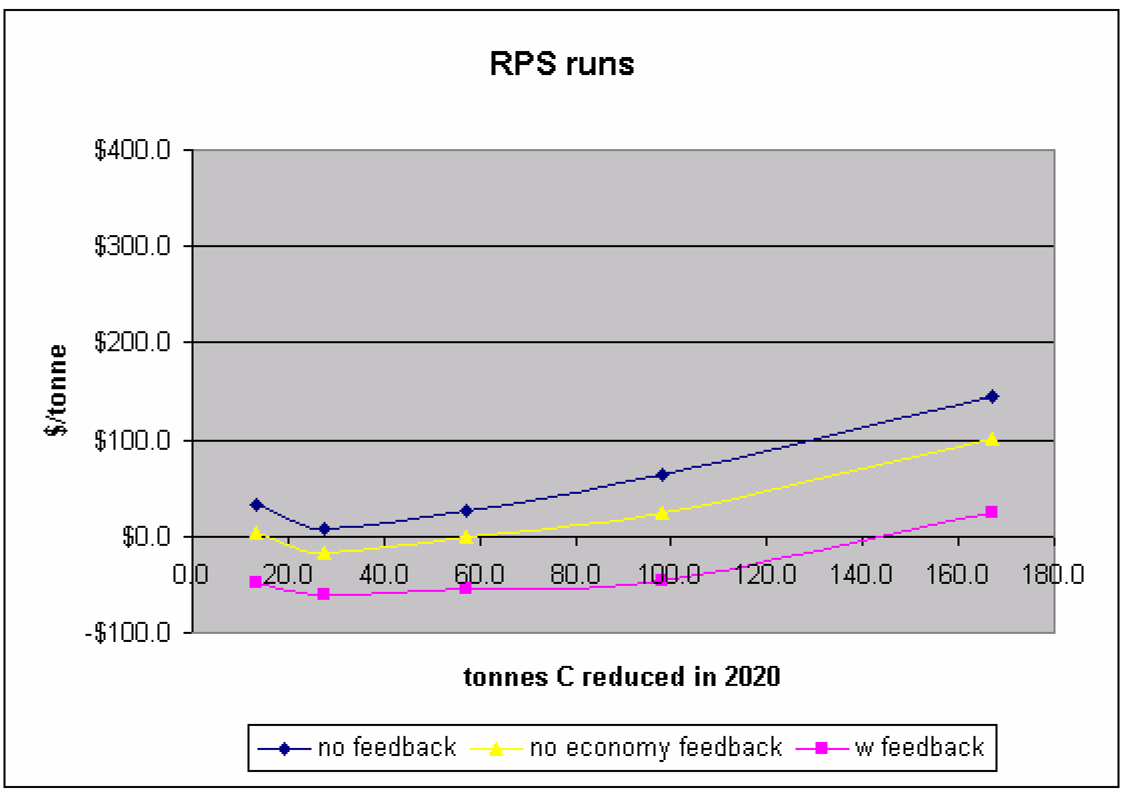
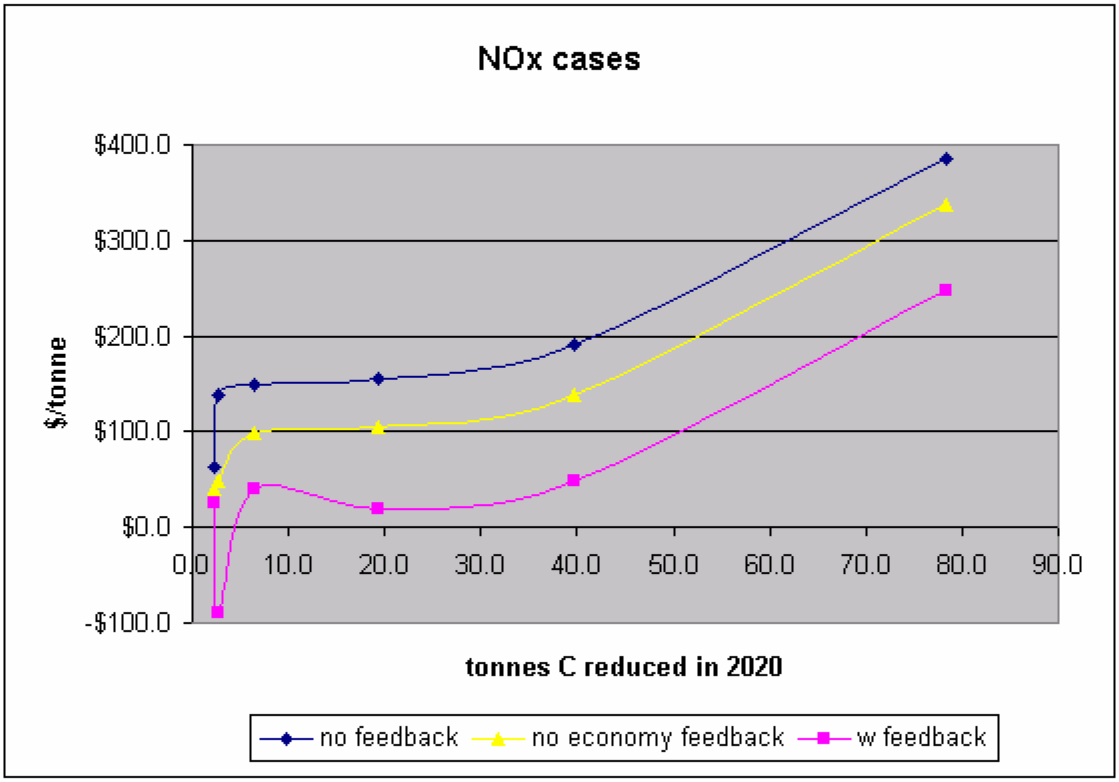


Figure 21 NOx cases showing impacts of natural gas feedback



Natural gas price feedbacks for the multipollutant runs are shown in table 16. The feedbacks lead to increased costs since the multipollutant runs result in greater natural gas demand and thus higher prices.

Table 16 Natural gas price feedback in Multipollutant runs

		resource cost decomposition			Cost of saved carbon		
	Resource Cost billion $	NG feedback from rest of economy billion $	NG price feedback in electricity billion $	remainder (electric sector capital , fuel, O&M) billion $	based on total resource cost $/tonne C	with no feedback to rest of economy $/tonne C	no feedback to economy or electricity $/tonne C
multipollutant with RPS	$169.6	$4.8	$62.2	$102.6	$117.4	$114.0	$71.0
multipollutant	$213.3	$57.9	$109.8	$45.6	$144.5	$105.3	$30.9
RPS + 5% SO2	$40.4	-$30.6	-$16.9	$87.9	$67.6	$118.9	$147.2
RPS	$12.7	-$38.9	-$22.0	$73.6	$24.8	$101.3	$144.4
$34 / MWh	$55.3	-$34.7	-$19.5	$109.4	$144.3	$234.8	$285.7
Tightened SO2 cap 5% per year	$19.3	$6.2	$3.3	$9.8	N/A	N/A	N/A

9. Conclusions

This analysis has shown that increasing penetration of renewable electricity provides direct economic benefits, up to a certain amount of renewables. At higher levels, the renewables lead to net economic costs yet still yield benefits through increased emission reductions. However, the choice of policy for encouraging renewables will be key to achieving increased levels.

In particular, we have shown:

1. Substantial increases in the amount of renewables are beyond the capability of a set-aside policy, since more allowances would need to be transferred to renewable generated than are available in the cap and trade program. Thus a set-aside program alone will likely only result in small increases in renewable generation, small decreases in carbon and mercury emissions and no changes in SO_2 and NO_x emissions.

2. Tightening the SO_2 cap in the CAAA will reduce SO_2 and mercury emissions, but will have almost no impact on renewable generation, carbon emissions and NO_x emissions. In general, the tighter SO_2 caps lead to increased use of control equipment in coal plants rather than encouraging plant retirements and renewables.

3. Combining tightened SO_2 caps with enhanced set-asides will help provide some additional incentives for renewables through increasing the value of the credits available in the CRER. This combination can *partly* lead to achieving clean air and clean energy objectives, but is inherently limited.

4. A national RPS provides similar changes in emissions and energy use as increasing incentive factors within the CAAA. However, the extent of the RPS is not constrained by availability of allowances, so it can be designed to lead to far greater increase in renewables and associated reductions in carbon emission.

5. In general, increased generation from renewables has very little effect on emissions that are already controlled by cap and trade systems and can be effectively limited through control equipment (SO_2 and NO_x) or fuel switching, but does reduce other emissions (carbon and mercury) through reductions in fossil fuel use. These benefits are limited, however, as the renewables tend to displace natural gas rather than coal generation. This is because renewable sources are most likely to displace new plants and most new plants are expected to be natural gas. Displacing natural gas limits the impacts on carbon emissions, since the avoided plants would likely be efficient and natural gas has lower emissions than coal but does provide a strong economic benefit to the whole economy. The decreased demand for natural gas leads to lower natural gas prices. These lower prices lead to benefits to all natural gas users. The modeling work indicated that the prices were not large enough to lead to increased natural gas consumption but the small

price change multiplied by natural gas consumption throughout the country results in a significant economic benefit.[8]

6. Multi-pollutant cap and trade policies can directly achieve large reductions in the targeted emissions, with the policy design being the only limit on reduction potential. However, much of the emission reductions can be achieved through control equipment or fossil fuel switching so even the multi-pollutant approach provides only minimal encouragement for renewable energy.

7. Combined multi-pollutant cap and trade policies with a national RPS achieves the stated clean air and clean energy objectives – precisely because of its design. The addition of renewable generation decreases the cost of achieving the multipollutant reductions.

[8] It is possible that at high enough natural gas prices, and barring other constraints, new plants would be dominated by coal. At or near the crossover point in their costs, the economics of the options would be comparable but for the foregone feedback effects, while the avoided emissions would be far greater.

Appendix A

Renewable Energy Characterizations in NEMS (AEO2002)

Review and Recommendations

Plus Final Changes Accepted by NREL

NEMS Model Modifications for Renewables – Review and Recommendations

The following changes were applied to NEMS (AEO2001 version) for analysis that Tellus completed with the Union of Concerned Scientists. Some of these changes may be appropriate for NREL's project for Aligning Clean Air and Clean Energy Goals.

1. Remove regional build limits for biomass and solar technologies
AEO2002 assumes 1 GW limits per NEMS-NERC region per year but we have not found the justification for this assumption.

2. Remove long-term capital cost multipliers for biomass gasification
AEO2002 also assumes no capital cost multipliers for biomass gasification (although AEO2001 did include multipliers)

3. Change wind capital cost multipliers and intermittency constraint
EIA uses capital cost multipliers in NEMS because "capital costs for generating technologies using biomass, geothermal, or wind resources are assumed to increase as a function of exhaustion of most favorable resources. In general, capital costs are assumed to increase because of any or all of three broad conditions: (1) necessity of using less favorable natural resources, (2) increasing costs of upgrading existing distribution and transmission networks - separate from costs of building and interconnecting, and (3) increasing costs competing for other uses of the biomass or wood resource, including increasing costs in meeting environmental concerns." (NEMS model documentation for AEO2001 version of renewable energy submodule, February 2001).

Table 1 presents the capital cost multipliers used in AEO2002 based on the capacity to which the multipliers are applied in each region. The table should be read from left to right, the amount in the first column is the amount of capacity in which the capital costs

Table 1. The AEO2002 capital cost multipliers based on capacity being used

Multiplier → Region ↓	1	1.2	1.5 (MW)	2	3	Total potential capacity (MW)
1 ECAR	390	390	390	390	2,342	3,904
2 ERCOT	2,193	1,495	3,489	2,093	698	9,968
3 MAAC	927	927	927	927	5,562	9,270
4 MAIN	-	-	-	-	-	-
5 MAPP	7,084	14,168	42,505	42,505	1,310,567	1,416,829
6 NY	340	340	340	340	2,039	3,398
7 NE	883	883	1,766	1,766	3,532	8,831
8 FLOR.	-	-	-	-	-	-
9 STV	177	177	354	354	708	1,769
10 SPP	2,405	4,811	14,432	14,432	444,994	481,074
11 NWP	7,556	12,996	8,463	1,511	271,710	302,236

12 RA	3,955	3,955	7,910	19,775	162,156	197,751
13 CNV	2,950	787	787	787	14,355	19,664

will be multiplied by 1 (no change). Once that amount of capacity has been built, the next column shows the amount of capacity that will have capital costs multiplied by 1.2. So in region 13, CNV (California plus Las Vegas), the first 2,950 MW of wind capacity built will have no changes to capital costs, the next 787 MW built will have capital costs multiplied by 1.2. After 5,309 MW (2950+787+787+787) have been built, the remaining 14,355 MW will have capital costs multiplied by 3.

We suggest following the approach

1. Decrease available windy land areas based on analysis by Michael Brower and Steve Clemmer
2. Change capital cost multipliers based on analysis by *Clean Energy Future* but using slightly lower values for the required cost of combustion turbine back-up for wind

In the UCS analysis, windy land areas were reduced from AEO2001 assumptions by the amounts in Table 2. The mountainous region reductions are based on analysis by Michael Brower for the Northwest, the non-mountainous reductions are half of the mountainous areas based on analysis by Steve Clemmer, Union of Concerned scientists.

Table 2. % reduction by resource class

	Mountainous Regions	Non-Mountainous
6	39%	20%
5	35%	17%
4	35%	17%

These changes lead to a more conservative estimate of total potential wind capacity than in the AEO2002.

The second change is based on the *Clean Energy Future* (CEF) analysis that found no evidence of penalties to wind installations of greater than 20%. CEF used capital cost multipliers to capture the 20% penalty plus charges for ancillary services and other back-up capacity charges. The extra charges used by CEF reflect the cost of a natural gas turbine. The costs, estimated at 40% of the capital cost of a wind system, are appended to the cost of the wind system as penetration in a region grows from 10% to 20% and additional to the 20% penalty taken from EIA's assumptions. Thus the highest multiplier used by CEF is 1.6 times the capital cost.

However, we revised the level of the back-up charges. Discussions between UCS and Walter Short led UCS to propose extra charges of 20%, rather than 40%, of the capital cost of wind, since the full cost of the natural gas turbine wouldn't be required to cover the intermittency requirements of wind. Thus the highest multiplier used for the UCS analysis was 1.4 times the capital cost; we recommend using these lower capital cost multipliers for the NREL analysis. NEMS also includes subroutine for providing backup for intermittents (in calculating the contribution to reserve margin calculations, wind and photovoltaics do not receive full credit for their available capacity, only 75%. The model then chooses the cost effective means for providing backup capacity). Thus the multipliers outlined above will include some double counting for back-up provision. But we feel this method captures the reliability issues of wind by using values that are associated with system costs, and any double-counting errors will be on the side of us being slightly conservative.

Table 3 presents capital cost multipliers used in *Clean Energy Future* based on the capacity to which the multipliers are applied in each region. The table should be read from left to right, the amount in the first column is the amount of capacity in which the capital costs will be multiplied by 1 (no change). Once that amount of capacity has been built, the next column shows the amount of capacity that will have capital costs multiplied by 1.2, continuing in the same manner through the rest of the columns. The capital cost multipliers in this case reflect the costs of additional backup requirements (combustion turbines) at greater penetrations of wind generation.

Table 3. *Clean Energy Futures* Capital cost multipliers based on capacity being used

Multiplier → Region ↓	1	1.2	1.3 (MW)	1.4	1.6	Total potential capacity (MW)
1 ECAR	390	3,513	0	0	0	3,904
2 ERCOT	1,495	5,074	1,640	1,640	120	9,968
3 MAAC	927	5,506	1,613	1,224	0	9,270
4 MAIN	0	0	0	0	0	-
5 MAPP	3,542	2,125	1,204	1,204	1,408,328	1,416,829
6 NY	340	2,742	316	0	0	3,398
7 NE	883	2,119	751	751	4,327	8,831
8 FLOR.	0	0	0	0	0	-
9 STV	177	1,592	0	0	0	1,769
10 SPP	4,570	3,127	1,684	1,684	470,010	481,074
11 NWP	6,800	1,965	1,632	1,632	290,146	302,236
12 RA	1,978	2,373	1,068	1,068	191,324	197,751
13 CNV	2,360	2,910	1,317	1,317	11,759	19,664

The following table indicates the revised values for capital cost multipliers based on the combination of decreased wind areas and altered capital cost multipliers. The values in the table are the fraction of available resource at each of the capital cost multipliers (column headings). The change in windy areas leads to decreases in total potential capacity. The capital cost multipliers follow the multipliers from the *Clean Energy Future* for matching levels of capacity.

Table 4. Suggested Capital cost multipliers based on capacity being used

Multiplier → / Region ↓	1	1.2	1.25 (MW)	1.3	1.4	Total potential capacity (MW)
1 ECAR	390	2,840	0	0	0	3,230
2 ERCOT	1,495	6,754	0	0	0	8,249
3 MAAC	927	5,145	0	0	0	6,072
4 MAIN	0	0	0	0	0	0
5 MAPP	3,542	2,125	1,204	1,204	1,164,350	1,172,426
6 NY	340	1,886	0	0	0	2,226
7 NE	883	2,119	751	751	1,112	5,616
8 FLOR.	0	0	0	0	0	0
9 STV	177	977	0	0	0	1,154
10 SPP	4,570	3,127	1,684	1,684	387,024	398,089
11 NWP	6,800	1,965	1,632	1,632	182,923	194,952
12 RA	1,978	2,373	1,068	1,068	122,046	128,532
13 CNV	2,360	2,910	1,317	1,317	4,632	12,537

4. Change intermittency constraint

We suggest increasing the intermittency constraint to 30% of generation per region. Beyond this level, NEMS prohibits further building of wind or photovoltaics. AEO2002 applies a constraint of 12% of generation per region but EIA has increased this constraint to 15% for cases with carbon emission limits. Parts of Spain, Germany and Denmark have wind penetration of at least 20%. NEMS applies a capacity scaling factor of 75% to intermittent technologies when calculating the contribution of plants to meeting peak demand so that all intermittent plants are forced to have some backup. NEMS does not allow this scaling factor to change based on amount of installed capacity.

5. Reduce geothermal capital cost multipliers

Reduced geothermal costs as follows (based on information from Dan Entingh, PERI):

Exploration: no change	Drilling: reduce by 15%
Field: reduce by 12%	Power plant: reduce by 25%

And removed capital cost multipliers (cost does not depend on fraction of resource used).

Note that the AEO2002 assumptions have a significant decrease in the potential capacity from each site, compared with the AEO2001 capacity assumptions, and annual build restrictions have been added. EIA describes the changes as "more realistic" for capacity availability through 2020 and "reflecting industry practice of expanding development gradually" (EIA 2001, p 116). Geothermal generation has been significant in runs that we did using AEO2001 assumptions so we expect these changes to have a large impact on the results.

6. Cofiring

NEMS allows cofiring of biomass in coal generation plants without additional capital expenditures but the level of cofiring per plant is limited. In the AEO2001 and AEO2002 the limit is about 4.2% (varies by region). The EIA increased this limit to 10% in runs that specifically encourage renewable energy, such as their analyses of Renewable Portfolio Standards. This change was also applied in the analysis for UCS.

7. Cost and performance assumptions

For previous work, we also considered a "Research and Development" case. This was modeled through turning off NEMS learning (scale economy) features and by hard-wiring capital costs, O&M costs and capacity factors (for solar and wind) based largely on EIA high renewables case (for AEO2001). The drawback with this method is that it eliminates the feedback relationship between increased capacity leading to lower capital costs through learning. NEMS has several parameters that influence the capital costs and changes to these costs over time.

We are open to exploring adjustments to these parameters (rate of learning, maximum cost by end of period) and happy to discuss any ideas on methods to more accurately portray the current environment or expected changes to the environment due to increased generation by renewables.

The following describe the changes that were made to reflect research and development for the UCS analysis. The values are reported in table 5.

- *Biomass gasification*

Use AEO 2001 high renewables biomass supply curve plus hardwired capital costs based on EPRI/DOE projections.

- *Wind*

Hard-wire capital costs and use alternative capacity factors contained in AEO2001 high renewable case input files.

- *Solar Thermal*

Increase capacity factors based on AEO 2001 High Renewables Case plus hardwired capital costs from AEO2001 High Renewables case.

- *PV (Central Station)*

1. Hard-wire capital costs based on EPRI/DOE projections for utility scale flate plate thin film PV
2. Assume 20.7% capacity factor 2000-2020, as assumed in the high renewables case.

The following table represents the capital costs and capacity factors used for AEO2001 and AEO2002. For AEO2001, we also report the costs and capacity factors for the UCS R&D technology characterizations as described above. For AEO2002, we report the characterizations for high renewables case that EIA uses as a sensitivity case.
Note that the costs for the AEO2001 and AEO2002 cases include the EIA learning function. This input under a different environment (eg. with additional incentives for

renewables) could lead to different capital costs in later years depending on penetration of these systems. The costs for the R&D UCS and High Renewables cases follow a user-specified temporal change, regardless of technology penetrations.

Table 5. Cost and capacity factors assumed in AEO2001 and AEO2002

		AEO2001 Overnight Cost ($1999/kW)		AEO2001 capacity factors		AEO2002 Overnight Cost ($1999/kW)		AEO2002 capacity factors	
		AEO 2001	R&D UCS	AEO 2001	R&D UCS	AEO 2002	High ren-ewables	AEO 2002	High ren-ewables
Biomass	**2000**	1,723	1,723			1,687	1,687		
	2005	1,637	1,612	80	80	1,522	1,477	80	80
	2010	1,294	1,468	80	80	1,393	1,398	80	80
	2015	1,179	1,339	80	80	1,346	1,349	80	80
	2020	1,171	1,248	80	80	1,274	1,286	80	80
Landfill Gas	**2000**	1,395	1,395			1,398	1,398		
	2005	1,378	1,378	90	90	1,386	1,386	90	90
	2010	1,360	1,360	90	90	1,371	1,371	90	90
	2015	1,343	1,343	90	90	1,357	1,357	90	90
	2020	1,325	1,325	90	90	1,343	1,343	90	90
Geothermal	**2000**	1,708	1,708			1,708	1,708		
	2005	1,778	2,123	87	87	1,658	1,473	95	95
	2010	1,699	2,338	87	87	1,551	1,264	95	95
	2015	1,696	2,239	87	87	1,643	1,426	95	95
	2020	1,696	1,967	87	87	1,982	1,672	95	95
Wind	**2000**	983	983			961	961		
	2005	928	849	32	41	901	912	39	44
	2010	898	976	34	45	887	852	41	46
	2015	871	880	36	46	857	793	42	47
	2020	820	788	38	47	808	734	42	48
Solar Thermal	**2000**	2,946	2,946			2,483	2,483		
	2005	2,916	2,825	42	44	2,400	2,842	42	52
	2010	2,730	2,577	42	56	2,297	2,925	42	63
	2015	2,585	2,377	42	68	2,194	2,870	42	75
	2020	2,402	2,200	42	77	2,090	2,814	42	77
Photovoltaic	**2000**	4,252	4,252			3,746	3,746		
	2005	3,089	3,202	28	21	2,662	3,189	30	30
	2010	2,599	1,655	29	21	2,351	1,649	30	30
	2015	2,481	1,438	30	21	2,243	1,434	30	30
	2020	2,400	1,210	30	21	2,170	1,219	30	30

For comparison, the following table presents capital costs and capacity factors from the EPRI/DOE report, *Renewable Energy Technology Characterizations* (EPRI/DOE 1997) and from the *Clean Energy Future* report. The values in all cases in this table are independent of technology penetration.

Table 6. Cost and capacity factors projected by EPRI/DOE and those used in moderate and advanced cases for *Clean Energy Future*

		EPRI/DOE			CEF-NEMS		
		Overnight Cost ($1999/kW)			Overnight Cost ($1999/kW)		capacity factor
			Capacity factor		Moderate	Advanced	
Biomass	2000	1,944			1,620	1,620	
	2005	1,696	80		1,433	1,433	80
	2010	1,505	80		1,319	1,319	80
	2015				1,221	1,221	80
	2020	1,293	80		1,200	1,200	80
Landfill Gas	2000						
	2005						
	2010						
	2015						
	2020						
Geothermal	2000	1,410			1,487	1,487	
	2005	1,285	93		1,397	1,285	96
	2010	1,227	95		1,340	1,227	96
	2015				1,289	1,179	96
	2020	1,130	96		1,282	1,130	96
			class 6	class 4			
Wind	2000	771	40	30	699	699	
	2005	740	45	35	662	662	class 6 40-49
	2010	694	46	36	638	638	class 4 30-38
	2015				629	629	
	2020	673	48	38	625	625	
Solar Thermal	2000	4,486	43		3,653	3,653	
	2005	2,394	44		2,816	2,816	
	2010	2,677	65		2,457	2,457	43-77
	2015				2,419	2,419	
	2020	2,593	77		2,403	2,403	
Photovoltaic	2000	5,447	21		3,971	3,971	
	2005	2,980	21		2,187	2,187	
	2010	1,542	21		1,329	1,329	varies by
	2015				1,146	1,146	region
	2020	1,141	21		1,038	1,038	

8. Learning

The AEO2001 and AEO2002 versions of NEMS include learning functions leading to decreased capital costs for technologies as their cumulative installed capacity increases. The UCS, EPRI/DOE and Clean Energy Future reports did not include explicit links between cumulative installed capacity and capital costs but instead specified costs that changed over time. This latter method allows other factors that influence capital costs to also be included through the user-specified costs, such as effects of focused research and development.

The following table presents the progress ratios (the change in capital cost for each doubling of installed capacity) applied in AEO2001 and AEO2002. In NEMS, different progress ratios are applied depending on the "maturity" of the technology. As more capacity is built, the capital costs decrease at a slower rate. The periods in the table refer to the maturity of the technology. For example, the capital costs for biomass technologies decline to 90% of the starting capital cost for each doubling of capacity up to 3 doublings. For the next 5 doublings of capacity, the costs decline to 95% for each doubling. After that, costs only decline to 99% of the cost for each doubling of capacity. NEMS also includes a minimum decline in capital cost by 2020, regardless of the penetration of the technology. This decline is converted to an annual change and if the penetration of the technology does not cause the cost to decline at the rate required to reach the minimum, NEMS will overwrite the learning function costs with the costs required to meet the minimum decline.

Table 7. Learning Parameters from AEO2002

Technology	Progress Ratio			Doublings		Minimum Total Learning By 2020
	Period 1	Period 2	Period 3	Period 1	Period 2	
Biomass	90%	95%	99%	3	5	80%
Geothermal		95%	99%		5	90%
Wind		95%	99%		5	80%
Solar thermal	90%	95%	99%	3	5	80%
Photovoltaic	90%	95%	99%	3	5	80%

For comparison, we reviewed the relevant literature on the relationship between productions and capital costs and summarized the findings in the table below. This review indicates that assumptions for learning in AEO2001 and AEO2002 for wind and solar thermal are close to the literature but we could consider using progress ratios of 80% for photovoltaics.

Table 8. Learning Parameters from Literature

	Source			
	Bernow, S. et al. 2000	Greening, L. et al, 2000	Macdonald, A. and L. Schrattenholzer, 2000	Junginger, M. 2000

Wind	95%	90%	83%-92%	85%-96%
Solar thermal		90%		
Photovoltaics	82%	70%	78%	

Recommendations for capital costs

In general we prefer using the endogenous learning function to capture the benefits of increased installed capacity on the capital costs of technologies. The learning function parameters are close to published literature in most cases but we are willing to modify these based on NREL experience.

Runs

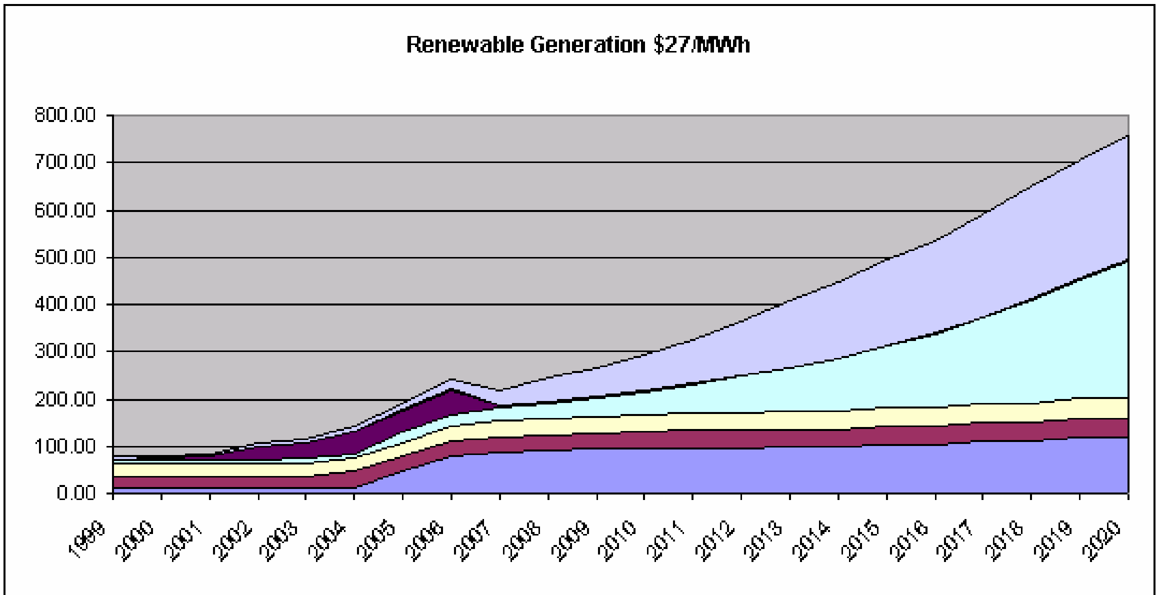
The following results, using NEMS2001, indicate some of the effects of changing the renewable energy technology characteristics discussed above. Four runs are compared
Basecase – based on AEO2001 but including all changes discussed above for the UCS analysis except the capital costs associated with the UCS R&D run

Each policy run includes an incentive factor for renewables equal to $27/MWh (1999$).
$27/MWh – uses the same renewable characteristics as the basecase, but also allows up to 10% biomass cofiring
$27/MWh, no adjustments – uses the AEO2001 renewable energy characteristics
$27/MWh, with R&D – uses the basecase characteristics plus the annual capital costs from the UCS R&D run, allows up to 10% biomass cofiring.

The following tables and graphs present the national amount of generation from renewable sources.

Table 9. Electricity Generation from Renewable Energy (TWh), 4 Cases

	2000	2005	2010	2015	2020	Capital cost in 2020 ($1999/kW)
Basecase (with adjustments to renewable characteristics, learning function in use)						
Geothermal	13.39	17.22	27.46	27.64	27.67	$ 1,696
Municipal Solid Waste	22.39	26.69	29.39	32.26	33.31	$ 1,325
Wood (cogen)	27.06	29.92	35.01	39.55	41.18	
Dedicated biomass	7.70	8.67	10.88	12.99	13.35	$ 1,171
Cofiring	2.87	9.65	11.38	9.67	8.78	
Solar Thermal	0.89	0.96	1.11	1.24	1.37	$ 2,402
Solar Photovoltaic	0.04	0.20	0.51	0.92	1.36	$ 2,400
Wind	5.18	9.42	12.33	12.84	12.94	$ 820
Total renewables	**79.52**	**102.73**	**128.07**	**137.11**	**139.94**	
$27/MWh (with adjustments to renewable characteristics, learning function in use)						
Geothermal	13.39	45.95	94.68	104.26	120.60	$ 2,213
Municipal Solid Waste	22.39	32.32	35.43	38.44	39.48	$ 1,325
Wood (cogen)	27.06	29.92	35.01	39.55	43.52	
Dedicated biomass	7.69	21.04	49.83	130.17	288.29	$ 891
Cofiring	4.29	46.95	0.27	0.00	0.00	
Solar Thermal	0.89	0.96	1.11	1.24	1.37	$ 2,402
Solar Photovoltaic	0.04	0.20	0.51	0.92	1.36	$ 2,400
Wind	5.18	13.73	75.85	180.27	263.58	$ 1,015
Total renewables	**80.93**	**191.08**	**292.69**	**494.85**	**758.20**	
$27/MWh - No Adjustments to renewables (learning function in use)						
Geothermal	13.39	43.66	63.15	69.89	69.91	$ 2,633
Municipal Solid Waste	22.39	32.32	35.43	38.44	39.48	$ 1,325
Wood (cogen)	27.06	29.92	35.01	39.55	43.52	
Dedicated biomass	7.70	26.84	51.99	132.62	243.88	$ 942
Cofiring	2.63	2.73	0.30	0.00	0.00	
Solar Thermal	0.89	0.96	1.11	1.24	1.37	$ 2,402
Solar Photovoltaic	0.04	0.20	0.51	0.92	1.36	$ 2,400
Wind	5.18	9.99	45.41	84.24	149.32	$ 977
Total renewables	**79.28**	**146.62**	**232.91**	**366.89**	**548.85**	
$27/MWh withRD (plus other adjustment to renewables, learning function not in use)						
Geothermal	13.39	45.82	90.44	94.72	115.11	$ 1,967
Municipal Solid Waste	22.39	32.32	35.43	38.44	39.48	$ 1,325
Wood (cogen)	27.06	29.92	35.01	39.55	43.52	
Dedicated biomass	7.69	16.05	46.12	101.18	149.97	$ 1,248
Cofiring	4.45	50.15	0.51	0.00	0.00	
Solar Thermal	0.89	0.96	1.11	1.24	4.75	$ 2,200
Solar Photovoltaic	0.04	0.20	0.51	0.92	1.40	$ 1,210
Wind	5.18	15.95	124.07	209.58	291.88	$ 788
Total renewables	**81.09**	**191.37**	**333.20**	**485.62**	**646.11**	


Renewable Generation $27/MWh
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
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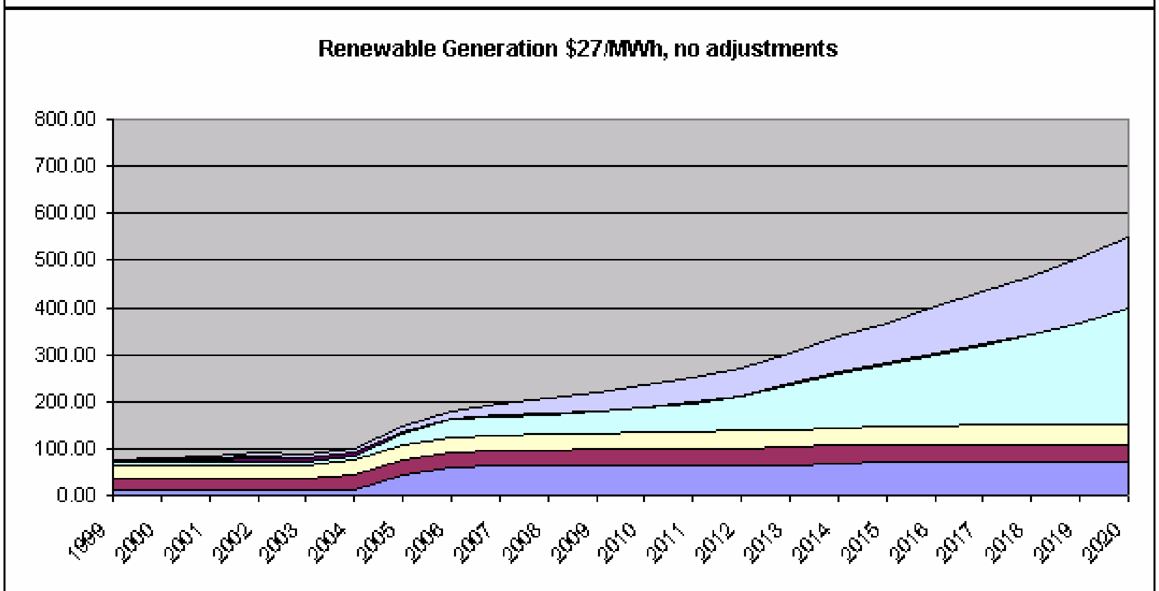
Renewable Generation $27/MWh, no adjustments
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
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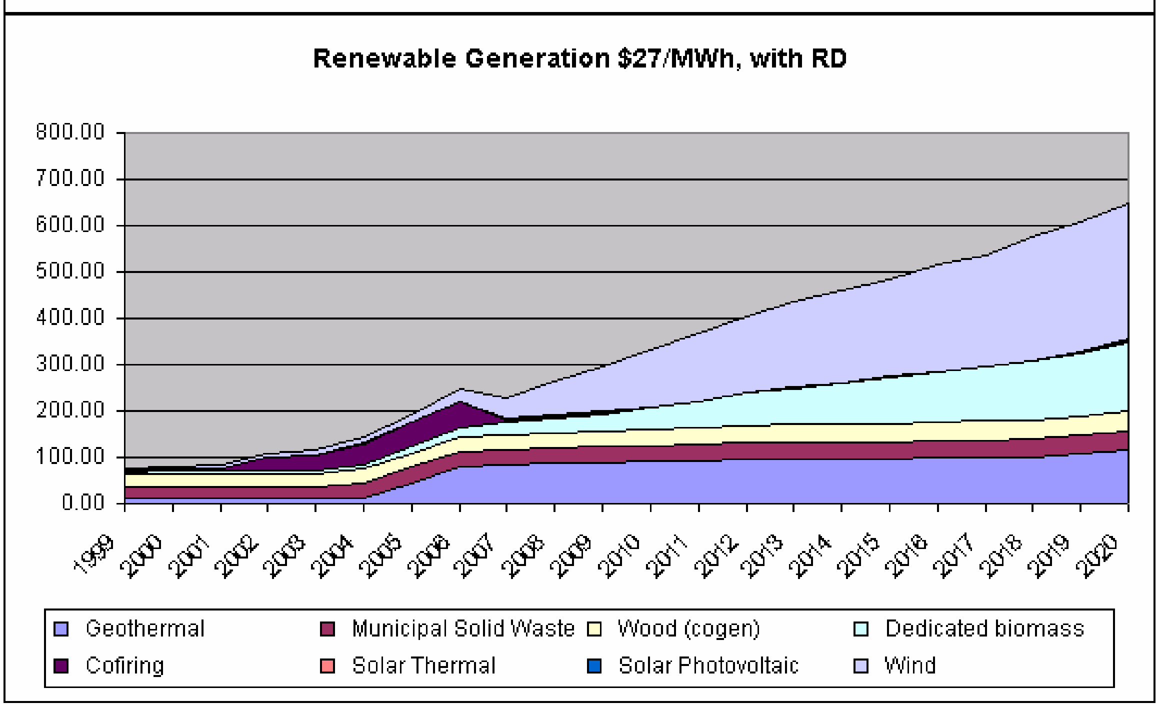
Renewable Generation $27/MWh, with RD
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
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2012
2013
2014
2015
2016
2017
2018
2019
2020
Geothermal
Municipal Solid Waste
Wood (cogen)
Dedicated biomass
Cofiring
Solar Thermal
Solar Photovoltaic
Wind

These results indicate several issues relevant to setting the technology characteristics.

Co-firing – allowing biomass co-firing up to 10% of an individual coal plant's input leads to a large increase in co-firing generation in the 2002-2007 period. However, after this time the economics (biomass costs, coal prices, declining costs for dedicated biomass plants) lead to a large decrease in co-firing. Note that co-firing did not receive any incentive in the runs described above and seems to be excluded from receiving credits under the current Clean Air Act.

RD run – this run bases declines in capital costs for renewable technologies on time rather than changes in production. The input annual capital costs lead to greater generation from renewables in 2010 but lower generation by 2020 (compared with the run that decreases costs based on changes in production levels). Wind generation is greater in the R&D case with dedicated biomass generation much lower. It has been shown that R&D spending can lead to as large an effect on capital costs as changes in production levels (Bernow et al 2000). However the choice of modeling method depends on the type of policies envisioned for this analysis (e.g. just incentive for generation or combination of incentives plus focused R&D).

We need advice from NREL on the following model modifications for all runs

1. **Remove regional build limits for biomass and solar technologies**
   we recommend making this change
2. **Remove long-term capital cost multipliers for biomass gasification**
   no change required
3. **Change wind capital cost multipliers**
   we recommend making this change
4. **Change intermittency constraint to 30%**
   we recommend making this change
5. **Reduce geothermal capital cost multipliers**
   we recommend making this change and also consider using capacity levels from AEO2001
6. **Increase co-firing limit to 10% of energy input**
   we recommend making this change
7. **Alter cost and performance characterizations**
   we recommend using the AEO2002 costs, capacity factors and learning functions, unless NREL wants to explicitly include a R&D policy.

FINAL CHANGES

1. **Remove regional build limits for biomass and solar technologies**
   this change was made
2. **Remove long-term capital cost multipliers for biomass gasification**
   no change was required

5. **Change wind capital cost multipliers**
   this change was made
6. **Change intermittency constraint to 30%**
   Intermittency constraint was set to 20%

5. **Reduce geothermal capital cost multipliers**

geothermal capital cost multipliers changes were made. No changes made to AEO2002 assumptions on potential site capacities following discussions with Dan Entingh from PERI (who recommended the capital cost multiplier changes) and review of AEO2002 assumptions by geothermal expert in NW (Dave Mclean). Dave did not fully endorse all the AEO2002 values but on balance they seemed to be speculative/high. We found no compelling reason to stick with AEO2001 values.

6. **Increase co-firing limit to 10% of energy input**
   this change was not made – little effect on the current analysis
7. **Alter cost and performance characterizations**
   used AEO2002 characteristics except wind capacity factors:

The following capacity factors are used to wind – they are based on input used in an analysis completed by LBL for NREL, *Green Pricing/Renewable Additions Analysis*.

# YEAR	CLASS6	CLASS5	CLASS4
1990	0.264	0.230	0.200
1995	0.32	0.27	0.24
2000	0.37	0.33	0.29
2005	0.45	0.39	0.33
2010	0.50	0.45	0.40
2015	0.51	0.46	0.41
2020	0.52	0.46	0.410
2025	0.52	0.46	0.410
2030	0.52	0.46	0.410

Also changed the learning factor for wind to more closely match the results from the LBL analysis, changed the learning rate for wind from 0.05 to 0.08 (% drop in capital cost for each doubling of domestic capacity) for 2^{nd} to 4^{th} doublings (parameter is 0.10 for first doubling and 0.01 for all doublings after 4^{th}, unchanged from AEO2002 assumptions)

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Appendix B

Electricity Generation and Capacity for Analysis

Results in 2010 and 2020

Electricity generation by Type – Baseline Runs

		NEMS basecase	NREL basecase	Extern 1.4	Extern 2.8	Extern 6.9	Extern 13.8	Extern 27.5	Extern 34.4	SO2 decli 3%	SO2 decli 5%
	1999	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010
Electricity Sales											
(billion kilowatthours).......	3324.05	4168.04	4169.25	4169.58	4170.25	4169.75	4171.03	4170.33	4171.02	4164.50	4151.35
Electricity Prices											
(2000 cents per kilowattho	6.73	6.35	6.34	6.34	6.34	6.34	6.30	6.30	6.27	6.38	6.46
Generation by Fuel											
(billion kilowatthours)											
Coal.........................	1887.14	2262.82	2263.79	2262.30	2261.53	2262.62	2254.94	2243.35	2233.66	2249.91	2212.37
Natural Gas..................	561.08	1154.35	1153.40	1149.67	1152.61	1145.46	1102.83	1072.54	1019.16	1164.00	1182.11
Oil..........................	123.96	36.77	37.32	37.33	37.74	37.69	36.62	35.39	33.36	35.17	29.83
Nuclear......................	728.34	736.88	736.88	736.88	736.88	736.88	736.88	736.88	736.88	736.88	744.09
Conventional Hydropower	315.75	305.46	305.46	305.46	305.46	305.46	305.46	305.46	305.46	305.46	305.46
Geothermal...................	15.43	20.10	20.16	21.02	20.51	21.20	23.86	25.96	25.98	19.98	20.23
Municipal Solid Waste......	21.19	31.07	31.07	35.33	31.99	32.35	37.61	38.17	38.96	31.29	34.81
Wood and other Biomass..	37.48	58.52	58.35	58.49	59.34	59.79	70.33	75.70	116.63	58.60	58.30
Dedicated Plants.........	7.01	9.72	9.72	9.72	9.72	14.90	32.29	34.37	78.59	9.72	9.73
Cofiring.................	0.51	10.76	10.59	10.73	11.58	6.85	0.00	3.29	0.00	10.84	10.53
Solar Thermal................	0.87	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Solar Photovoltaic...........	0.01	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Wind.........................	4.17	19.45	20.02	20.56	21.32	25.79	62.70	98.82	125.04	20.48	20.81
Other........................	17.61	12.85	12.86	12.85	12.86	12.86	12.87	12.87	12.87	12.87	12.86
Total......................	3713.02	4640.31	4641.36	4641.92	4642.29	4642.14	4646.14	4647.18	4650.02	4636.69	4622.92

	NEMS basecase	NREL basecase	Extern 1.4	Extern 2.8	Extern 6.9	Extern 13.8	Extern 27.5	Extern 34.4	SO2 declin 3%	SO2 declin 5%
	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
Electricity Sales										
(billion kilowatthours).......	4916.97	4919.59	4919.88	4920.24	4924.37	4932.82	4924.10	4910.40	4900.34	4896.11
Electricity Prices										
(2000 cents per kilowattho	6.47	6.44	6.43	6.44	6.40	6.33	6.34	6.35	6.51	6.56
Generation by Fuel		16.17								
(billion kilowatthours)		18.15								
Coal.........................	2481.12	2464.95	2437.82	2436.61	2417.39	2362.98	2291.31	2201.45	2436.57	2392.63
Natural Gas..................	1725.10	1706.96	1686.53	1674.70	1597.98	1517.07	1372.42	1042.11	1710.27	1759.20
Oil..........................	46.90	46.89	46.41	46.02	44.65	38.33	34.70	28.12	41.51	36.98
Nuclear......................	701.76	701.76	701.76	701.76	701.76	701.76	683.65	672.30	701.76	701.76
Conventional Hydropower	304.30	304.30	304.30	304.30	304.30	304.30	304.30	304.26	304.30	304.30
Geothermal...................	34.61	34.79	35.93	35.45	35.95	40.24	43.26	43.17	34.60	34.68
Municipal Solid Waste......	34.27	34.27	37.83	34.48	34.85	40.16	40.71	41.47	34.27	37.32
Wood and other Biomass..	65.69	64.73	68.49	71.68	86.09	154.42	378.87	796.30	65.55	70.45
Dedicated Plants.........	11.78	11.67	15.94	20.89	37.09	105.42	329.87	747.30	11.09	10.44
Cofiring.................	4.91	4.06	3.55	1.78	0.00	0.00	0.00	0.00	5.47	11.01
Solar Thermal................	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12
Solar Photovoltaic...........	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Wind.........................	24.14	62.46	102.10	117.99	203.10	277.06	285.11	307.13	78.19	64.99
Other........................	15.37	15.37	15.34	15.35	15.35	15.35	15.37	15.49	15.34	15.31
Total......................	5436.04	5439.26	5439.28	5441.12	5444.20	5454.44	5452.46	5454.59	5425.14	5420.40

Electricity Capacity by Type – Baseline Runs

		NEMS basecase	NREL basecase	Extern 1.4	Extern 2.8	Extern 6.9	Extern 13.8	Extern 27.5	Extern 34.4	SO2 decli 3%	SO2 declin 5%
	1999	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010
Electricity Generating Cap...											
(gigawatts)											
Coal Steam....................	304.57	306.05	305.87	305.72	305.68	305.41	304.13	303.02	302.64	304.42	304.17
Other Fossil Steam	135.69	115.53	115.53	115.53	115.53	115.45	115.53	115.45	115.45	115.23	115.09
Combined Cycle................	20.67	142.04	139.75	139.79	139.38	138.75	135.84	129.37	122.67	143.14	141.51
Combustion Turbine/Diesel	63.19	128.23	129.33	129.12	128.88	129.83	128.31	131.67	131.16	127.52	126.05
Nuclear Power.................	97.47	94.34	94.34	94.34	94.34	94.34	94.34	94.34	94.34	94.34	95.21
Pumped Storage/Other	19.18	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64
Fuel Cells....................	0.00	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Conventional Hydropower...	79.30	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90
Geothermal	2.79	3.56	3.57	3.68	3.61	3.69	4.02	4.28	4.28	3.55	3.58
MSW............................	2.75	3.88	3.88	4.42	3.99	4.04	4.71	4.78	4.88	3.91	4.35
Biomass	1.37	1.73	1.73	1.73	1.73	2.50	5.13	5.44	12.09	1.73	1.73
Solar Thermal	0.33	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Solar Photovoltaic	0.01	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Wind...........................	2.33	7.65	7.80	7.94	8.16	9.40	19.35	31.34	40.51	7.93	8.00
Total........................	729.64	903.17	901.95	902.42	901.45	903.58	911.51	919.86	928.19	901.91	899.84

	NEMS basecase	NREL basecase	Extern 6.9	Extern 13.8	Extern 27.5	Extern 34.4	SO2 decli 3%	SO2 decli 5%
	2020	2020	2020	2020	2020	2020	2020	2020
Electricity Generating Cap...								
(gigawatts)								
Coal Steam....................	330.54	328.00	321.29	314.65	307.17	304.50	325.07	321.51
Other Fossil Steam	113.17	113.17	112.58	112.51	111.98	100.84	112.33	110.34
Combined Cycle................	214.10	212.92	200.62	190.84	174.60	159.94	218.19	221.66
Combustion Turbine/Diesel	177.91	178.12	183.58	181.06	178.97	161.34	169.40	173.27
Nuclear Power.................	88.02	88.02	88.02	88.02	85.48	83.82	88.02	88.02
Pumped Storage/Other	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64
Fuel Cells....................	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Conventional Hydropower...	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90
Geothermal	5.31	5.33	5.47	5.99	6.36	6.36	5.30	5.31
MSW............................	4.30	4.30	4.38	5.05	5.12	5.22	4.30	4.69
Biomass	2.04	2.03	5.89	16.14	49.82	112.43	1.94	1.83
Solar Thermal	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Solar Photovoltaic	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Wind...........................	9.08	17.97	53.95	75.90	81.26	88.35	21.86	18.51
Total........................	1044.95	1050.33	1076.23	1090.63	1101.22	1123.26	1046.89	1045.61

Electricity Generation by Type – RPS runs

	1999	NREL basecase 2010	Extern 6.9 2010	Extern 13.8 2010	Extern 27.5 2010	Extern 34.4 2010	NREL basecase 2020	Extern 6.9 2020	Extern 13.8 2020	Extern 27.5 2020	Extern 34.4 2020
Electricity Sales											
(billion kilowatthours)…….	3324.05	4169.25	4167.42	4166.03	4161.33	4155.75	4919.59	4921.72	4921.03	4906.86	4801.11
Electricity Prices											
(2000 cents per kilowatthour	6.73	6.34	6.34	6.35	6.37	6.38	6.44	6.40	6.38	6.42	7.23
Generation by Fuel											
(billion kilowatthours)											
Coal………………………	1887.14	2263.79	2245.85	2237.96	2234.16	2210.33	2464.95	2379.73	2307.92	2228.30	2116.28
Natural Gas………………	561.08	1153.40	1126.21	1102.76	1053.03	920.27	1706.96	1652.40	1559.16	1376.95	1038.53
Oil………………………	123.96	37.32	36.33	32.93	32.52	29.22	46.89	45.54	38.91	31.04	26.10
Nuclear…………………..	728.34	736.88	736.88	736.88	736.88	744.62	701.76	701.76	696.49	692.38	676.54
Conventional Hydropower…	315.75	305.46	305.46	305.46	305.46	305.46	304.30	304.30	304.30	304.31	304.30
Geothermal……………….	15.43	20.16	21.26	24.19	23.60	27.55	34.79	32.83	40.59	49.36	66.05
Municipal Solid Waste………	21.19	31.07	31.97	31.98	32.33	36.34	34.27	34.48	38.69	45.05	68.93
Wood and other Biomass….	37.48	58.35	58.35	58.46	85.88	181.22	64.73	100.82	146.49	389.56	710.75
Dedicated Plants……….	7.01	9.72	9.72	9.72	42.04	140.95	11.67	10.24	18.75	263.03	635.83
Cofiring………………	0.51	10.59	10.59	10.70	5.80	2.22	4.06	41.58	78.74	77.53	25.94
Solar Thermal…………….	0.87	0.96	0.96	0.96	0.96	0.96	1.12	1.12	1.12	1.12	8.01
Solar Photovoltaic…………	0.01	1.07	1.07	1.07	1.07	1.07	1.66	1.66	1.66	1.66	3.16
Wind………………………	4.17	20.02	62.68	93.06	117.14	163.54	62.46	172.34	292.30	304.42	311.14
Other…………………….	17.61	12.86	12.85	12.85	12.85	12.87	15.37	15.34	15.34	15.38	15.50
Total………………….	3713.02	4641.36	4639.88	4638.57	4635.89	4633.46	5439.26	5442.31	5442.95	5439.51	5345.30

Electricity Capacity by Type – RPS runs

	1999	NREL basecase 2010	Extern 6.9 2010	Extern 13.8 2010	Extern 27.5 2010	Extern 34.4 2010	NREL basecase 2020	Extern 6.9 2020	Extern 13.8 2020	Extern 27.5 2020	Extern 34.4 2020
Electricity Generating Cap…											
(gigawatts)											
Coal Steam……………….	304.57	305.87	303.60	302.59	302.66	302.50	328.00	321.07	316.38	308.82	300.72
Other Fossil Steam ………..	135.69	115.53	115.53	115.53	115.45	114.36	113.17	112.34	111.62	110.75	108.30
Combined Cycle…………….	20.67	139.75	137.24	133.82	125.45	109.34	212.92	205.69	195.57	175.96	148.67
Combustion Turbine/Diesel…..	63.19	129.33	130.64	131.06	131.74	132.77	178.12	181.42	182.29	176.18	162.87
Nuclear Power……………..	97.47	94.34	94.34	94.34	94.34	95.45	88.02	88.02	87.26	86.74	84.49
Pumped Storage/Other ………	19.18	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64
Fuel Cells……………….	0.00	0.16	0.16	0.16	0.16	0.16	0.25	0.25	0.25	0.25	0.25
Conventional Hydropower……..	79.30	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90
Geothermal ……………….	2.79	3.57	3.70	4.07	4.00	4.50	5.33	5.09	6.05	7.23	9.38
MSW………………………	2.75	3.88	3.99	3.99	4.04	4.55	4.30	4.33	4.86	5.67	8.70
Biomass …………………..	1.37	1.73	1.73	1.73	6.60	21.46	2.03	1.79	3.00	39.61	95.65
Solar Thermal ……………..	0.33	0.36	0.36	0.36	0.36	0.36	0.41	0.41	0.41	0.41	2.44
Solar Photovoltaic …………	0.01	0.11	0.11	0.11	0.11	0.11	0.27	0.27	0.27	0.27	0.94
Wind……………………..	2.33	7.80	19.25	28.58	36.80	52.17	17.97	47.48	82.02	87.92	91.64
Total…………………..	729.64	901.95	910.18	915.86	921.24	937.27	1050.33	1067.71	1089.54	1099.36	1113.59

Electricity Generation by Type – NO_x runs

		NREL	NOx	NOx	NOx	NOx	NOx	NOx	NOx	NREL	NOx	NOx	NOx	NOx	NOx	NOx	NOx
		basecase	0.7	1.4	2.8	6.9	13.8	27.5	34.4	basecase	0.7	1.4	2.8	6.9	13.8	27.5	34.4
	1999	2010	2010	2010	2010	2010	2010	2010	2010	2020	2020	2020	2020	2020	2020	2020	2020
Electricity Sales																	
(billion kilowatthours).......	3324.1	4169.3	4169.6	4168.5	4169.6	4169.3	4170.5	4171.8	4170.6	4919.6	4917.8	4919.0	4919.8	4922.6	4924.3	4930.4	4950.8
Electricity Prices																	
(2000 cents per kilowatthour)	6.73	6.34	6.34	6.34	6.34	6.34	6.33	6.31	6.31	6.44	6.45	6.44	6.44	6.42	6.40	6.32	6.09
Generation by Fuel																	
(billion kilowatthours)																	
Coal..........................	1887.1	2263.8	2263.7	2262.9	2263.1	2263.7	2263.8	2257.4	2255.6	2465.0	2458.6	2454.5	2451.7	2450.9	2422.0	2372.7	2302.4
Natural Gas..................	561.1	1153.4	1153.7	1152.2	1153.3	1150.3	1142.8	1124.9	1111.9	1707.0	1702.5	1705.7	1703.0	1676.0	1621.3	1537.9	1374.1
Oil..........................	124.0	37.3	37.2	37.7	37.4	37.5	37.3	36.5	35.8	46.9	45.4	47.7	48.4	44.9	42.5	37.5	31.5
Nuclear......................	728.3	736.9	736.9	736.9	736.9	736.9	736.9	736.9	736.9	701.8	701.8	701.8	701.8	701.8	701.8	696.5	676.4
Conventional Hydropower....	315.8	305.5	305.5	305.5	305.5	305.5	305.5	305.5	305.5	304.3	304.3	304.3	304.3	304.3	304.3	304.3	304.3
Geothermal...................	15.4	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	34.8	34.7	34.7	34.7	34.8	35.0	34.6	34.3
Municipal Solid Waste.........	21.2	31.1	31.3	31.5	31.8	32.1	34.3	34.9	34.9	34.3	34.3	34.3	34.3	34.6	36.9	37.4	37.4
Wood and other Biomass.....	37.5	58.4	58.4	58.4	58.3	59.1	63.4	77.4	92.4	64.7	67.5	68.0	70.3	79.0	121.2	273.2	556.9
Dedicated Plants..........	7.0	9.7	9.7	9.7	9.7	12.6	21.6	36.8	51.9	11.7	12.5	14.4	19.5	30.0	72.2	223.4	507.3
Cofiring..................	0.5	10.6	10.6	10.7	10.6	8.5	3.7	2.6	2.5	4.1	6.0	4.6	1.8	0.0	0.0	0.7	0.6
Solar Thermal.................	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Solar Photovoltaic............	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Wind..........................	4.2	20.0	20.3	20.4	20.5	21.7	24.4	36.2	36.4	62.5	69.9	69.5	73.3	97.5	140.9	139.3	142.7
Other.........................	17.6	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	15.4	15.3	15.4	15.4	15.2	15.3	15.3	15.3
Total.......................	3713.0	4641.4	4641.9	4640.5	4641.8	4641.7	4643.3	4644.8	4644.5	5439.3	5437.1	5438.6	5439.8	5442.0	5443.9	5451.4	5478.1

Electricity Capacity by Type – NO_x runs

		NREL	NOx	NOx	NOx	NOx	NOx	NOx	NOx	NREL	NOx	NOx	NOx	NOx	NOx	NOx	NOx
		basecase	0.7	1.4	2.8	6.9	13.8	27.5	34.4	basecase	0.7	1.4	2.8	6.9	13.8	27.5	34.4
	1999	2010	2010	2010	2010	2010	2010	2010	2010	2020	2020	2020	2020	2020	2020	2020	2020
Electricity Generating Cap...																	
(gigawatts)																	
Coal Steam....................	304.57	305.87	305.86	305.83	305.74	305.80	305.42	304.84	304.95	328.00	327.61	326.80	326.04	325.73	322.31	317.25	317.54
Other Fossil Steam	135.69	115.53	115.53	115.53	115.53	115.53	115.53	115.53	114.78	113.17	113.24	113.24	112.91	113.17	113.17	110.95	106.11
Combined Cycle................	20.67	139.75	139.71	139.93	139.72	139.08	138.59	135.10	133.96	212.92	211.62	212.28	211.41	207.48	201.99	192.32	190.44
Combustion Turbine/Diesel.	63.19	129.33	129.48	128.73	128.73	129.12	127.66	128.20	130.64	178.12	177.84	178.01	179.18	180.04	180.01	178.83	177.33
Nuclear Power.................	97.47	94.34	94.34	94.34	94.34	94.34	94.34	94.34	94.34	88.02	88.02	88.02	88.02	88.02	88.02	87.26	84.34
Pumped Storage/Other	19.18	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64	19.64
Fuel Cells...................	0.00	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Conventional Hydropower...	79.30	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90
Geothermal	2.79	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	5.33	5.32	5.31	5.32	5.33	5.35	5.30	5.27
MSW...........................	2.75	3.88	3.91	3.94	3.97	4.01	4.29	4.36	4.36	4.30	4.30	4.30	4.30	4.35	4.63	4.70	4.70
Biomass	1.37	1.73	1.73	1.73	1.73	2.15	3.52	5.84	8.11	2.03	2.15	2.44	3.23	4.82	11.14	33.81	76.36
Solar Thermal	0.33	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Solar Photovoltaic	0.01	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Wind..........................	2.33	7.80	7.88	7.91	7.95	8.29	9.09	13.40	13.55	17.97	19.80	19.68	20.67	27.33	38.86	39.73	40.80
Total.......................	729.64	901.95	902.15	901.66	901.43	902.06	902.17	905.35	908.41	1050.33	1050.39	1050.56	1051.54	1056.75	1065.96	1070.63	1103.36