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Impacts of a 10-Percent Renewable Portfolio Standard

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Contacts

This report was prepared by the staff of the Office of Integrated Analysis and Forecasting of the Energy Information Administration. General questions concerning the report may be directed to Mary J. Hutzler (202/586-2222, mhutzler@eia.doe.gov), Director, Office of Integrated Analysis and Forecasting, or Scott Sitzer (202/586-2308, ssitzer@eia.doe.gov), Director, Coal and Electric Power Division,. Specific questions about the report may be directed to the following analysts:

Electricity	J. Alan Beamon	202/586-2025	jbeamon@eia.doe.gov
	Jeffrey Jones	202/586-2038	jjones@eia.doe.gov
	Laura Martin	202/586-1494	lmartin@eia.doe.gov
Renewables	Zia Haq	202/586-2869	zhaq@eia.doe.gov
	Christopher Namovicz	202/586-7120	cnamovicz@eia.doe.gov
	Thomas Petersik	202/586-6582	tpetersi@eia.doe.gov

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Introduction

On December 20, 2001, Sen. Frank Murkowski, the Ranking Minority Member of the Senate Committee on Energy and Natural Resources requested an analysis of selected portions of Senate Bill 1766 (S. 1766, the Energy Policy Act of 2002) and House Bill H.R. 4 (the Securing America's Future Energy Act of 2001)[1]. On February 6, 2002, Sen. Murkowski provided specific information on the provisions of S. 1766 that were to be analyzed, as well as, guidance on additional analysis.[2] In response, the Energy Information Administration (EIA) has prepared a series of analyses showing the impacts of each of the selected provisions of the bills on energy supply, demand, and prices, macroeconomic variables where relevant, import dependence, and emissions. The analysis provided is based on the *Annual Energy Outlook 2002*[3] (*AEO2002*) midterm forecasts of energy supply, demand and prices through 2020.

Because of the rapid delivery requested by Sen. Murkowski, each requested component of the Senate and House bills was analyzed separately, that is, without analyzing the interactions among the various provisions. Because of the approach taken:

- The combined impact of the individual policies cannot be determined by simply summing the individual policy impacts. For example, a provision establishing a renewable portfolio standard (RPS) for electricity production, and one that establishes a bio-diesel program for transportation fuels, each increases the use of biomass. The simultaneous enactment of the two provisions would be likely to increase biomass costs because of the competition for land and other needed resources. The estimated fossil energy displaced will therefore be lower than the sum of the two individual policy impacts because of the higher resource costs. Stated another way, the impacts of multiple simultaneous policies are non-linear.

- Some policies will interact to increase the overall response while others may interact to mitigate the impacts of each other. For example, when two separate policies increase demand and, consequently, production of an advanced technology, the reductions in manufacturing costs expected from increased production are likely to be accelerated, making the technology even more attractive in later years. The total adoption of the advanced technology in this case could be greater than the sum of the parts.

In addition, the following should also be noted:

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[1] Letter from Sen. Murkowski to Mary J. Hutzler, dated December 20, 2001.
[2] Letter from Sen. Murkowski to Mary J. Hutzler, dated February 6, 2002.
[3] *Annual Energy Outlook 2002*, *With Projections to 2020*, U.S. Department of Energy, Energy Information Administration, DOE/EIA-0383(2002), January 2002.

- Computation of expected benefits and costs of equipment installed at the end of the forecast horizon (e.g., 2020) requires estimates of costs and prices for a number of years beyond this period. Since EIA does not project costs, prices or benefits past 2020, the estimates of the benefits after 2020 must be assumed for equipment installed by 2020. For example, analyzing consumer product standards for air conditioners through 2020 requires an estimate of the savings through 2036, because of the expected operating life of the new equipment that is projected to be installed. *AEO2002*, however, only produces projections through 2020. For the remaining years from 2021 to 2036, we have assumed the savings remain constant at 2020 levels. Such estimates of savings are highly uncertain and could be higher or lower than this estimate.

- Some aspects of the bills cannot be modeled because they lack specificity. For example, several provisions of the bill require the Department of Energy (DOE) to evaluate the desirability of setting standards for stand-by power and other electronic devices. Because the legislation does not state what the standards will be, EIA cannot quantitatively analyze them.

EIA's projections are not statements of what will happen but what might happen, given known technologies, current technology and demographic trends, and current laws and regulations. Thus, the *AEO2002* provides a policy-neutral reference case that can be used to analyze energy policy initiatives, as has been done in each of these studies. EIA does not propose, advocate or speculate on future legislative or regulatory changes. Laws and regulations are assumed to remain as currently enacted or in force in the reference case; however, the impacts of emerging regulatory changes, when clearly defined, are reflected.

Models are simplified representations of reality. Projections are highly dependent on the data, methodologies, model structure and assumptions used to develop them. Because many of the events that shape energy markets are random and cannot be anticipated (including severe weather, technological breakthroughs, and geo-political disruptions), energy market projections are subject to uncertainty. Further, future developments in technologies, demographics and resources cannot be foreseen with any degree of certainty. These uncertainties are addressed through analysis of alternative cases in the *AEO2002*.

This study addresses the renewable portfolio standard provision of S. 1766. At Senator Murkowski's request it also includes an analysis of the impacts of a renewable portfolio standard patterned after the one called for in S. 1766, but where the required share is based on a 20 percent RPS by 2020 rather than the 10 percent RPS called for in S. 1766. This analysis does not incorporate any other provisions of S. 1766, such as new appliance efficiency standards or new car fuel efficiency standards.

Analysis Summary

The key results of this analysis are:

- The sunset and civil penalty provisions of S. 1766 have a significant impact on the amount of renewables stimulated by the RPS. S. 1766 states that the RPS requirement ends (sunsets) on December 31, 2020. It also imposes a civil penalty of up to 3 cents per kilowatt-hour for retail electricity suppliers who do not submit their required number of renewable credits in any given year.
- Under the AEO 2002 Reference case assumptions, the 10-percent RPS called for in S. 1766 target is not projected to be achieved because of the 3-cent per kilowatt-hour credit penalty and the sunsetting of the program in 2020. As the end of the program approaches (December 31, 2020), electricity suppliers are projected to pay the penalty rather than invest in additional renewables that would only receive the credit for a few years. The level achieved by 2020 is projected to be 8.4 percent.[4] If the sunset provision were removed the required RPS is projected to be achieved.
- A 10-percent RPS requirement would lead to greater generation from wind, biomass, and to a lesser extent, geothermal, resources. Conversely, the imposition of the RPS would lead to lower generation from natural gas and coal facilities.
- The S. 1766 RPS target is projected to be achieved if more optimistic cost and performance assumptions for new renewable technologies are used. A key uncertainty with respect to impacts of an RPS program is the future cost and performance of renewable generation technologies. If their costs fall and/or their performance improves more than is expected in the Reference case, the RPS program could be less expensive resulting in qualifying renewables reaching a share of 10 percent. Conversely, if the cost of new renewable technologies does not improve the share achieved is projected to be 6.9 percent. With these assumptions, the credit price is projected to reach the 3-cents per kilowatt-hour cap earlier than under Reference case assumptions.
- The retail electricity price impacts of the RPS are projected to be small because the price impact of buying renewable credits and building the required renewables is projected to be relatively small when compared with total electricity costs and to be mostly offset by lower gas prices that result from reduced gas use.
- The net increase in cumulative resource costs to the industry from 2000 to 2020 in the RPS 10 case when compared to the Reference case sum to $7 billion, an increase of approximately 1 percent.
- The total value of the credits received by qualifying renewable generators in 2020 is projected to be approximately $12 billion. The renewables covered by the RPS are essentially supported by payments from nonrenewable facilities.
- The Indian lands provision could lead to fewer new renewables being built in response to the RPS because there are wind resources on Indian lands. If these

[4] Throughout this report, unless otherwise specified the renewable shares achieved are given using the definition specified in S. 1766. Because of exemptions in the definition the actual non-hydroelectric renewable share of sales required to meet the S. 1766 10 percent target is only 9.5 percent.

resources were developed they would receive double RPS credits and reduce the amount of qualifying renewable generation needed to comply with the RPS.

- If a 20 percent RPS were imposed under the same provisions as S. 1766, the electricity price and cost impacts are projected to be larger. In 2020, the retail price of electricity is projected to be 3 percent above the Reference case with a 20 percent RPS and electricity supplier resource costs are projected to be $ 21 billion higher than in the Reference case.
- As in the 10 percent RPS case, the 20 percent RPS target is not projected to be achieved. The level achieved is projected to be 12 percent. This mainly occurs because of the high cost of the level of renewables that would be needed to meet the RPS target. Also, as the December 31, 2020, end of the program approaches, electricity suppliers are projected to pay the penalty rather than invest in additional renewables that would only receive the credit for a few years.

Background

To stimulate an increase in the use of renewable fuels to generate electricity, several bills in Congress call for the establishment of a renewable portfolio standard (RPS) for all electricity retail suppliers. A typical RPS requires that a share of the power sold in the United States must come from qualifying renewable facilities. Companies who generate power from qualifying renewable facilities will be issued credits that they can hold for their own use or sell to others. To meet the RPS requirement, each individual electricity seller must hold credits - issued to their own qualifying renewable facilities or purchased from others - equal to the share required in each year. For example, a supplier with 100 billion kilowatt-hours of retail electricity sales in a year with a 5-percent RPS requirement would have to hold 5 billion kilowatt-hours of credits. In a competitive market, the price of renewable credits should rise to the level needed to stimulate power plant developers to bring on the amount of qualifying renewable capacity needed to meet the RPS requirement. Thus, the RPS provides a subsidy to renewables to make them competitive with other resource options. However, it allows the market to determine the most economical renewable options to develop to comply.

The RPS program in S. 1766 has the following characteristics:

- The program begins in 2003 with the required renewable share growing from 2.5 percent of retail electricity sales in 2005 to 10 percent in 2020 in annual 0.5 percentage point increments. The shares required for 2003 and 2004 are to be set by the Secretary of Energy at a value under the 2.5 percent required in 2005. For this analysis it was assumed that the 2003 share would be set to 0.5 percent and the 2004 share would be set to 1.5 percent. The program expires (sunsets) on December 31, 2020.
- All power sellers with retail sales of 500,000,000 kilowatt-hours per year are required to hold credits. Small utilities with retail sales below 500,000,000 kilowatt-hours per year are exempt.
- The amount of qualifying renewable generation required each year is calculated by multiplying the total electricity retail sales minus renewable generation times

the required share. Subtracting for the sales from small utilities the qualifying renewable generation is given by:

Qualifying renewable generation = RPS share X (Total Electricity Sales – Small Utility Sales – Total Renewable Generation).

- Qualifying renewable facilities include all new renewable generation facilities (including upgrades, repowerings, and co-firing changes) that are placed in service on or after January 1, 2002. Qualifying fuels include hydroelectric, geothermal, biomass, solar, wind, ocean and landfill gas. Renewable facilities in service prior to January 1, 2002 do not receive credits.
- If a qualifying renewable facility is built on Indian land, two renewable credits will be issued for each kilowatt-hour generated.
- Renewable credits will also be issued to utilities for the portion of renewable generation at customer sites that flows to the grid if the utility paid part of the cost of the facility. For example, if a utility pays part of the cost of a photovoltaic system in a customer's house the utility will receive renewable credits equal to the net sales to the grid from the system.
- A civil penalty of up to 3 cents per credit may be applied for each required renewable credit not submitted by a covered retail electricity supplier.[5]

Analysis Methodology

The projections and quantitative analysis for this chapter were prepared using the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economic model of the U.S. energy system for the mid-term forecast horizon, through 2020. NEMS projects production, imports, conversion, consumption, and prices of energy, subject to assumptions about macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. Using econometric, heuristic, and linear programming techniques, NEMS consists of 13 submodules that represent the demand (residential, commercial, industrial, and transportation sectors), supply (coal, renewables, oil and natural gas supply, natural gas transmission and distribution, and international oil), and conversion (refinery and electricity sectors) of energy, together with a macroeconomic module that links energy prices to economic activity. An integrating module controls the flow of information among the submodules, from which it receives the supply, price, and quantity demanded for each fuel until convergence is achieved.[6]

Domestic energy markets are modeled by representing the economic decision-making involved in the production, conversion, and consumption of energy products. For most

[5] S. 1766 does not specify whether this maximum civil penalty is in real or nominal dollars. For this analysis it is assumed to be in real 2000 dollars.

[6] For more information on the National Energy Modeling System see, The National Energy Modeling System An Overview 2000, DOE/EIA-0581(2000), April 7, 2000, Washington, DC.

sectors, NEMS includes explicit representation of energy technologies and their characteristics. In each sector of NEMS, economic agents—for example, representative households in the residential demand sector and producers in the industrial sector— are assumed to evaluate the cost and performance of various energy-consuming technologies when making their investment and utilization decisions. The costs of making capital and operating changes to comply with laws and regulations governing power plant and other emissions are included in the decisionmaking process.

The EMM simulates the capacity planning and retirement, operating, and pricing decisions that occur in U.S. electricity markets. It operates at a 13-region level based on the North American Electric Reliability Council (NERC) regions and subregions. Based on the cost and performance of 27 different generating technologies, the costs of fuels, and constraints on emissions, the EMM chooses the most economical approach for meeting consumer demand for electricity. As new technologies penetrate the market in NEMS, their costs are assumed to decline to reflect the expected impact of technological learning. During each year of the analysis period, the EMM evaluates the need for new generating capacity to meet consumer needs reliably or to replace existing electric power plants that are no longer economical. The cost of building new capacity is weighed against the costs of continuing to operate existing plants and consumers' willingness to pay for reliable service.

The EMM includes the representation of programs aimed at increasing the amount of generation coming from renewable fuels – both state and federal programs. For example, 10 States currently have State renewable portfolio standards or targets. To represent these programs, estimates of the types of renewable capacity expected to be encouraged by these programs are made and entered into the model. All cases in this analysis include estimates of new renewable energy capacity expected to be stimulated by State-level renewable programs. Over the 2001 to 2020 timeframe, these estimates include 4,859 megawatts of capacity resulting from State RPS programs, and 2,178 megawatts expected under other State renewable stimulus programs. Capacity built under State RPS programs reduces the incremental quantity needed to comply with a Federal RPS and lowers its costs. The costs of complying with the State RPS programs are not included in the costs attributed to the Federal RPS program in this analysis.

All cases in this analysis include the 10 percent investment tax credit for new geothermal and solar-electric power plants that was permanently extended in the Energy Policy Act of 1992. However, this analysis does not assume that the Federal production tax credit (PTC) for generation from new wind and closed-loop biomass plants will be extended beyond its current expiration date of December 31, 2001. Senator Murkowski, in his letter of December 20, 2001, stated that this analysis not assume any changes in tax policy. For the same reason this analysis does not assume that the renewable energy production incentive (REPI) program, will be extended beyond its current 2003 expiration date.

To represent a national RPS, the EMM has the ability to require that generation from renewable facilities (including all generation from cogenerators) be equal to or greater than a specified amount. When this is done, the most economical renewable options are constructed to meet the RPS requirement. The projected price of the renewable credits represents the incentive needed by renewables to make them competitive with other options. The renewable credit price times the required share in each year becomes part of the operating costs of non-qualifying facilities since sellers of power from these facilities must purchase renewable credits for them in order to comply with the required RPS share.[7]

S. 1766 allows new (incremental) hydroelectric capacity at existing facilities or repowering upgrades at other existing renewable facilities to qualify for renewable credits. While, it is possible that incremental hydroelectric capacity could play a small role in meeting the RPS, EIA believes that it is not likely to have a large impact on this analysis and, thus, it is not directly represented. The U.S Hydropower Resource Assessment found that upgrades at existing hydroelectric facilities could add 7.8 gigawatts to total hydroelectric capacity.[8] However, after adjusting this value to reflect environmental concerns, the report authors reduced this value to 4.3 gigawatts of possible upgrades at existing sites. The report also included estimates of additional hydroelectric capacity at currently undeveloped sites, but since S. 1766 does not provide renewable credits to new hydroelectric sites their development will not be encouraged by the RPS. Assuming a 45 percent capacity factor for typical hydroelectric facilities, this means that, at most, the 4.3 gigawatts of incremental hydroelectric facilities could provide 17 billion kilowatt-hours of additional generation, or approximately 4 percent of the increase in renewable generation needed to comply with the RPS called for in S. 1766. However, because costs estimates for these potential upgrades are not available it is impossible to determine if they would be economical. If any of these upgrades proved to be uneconomical, the contribution from incremental hydroelectric facilities would be even smaller. If they were economical, their development would be expected to lower the costs of implementing the RPS slightly below what is reported in this report.

Similar to existing hydroelectric facilities, a small amount of additional capacity may be available through the repowering at existing geothermal plants. While very uncertain, it is estimated that U.S. geothermal capacity might be able to increase up to 5 percent at costs of $500 per kilowatt or less for a total potential increase of a few hundred megawatts of capacity. However, S. 1766 does not specify what actions at geothermal facilities would qualify as repowering and how the resulting change in capacity would be measured. For example, some existing geothermal capacity has been derated – its currently reported capacity is lower than its originally installed capacity. The potential amount of repowered geothermal capacity that might be stimulated by an RPS would be

[7] For more information on the representation of a renewable portfolio standard in the National Energy Modeling System see, Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard, page 18, SR/OIAF/2001-03, July 2001, Washington, DC, The Comprehensive Electricity Competition Act: A Comparison of Model Results, page 4, SR/OIAF/99-04, September 1999, Washington, DC, and Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997, SR/OIAF/98-01, February 1998, Washington, DC.

[8] Conner, Francfort, and Rinehart, U.S. Hydropower Resource Assessment, DOE/ID-10430.2, December 1998.

very sensitive to whether capacity changes were based on increases from original or current capacity. If it were based on original capacity the potential increase would be less than is reported above.

It is also possible that a small amount of renewable credits will be generated by utility sponsored small-scale renewable generators installed at customer sites that reduce the amount of electricity they purchase from the grid. However, these types of facilities tend to be much more expensive than larger grid-serving facilities and it is expected that an RPS would have little impact on their development.

To represent the specific requirements of the RPS program in S. 1766, the annual renewable share of sales called for in S. 1766 were converted into the total nonhydroelectric renewable shares used in NEMS. As shown in Table 1, the shares used in NEMS differ from the annual RPS shares called for in S. 1766 because the NEMS shares represent the total non-hydroelectric renewable generation share[9] - including the generation from facilities that began operation before January 1, 2002 - required to comply with the RPS requirement (NEMS does not distinguish between generation coming from new or existing facilities so total nonhydroelectric renewable shares are used). Also, as called for in S. 1766, the share represented in NEMS accounts for the exclusion of utilities with sales fewer than 500,000,000 kilowatt-hours, and the exclusion of renewable generation from sales when applying the RPS share. For example, in 2005 the S. 1766 RPS share is 2.5 percent, total electricity sales are projected to be 3,793 billion kilowatt-hours, sales from small utilities are assumed to be 270 billion kilowatt-hours, the generation from non-qualifying non-hydroelectric renewable generators (those coming on prior to January 1, 2002) are assumed to be 81 billion kilowatthours and the generation from hydroelectric facilities is projected to be 300 billion kilowatt-hours.[10] Using this information, the amount of qualified renewables required is calculated as follows:

0.025 X (3,793 – 270 – 81 – 300) = 79 billion kilowatt-hours.

Converting this into the total non-hydroelectric share used in NEMS gives:

(79 + 81) / 3,793 = 4.2 percent.

As shown, through 2016 the adjusted shares used in NEMS exceed the shares called for in S. 1766 because the effect of including existing non-hydroelectric renewables in the NEMS values exceeds the adjustments for excluding small utility sales and total renewable generation from the base. After 2017, however, the exclusion of total renewable generation from the baseline when applying the RPS share causes this relationship to reverse. In the 20 percent RPS case, the effective share of non-hydroelectric renewables required in 2020 to comply is 16.1 percent of total sales.

[9] Hydroelectric generation is excluded from these shares. The opportunities for increased hydroelectric generation are expected to be small and they are excluded from this analysis.
[10] In 1999, total sales from small utilities (those with total sales under 500,000,000 million kilowatt-hours) were 270 billion kilowatt-hours. This value is assumed to remain constant throughout the projections.

Table 1. Renewable Generation Share of Sales Required

Year	Required RPS Share in S. 1766	Target Non-Hydroelectric Renewable Share set in NEMS to Achieve S. 1766 Targets	Target Non-Hydroelectric Renewable Share set in NEMS to Achieve 20 Target
2003[a]	0.5	3.0	3.0
2004[a]	1.5	3.6	3.6
2005	2.5	4.2	4.2
2006	3.0	4.5	5.0
2007	3.5	4.9	5.9
2008	4.0	5.2	6.8
2009	4.5	5.6	7.6
2010	5.0	6.0	8.4
2011	5.5	6.3	9.3
2012	6.0	6.7	10.1
2013	6.5	7.0	10.9
2014	7.0	7.4	11.6
2015	7.5	7.8	12.4
2016	8.0	8.1	13.2
2017	8.5	8.5	13.9
2018	9.0	8.8	14.7
2019	9.5	9.2	15.4
2020	10.0	9.5	16.1
After 2020	0.0	0.0	0.0

[a] The values for 2003 and 2004 are assumed for this analysis. They are not explicitly set in the bill.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting and S. 1766, the Energy Policy Act of 2002.

S. 1766 says that a civil penalty of up to 3-cents per kilowatt-hour may be imposed on retail electricity suppliers who do not submit sufficient renewable credits to cover their sales. For analysis purposes, this maximum 3-cent per kilowatt-hour noncompliance penalty is treated as an upper bound (cap) on the renewable credit price. In other words, if the calculated credit price exceeds 3-cents per kilowatt-hour, retail electricity suppliers are assumed to pay a 3-cent per kilowatt-hour penalty rather than purchase additional credits. If this occurs, the required level of qualifying renewables will not be achieved. It is possible that some companies may be willing to purchase renewable credits for more than 3-cents per kilowatt-hour to avoid the negative perception associated with facing a civil penalty. However, it is impossible to determine how much above the 3-cent penalty they might be willing to pay.

The results from two main cases, the Reference case (from the Annual Energy Outlook 2002) and the RPS 10 case, are discussed in the results section. The results of the RPS 10 case are compared to those from the Reference case to illustrate the impacts of the RPS under the most likely scenario. However, given the importance of some of the RPS provisions in S. 1766 and uncertainty involved in any 20-year projection, the impacts of the RPS under alternative assumptions are also discussed. One key provision in the S. 1766 proposal is the sunset provision ending the program in December 31, 2020. To illustrate the importance of this provision a case without it is also discussed.

A key uncertainty with respect to the RPS is the future cost and performance of renewable generation technologies. If their costs fall and/or their performance improves more than is expected in the Reference case, the RPS program could be less expensive. As a result, two additional cases with more optimistic assumptions about the improvements in renewable energy technology cost and performance – the High Renewable Technology case (from AEO 2002) and the High Renewable Technology case with RPS are also discussed. These cases were prepared to examine the impact of the more optimistic assumptions on the renewable credit and the required renewable share achieved. The high renewable technology cases are meant to illustrate the impact of the RPS with more optimistic assumptions about improvements in the cost and performance of new renewable generating technologies. The key assumptions in the High Renewable Technology case include:

- Biomass: Capital and operating costs are consistent with estimates prepared by Department of Energy Office of Energy Efficiency and Renewable Energy and the Electric Power Research Institute (EERE/EPRI) (Table 2). In addition, biomass supplies are increased by 10 percent.
- Geothermal: Capital costs are assumed to decline by 3 percentage points per year from 2000 to 2010, and 0.6 percentage point per year from 2011-2020. These changes were made to be consistent with estimates prepared EERE/EPRI.
- Photovoltaics (Central Station): Reduced capital and operations and maintenance costs, corresponding to EERE/EPRI utility scale flat plate, “Thin Film” technology.
- Solar Thermal: Significantly improved performance (as measured by capacity factor) is assumed together with higher capital costs. The values used correspond to the Central Receiver (Solar Power Tower) technology from EERE/EPRI.
- Wind: Reduced costs and improved performance is assumed in all wind classes to make them consistent with EERE/EPRI estimates for 2020.

Table 2. Cost and Performance Characteristics for Renewable Energy Generating Technologies: Reference and High Renewable Technology Case

Technology/ Decision Year	Total Overnight Costs[1]			Best Available Capacity Factors	
	Overnight Costs in 2001 (Reference) ($2000/kw)	Reference ($2000/kw)	High Renewable Technology ($2000/kw)	Reference (%)	High Renewable Technology (%)
Dedicated Biomass	1,725				
2005		1,556	1,510	80	80
2010		1,424	1,429	80	80
2015		1,376	1,379	80	80
2020		1,303	1,315	80	80
MSW /Landfill Gas[2]	1,429				
2005		1,417	1,417	90	90
2010		1,402	1,402	90	90
2015		1,387	1,387	90	90
2020		1,373	1,373	90	90
Geothermal[3]	1,746				
2005		1,695	1,506	95	95
2010		1,586	1,292	95	95
2015		1,680	1,458	95	95
2020		2,026	1,709	95	95
Wind	982				
2005		921	932	39	44
2010		907	871	41	46
2015		876	811	42	47
2020		826	750	42	48
Solar Thermal	2,539				
2005		2,454	2,906	42	52
2010		2,348	2,990	42	63
2015		2,243	2,934	42	75
2020		2,137	2,877	42	77
Photovoltaic	3,830				
2005		2,722	3,260	30	30
2010		2,404	1,686	30	30
2015		2,293	1,466	30	30
2020		2,219	1,246	30	30

[1] Overnight capital cost (i.e. financing costs), plus contingency factors and learning, excluding regional multipliers.
[2] Provided to show evolution of landfill gas costs through 2020; for landfill gas, assumptions in the High Renewable Technology case are unchanged from the reference case.
[3] Because geothermal cost and performance characteristics are specific for each site, the table entries represent the least cost units available in the Northwest Power Pool region, where most of the proposed sites are located.

Source: Capital Costs: Initial-year capital costs for renewable energy technologies are determined by the Energy Information Administration from analyses, reports, and discussions with various industry and government sources; forecast-year capital costs in each modeling run are uniquely determined in the run as a result of levels of demand and supply, previous investment, and other factors applied by the National Energy Modeling System (NEMS). The data in this table are output of the following runs; aeo2002.d102001b, hirenew02.d102301a; capacity factors: Energy Information Administration, Office of Integrated Analysis and Forecasting.

It is impossible to assign a probability that the improvements in renewables assumed in the High Renewable Technology cases might occur. The results in the cases should be viewed as illustrative of what might occur if the assumed changes in cost and performance could be realized. The costs and performance characteristics used in the Reference case are considered most likely.

Of course, it is also possible that costs will not improve even as much as is shown for the reference case, or that costs will increase more rapidly than expected after the best renewable resource sites are developed. To represent this possibility, a Low Renewable Technology case was prepared where total overnight costs were held constant at the 2001 level in Table 2. This case is meant to show the sensitivity of the results to today's renewable technology costs, assuming no improvement in cost and performance.

The Indian lands and generation offset provisions of S. 1766 are not explicitly addressed in this analysis. There is substantial uncertainty about the quality of renewable resources on Indian lands and the costs of bringing those resources to market. To assess the potential impact of the Indian lands provision, a Geographic Information System (GIS) was used to identify renewable resources available on Indian lands. The analysis concluded that the available biomass supply on Indian lands is relatively scarce and too high a cost to be stimulated by the provision. Similarly, only small amounts of geothermal resources were found to be on Indian lands. However, this analysis found that about 8 percent of relatively high-quality (wind classes 4, 5, and 6) windy land is on Indian lands. However, there are significant concerns about whether these wind resources could be developed economically. Many factors besides the simple cost of the generating equipment can make otherwise high quality wind sites unattractive. These include environmental or cultural concerns such as those associated with building in national parks or national monument areas. For example, wind projects (such as the proposed Columbia Hills project in Washington) have been abandoned in part because of visual impacts on Native American cultural sites. The need to upgrade weak transmission systems or build on rough terrain with poor infrastructure can also impact the economic attractiveness of many potential high quality sites. While definitive data is not available, the remote nature of many Indian Lands may make these factors more important than they are on non-Indian land. EIA estimates that approximately 5 percent or 10 gigawatts of the wind resource on Indian lands could become economical under an RPS. In addition, the special status of Indian Lands as sovereign territories held under Federal trust imposes additional bureaucratic burden and legal risk that may not be present when developing on non-Indian lands.

Analysis

Reference and RPS Cases

Generation

The imposition of the RPS is projected to have impacts on all aspects of the electricity business, including the fuels and technologies used to generate electricity, the types of capacity built, the various fuels consumed and their prices, power plant emissions, electricity prices, and resource costs. In the AEO 2002 reference case, plants using fossil fuels are projected to meet most of the growth in demand expected over the next 20 years (Table 3). Increased generation from natural gas is expected to be especially important. For example, between 1999 and 2020 the generation from natural gas is projected to increase from 561 billion kilowatt-hours to 1,733 billion kilowatt-hours. The share of total generation coming from natural gas is projected to increase from 15 percent to 32 percent over the same time period. New natural gas-fired combustion turbine and combined cycle facilities are expected to be the most economical option for meeting the

Table 3. Key RPS Results in Reference and RPS 10 Case, 2005, 2010, 2020

Generation by Fuel (Billion Kilowatt-hours)	1999	2005		2010		2020	
		Reference	RPS 10	Reference	RPS 10	Reference	RPS 10
Coal	1,887.1	2,135.2	2,109.9	2,264.4	2,233.9	2,472.2	2,319.1
Natural Gas	561.1	846.6	827.1	1,152.6	1,054.2	1,732.9	1,620.3
Nuclear	728.3	758.8	754.8	736.9	747.5	701.8	692.0
Oil	124.0	48.6	45.1	38.3	30.5	48.6	40.5
Hydro	310.3	301.3	301.3	301.1	301.1	300.0	300.0
Geothermal	15.3	15.7	16.6	20.2	36.5	34.7	51.2
MSW	21.2	28.2	35.3	31.1	38.9	34.3	40.2
Biomass Dedicated	37.0	42.7	43.6	47.8	49.8	60.2	62.4
Biomass Cofiring	0.5	6.0	41.1	11.1	27.7	4.1	97.7
Solar Thermal	0.9	0.9	0.9	1.0	1.0	1.1	1.1
Solar PV	0.0	0.1	0.1	0.3	0.3	0.7	0.7
Wind	4.2	16.7	27.2	19.4	102.3	24.1	162.0
Ocean[b]	--	--	--	--	--	--	--
Other	17.6	12.0	12.0	12.9	12.9	15.4	15.4
Total	3,707.4	4,212.8	4,214.7	4,637.0	4,636.7	5,430.1	5,402.7
Electricity Sales (Billion Kilowatt-hours)	3,324	3,793	3,795	4,170	4,168	4,916	4,897
% S. 1766 Qualifying Renewable	NA	0.7%	2.5%	1.2%	5.0%	1.7%	8.4%
Capacity by Technology (Gigawatts)							
Coal	313.0	312.6	313.4	314.3	313.7	337.6	328.6
Oil and Gas	256.0	335.6	337.7	435.6	435.0	578.5	569.0
Nuclear	97.5	97.7	97.7	94.3	96.3	88.0	87.3
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6
Hydroelectric	79.3	79.8	79.8	79.9	79.9	79.9	79.9
Geothermal	2.8	3.1	3.2	3.6	5.6	5.3	7.4
MSW	3.3	4.0	4.9	4.4	5.4	4.8	5.6
Biomass Dedicated	6.6	7.5	7.7	8.4	8.7	10.4	10.6
Solar Thermal	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Solar PV	0.0	0.0	0.1	0.1	0.1	0.3	0.3
Wind	2.3	6.8	10.2	7.6	33.4	9.1	51.8
Ocean[b]	--	--	--	--	--	--	--
Other	1.6	2.0	2.0	2.1	2.1	2.4	2.4
Total	781.8	869.1	876.6	970.3	1,000.1	1,136.4	1,162.9
Credit Price (2000 Cents per Kilowatt-hour)	NA	NA	2.4	NA	2.1	NA	3.0
Retail Electricity Price (2000 Cents per Kilowatt-hour)	6.7	6.4	6.4	6.3	6.3	6.5	6.6
Emissions (Million Tons)[a]							
Nitrogen Oxides	5.7	3.9	3.9	4.0	4.0	4.2	4.1
Sulfur Dioxide	12.5	10.4	10.4	9.7	9.7	8.9	9.0
Carbon Dioxide	560.1	635.7	625.3	688.8	666.1	790.2	737.1
Fuel Prices							
Natural Gas Wellhead (2000 $ per thousand cubic feet)	2.27	2.66	2.64	2.85	2.72	3.26	3.14
Coal Minemouth ($ per short ton)	17.01	14.99	14.84	14.11	13.66	12.79	12.72

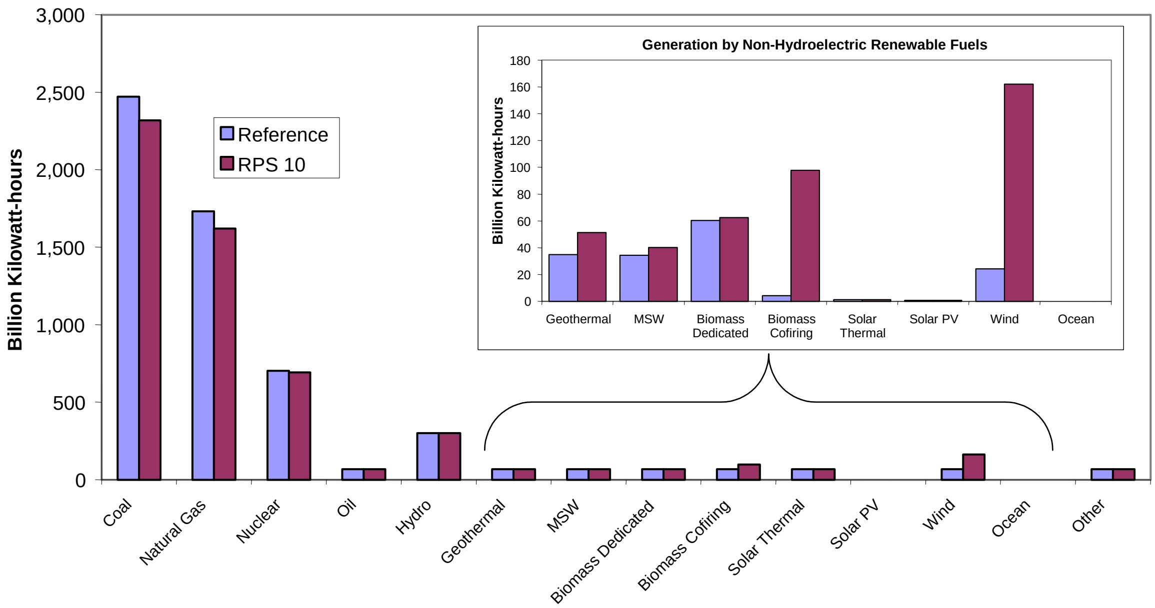
[a]Emissions are in million short tons for sulfur dioxide and nitrogen dioxides and million metric tons carbon equivalent for carbon dioxide.
[b]Ocean technologies are not represented in the National Energy Modeling System.
Note: All prices are in 2000 dollars. NA: not applicable.
Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

growing demand for electricity in most cases over the next 20-years. These technologies are generally less expensive and more efficient than other combustion options.

The generation from nonhydroelectric renewable fuels is projected to grow from 79 billion kilowatt-hours in 1999 to 159 billion kilowatt-hours in 2020 in the AEO 2002 Reference case. Much of this growth in generation from nonhydroelectric renewable fuels is expected to be encouraged by various State programs, with only a small amount coming from new merchant power plants. However, even with this doubling of generation, the share of generation coming from these fuels is only projected to increase from 2.1 percent in 1999 to 2.9 percent in 2020.

Even with the increase in renewable generation projected in the RPS 10 case the mix of fuels used to produce electricity is not expected to change dramatically (Figure 1). For example, while generation from natural gas is projected to account for 32 percent of total generation in 2020 in the Reference case, it is projected to account for 30 percent in the RPS 10 case. Similarly, generation from coal is projected to account for 46 percent of total generation in 2020 in the Reference case and 43 of total generation in the RPS 10 case. Because the RPS in S. 1766 is defined as a percentage of sales (excluding small utilities) minus renewable generation, when converted into the percentage of generation required to come from all nonhydroelectric renewables in 2020, it amounts to approximately 8.7 percent.

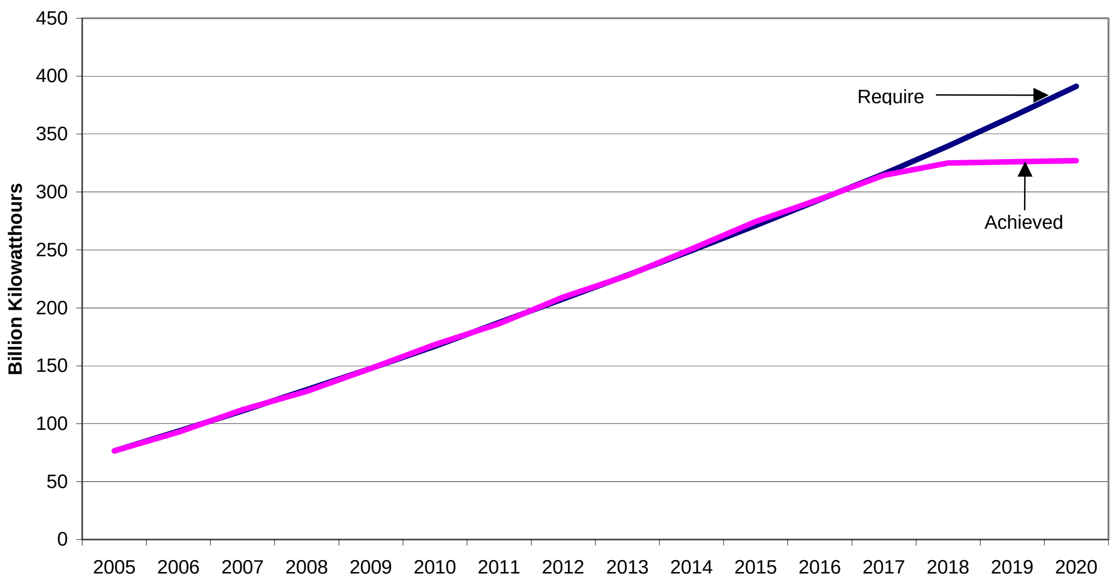
Figure 1. Generation by Fuel in the Reference and RPS 10 Cases, 2020



Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

The lower coal and gas generation projected in the RPS 10 case is offset by the higher renewable generation stimulated by the RPS. In the Reference case, the generation from qualifying renewable generators (as defined from S. 1766) is projected to reach 1.7 percent of electricity sales in 2020. In the RPS 10 case, the 2020 share for qualifying renewables is projected to reach 8.4 percent. The generation from qualifying renewables is not projected to reach the share called for in S. 1766 in 2020 (Figure 2). This is projected to occur because of the 3-cent per kilowatt-hour credit price cap and the 2020 sunset of the RPS. In the later years of the projections, as 2020 gets closer, the number of years during which new renewable power plants will receive credits declines and, as a result, the value of the credit over the remaining years must increase to make them competitive with other generation options. In 2018 and beyond, in the RPS 10 case, the credit price needed to make new renewable plants competitive is projected to exceed 3-cents per kilowatt-hour. This causes retail electricity suppliers to pay the penalty rather than build new renewables or purchase additional credits.

Figure 2. Qualifying Renewable Generation Required and Achieved in the RPS 10 Case



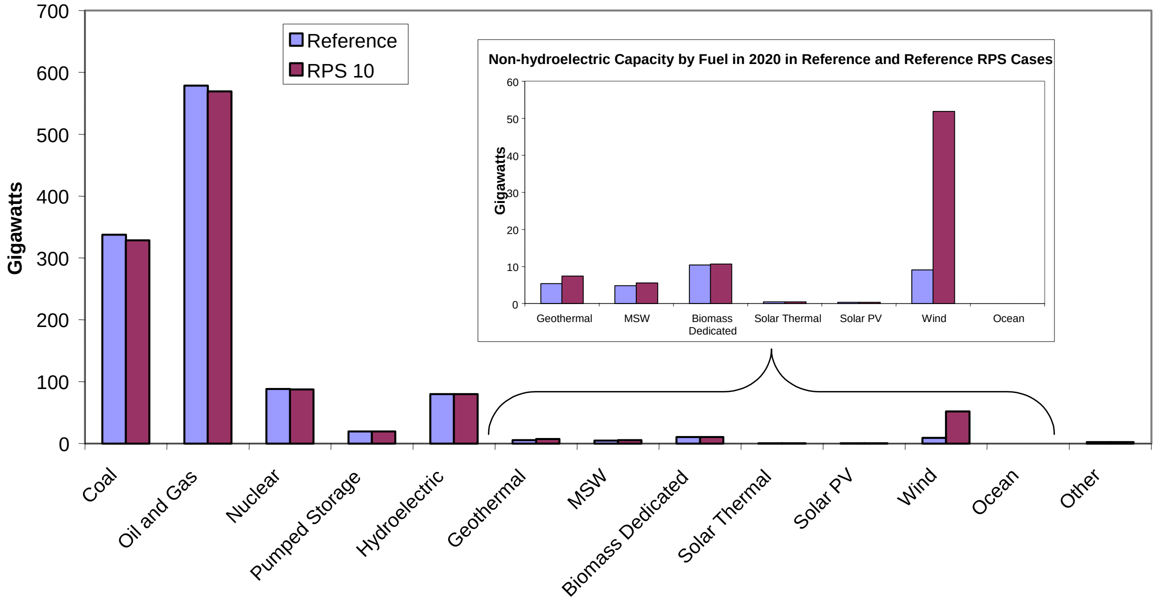
Sources: National Energy Modeling System Runs: RPS 10, rps1766.d013002a.

Wind, biomass, and to a much lesser extent geothermal, are projected to be the most important renewable fuels stimulated by the RPS. The increased wind and geothermal generation is projected to come from new power plants while the increased biomass generation is projected to come primarily from the increased use of biomass in coal plants – what is referred to as cofiring.

Capacity

As with generation, the addition of renewable capacity to comply with the RPS is not projected to lead to a dramatic shift in the mix of generating capacity (Figures 3 and 3a).

Figure 3. Capacity by Fuel in 2020 in Reference and RPS 10 Cases



Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

Only wind capacity is projected to make a significant change between the Reference and RPS cases. As is the case with generation by fuel, coal and gas capacity are lower in the RPS 10 case than in the Reference case. However the combined reduction in coal and gas capacity is much less than the increase in renewable capacity. Total capacity is higher in the RPS 10 case than in the Reference case because of the intermittent nature of wind resources. In addition, there is a shift in the type of natural gas capacity added when the RPS is imposed. Over the 2000 to 2020 period, relative to the Reference case, 16 gigawatts fewer natural gas combined cycle plants are projected to be added while 7 gigawatts more natural gas combustion turbines are added in the RPS 10 case. Because generation from wind plants is only available when the wind is blowing, more backup capacity – generally natural gas turbines - is needed to ensure that consumers' demands can be met at all times.

Overall wind capacity in 2020 is projected to be more than 5 times the Reference case level in the RPS 10 case. Though not broadly competitive in the Reference case, a small number of unsubsidized new wind plants are expected to be built in the later years of the projections when natural gas prices rise. Over the last 10 to 20 years, the cost and performance of new wind plants has improved and they are expected to continue to improve as new plants are built. In the Reference case, the basic cost[11] of new wind plants is expected to decline from just under $918 per kilowatt in 1999 ($982 with contingencies) to approximately $773 per kilowatt-hour ($826 with contingencies) in 2020. When the RPS is imposed, the revenue from credit sales is expected to make more new wind plants competitive and lead to more wind capacity being built. As more wind plants are built their costs are expected to decline further as manufacturers and project developers learn more about their construction and operation. For example, in the RPS

[11] This value excludes site-specific cost adjustments.

10 case the cost of new wind plants is projected to decline to $725 ($776 with contingencies) per kilowatt by 2020. However, at the same time, to reach the quantity of new wind capacity called for in the RPS 10 case – from just 2 gigawatts in 1999 to 52 gigawatts of wind capacity by 2020 – developers are projected to have to build on less attractive sites, such as those requiring upgrades to existing transmission lines, those with more expensive land, and those having more difficult terrain. After adjusting the $725 per kilowatt to reflect these factors the cost of new wind plants in the RPS 10 case in 2020 is expected to be $916 per kilowatt, very close to the current value.[12] As might be expected, the costs of all new power plants are sometimes influenced by these factors. All new plants must incur some site-specific development and transmission interconnection costs and these costs are incorporated in this analysis. However, while wind plants have no choice but to locate where high quality wind resources are available, new natural gas plants are more flexible in their location and their developers will attempt to avoid sites that require above average development expenditures.

Little change in dedicated biomass capacity is projected even though biomass generation is projected to increase significantly. The increased biomass generation comes from increased use of biomass in existing coal plants rather than in dedicated biomass facilities. In this analysis, it is assumed that coal plants can use biomass for up to 5 percent of their total fuel use if sufficient biomass supplies are available within the region the plant is located. Studies have shown that coal plants can use this level of biomass without major plant modifications or changes in other operating costs. Without the RPS, few coal plants are expected to find it economical to displace relatively low cost coal with higher cost biomass fuels. It is possible that with the RPS incentive it might be economical for some coal plants to make modifications to allow them to use even larger shares – 10 percent or more - of biomass fuels. If this occurred these plants could satisfy a large percentage of the RPS requirement. For example, if 10 percent of the projected coal generation in 2020 in the Reference case – 247 billion kilowatt-hours – were to come from using biomass rather than coal, that could satisfy approximately 60 percent of the RPS generation requirement in S. 1766. However, in today's market, coal plant operators are focused on how future environmental regulations, particularly any efforts to reduce U.S. carbon emissions, might impact them and they are wary about making investments in their plants. If the power sector were required to significantly reduce its carbon emissions, the opportunities for increased biomass cofiring to comply with the RPS would be much lower because many coal plants would probably retire and those that continued to operate would be running much less intensively. In addition, many coal plants would probably not have sufficient low-cost biomass available to reach a 10 percent share.

Besides wind, only geothermal and municipal solid waste (landfill gas facilities) are projected to appreciably increase capacity in response to the RPS. Geothermal is projected to play a role in the west where economically accessible geothermal resources are located. However, even with the RPS credit many of the potential sites are expected

[12] For more information on the representation of wind supply in NEMS see, Energy Information Administration, Issues in Midterm Analysis and Forecasting 1999, "Modeling the Costs of U.S. Wind Supply", DOE/EIA-0607(99), August 1999, Washington, DC.

to remain uneconomical. New landfill gas facilities are limited by the amount of waste that is expected to be put into relatively large landfills where gas collection facilities are economical.

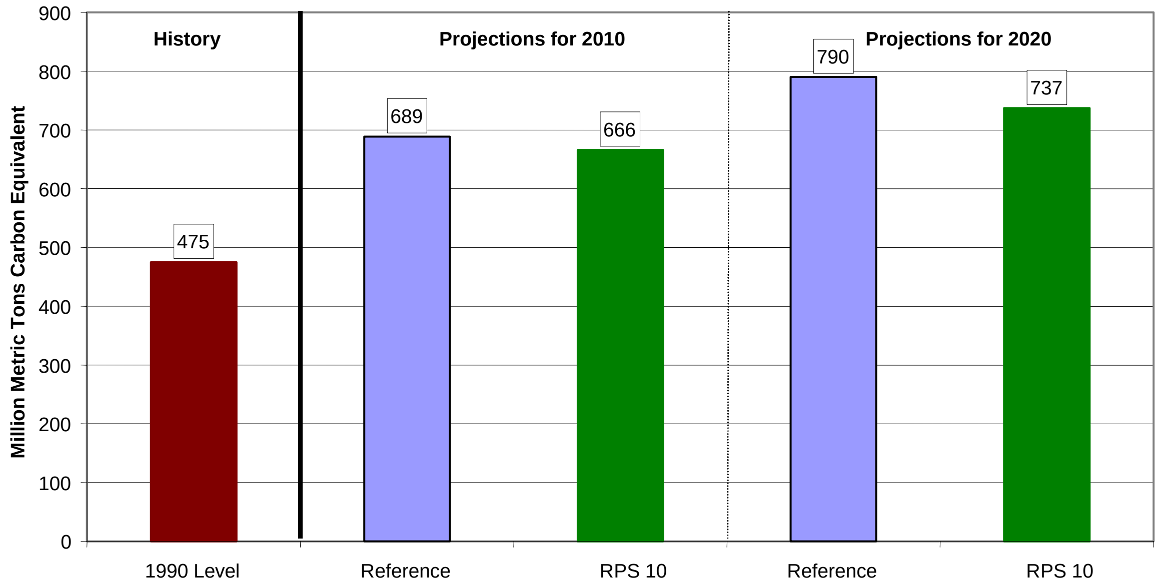
Other nonhydroelectric technologies such as solar thermal, solar photovoltaic and ocean technologies are not projected to respond to an RPS. The relatively high capital costs of solar technologies make them uneconomical when compared to other renewable options such as wind and biomass. The various ocean technologies, either kinetic (including ocean wave, tidal, or ocean current) or thermal (taking advantage of temperature differences between surface and deep water) technologies, are in a very early stage of development and they are not expected to contribute to meeting the RPS called for in S. 1766. Ocean thermal efforts in Hawaii over the past 20 years have not lead to commercial development. No commercial ocean wave projects are currently operating in the United States, although a 500-kilowatt project in Britain has been completed and plans for a 1-megawatt ocean wave demonstration plant some miles off the Washington State coast are ongoing. Current costs appear to be well over $2,000 per kilowatt, making them more expensive then other renewables, such as wind or biomass[13]

Emissions

While the RPS is projected to have little impact on sulfur dioxide (SO2) or nitrogen oxide (NOx) emission levels, it is projected to have a significant impact on the SO2 allowance market. The 9-million ton emission cap established in the Clean Air Amendments of 1990 governs the level of power plant SO2 emissions and it is projected to be met with or without an RPS. However, because the RPS is projected to induce biomass co-firing in coal plants thereby reducing coal generation, the incremental costs of complying with this cap are expected to be lower when an RPS is imposed. As a result, in 2020, the cost of SO2 allowances is projected to be 31 percent lower in the RPS 10 case than in the Reference case, while SO2 emissions remain at the CAAA cap. However, the increase in co-firing does not have the same impact on NOx emissions, because NOx emissions are mainly determined by a plants' boiler type and emissions control equipment, rather than the fuel it is using. The RPS is projected to lead to lower carbon dioxide emissions because fossil fuel generation is displaced by carbon free renewable generation (Figure 4). In 2010, power sector carbon dioxide emissions in the RPS 10 case are projected to be 3 percent below the level projected in the Reference case, while in 2020 they are 7 percent lower. However, even with this reduction they will remain 55 percent above the 1990 level for the power sector in 2020.

[13] See http://www.envirospace.com/print.asp?article_id=428.

Figure 4. Electricity Sector Carbon Emissions, 1990 and Projected For 2010 and 2020



Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

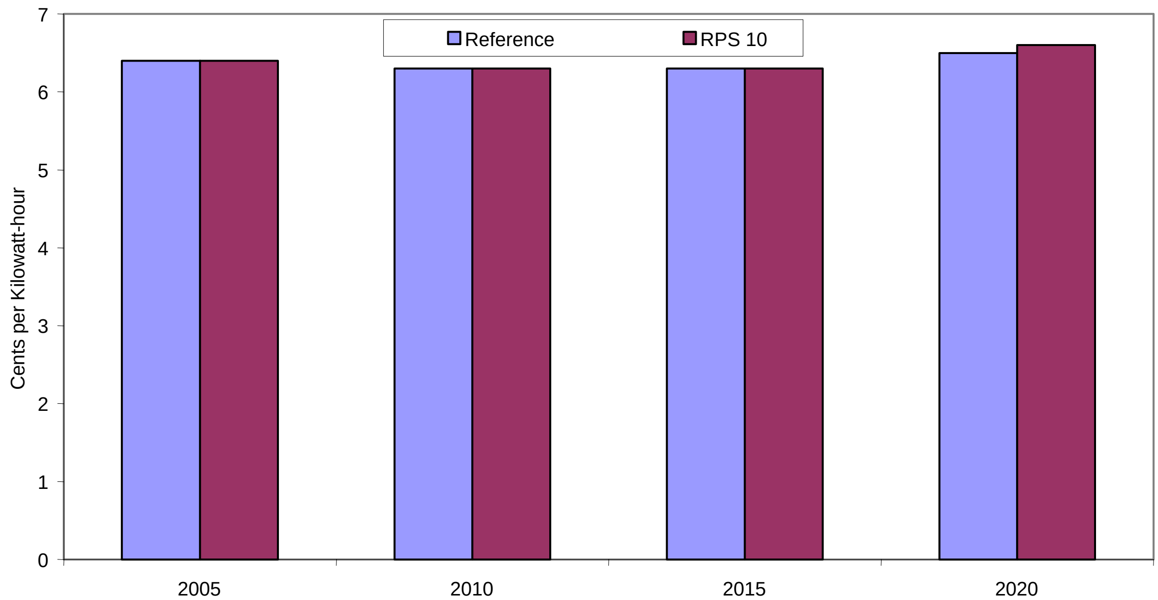
Electricity Price and Costs

The impact of the RPS requirement on retail electricity prices is projected to be small. This occurs because of the relatively low renewable share required – about 5 percentage points higher than is forecast without an RPS - and the impact on natural gas prices of displacing some gas capacity with higher cost renewables when the RPS is imposed. As mentioned, S. 1766 nominally calls for a 10 percent RPS in 2020, but because of the definition of qualifying renewables used and that credits are only required to cover non-renewable generation, the actual non-hydroelectric renewable share of generation needed to meet the target is 8.7 percent.

In simple terms, an RPS is a way of subsidizing qualifying facilities (renewables) through a fee on non-qualifying facilities (coal, gas, nuclear, and oil facilities). Without the credit revenue from the non-qualifying facilities, the renewable facilities would require higher electricity prices to be economically viable. The overall cost and price impacts of an RPS program are driven by the combination of the higher costs spent on renewables minus any change in costs for other technologies that occurs because of the RPS. In this analysis, the RPS is projected to lead to a fall in natural gas prices that just about offsets the higher costs of the new renewables. The retail price of electricity in the RPS 10 case is only projected to be appreciably above the Reference case in the last few years of the projections when the renewable credit price is expected to reach 3 cents per kilowatt-hour (Figure 5). In 2020, the nation’s electricity bill is projected to be $3.1 billion higher in the RPS 10 case than in the Reference case. The 3-cent penalty is reached in 2018 and beyond because, with only a few years left when the credit will be available (it sunsets in

2020), it would have to be much higher than 3 cents per kilowatt-hour to make additional renewables economic.

Figure 5. Retail Electricity Prices in the Reference and RPS 10 Cases



Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

While retail electricity prices are not expected to be significantly impacted by the imposition of an RPS, the industry is projected to face higher total costs and there will be large wealth transfers between nonqualifying generators and qualifying renewable generators. Over the 2000 to 2020 time period, the cumulative total electricity supplier resource costs that include fuel, non-fuel operating and maintenance costs, the capital, financing, and tax costs for new plant and equipment, and any civil penalty payments, are projected to be $7 billion higher in the RPS than in the Reference case (Table 4).[14] Relative to the total resource costs of the industry over the 2000 to 2020 time period, this change is small, a 1 percent increase relative to the Reference case.

The market for renewable credits that retail electricity suppliers will have to hold for generation for nonqualifying generators is expected to grow as the RPS share and credit price increases over time (Figure 6). In 2020 in the RPS 10 case, the renewable credit market together with penalty costs paid by retail electricity suppliers is projected to reach $12 billion ($10 billion in credits and $2 billion in penalty payments). For existing coal, nuclear and oil facilities who are not projected to see significantly lower fuel prices or higher electricity prices in the RPS 10 case, the costs of holding renewable credits will reduce their operating profits. On the other hand, for existing natural gas plants, the costs of holding renewable credits are projected be offset by lower natural gas costs.

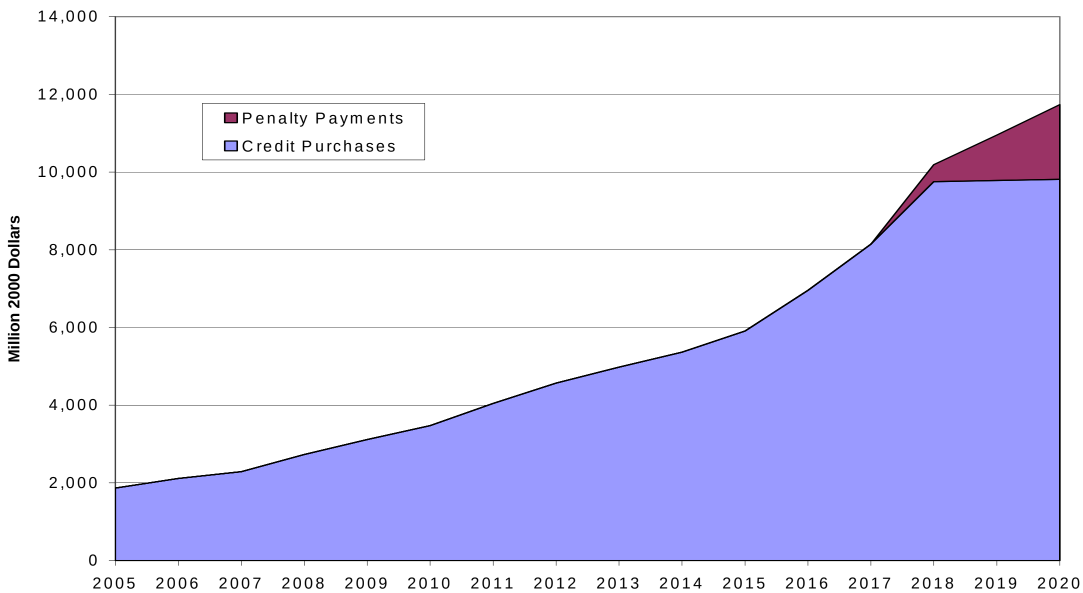
[14] This value represents the discounted present value of the annual change in resource costs over the 2000 to 2020 period using an 8 percent real discount rate, the real cost of capital for generation companies.

Table 4. Change in Discounted Electricity Supplier Resource Costs (Million 2000 Dollars)

Cost Category	Change
Investment Costs	23,950
Operations and Maintenance Costs	4,803
Fuel Costs	-22,743
Penalty Costs	818
Total	6,828

Notes: Investment costs include new generating plant costs, transmission interconnection costs, and capital costs for upgrading plants with emissions control equipment. Fuel costs include fuel costs and costs for importing power purchasing power from cogenerators.
Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

Figure 6. Credit and Penalty Costs in the RPS 10 Case, 2005 to 2020



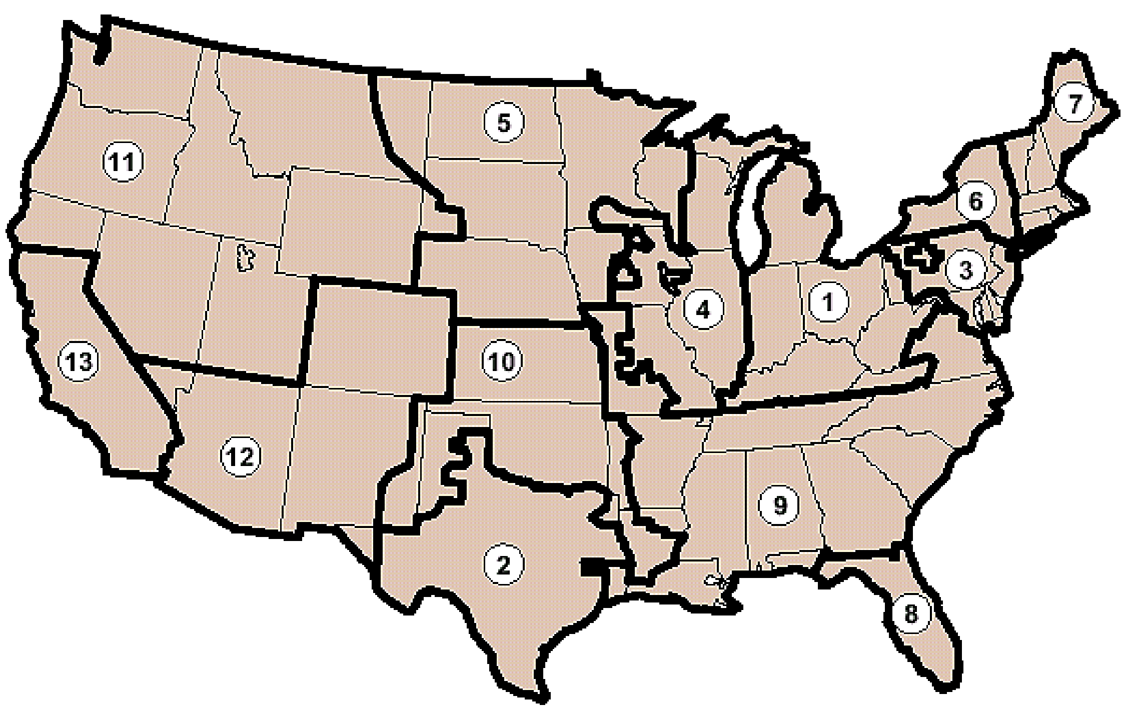
Sources: National Energy Modeling System Runs: RPS 10, rps1766.d013002a.

The lower natural gas prices stimulated by the RPS does have impacts outside of the electricity sector – leading to lower residential, commercial and industrial sector natural gas bills. For example, in 2010 the total residential natural gas bill is projected to be $534 million (1 percent) lower in the RPS 10 case than in the Reference case. For the commercial and industrial sectors the bills in 2010 are $387 million (2 percent) and $1,403 million (4 percent) lower in the RPS 10 case than in the Reference case.

Regional Impacts

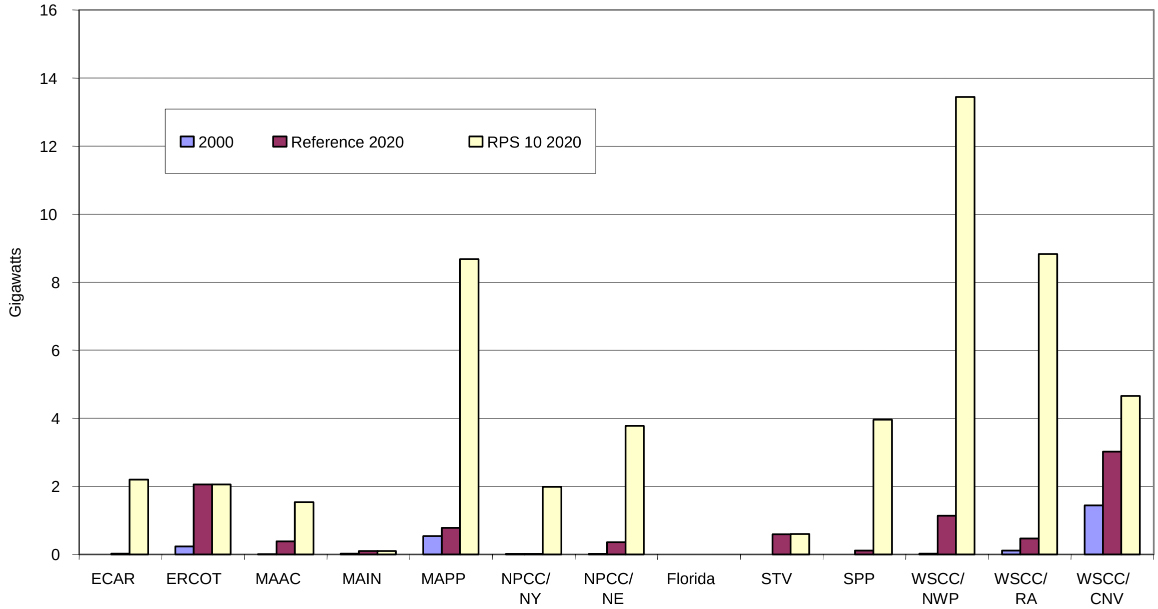
Because renewable resources are not distributed equally throughout the US, some regions of the country are expected to be impacted more than others (Figure 7). For example, most of the 52 gigawatts of wind capacity called for in 2020 in the RPS 10 case are projected to be located in the Northwest Power Pool (NWP), the Rocky Mountain, Arizona, New Mexico, Southern Nevada (RA) and the Mid-Continent Area Power Pool (MAIN) regions which each have substantial wind resources (Figure 8). For biomass, the key regions are East Central Area Reliability Coordination Agreement (ECAR) and South Eastern Electric Reliability Council (SERC) (Figure 9). These two regions have a large amount of coal capacity that is projected to find it economical to cofire with biomass when an RPS is imposed. Most are generally expected to see small price changes because of the RPS. In the later years, when the credit price reaches 3 cents per kilowatt-hour, consumers in regions which develop large amounts of renewables, such as the MAIN and NWP regions, are projected to see lower prices because the additional money that generators in these regions make from selling renewable credits is assumed to be returned to customers in these regulated regions.

Figure 7. National Energy Modeling System Electricity Supply Regions



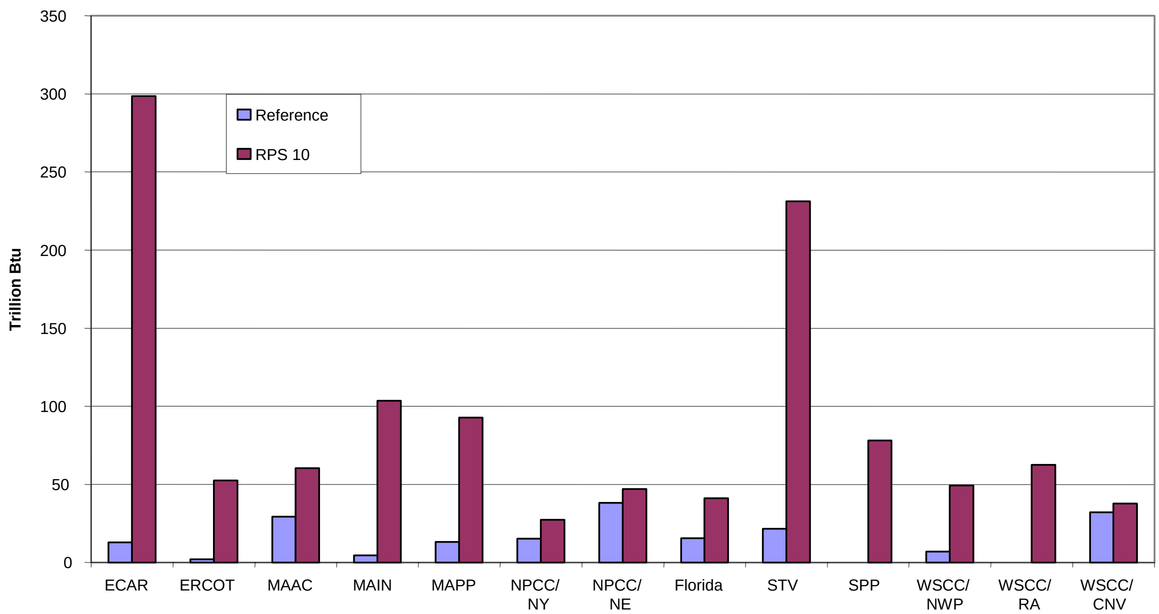
1 East Central Area Reliability Coordination Agreement
2 Electric Reliability Council of Texas
3 Mid-Atlantic Area Council
4 Mid-America Interconnected Network
5 Mid-Continent Area Power Pool
6 New York
7 New England
8 Florida Reliability Coordinating Council
9 Southeastern Electric Reliability Council
10 Southwest Power Pool
11 Northwest Power Pool
12 Rocky Mountain, Arizona, New Mexico, Southern Nevada
13 California

Figure 8. Regional Wind Capacity, 2000 and 2020



Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

Figure 9. Regional Biomass Consumption for Electricity Generation in 2020

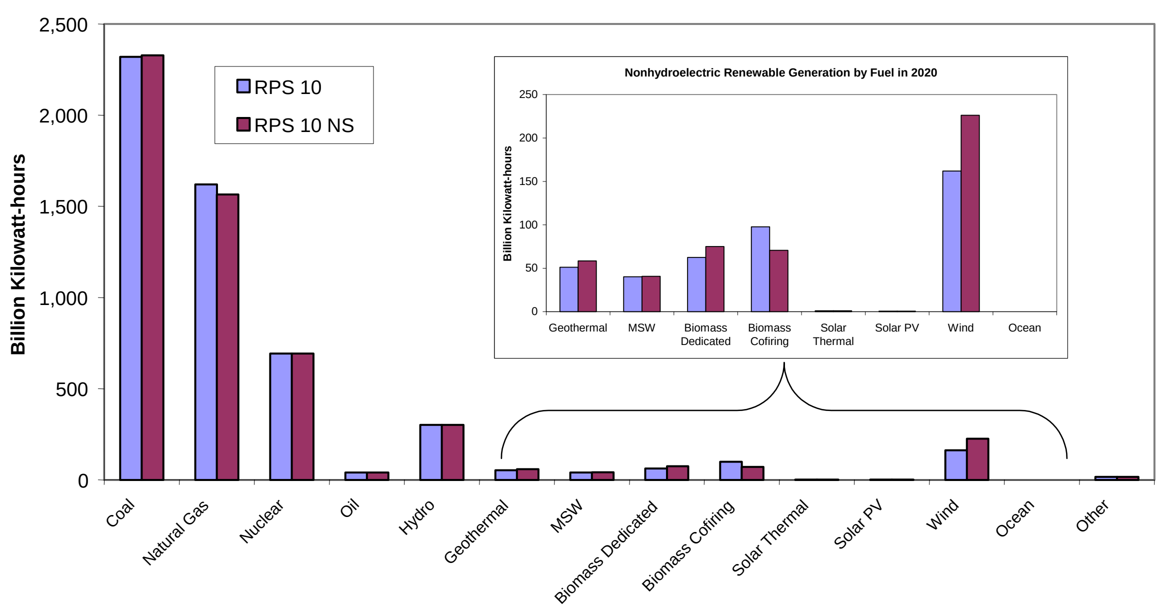


Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS 10, rps1766.d013002a.

RPS 10 Case Without Sunset Provision

Removing the sunset provision from the RPS proposed in S. 1766 has a significant impact on the estimated renewable credit prices and the level of qualifying renewable generation reached in the last few years of the projections. In the RPS 10 case (which incorporates the sunset provision called for in S. 1766) the price of renewable credits is projected to reach the 3 cent per kilowatt-hour penalty in 2018 through 2020 and the level of qualifying renewables developed does not reach the RPS target. When the sunset provision is removed, the renewable credit price in 2020 is projected to be 1.7 cents per kilowatt-hour rather than the 3.0 cents per kilowatt-hour value reached in the RPS 10 case with the sunset provision. As shown in Figure 10, relative to the RPS 10 case, when the sunset provision is removed, additional generation from wind, dedicated biomass and geothermal facilities is expected to be added to comply with the RPS requirement. The generation from biomass cofiring is actually lower when the sunset provision is removed. This occurs because capital-intensive renewable technologies like wind, geothermal, and dedicated biomass plants become more attractive when they can receive the revenue from selling renewable credits for a longer period of time. As in the RPS 10 case, the electricity price impacts in the RPS 10 case without sunsetting are projected to be small. However, because more renewables are built to comply with the RPS, the cumulative resource costs between 2001 and 2020 are $10 billion higher than in the Reference case, $3 billion higher than in the RPS 10 case with sunsetting .

Figure 10. Generation by Fuel in RPS and RPS No Sunset Cases, 2020



Sources: National Energy Modeling System Runs: Reference, RPS 10, rps1766.d013002a, RPS 10 NS, rps1766ns.d013002a.

High and Low Renewable Technology Cases

Incorporating more optimistic assumptions about improvements in the cost and/or performance of new renewable generating plants also has a significant impact on the estimated renewable credit prices and the level of qualifying renewable generation achieved (Table 5). The S. 1766 RPS target is projected to be achieved in the High Renewable Technology RPS case even with the sunset provision. The more optimistic cost and performance assumptions for new renewable technologies used in the High Renewable Technology cases lead to more renewables even without an RPS and lowers the credit price needed to stimulate enough new renewable generation to meet the target when an RPS is imposed. For example, in the Reference case (without the RPS) the share of sales coming from renewables that would qualify for the S. 1766 RPS reaches 1.2 percent in 2010 and 1.7 percent in 2020. In the High Renewable Technology case (without the RPS) these values are 1.6 and 4.1, respectively. In the RPS 10 case, the renewable credit price is projected to be 2.1 cents per kilowatt-hour in 2010 and 3.0 cents per kilowatt-hour in 2020. In contrast, in the High Renewable Technology RPS case, the renewable credit prices are 1.5 and 2.0, in 2010 and 2020, respectively. Because new renewable facilities are assumed to be less expensive in the High Renewable Technology cases, the cumulative resource costs between 2001 and 2020 are only $2 billion higher in the High Renewable Technology RPS case than in the High Renewable Technology case. It is important to note that this result is contingent on renewable technologies improving more rapidly that do nonrenewable technologies. If more optimistic cost and performance assumptions for nonrenewable technologies were also included in this case, the results would likely be very similar to those in the RPS 10 case.

Among the renewable technologies, new wind plants and increased biomass co-firing are expected to be the key compliance options in the High Renewable Technology RPS case, as they are in RPS 10 case. Relative to the RPS 10 case, however, there is a slight shift towards wind and geothermal technologies. This occurs because of the cost and performance improvements assumed for these technologies that are shown in Table 2. In total, non-hydroelectric renewable generation in 2020 is 57 billion kilowatt-hours higher in the High Renewable Technology RPS than in the RPS 10 case where the S. 1766 target is not reached.

As might be expected the opposite result occurs in the Low Renewable Technology cases (Table 6). If renewable technologies do not improve as much as is expected in the Reference case it will be even more difficult to comply with the RPS called for in S. 1766. As in the RPS 10 case, the required RPS target is not projected to be met in the Low Renewable Technology RPS. Where the RPS 10 case was projected to achieve an 8.4 percent share in 2020, the Low Renewable Technology RPS is projected to achieve a share of 6.9 percent. After 2014, retail electricity suppliers are projected to pay the civil penalty of 3 cents per kilowatt-hour because the credit price that would be required to support additional renewable development with only 6 years of credits remaining is too high. Increased generation from wind plants and biomass cofiring are the key options

Table 5. Key Results in the Reference, High Renewable Technology, and High Renewable Technology RPS Cases

Generation by Fuel (Billion Kilowatt-hours)	1999	2010 Reference	2010 High Renewable Technology	2010 High Renewable Technology RPS	2020 Reference	2020 High Renewable Technology	2020 High Renewable Technology RPS
Coal	1,887.1	2,264.4	2,262.0	2,242.8	2,472.2	2,443.7	2,312.1
Natural Gas	561.1	1,152.6	1,146.5	1,051.0	1,732.9	1,671.7	1,592.4
Nuclear	728.3	736.9	736.9	747.5	701.8	701.8	686.7
Oil	124.0	38.3	36.8	29.1	48.6	45.9	36.2
Hydro	310.3	301.1	301.1	301.1	300.0	300.0	300.0
Geothermal	15.3	20.2	24.0	37.9	34.7	56.5	59.0
MSW	21.2	31.1	31.1	38.5	34.3	34.3	39.7
Biomass Dedicated	37.0	47.8	51.6	52.9	60.2	72.0	71.9
Biomass Cofiring	0.5	11.1	11.4	13.8	4.1	4.0	84.9
Solar Thermal	0.9	1.0	1.0	1.0	1.1	1.1	1.1
Solar PV	0.0	0.3	0.3	0.3	0.7	0.7	0.7
Wind	4.2	19.4	23.4	113.1	24.1	87.1	214.5
Ocean[b]	--	--	--	--	--	--	--
Other	17.6	12.9	12.9	12.9	15.4	15.4	15.4
Total	3,707.4	4,637.0	4,638.9	4,642.0	5,430.1	5,434.0	5,414.6
Electricity Sales (Billion Kilowatt-hours)	3,324	4,170	4,169	4,169	4,916	4,912	4,903
% S. 1766 Qualifying Renewable	NA	1.2%	1.6%	5.0%	1.7%	4.1%	10.0%
Capacity by Technology (Gigawatts)							
Coal	313.0	314.3	314.6	313.0	337.6	334.1	326.0
Oil and Gas	256.0	435.6	433.8	434.7	578.5	571.4	565.0
Nuclear	97.5	94.3	94.3	96.3	88.0	88.0	86.5
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6
Hydroelectric	79.3	79.9	79.9	79.9	79.9	79.9	79.9
Geothermal	2.8	3.6	4.0	5.8	5.3	8.0	8.4
MSW	3.3	4.4	4.4	5.4	4.8	4.8	5.5
Biomass Dedicated	6.6	8.4	9.0	9.2	10.4	12.3	12.2
Solar Thermal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Solar PV	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Wind	2.3	7.6	8.7	33.9	9.1	25.3	62.8
Ocean[b]	--	--	--	--	--	--	--
Other	1.6	2.1	2.1	2.1	2.4	2.4	2.4
Total	781.8	970.3	970.9	1,000.3	1,136.4	1,146.5	1,169.1
Credit Price (Cents per Kilowatt-hour)	NA	NA	NA	1.5	NA	NA	2.0
Retail Electricity Price (Cents per Kilowatt-hour)	6.7	6.3	6.3	6.3	6.5	6.4	6.5
Emissions (Million Tons)[a]							
Nitrogen Oxides	5.7	4.0	4.0	4.0	4.2	4.1	4.1
Sulfur Dioxide	12.5	9.7	9.7	9.7	8.9	9.0	9.0
Carbon Dioxide	560.1	688.8	686.1	668.3	790.2	775.5	732.8
Fuel Prices							
Natural Gas Wellhead ($ per thousand cubic feet)	2.27	2.85	2.83	2.70	3.26	3.20	3.11
Coal Minemouth ($ per short ton)	17.01	14.11	13.77	13.61	12.79	12.70	12.67

[a]Emissions are in million short tons for sulfur dioxide and nitrogen dioxides and million metric tons carbon equivalent for carbon dioxide.
[b]Ocean technologies are not represented in the National Energy Modeling System.
Note: All prices are in 2000 dollars. NA: not applicable.
Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; High Renewable Technology, hirenew02.102301a; High Renewable Technology RPS, .rps1766hr.d013002a.

Table 6. Key Results in the Reference, Low Renewable Technology, and Low Renewable Technology RPS Cases

Generation by Fuel (Billion Kilowatt-hours)	1999	2010			2020		
		Reference	Low Renewable Technology	Low Renewable Technology RPS	Reference	Low Renewable Technology	Low Renewable Technology RPS
Coal	1,887.1	2,264.4	2,262.5	2,230.1	2,472.2	2,478.4	2,338.0
Natural Gas	561.1	1,152.6	1,155.5	1,056.3	1,732.9	1,731.1	1,648.5
Nuclear	728.3	736.9	736.9	747.5	701.8	701.8	692.0
Oil	124.0	38.3	37.7	31.5	48.6	48.6	40.8
Hydro	310.3	301.1	301.1	301.1	300.0	300.0	300.0
Geothermal	15.3	20.2	19.9	36.2	34.7	33.0	48.1
MSW	21.2	31.1	31.1	38.9	34.3	34.3	40.2
Biomass Dedicated	37.0	47.8	47.8	49.8	60.2	59.1	61.5
Biomass Cofiring	0.5	11.1	11.8	34.4	4.1	4.5	98.0
Solar Thermal	0.9	1.0	1.0	1.0	1.1	1.1	1.1
Solar PV	0.0	0.3	0.3	0.3	0.7	0.7	0.7
Wind	4.2	19.4	19.4	95.7	24.1	21.9	111.2
Ocean[b]	--	--	--	--	--	--	--
Other	17.6	12.9	12.9	12.9	15.4	15.4	15.4
Total	3,707.4	4,637.0	4,637.9	4,635.7	5,430.1	5,429.7	5,395.4
Electricity Sales (Billion Kilowatt-hours)	3,324	4,170	4,171	4,168	4,916	4,917	4,890
% S. 1766 Qualifying Renewable	NA	1.2%	1.2%	5.0%	1.7%	1.6%	6.9%
Capacity by Technology (Gigawatts)							
Coal	313.0	314.3	314.5	313.7	337.6	338.5	331.2
Oil and Gas	256.0	435.6	436.0	435.9	578.5	577.8	569.9
Nuclear	97.5	94.3	94.3	96.3	88.0	88.0	87.3
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6
Hydroelectric	79.3	79.9	79.9	79.9	79.9	79.9	79.9
Geothermal	2.8	3.6	3.5	5.5	5.3	5.1	7.0
MSW	3.3	4.4	4.4	5.4	4.8	4.8	5.6
Biomass Dedicated	6.6	8.4	8.4	8.7	10.4	10.2	10.5
Solar Thermal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Solar PV	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Wind	2.3	7.6	7.6	31.1	9.1	8.4	35.7
Ocean[b]	--	--	--	--	--	--	--
Other	1.6	2.1	2.1	2.1	2.4	2.4	2.4
Total	781.8	970.3	970.8	998.7	1,136.4	1,135.6	1,149.8
Credit Price (Cents per Kilowatt-hour)	NA	NA	NA	2.3	NA	NA	3.0
Retail Electricity Price (Cents per Kilowatt-hour)	6.7	6.3	6.3	6.3	6.5	6.5	6.6
Emissions (Million Tons)[a]							
Nitrogen Oxides	5.7	4.0	4.0	4.0	4.2	4.2	4.2
Sulfur Dioxide	12.5	9.7	9.7	9.7	8.9	8.9	8.9
Carbon Dioxide	560.1	688.8	687.5	665.6	790.2	791.8	744.3
Fuel Prices							
Natural Gas Wellhead ($ per thousand cubic feet)	2.27	2.85	2.86	2.72	3.26	3.25	3.18
Coal Minemouth ($ per short ton)	17.01	14.11	13.89	13.69	12.79	12.85	12.73

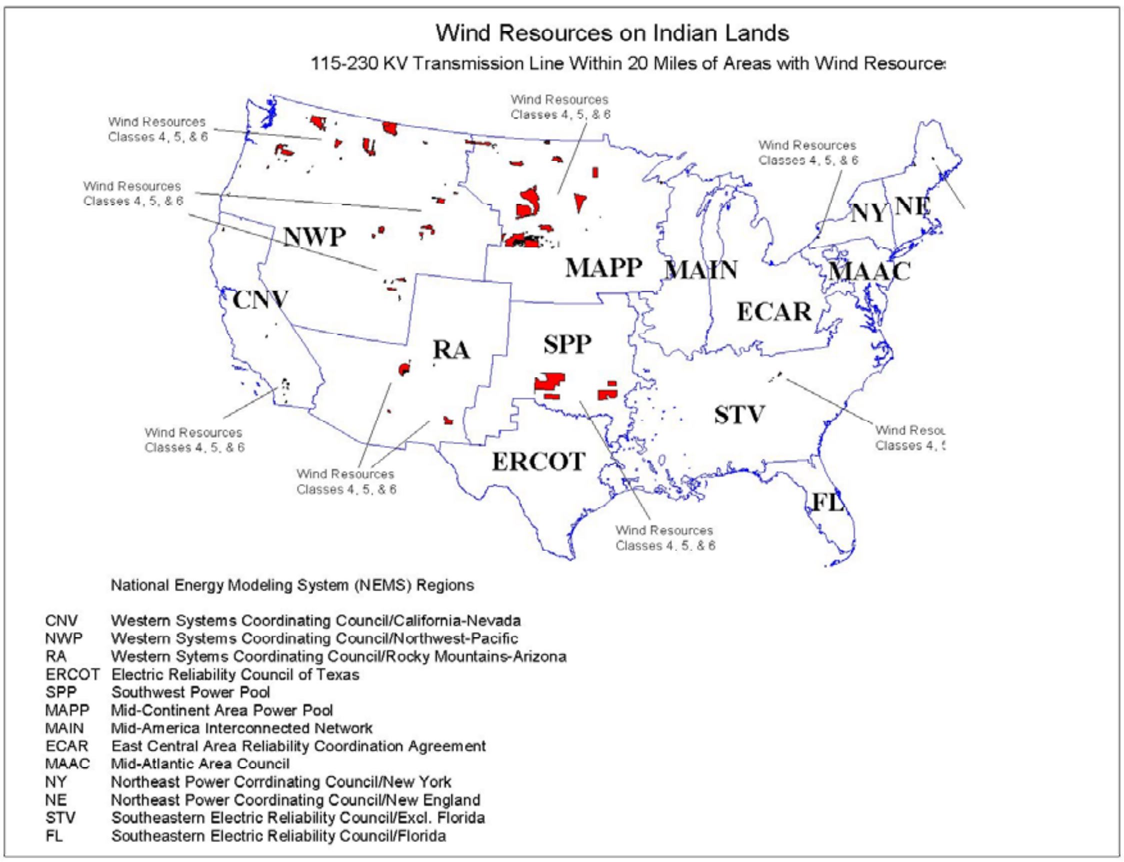
[a]Emissions are in million short tons for sulfur dioxide and nitrogen dioxides and million metric tons carbon equivalent for carbon dioxide.
[b]Ocean technologies are not represented in the National Energy Modeling System.
Note: All prices are in 2000 dollars. NA: not applicable.
Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; Low Renewable Technology, aeolornw.012802a; Low Renewable Technology RPS, .rps1766lr.d013002a.

used to reach the 6.9 percent share achieved. Relative to the other RPS cases presented in this report, biomass cofiring is more important in the Low Renewable Technology RPS. This occurs because the less optimistic renewable technology assumptions made in this case make biomass cofiring relatively more attractive.

Potential Impact of Indian Lands Provision

As mentioned, using a Geographic Information System (GIS) it was found that Indian lands contain a substantial amount of wind resources, but little biomass or geothermal resources. As mentioned, few biomass or geothermal resources were found on Indian lands, but 8 percent of high-quality (wind classes 4, 5, and 6) windy land is on Indian lands (Figure 11). However, much of this resource is expected to be relatively high cost and unlikely to be stimulated by an RPS. In this analysis, the costs of new wind projects are adjusted to reflect increases that are expected to occur as developers move from the most economically attractive sites to less attractive sites. These costs adjustments are

Figure 11. Wind Resources on Indian Lands



broken into 5 categories with the first category receiving no cost adjustment, the second receiving a 20 percent cost adjustment, the third a 50 percent cost adjustment, the fourth a 100 percent cost adjustment and fifth a 200 percent cost adjustment. The percentage of the wind resources expected to fall into each category varies from region to region, but the amount that falls into the first three categories is generally quite small – roughly 5 percent. If it is assumed that the cost adjustments on wind resources are distributed in the same pattern as for the total wind resource in each region, roughly 10 gigawatts of the 200 gigawatts of potential wind capacity on Indian lands could be developed in the first three cost adjustment categories which would be expected to become economical when an RPS with double credits for projects on Indian lands were imposed. Translating this into potential generation using a 35 percentage capacity factor gives 31 billion kilowatt-hours of increased wind generation from projects on Indian lands in response to the RPS.

In the RPS 10 case, over 50 gigawatts of new wind capacity is projected to be built. If the Indian lands double credit provision were incorporated in the RPS 10 case, up to 10 gigawatts of this capacity might be constructed on Indian lands. If this were to occur, it would lower the amount of qualifying renewable generation required to comply with the RPS. Essentially, the double credit provision would count the generation from new wind plants on Indian lands twice, reducing the overall amount of renewables needed for the RPS. However, given that only 10 gigawatts of wind resources on Indian lands are likely to be stimulated by an RPS, the overall results should be similar to those for the RPS 10 case shown in this analysis.

20 Percent RPS

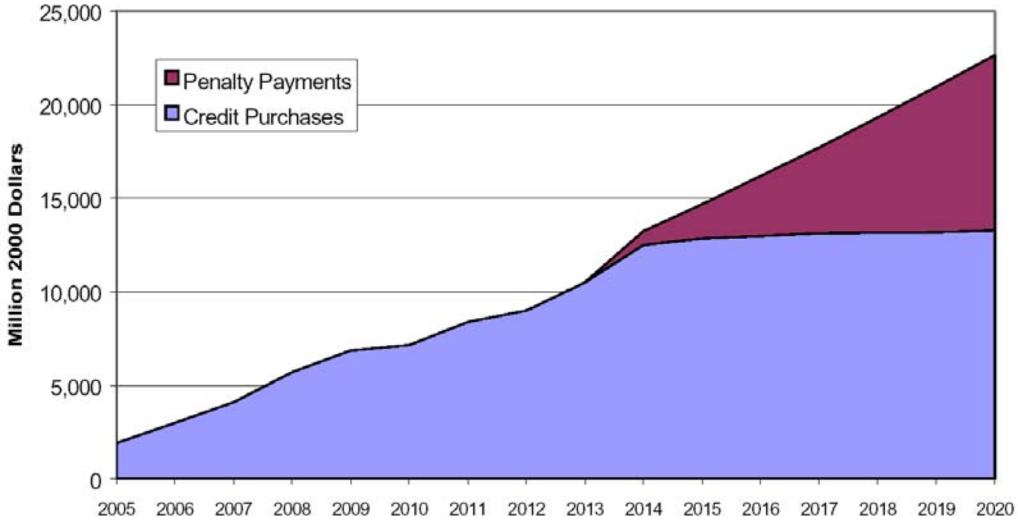
The key result in the RPS 20 case is that, like in the RPS 10 case the targeted renewable share is not projected to be achieved (Table 7). By 2020 the share is projected to reach 12 percent, well below the 20 percent target. This mainly occurs because of the high cost of the level of renewables that would be needed to meet the RPS target. Also, as the December 31, 2020, program sunset date grows closer; new renewable facilities would not have enough time to recover their higher costs through credit revenue. Thus, retail electricity suppliers are expected to pay the penalty rather than support new renewable facilities (Figure 12). However, the RPS 20 case does build more renewables than the RPS 10 case. In fact, the 10 percent RPS target called for in the RPS 10 case is achieved in the RPS 20 case. This occurs because higher RPS shares are called for in the RPS 20 case earlier than in the RPS 10 case allowing new renewable facilities to recover their higher costs through credit sales before the end of the program. For example, in the RPS 20 case, the renewable share required reaches 10 percent between 2011 and 2012, versus in 2020 in the RPS 10 case. This means that new renewable facilities could be brought on in 2012 to bring the share to 10 percent allowing eight years to recover the higher costs through credit sales.

Table 7. Key RPS Results in Reference, RPS and RPS 20 Cases

Generation by Fuel (Billion Kilowatt-hours)	1999	2010			2020		
		Reference	RPS 10	RPS 20	Reference	RPS 10	RPS 20
Coal	1,887.1	2,264.4	2,233.9	2,172.4	2,472.2	2,319.1	2,270.1
Natural Gas	561.1	1,152.6	1,054.2	1,015.2	1,732.9	1,620.3	1,544.6
Nuclear	728.3	736.9	747.5	747.5	701.8	692.0	692.0
Oil	124.0	38.3	30.5	28.4	48.6	40.5	33.4
Hydro	310.3	301.1	301.1	301.1	300.0	300.0	300.0
Geothermal	15.3	20.2	36.5	42.1	34.7	51.2	56.9
MSW	21.2	31.1	38.9	39.5	34.3	40.2	40.8
Biomass Dedicated	37.0	47.8	49.8	58.8	60.2	62.4	93.7
Biomass Cofiring	0.5	11.1	27.7	90.3	4.1	97.7	101.0
Solar Thermal	0.9	1.0	1.0	1.0	1.1	1.1	1.1
Solar PV	0.0	0.3	0.3	0.3	0.7	0.7	0.7
Wind	4.2	19.4	102.3	123.9	24.1	162.0	236.7
Ocean[b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	17.6	12.9	12.9	12.9	15.4	15.4	15.4
Total	3,707.4	4,637.0	4,636.7	4,633.4	5,430.1	5,402.7	5,386.3
Electricity Sales (Billion Kilowatt-hours)	3,324	4,170	4,168.0	4,165	4,916	4,897.4	4,876
% S. 1766 Qualifying Renewable	NA	1.2%	5.0%	8.3%	1.7%	8.4%	11.7%
Capacity by Technology (Gigawatts)Capacity							
Coal	313.0	314.3	313.7	313.3	337.6	328.6	322.9
Oil and Gas	256.0	435.6	435.0	432.6	578.5	569.0	558.6
Nuclear	97.5	94.3	96.3	96.3	88.0	87.3	87.3
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6
Hydroelectric	79.3	79.9	79.9	79.9	79.9	79.9	79.9
Geothermal	2.8	3.6	5.6	6.3	5.3	7.4	8.1
MSW	3.3	4.4	5.4	5.5	4.8	5.6	5.6
Biomass Dedicated	6.6	8.4	8.7	9.9	10.4	10.6	15.3
Solar Thermal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Solar PV	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Wind	2.3	7.6	33.4	40.7	9.1	51.8	77.5
Ocean[b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	1.6	2.1	2.1	2.1	2.4	2.4	2.4
Total	781.8	970.3	1,000.1	1,006.7	1,136.4	1,162.9	1,178.0
Credit Price (Cents per Kilowatt-hour)	NA	NA	2.1	2.7	NA	3.0	3.0
Retail Electricity Price (Cents per Kilowatt-hour)	6.7	6.3	6.3	6.3	6.5	6.6	6.7
Emissions (Million Tons)							
Nitrogen Oxides	5.7	4.0	4.0	4.0	4.2	4.1	4.1
Sulfur Dioxide	12.5	9.7	9.7	9.7	8.9	9.0	8.9
Carbon Dioxide	560.1	688.8	666.1	668.3	790.2	737.1	732.8
Fuel Prices							
Natural Gas Wellhead ($ per thousand cubic feet)	2.27	2.85	2.72	2.67	3.26	3.14	3.04
Coal Minemouth ($ per short ton)	17.01	14.11	13.66	13.64	12.79	12.72	12.72

[a]Emissions are in million short tons for sulfur dioxide and nitrogen dioxides and million metric tons carbon equivalent for carbon dioxide.
[b]Ocean technologies are not represented in the National Energy Modeling System.
Note: All prices are in 2000 dollars. NA: not applicable.
Sources: National Energy Modeling System Runs: Reference, aeo2002.d102001b; RPS, rps1766.d013002a, RPS 20, rps176620.d013102a.

Figure 12. Credit and Penalty Costs in the RPS 20 Case, 2005 to 2020



Sources: National Energy Modeling System Run: RPS 20, rps176620.d013102a.

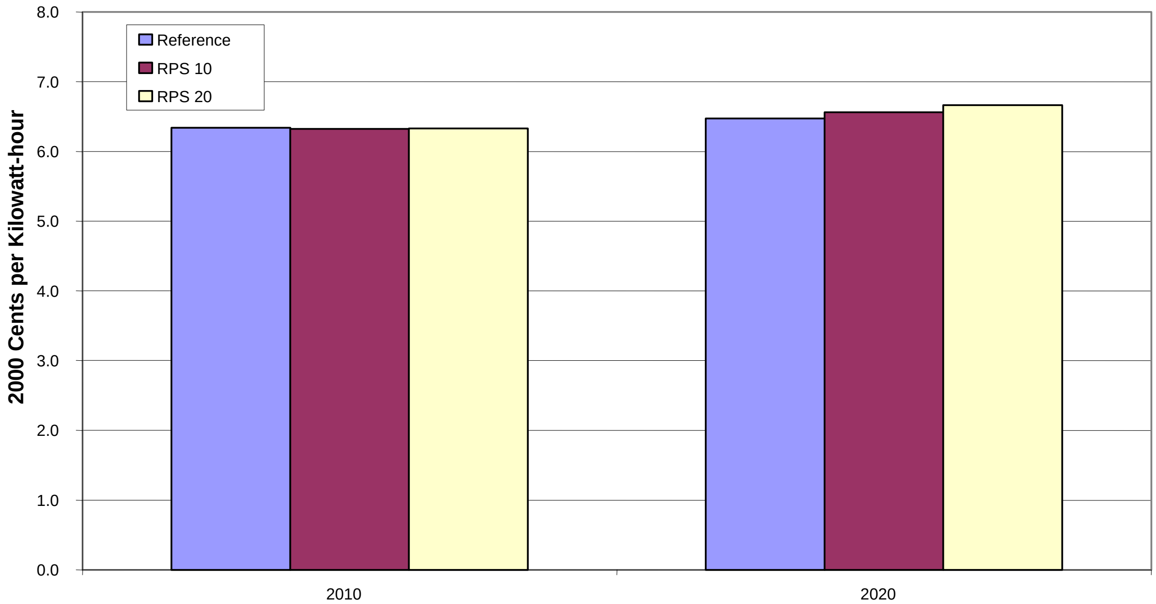
Increased generation from wind, biomass cofiring, biomass dedicated[15] and geothermal are projected to be the key compliance options in the RPS 20 case. Relative to the RPS 10 case, wind and biomass dedicated are projected to see the largest increases. Renewable credit prices are projected to be higher in the RPS 20 than in the RPS 10. For example, in 2010 they are projected to be 2.1 cents per kilowatt-hour in the RPS 10 versus 2.7 cents per kilowatt-hour in the RPS 20 case. The impact on electricity prices and resource costs is projected to be larger in the RPS 20 case than in RPS 10 case (Figure 13). In 2020, retail electricity prices are projected to be 3 percent above the reference case level in the RPS 20 case. The increase in discounted resource costs over the 2001 to 2020 time period is projected to be $21 billion.

Uncertainties

As with any long-term projections there are considerable uncertainties in these results. Among the key uncertainties are projections of the growth in the demand for electricity, future fuel prices, and the cost and performance of new generating equipment – renewable and nonrenewable. In addition, the design of the RPS program in S. 1766 could provide some incentives that are counter productive to the goal of increasing renewable generation. In the 1990s, the demand for electricity grew 2.3 percent per year. However, because of efficiency improvements in new appliances and equipment and the reduced energy intensity of the US economy, the demand for electricity is projected to grow 1.8 percent per year between 2000 and 2020 in the AEO Reference case. If the historical growth were to continue, the need for new capacity – both renewable and nonrenewable – would be larger and it could be more difficult to comply with the RPS.

[15] Biomass dedicated plants are facilities built specifically to produce electricity from biomass fuels.

Figure 13 Retail Electricity Prices in the Reference, RPS 10 and RPS 20 Cases, 2010 and 2020



Sources: National Energy Modeling System Runs: Reference, RPS 10, rps1766.d013002a, RPS NS, rps1766ns.d013002a RPS 20, rps176620.d013102a.

Since natural gas plants are expected to account for most of the new capacity added over the next 20 years, future natural gas prices are important in determining the credit price needed to make new renewable plants competitive with other generation options. If natural gas prices turn out to be lower than are projected in this report, the renewable credit needed would be larger. Conversely, it would be lower if natural gas prices turn out to be higher than expected.

Projections of the future cost and performance of new generating equipment are always difficult, particularly for technologies that currently have little or no market experience. Nonhydroelectric renewable technologies currently produce about 2 percent of the power generated in the United States. Spurring the market penetration of these technologies with an RPS might allow developers – through mass production techniques and learning by doing – to make reductions in their costs and improve their performance. These types of improvements are incorporated in the NEMS. However, it could turn out that the current relatively low market shares for these technologies are due to high costs that cannot be easily reduced. In addition, even if renewable technology developers are successful in improving the cost and performance of their technologies their ability to penetrate the market will depend on what happens to the costs and performance of nonrenewable technologies. If renewable and nonrenewable technologies improve by similar amounts, the relative advantage that nonrenewable technologies have today would likely remain.

While there is uncertainty about the cost and performance of new generating technologies, the level of cofiring that might be stimulated by an RPS is also unknown. As mentioned, in this analysis coal plants are expected to be able to replace up to 5 percent of the coal they use with biomass when they receive a renewable credit. Without the RPS, few coal plants are expected to find it economical to displace relatively low cost coal with biomass fuels. It is possible that with the RPS incentive it might be economical for some coal plants to make modifications to allow them to use even larger shares – 10 percent or more - of biomass fuels. If this occurred these plants could satisfy a larger percentage of the RPS requirement than projected in the RPS 10 case. However, in today's market coal plant operators are focused on how future environmental regulations, particularly any efforts to reduce U.S. carbon emissions, might impact them, and they are wary about making investments in their plants.

For both wind and biomass the level of development called for in the RPS 10 case comes with some uncertainty. The RPS 10 case shows wind capacity increasing from approximately 2 gigawatts in 1999 to 52 gigawatts in 2020 – a 2,500 percent increase. While data suggest that sufficient wind resources exist to support this level of development, it is difficult to predict how the costs of development might change as developers move from the best sites to those that are less economically attractive. In some cases, developers may have to forego building on economically attractive sites because of public resistance arising from concerns about visibility or injuries to birds. In this analysis, costs are assumed to increase as developers turn to more costly sites such as those with higher interconnection costs, higher land costs, or more difficult terrain. However, there is significant uncertainty about the actual cost increases that might occur. Wind development may also be constrained by its intermittent nature which leads to the need for backup capacity to ensure that consumers' needs for electricity can be met at all times. In this analysis, wind and other intermittent resources (primarily solar) are limited to accounting for 15 percent of a region's total generation. In some regions with intensive wind building, this constraint limits the construction of new wind capacity in otherwise low-cost resource areas. In reality, the additional cost of providing backup capacity for intermittent generators could begin to impact the cost of this technology at penetration levels below 15 percent.[16] Furthermore, markets may be able to absorb penetrations in excess of 15 percent by investing in additional backup capacity and other mitigating technologies (energy storage, improved grid monitoring and control, and improved power conversion on the wind turbine) if economic and policy conditions warrant.

As with wind, data suggest that there are sufficient biomass resources to fuel the increased biomass generation projected in the RPS 10 case. However, currently there are very few coal plants that cofire with biomass. To achieve the level of biomass cofiring called for in the RPS 10 case, infrastructure to reliability gather, process and deliver the available biomass to coal plants would have to be developed. This analysis includes estimates of the costs of building this infrastructure, but given the low level of biomass cofiring occurring today, these costs are highly uncertain. In addition, if power sector carbon emissions reductions were required, the potential for cofiring in coal plants would be much lower because coal generation would likely be much lower.

[16] Eric Hirst, "Interactions of Wind Farms With Bulk-Power Operations and Markets", Project for Sustainable FERC Energy Policy, September 2001

And, finally, two provisions of the RPS program in S. 1766, the small utilities exemption and the restriction of credits to new renewables, may provide incentives that lead to unwanted outcomes. As mentioned in the methodology section of this analysis, retail electricity providers with sales of less than 500,000,000 kilowatt-hours are exempt from the requirements of the program. In 1999, these companies accounted for 270 billion kilowatt-hours of sales or 9 percent of total sales. In this analysis, it is assumed that the 270 billion kilowatt-hours sales figure will remain constant through 2020. However, this RPS exemption for small companies could provide an incentive for potential retail suppliers to limit their size in order to avoid having to comply with the RPS program. If this occurred, it would lead to lower renewable generation than is projected in this analysis. Of course, requiring small companies to comply could also be burdensome for them. The restriction of renewable credits to new renewables could have the same impact for a different reason. This restriction could cause renewable project operators to try to find ways to convert their existing renewable facilities into new facilities. For example, when faced with the S. 1766 RPS program, an operator of an existing wind or geothermal facility might retire it arguing that it has become uneconomical, and replace it with a new facility on a nearby site. They could argue that the new plant should get full RPS credits because it is a totally new plant and the retirement decision on the old plant had nothing to do with the RPS. The impact of this type of action would be to lower the increase in renewable generation projected in this analysis. Clearly, restricting the credit to new or upgraded facilities is done to reduce the cost of the program by avoiding paying facilities who were built without the program (what economists would call free riders).

Appendix A.

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150
ENERGY.SENATE.GOV

December 20, 2001

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC, 20585

Dear Acting Administrator Hutzler:

The Senate is considering comprehensive legislation to update U.S. national energy strategy in light of the volatility of energy markets in calendar year 2000 and the growing energy security concerns in light of recent events that highlight our dependence on foreign imported oil. To this end, there have been several legislative proposals introduced in the 107th Congress on the subject of national energy policy, and the Majority Leader has indicated that the Senate will debate energy policy early in the next session of Congress. Our decisions will benefit from an analysis of the strengths and weaknesses of the various energy policy proposals that have been introduced to date.

With that in mind, I request that the Energy Information Administration (EIA) analyze the potential costs and benefits of proposed legislation to update and revise our national energy strategy, namely, H.R. 4 as passed by the House of Representatives in August 2001, and S. 1766 as proposed by Senators Daschle and Bingaman earlier this month. I understand that EIA has the ability to conduct such analysis, including the use of both sectoral and economy-wide energy models. Using the most recent *Annual Energy Outlook 2002* as a reference case, I ask that EIA assess the impacts of these energy policy proposals on, at minimum:

- macroeconomic indicators (jobs, Gross Domestic Product, trade balance, etc.);
- energy supply and demand by fuel and process;
- energy prices to consumers (residential, industrial, and commercial) by fuel;
- dependence on foreign oil imports and impacts on energy security;
- impacts on energy infrastructure (transmission, pipelines, refineries, etc.); and
- emissions of greenhouse gases and air pollutants.

As the Daschle/Bingaman bill (S. 1766) contains several "placeholders" reserved for future legislative proposals, I ask that for the purposes of your analysis, you include for Section 801 of S. 1766, S. 804, introduced by Senators Feinstein, Snowe and Reed making changes to the Corporate Average Fuel Economy (CAFE) program. For Section 1821 of S. 1766, use the provisions contained in S. 1746, introduced by Senator Reid on nuclear facility security. Also, to ensure a consistent comparison, please exclude from your analysis of H.R. 4 the amendments to the tax code contained in Division C of that bill. I expect to request from EIA a follow-up analysis of the tax-related proposals contained in H.R. 4 and an expected Senate Finance Committee mark at a subsequent date.

When assessing the costs and benefits of these legislative proposals, please be sure to point out which specific policy actions have the most significant positive or negative impacts on the factors outlined above. In order to inform our deliberations on national energy policy which are due to begin in the next several weeks, I ask that the requested information be made available by January 23, 2002. In addition, I request that a briefing of your results prior to release of any written report.

If you have any questions regarding this request, or desire further clarification with respect to translating legislative proposals into assumptions you will use in your analysis, please contact Bryan Hannegan with my Senate Energy and Natural Resources Committee staff at 224-7932. Thank you for your timely attention to this request, and for your efforts to ensure that our Nation's energy policy decisions are informed with the best available analysis.

Sincerely,

Frank H. Murkowski

Frank H. Murkowski
Ranking Member

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

February 6, 2002

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC, 20585

Dear Acting Administrator Hutzler:

As a follow-up to my letter of December 20, 2001 in reference to analysis of comprehensive energy legislation, please find below additional information to assist you in your analysis of key portions of S. 1766 and H.R. 4 identified as follows:

Renewable Portfolio Standard (RPS): For H.R. 4, assume no changes in current law. For S. 1766, assume a 2.5% mandate for new renewable electricity starting in 2005, increasing 0.5% each year through 2020 (10% new renewables by 2020). In addition, please provide analysis of a new scenario that reflects a 20% RPS by 2020 under the same provisions as in S. 1766. Key analysis questions include: whether or not such amounts of new renewable energy are possible with reasonable technology improvements, what renewable technologies benefit most, whether consumer retail electricity costs are affected by the RPS, and how the higher incremental costs of renewable electricity generation are absorbed by generators, utilities and/or consumers. Also, please describe the effect of the civil penalty imposed for failing to meet the RPS and whether that affects estimates of renewable electricity production, economic impacts, and macroeconomic effects.

Alaska Oil Production: For S. 1766, please provide your baseline Annual Energy Outlook 2002 (AEO) forecast without production from ANWR and compare it with several scenarios for H.R. 4: (1) median USGS ANWR production estimate and AEO 2002 world oil prices; (2) high-range USGS ANWR production estimate and AEO 2002 world oil prices; (3) high-range USGS estimate, using your "High Oil Price" side case; and (4) high-range USGS estimate, using your AEO 2002 "High Technology" side case that assumes rapid transportation technology development. Key variables to consider include the percentage of U.S. foreign oil dependence, and a summary of crude oil supply, demand, and disposition.

Alaska Natural Gas: For H.R. 4, assume no changes in law. For S. 1766, please analyze the impact of the proposed $10 billion loan guarantee (Sec. 6501-6512) on project economics and timing of construction assuming that the "over the top" route for the pipeline is prohibited (Sec. 701). Key analysis variables should include: the date at which natural gas from Alaska is first delivered to market in the Lower 48, the impact of the pipeline on the price of natural gas, and the sensitivity of these variables to higher or lower natural gas prices in the U.S. market.

Automobile Fuel Economy Standards (CAFE): For H.R. 4, assume increases in CAFE standards for model years 2004 through 2010 so as to decrease total gasoline consumption by 5 billion gallons over that period of time. For S. 1766, assume the adoption of provisions of S. 804 (Feinstein) – require 25 mpg for SUVs and light trucks produced between model years 2005 and 2007 and 27.5 mpg for SUVs and light trucks produced thereafter. Use as a reference case technology frozen at model year 2002 levels and performance, and assume further no change in fuel economy for passenger vehicles. Please analyze a second case which assumes a 5% increase in fuel economy standards over model year 2000 levels by model year 2005 for both passenger vehicles and SUVs/light trucks, with a further 5% increase for all vehicles by model year 2010. In all cases, please provide analysis on total net costs to consumers (e.g. up-front additional costs minus life-cycle fuel economy savings), macroeconomic effects on non-agricultural jobs, whether such fuel economy goals can be meet through reasonable technology assumptions, and estimates of carbon dioxide emissions.

Renewable Fuels/MTBE: For H.R. 4, assume no change in current law, and use the Annual Energy Outlook 2002 reference forecast as the base case. For S. 1766, assume a renewable fuel standard of 2.3 billion gallons renewable fuel by 2004 increasing per Section 818 of the legislation to 5.0 billion gallons by 2012. Include in your analysis of S. 1766 a ban on MTBE within four years and assume that, given the opportunity to opt out of the 2% oxygenate requirement, California RFG and East Coast RFG areas do so. Also, please analyze a third case where the renewable fuel standard is as proposed in Section 818 of S. 1766, but assume complete repeal of the 2% oxygenate standard, and that States are given the ability to ban MTBE if they wish starting in 2003 or 2004. Key analysis variables should include effects on motor gasoline and RFG prices and fuel imports, GDP, and energy expenses, and estimates of carbon dioxide emissions.

Air Conditioning/Heat Pump Standard: For H.R. 4, assume a 12 SEER/7.4 HSPF standard for air conditioners and heat pumps manufactured for Federal agency use only on or after date of enactment, and for S. 1766 assume a 13 SEER/7.7 HSPF standard enacted for all air conditioners and heat pumps manufactured on or after January 23, 2006. Key analysis variables include: electricity savings, net energy cost savings (increased up-front stock cost minus life cycle energy bill savings), and carbon dioxide emissions evaluated relative to the current 10 SEER standard.

Other Provisions: Pursuant to my letter of December 20, 2001, please also provide qualitative analyses for the following provisions:

Price-Anderson Act	S. 1766 (Sec 501-508) and H.R. 2983
Energy R& D	S. 1766 (Sec. 1211-1245) H.R. 4 (Corresponding provisions in Division B)
Other Consumer Product Standards	S. 1766 (Sec. 921- 929) H.R. 4 (Sec. 142-143)
Alternative Fuel Programs	S. 1766 (Sec. 811, 812, 814-819) H.R. 4 (Corresponding provisions in divisions A,B)
Hydro Relicensing	S. 1766 (Sec 301-308) H.R. 4 (Sec. 401- 402)

Pursuant to your conversations with my Energy Committee staff, I understand that your analysis will be issued in phases once available, starting with the Air Conditioning/Heat Pump Standard analysis delivered to me on January 23, 2002. As the Senate appears to be moving towards consideration of S. 1766 during the week of February 11th, I hope you can deliver as many of these phases as you and your staff are able to complete prior to that time and brief interested staff and Senators as appropriate at the earliest opportunity.

If you have any further questions regarding this request, or desire further clarification, please contact Bryan Hannegan with my Senate Energy and Natural Resources Committee staff at 224-7932. Thank you for your continued timely attention to this request, and for your efforts to ensure that our Nation's energy policy decisions are informed with the best available analysis.

Sincerely,

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