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Analysis of a 10-percent Renewable Portfolio Standard

May 2003

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Introduction

On May 8, 2003, Senator Jeff Bingaman, the Ranking Minority Member of the Senate Committee on Energy and Natural Resources, requested an analysis of a nationwide Renewable Portfolio Standard (RPS) program proposed to be amended to energy legislation currently pending before the U.S. Senate[1]. With his request Sen. Bingaman provided specific information on the program to be analyzed. This analysis was prepared in response to his request and projects the impact of the proposed program on energy supply, demand, prices, and emissions. The analysis is based on the *Annual Energy Outlook 2003* (*AEO2003*) projections of energy supply, demand, and prices through 2025, as updated in May 2003.

The *AEO2003* provides a policy-neutral reference case that is used to analyze energy policy initiatives. 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.

Key aspects of the program specified by Sen. Bingaman include:

- Extension of the renewable energy production tax credit (PTC) for generation from eligible facilities entering service by December 31, 2006, but no longer indexed to inflation.
- Implementation of an RPS with incremental increases in required renewable generation reaching 10 percent of most sales by 2020 (effectively 8.8 percent of all sales).
- Exemption of small utilities, those generating less than 4,000 billion kilowatt-hours per year, from holding renewable energy credits, plus exemption of all generation from existing hydroelectric and other renewables from the requirement.
- Only renewable facilities commissioned after the enactment of the legislation qualify to produce renewable energy credits.
- The allowance price for renewable energy credits is capped at 1.5 cents per kilowatt-hour, with no indexing for inflation.

[1] Letter from Senator Bingaman to EIA Administrator Guy Caruso dated May 8, 2003. See appendix A

Background

To stimulate an increase in the use of renewable resources to generate electricity, several bills or amendments 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 analyzed in this report has the following characteristics:

- The program begins in 2004 with the required renewable share growing from 2.5 percent of retail electricity sales in 2008 through 2011, 5 percent in 2012 through 2015, 7.5 percent in 2016 through 2019, to 10 percent in 2020 through 2030. The requirement to hold renewable energy credits expires December 31, 2030.[2]
- Power sellers with retail sales of at least 4,000 gigawatt-hours per year (4 billion kilowatt-hours) are required to hold credits. Small utilities with retail sales below this level are exempt.
- Generation from renewable resources, including hydroelectric, is not included in the generation base from which the required amount of new renewables is calculated.
- The amount of qualifying renewable generation required each year is calculated by multiplying the generation base (total electricity retail sales minus renewable generation and small utility sales) by the required share.
- Qualifying renewable facilities include all new renewable generation facilities, including cofiring modifications to existing coal plants, that are placed in service on or after the enactment date of the legislation. Qualifying fuels include hydroelectric, geothermal, solar, wind, ocean, landfill gas, and certain biomass and municipal solid waste feedstocks. Renewable facilities in service prior to the enactment of the law do not receive RPS credits.
- The cost of the credit is capped at 1.5 cents per kilowatt-hour, in nominal dollars.
- The renewable production tax credit (PTC) is extended from the current expiration date of December 31, 2003 to December 31, 2006. Eligibility for the credit is also expanded to other renewable energy technologies such as

[2] Although the requirement to hold credits doesn't begin until 2008, renewable facilities starting operation after the enactment date are eligible to produce credits.

geothermal, solar, and municipal sludge. New biomass cofiring at existing coal plants is eligible for PTC credits at a reduced rate (1.0 cents per kilowatt-hour) for a reduced period (5 years). Unlike the current PTC, which is indexed to inflation, the PTC analyzed in this paper remains constant in nominal dollars.

Analysis Summary

The key results of this analysis are:

- Although the proposed legislation indicates a 10 percent target, small utilities are exempt from holding renewable energy credits and all renewable generation is excluded from the generation base required to hold RPS credits. If targets are achieved, total renewable energy, excluding existing hydroelectric generation, would account for 8.8 percent of electricity sales by 2020.
- Under Reference case assumptions, the 8.8-percent target is not projected to be met because of the declining real value of the 1.5-cent per kilowatt-hour credit cap and the sunsetting of the program in 2030. As the end of the program approaches (December 31, 2030), electricity suppliers are projected to purchase credits from the Federal government rather than invest in additional renewables that would only be subsidized by the program for a few years. The level achieved of total renewable generation by 2025 is projected to be 5.6 percent of all U.S. sales, with maximum renewable share of generation achieved in 2019 at 6.2 percent[3,4].
- This RPS requirement would lead to greater generation from wind and biomass resources. Conversely, the imposition of the RPS would lead to lower generation from natural gas and coal facilities.
- 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; also higher renewable costs are somewhat offset by lower natural gas prices that result from reduced natural gas use.
- Because of reduced demand for natural gas by the electric power industry, natural gas prices to all users decline slightly with the RPS. Wellhead natural gas prices by 2025 are 1.5 percent lower with the RPS than in the Reference case.
- Compared with the Reference case, total residential expenditures on electricity in 2025 are $540 million higher (year 2001 dollars) due to the RPS. Total residential expenditures on natural gas are lower by $290 million (year 2001 dollars) with the RPS compared to the Reference case.
- The total cost of electricity to the end-use sectors (residential, commercial, industrial, and transportation) in 2025 increases from $351.9 billion in the Reference case to $353.4 billion in the RPS case, an increase of 0.4 percent. For natural gas, total end-use expenditures in 2025 decline from $136.0 billion to $135.2 billion, a decrease of 0.6 percent. Combined total end-use expenditures are 0.1 percent higher in 2025 due to the RPS.

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[3] As reported in this analysis, RPS share achieved should be compared with calculated target of all non-hydroelectric renewables as a share of all generation rather than all qualifying renewables as a share of the generation base specified in the RPS program. The resulting percentages are 7.1 percent in 2019 and 8.8 percent in 2025 rather than 7.5 percent in 2019 and 10 percent in 2025 as specified in the request letter.

[4] Absolute levels of renewables remain more or less constant once the cap price for credit allowances is reached, but since the overall electricity market is growing, the renewable share is decreasing.

- The net increase in cumulative net-present-value resource costs to the electric power industry from 2003 to 2025 with the RPS when compared to the Reference case sum to $3.6 billion (year 2001 dollars), an increase of less than 1 percent.
- The total value of the credits received by qualifying renewable generators in 2025 is projected to be approximately $2.5 billion. The higher costs of renewables covered by the RPS are mostly subsidized by payments from nonrenewable facilities. In 2025, payments to the Federal government to purchase renewable credits total to $1.15 billion.

Analysis Methodology

The projections and quantitative analysis for this paper 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 2025. 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.

Domestic energy markets are modeled by representing the economic decisionmaking involved in the production, conversion, and consumption of energy products. For most 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 2002 to 2025 timeframe, these estimates include 3,488 megawatts of capacity resulting from State RPS programs, and 1,718 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. Treatment of the 1.8 cent per kilowatt-hour production tax credit for wind and biomass conforms to the requested analysis and is discussed latter in this section.

A. Update to the Annual Energy Outlook 2003 Reference Case

NEMS has been updated to reflect changes in electric generating capacity since *AEO2003* was completed in November of 2002 and to incorporate revised expectations about near-term natural gas price trends. The following summarizes these key updates.

Generating Capacity. Within NEMS, only planned units that are reported as "under construction" are automatically included as being built during the forecast horizon. Additional renewable capacity expected from State-level mandates and programs are also included in the capacity projection. NEMS then forecasts the construction of additional unplanned capacity by type as needed to meet future demand.

For *AEO2003*, the information on planned generating units was based predominantly on 2001 data from the EIA-860 filings, "Annual Electric Generator Report," which provides information from both utility and non-utility generators. The EIA-860 data was supplemented by a second data source, the NewGen database developed by Platts Database,[5] which is updated on a monthly basis. The *AEO2003* contained data capacity plans from these sources as of July 2002. The NewGen database was used to update the EIA-860 information for more recent changes in plant operating status.

Based on new information available as of the end of March 2003, about 24 gigawatts of additional planned capacity are reported as being under construction, including 8.5 gigawatts in 2002, 14.3 gigawatts in 2003 and 1.2 gigawatts in 2004. About 16 gigawatts of the additions are gas-fired combined cycle, 4.6 gigawatts are gas-fired turbines, and 2 gigawatts are dual-fired combined cycle units. The remaining 1.4 gigawatts are composed of dual-fired turbines and internal combustion units, several renewable units, and a relatively small coal unit.

Natural Gas Prices. Each month, EIA publishes 2-year projections of price, demand and supply, and stocks for each of the main energy sources in the *Short-Term Energy Outlook* (STEO). These projections are revised in response to observed changes in weather conditions, stock levels, and market conditions. For *AEO2003*, the September 2002

[5] NewGen Data and Analysis, Platts Database (Boulder, CO, March 2003).

STEO was the basis of the short-term outlook. Since then, the natural gas price forecasts have changed significantly. For example, the average natural gas wellhead price for 2003 was projected to be $4.52 (nominal dollars) per thousand cubic feet in April 2003, about 40 percent higher than the projection for 2003 used in *AEO2003*. To better align with the more recent market information, the natural gas supply and price forecasts were aligned with the April 2003 STEO forecasts. In particular, adjustments were made to natural gas production, imports, supplemental supplies, storage, consumption of lease, plant, and pipeline fuel, and prices at the wellhead and the burner-tip. These adjustments mainly affect the short-term projections, but since decisions made in the later years partially depend on earlier market conditions, the longer-term projections are also affected.

B. Representing the RPS

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 share of total annual generation. 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 the last increment of renewable capacity added to make it competitive with other options. The renewable credit price times the required generation in each year becomes part of the operating costs of non-qualifying facilities because sellers of power from these facilities must purchase renewable credits for them in order to comply with the required RPS share.

The proposed RPS allows new (incremental) hydroelectric capacity at existing 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 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[6]. However, after adjusting this value to reflect environmental concerns, the report authors reduced estimated hydro potential to a maximum of 4.3 gigawatts of possible upgrades at existing sites. The report also included estimates of additional hydroelectric capacity at currently undeveloped sites, but since the proposed RPS 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, at most, 4.3 gigawatts of incremental hydroelectric facilities could provide 17 billion kilowatt-hours of additional generation, or approximately 3.7 percent of the increase in renewable generation needed to comply with this RPS. However, because cost estimates for these potential upgrades are not available, it is impossible to determine if they would be economical. If they were economical, their development would be expected to lower the costs of implementing the RPS slightly below what is reported in this paper.

To represent the specific requirements of the proposed RPS program, the annual qualified renewable share of sales called for in the proposed amendment was converted into total

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

non-hydroelectric renewable shares. As shown in Table 1, the shares used in NEMS differ from the annual RPS shares called for in the request because the NEMS shares represent the total non-hydroelectric renewable generation share - including the generation from facilities that began operation before January 1, 2004 - required to comply with the RPS requirement (NEMS does not distinguish between generation coming from new or existing facilities so total non-hydroelectric renewable shares are used). Also, the share represented in NEMS is adjusted to account for the exclusion of utilities with sales fewer than 4,000,000 kilowatt-hours, and the exclusion of renewable generation from sales when applying the RPS share. For example, in 2008 the proposed RPS share is 2.5 percent, total electricity sales are projected to be 3,938 billion kilowatt-hours, sales from small utilities are assumed to be 711 billion kilowatt-hours, the generation from non-qualifying non-hydroelectric renewable generators (those coming on prior to January 1, 2004) are assumed to be 82 billion kilowatt-hours and the generation from hydroelectric facilities is projected to be 300 billion kilowatt-hours. Using this information, the amount of qualified renewables required is calculated as follows:

0.025 X (3,938 – 711 – 82 – 300) = 71 billion kilowatt-hours of new non-hydroelectric renewable generation.

Converting this into the total non-hydroelectric share used in NEMS gives (adding required new generation with non-hydroelectric renewable generation existing before enactment of the program, then dividing by all generation):
(71 + 82) / 3,938 = 3.9 percent.

As shown, through 2015 the adjusted shares used in NEMS exceed the shares called for in the proposal 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 2015, however, the exclusion of total renewable generation from the baseline when applying the RPS share causes this relationship to reverse.

The request from Sen. Bingaman indicates that the price of a renewable energy credit should be capped at 1.5 cents per kilowatt-hour. Furthermore, it specifies a penalty of the lesser of 1.5-cents per kilowatt-hour or twice the average credit value may be imposed on retail electricity suppliers who do not submit sufficient renewable credits to cover their sales. For analysis purposes, this maximum 1.5-cent per kilowatt-hour/200% noncompliance penalty is treated the same as the cap on the renewable credit price. If the marginal cost of new renewable capacity in a given year is too expensive even with a 1.5 cent per kilowatt-hour credit, the required level of qualifying renewables will not be achieved. In this case, the marginal renewable credit purchaser will pay the government for non-compliance rather than build new renewables. This cap is not indexed to inflation. In previous analyses of RPS programs with allowance price caps, EIA has assumed that the price cap was indexed to inflation (that is, in real dollars rather than nominal dollars)[7]. By treating the price cap as nominal for this analysis, the real ceiling on renewable energy credit prices gets lower over time, as shown in Table 2[8].

Table 1. Renewable Generation Share of Sales Required

Year	Legislative Target	NEMS Equivalent Target
2003	0.0	0.0
2004	0.0	0.0
2005	0.0	0.0
2006	0.0	0.0
2007	0.0	0.0
2008	2.5	3.8
2009	2.5	3.8
2010	2.5	3.8
2011	2.5	3.8
2012	5.0	5.5
2013	5.0	5.5
2014	5.0	5.4
2015	5.0	5.4
2016	7.5	7.1
2017	7.5	7.1
2018	7.5	7.1
2019	7.5	7.1
2020	10.0	8.7
2021	10.0	8.7
2022	10.0	8.7
2023	10.0	8.7
2024	10.0	8.7
2025	10.0	8.8

Source: Legislative Target from Letter from Sen. Bingaman to EIA Administrator Guy Caruso dated May 8, 2003. NEMS Target from Energy Information Administration, Office of Integrated Analysis and Forecasting.

The current PTC provides an inflation-indexed, 1.8 cent per kilowatt-hour (in 2003) tax credit for the first 10 years of generation from qualifying facilities. Qualifying facilities include wind and certain biomass processes ("closed-loop" facilities and facilities burning poultry waste) placed in service on or before December 31, 2003. The proposed program includes a provision to extend the eligibility date for facilities placed in service on or before December 31, 2006. In addition, the proposal expands the eligible renewable technologies to include open-loop biomass at both new and existing facilities as well as new geothermal, solar, small irrigation power, and municipal biosolid and sludge recycling facilities. For biomass generation at existing facilities, the proposed PTC provisions set the value and pay-out period at 1.0 cents per kilowatt-hour and 5 years, respectively.

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[7] See *Impacts of a 10-Percent Renewable Portfolio Standard.* U.S. Department of Energy, Energy Information Administration, DOE/EIA (SR/OIAF/2002-03), February 2002.

[8] The request letter specifies the value of the credit cap in 2003 dollars. This analysis shows the real value of the cap in 2003 dollars. All NEMS results are calculated and reported in real 2001 dollars.

Table 2. Nominal and Real Value of Renewable Energy Credit Cap

Year	Nominal Credit Cap (mills per kilowatt-hour)	Real Credit Cap (year 2003 mills per kilowatt-hour)
2003	15.00	15.00
2008	15.00	13.32
2009	15.00	13.05
2010	15.00	12.81
2011	15.00	12.57
2012	15.00	12.30
2013	15.00	12.00
2014	15.00	11.70
2015	15.00	11.40
2016	15.00	11.10
2017	15.00	10.80
2018	15.00	10.51
2019	15.00	10.21
2020	15.00	9.92
2021	15.00	9.64
2022	15.00	9.37
2023	15.00	9.10
2024	15.00	8.83
2025	15.00	8.56
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.		

NEMS does not model poultry waste, small irrigation power, or biosolid/sludge technologies. EIA believes that the total resource base for these technologies is quite small relative to other renewables and the electricity market as a whole. While eligibility for the PTC may cause significant growth in these sectors relative to their current sizes, such growth would not significantly impact the renewable energy or electricity markets.

The proposed program also modifies the PTC by removing the inflation index provision. This effectively reduces the value of the PTC to the project developer over the 10-year pay-out period, as the effective tax credit does not keep pace with inflation. This is modeled in NEMS by reducing the value of the PTC each year based on the forecast growth in the Gross Domestic Product index.

Analysis

A. Generation

The imposition of the RPS is projected to have modest impacts on some 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 Reference case, plants using fossil fuels are projected to meet most of the growth in demand expected over the next 20 years, as shown in Table 3. Increased generation from natural gas and coal are expected to be especially important; for example, between 2001 and 2025 the generation from natural gas is projected to increase from 618 billion kilowatt-hours to 1,637 billion kilowatt-hours. The share of total generation coming from natural gas is projected to increase from 17 percent to 28 percent over the same time period. Although coal generation increases by 900 billion kilowatt-hours from 2001 through 2025, its share of generation drops from 51 percent to 48 percent.

The generation from non-hydroelectric renewable resources is projected to grow from 80 billion kilowatt-hours in 2001 to 185 billion kilowatt-hours in 2025 in the Reference case, including combined heat and power applications. Much of this growth in generation from non-hydroelectric renewable resources is expected to be encouraged by various State mandates, RPS, and other programs, with a smaller amount coming from new merchant power plants. However, even with this increase in generation, the Reference case share of generation coming from these resources is only projected to increase from 2.2 percent in 2001 to 3.2 percent in 2025.

Table 3. Key RPS Results, 2010, 2020, 2025

	2001	2010		2020		2025	
		Reference	RPS	Reference	RPS	Reference	RPS
Generation (billion kilowatt-hours)							
Coal	1904.1	2293.0	2284.3	2567.9	2496.8	2802.8	2745.2
Petroleum	125.4	50.0	49.1	56.4	55.3	61.5	58.7
Natural Gas	618.3	946.3	939.0	1440.9	1379.1	1637.0	1578.0
Nuclear Power	768.8	789.8	782.6	792.9	785.6	792.9	785.6
Conventional Hydropower	218.1	305.1	305.1	304.3	304.3	304.6	304.6
Geothermal	13.8	22.0	25.2	33.4	37.1	38.1	37.7
Municipal Solid Waste/Landfill Gas	22.0	31.4	34.6	33.8	38.4	34.0	38.5
Dedicated Biomass	36.3	50.0	50.1	61.6	62.2	68.1	67.8
Biomass Cofiring	1.7	9.0	13.3	8.8	23.6	8.7	18.2
Solar Thermal	0.5	0.8	0.8	0.9	0.9	1.0	1.0
Solar Photovoltaic	0.0	1.1	1.1	2.0	2.0	2.9	2.9
Wind	5.8	22.9	36.7	29.2	140.7	32.0	140.7
Ocean[1]	--	--	--	--	--	--	--
Other	6	13	13	17	17	20	19
Total	3721.3	4534.4	4534.7	5349.2	5342.6	5803.1	5797.8
Renewable Portfolio Standard							
Electricity Sales (billion kilowatt-hours)	3414	4104	4102	4848	4838	5246	5234
% Qualifying Renewables	N/A	N/A	3.7	N/A	6.1	N/A	5.6
% Renewables Required	N/A	N/A	3.8	N/A	8.7	N/A	8.8
Capacity (gigawatts)							
Coal Steam	310.5	315.3	314.8	348.6	341.1	380.8	374.9
Other Fossil Steam	135.0	79.0	79.5	73.0	74.1	72.2	72.8
Combined Cycle	65.7	181.3	180.2	265.9	257.8	311.1	299.8
Combustion Turbine/Diesel	102.2	131.7	132.1	153.3	156.6	169.5	175.1
Nuclear Power	98.2	98.7	97.7	99.0	98.0	99.0	98.0
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3
Conventional Hydropower	79.2	79.8	79.8	79.7	79.7	79.7	79.7
Geothermal	2.8	3.8	4.2	5.2	5.6	5.8	5.7
Municipal Solid Waste	3.5	4.4	4.8	4.7	5.3	4.7	5.3
Wood and Other Biomass	6.2	8.0	8.0	10.0	10.0	11.1	10.9
Solar Thermal	0.3	0.4	0.4	0.5	0.5	0.5	0.5
Solar Photovoltaic	0.0	0.5	0.5	0.9	0.9	1.3	1.3
Wind	4.3	8.2	12.1	10.0	40.9	10.8	40.9
Ocean[1]	--	--	--	--	--	--	--
Other	0.0	1.8	1.7	11.9	10.8	17.9	16.6
Total	827.8	933.2	936.1	1083.1	1101.6	1184.7	1201.8

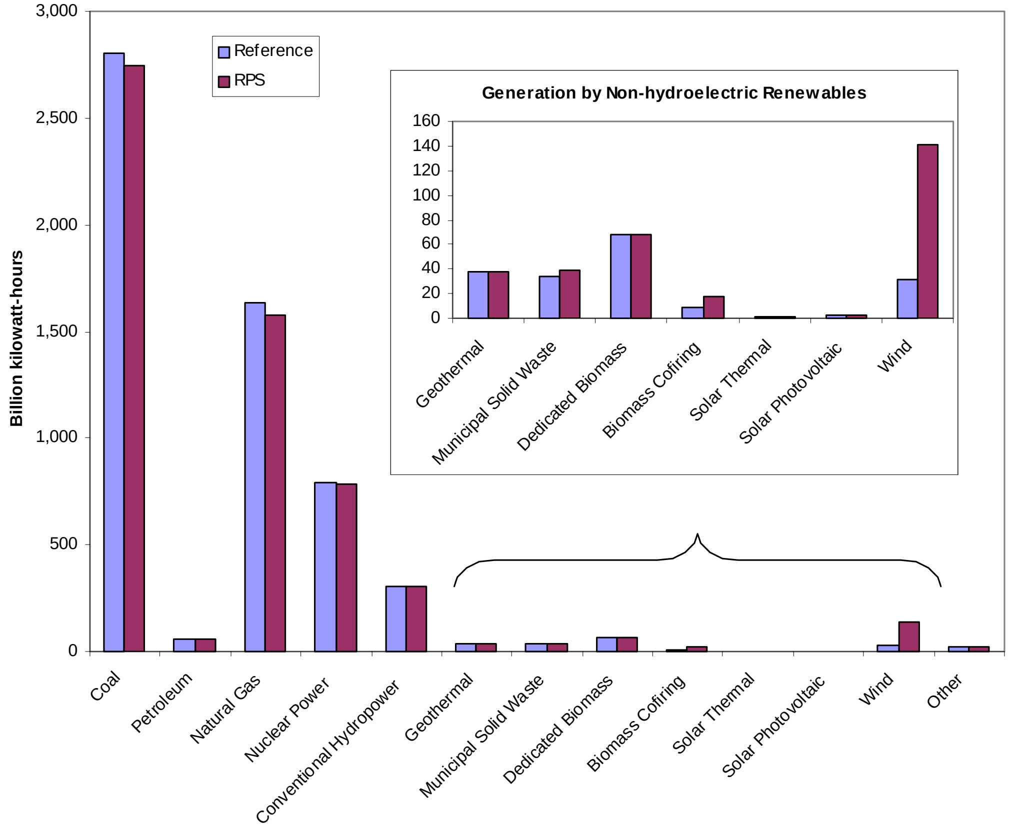
Table 3. Key RPS Results, 2010, 2020, 2025

	2001	2010		2020		2025	
		Reference	RPS	Reference	RPS	Reference	RPS
Prices (2001 cents per kilowatt-hour)							
Credit Price	N/A	N/A	0.54	N/A	0.96	N/A	0.83
Retail Electricity Price	7.3	6.4	6.4	6.7	6.7	6.7	6.8
Electric Sector Emissions (Million Metric Tons)							
Nitrogen Oxides	4.75	3.90	3.90	4.02	3.99	4.08	4.04
Sulfur Dioxide	10.63	9.69	9.73	8.95	8.95	8.95	8.95
Carbon Dioxide[2]	611.57	697.42	694.33	802.47	779.69	867.76	847.67
Fuel Prices							
Gas Wellhead Price(2001 $ per thousand cubic feet)	4.12	3.39	3.38	3.70	3.71	3.95	3.89
Coal Minemouth Price (2001 $ per ton)	17.59	15.06	15.03	14.34	14.28	14.39	14.42

1- Ocean energy technologies are not represented in NEMS
2- million metric tons carbon equivalent
Source: EIA Office of Integrated Analysis and Forecasting. National Energy Modeling System (NEMS) runs mlbase.d050303a (Reference case) and ml_brpssm.d051203d (RPS case)

Even with the increase in renewable generation projected to result from the RPS, the mix of fuels used to produce electricity is not expected to change dramatically from the Reference case (Figure 1). For example, while generation from natural gas is projected to account for 28 percent of total generation in 2025 in the Reference case, it is projected to account for 27 percent in the RPS case. Similarly, generation from coal is projected to account for 48 percent of total generation in 2025 in the Reference case and accounts for 47 percent of total generation in the RPS case. Because the RPS is defined as a percentage of sales (excluding small utilities) minus renewable generation, when converted into the percentage of sales required to come from all non-hydroelectric renewables in 2025, it amounts to approximately 8.8 percent of sales.

Figure 1. Generation by Fuel

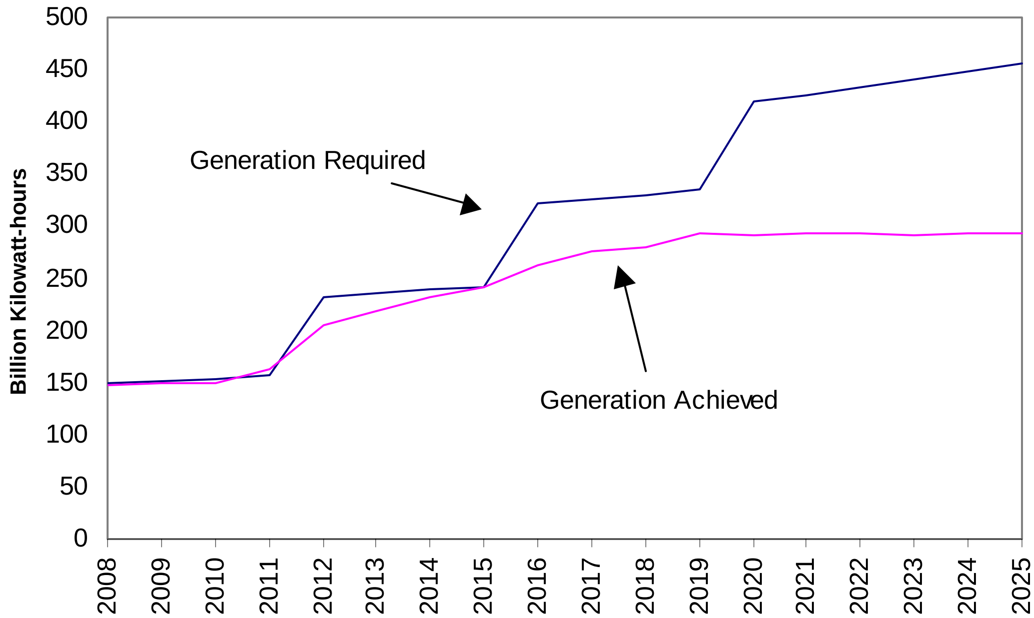


Sources: National Energy Modeling System. Reference mlbase.d050303a, RPS ml_brpssm.d051203d

The lower coal and gas generation projected with the RPS is offset by the higher renewable generation stimulated by the RPS. In the Reference case, the generation from non-hydroelectric renewable generators is projected to reach 3.3 percent of electricity sales in 2025. With the RPS, the 2025 share of qualifying renewables is projected to reach 5.6 percent of electricity sales.

The generation from qualifying renewables, shown in Figure 2, is not projected to reach the share as adjusted from the share called for by the RPS program. This is projected to occur because of the 1.5-cent per kilowatt-hour credit price cap and the 2030 sunset of the RPS. In the later years of the projections, as 2030 approaches, 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 2016 and beyond, with the RPS, the credit price needed to make new renewable plants competitive is projected to exceed the nominal 1.5- cents per kilowatt-hour. This results in retail electricity suppliers purchasing credits from the government rather than building new renewables or purchase additional credits on the private market.

Figure 2. Qualifying Renewable Generation Required and Achieved



Sources: National Energy Modeling System. Reference mlbase.d050303a, RPS ml_brpssm.d051203d

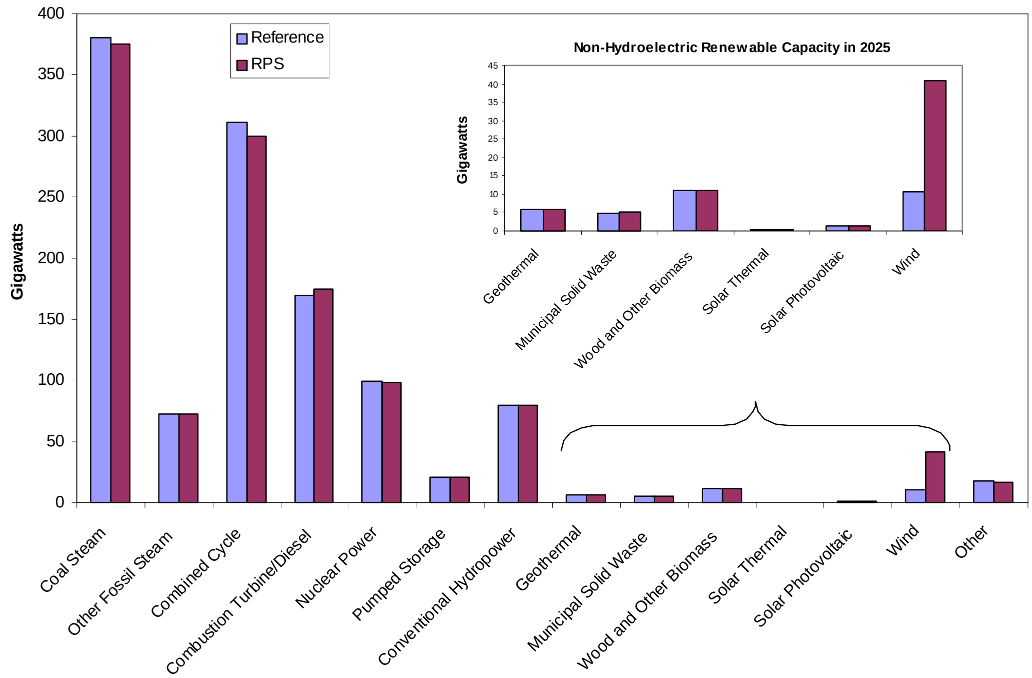
Wind and, to a lesser extent, biomass are projected to be the most important renewable resources stimulated by the RPS. The increased wind generation is projected to come from new power plants while the increased biomass generation is projected to come from the increased use of biomass in coal plants – known as cofiring. Since the capital cost of cofiring applications is much lower than for dedicated biomass capacity, it is much easier to recover costs with this option given the credit cap and sunset provision. Generation from landfill gas facilities increases relative to the Reference case, but is still a relatively small contributor to overall renewable generation. With the RPS, generation from geothermal resources increases early in the projection period, but by 2025 it is within 2 percent of its 2025 Reference case level. Generation from solar resources is not projected to change with the RPS.

B. 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). 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 with the RPS 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 with the RPS than in the Reference case because the intermittent nature of wind resources requires additional dispatchable capacity for back-up. This intermittency also contributes to a shift in the type of natural gas capacity added when the RPS is imposed. Over the 2001 to 2025 period, relative to the Reference case, 11 gigawatts fewer natural gas combined cycle plants are projected to be added while nearly 6 gigawatts more natural gas combustion turbines are added with the RPS. 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.

With the RPS, overall wind capacity in 2025 is projected to be almost 4 times the Reference case level. Though not broadly competitive in the Reference case, a small number of unsubsidized new wind plants are expected to be built over the course of the projections in response to relatively high natural gas prices. 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 capital cost of new wind plants is expected to decline from $1,004 per kilowatt in 2002 to approximately $989 per kilowatt-hour in 2025. 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 capital costs are expected to decline further as manufacturers and project developers learn more about their construction and operation. For example, with the RPS the cost of new wind plants is projected to decline to $971 per kilowatt by 2025. By 2025 with the RPS, capacity factors for new wind turbines in the best wind resources improve to 44%, compared with 42% in the Reference case. However, at the same time, to reach the quantity of new wind capacity called for in the RPS case – from just over 4 gigawatts in 2001 to 41 gigawatts of wind capacity by 2025 – 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 $971 per kilowatt to reflect these factors the cost of new wind plants in the RPS case in 2025 is expected to be as high as $1165 per kilowatt in some of the regions with the most windy land. As might be expected, the costs of all new power plants are 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. Further, with the increasing penetration levels seen in some regions, the natural variability of the wind will have an increasingly large impact on grid operations. In these regions, the aggregate of wind turbines will only contribute 20 to 25% of their total nameplate capacity toward meeting regional reliability requirements, with the marginal wind turbine providing essentially no contribution to reliability. This means that additional "back-up" power, such as combustion turbines, will need to be purchased as well, adding to the overall cost of integrating wind into the system.

Figure 3. Capacity by Fuel in 2025



Sources: National Energy Modeling System. Reference mlbase.d050303a, RPS ml_brpssm.d051203d

Significantly increased biomass generation comes from increased use of biomass in existing coal plants rather than in dedicated biomass facilities. Adding small amounts of biomass to coal feedstocks, up to 15% by heat value, is a relatively low investment cost option for increasing renewable fuel usage. Upgrading existing coal-fired plants to cofire biomass fuel requires modest capital expenditure compared with the construction of a dedicated biomass facility – starting at about $200 per kilowatt for a cofiring modification compared with $1764 per kilowatt for an efficient, integrated gasification combined cycle plant fueled with biomass[9]. Especially in the latter portion of the projection, the sunset provision limits the period in which renewable energy credits can be used to recover capital investments. This tends to favor the lower investment cost cofiring option over new dedicated facilities, even though cofiring will tend to have lower efficiencies (based on the efficiency of the host facility) and thus higher fuel costs per kilowatt-hour of generation.

Besides wind, only landfill gas facilities are projected to appreciably increase capacity in response to the RPS. 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.

With the RPS, other non-hydroelectric technologies such as geothermal, solar thermal, solar photovoltaic and ocean technologies are not projected to have net capacity additions beyond those projected in the Reference case. The RPS does result in the acceleration of

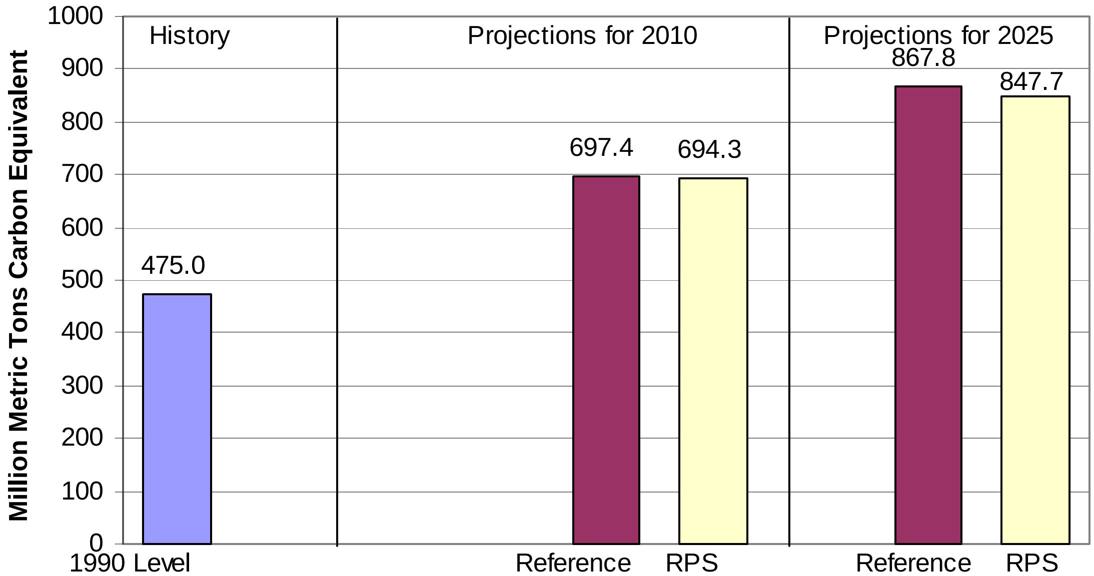
[9] See *Assumptions for the Annual Energy Outlook 2003 with Projections to 2025.* U.S. Department of Energy, Energy Information Administration, DOE/EIA-0554(2003), January 2003

some geothermal builds relative to the Reference case, but the decreasing real cap and shortening pay-back period before the requirement sunsets reduces the attractiveness of this option in the last 10 years of the projection period. By 2025 in the RPS case, geothermal capacity is 5.7 gigawatts, 100 megawatts less than the 2025 capacity in the Reference case. 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, although a few demonstration projects or other non-economic builds are possible, they are not expected to contribute to meeting the RPS. 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.

C. 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 Act Amendments of 1990 (CAAA) 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

Figure 4. Electricity Sector Carbon Dioxide Emissions, 1990 and Projected for 2010 and 2025



Sources: National Energy Modeling System. Reference mlbase.d050303a, RPS ml_brpssm.d051203d

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 2025, the cost of SO2 allowances is projected to be 32 percent lower with the RPS 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). By 2025, carbon dioxide emissions are projected to be 2.3 percent lower with the RPS than in the Reference case.

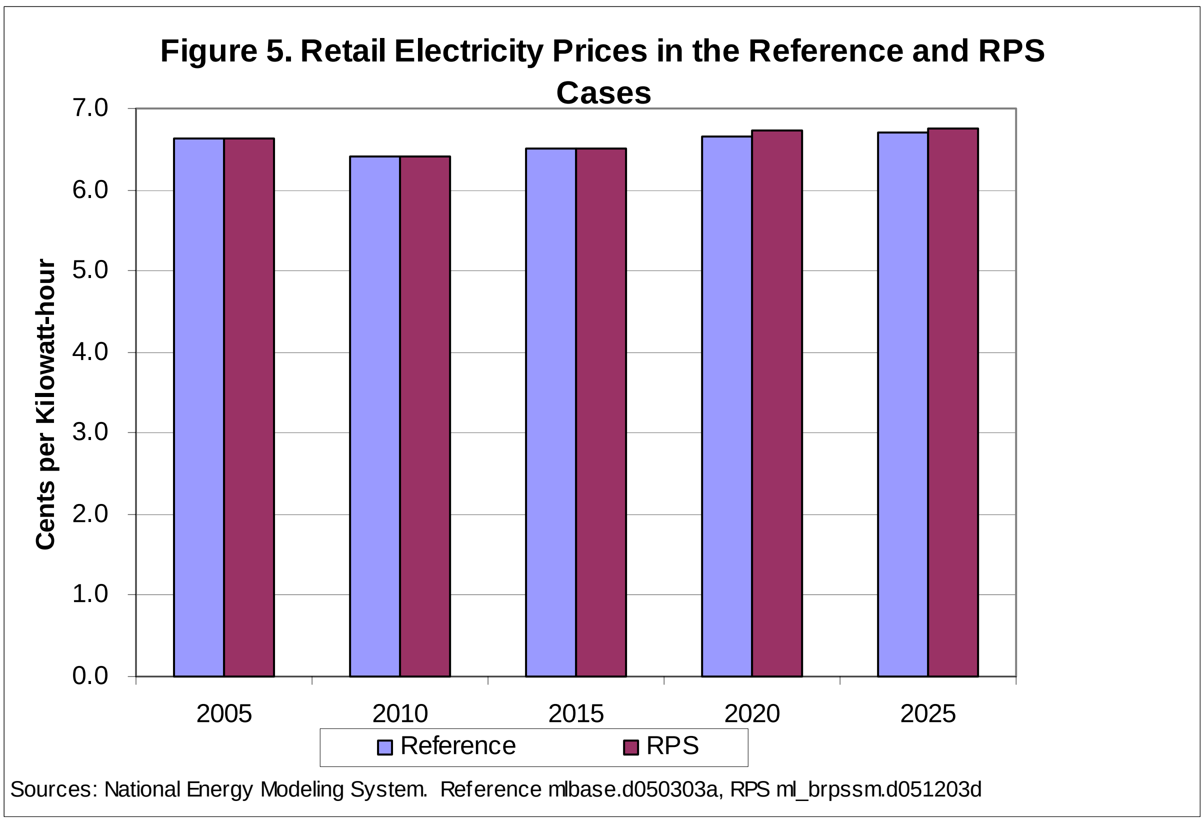
D. Electricity Price and Costs

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 other fuel prices with higher cost renewables when the RPS is imposed. Furthermore, the price cap, initially 1.5 cents per kilowatt-hour and declining to less than 0.9 cents per kilowatt-hour by 2025, ensures that the maximum price impact will be less than 0.08 cents per kilowatt-hour.[10] As mentioned, this RPS nominally calls for a 10 percent RPS by 2020, but because of the definition of qualifying renewables used and that credits are only required to cover

[10] If the credit price is at its maximum value of 0.9 cents per kilowatt-hour (year 2003 dollars), and each generator must have credits for 8.8 percent of generation, then the credits will contribute 0.08 cents (0.9 X 0.088) to the cost of each kilowatt-hour.

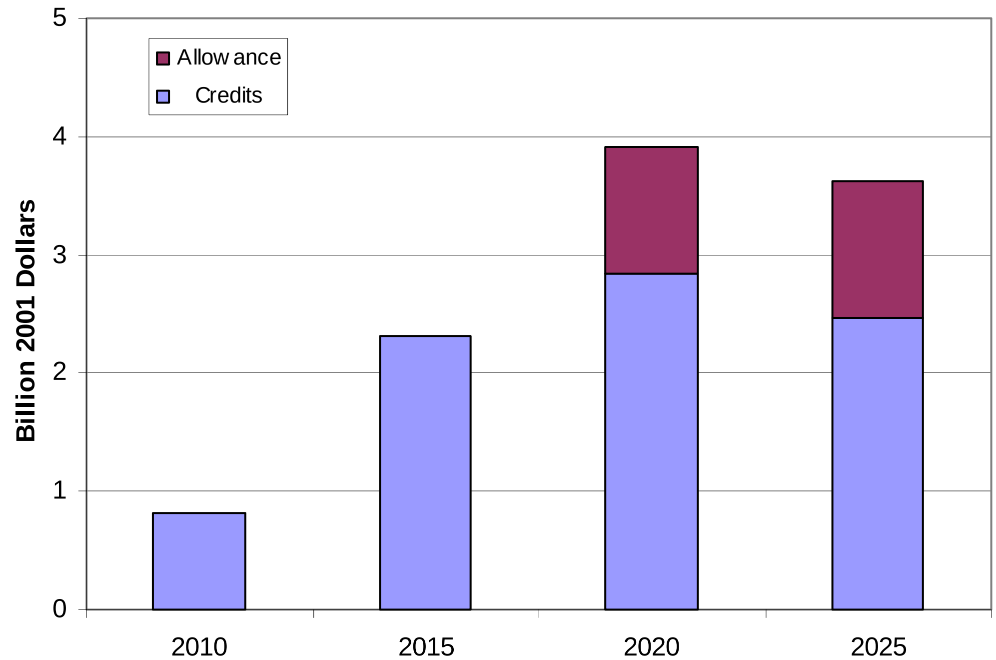
nonrenewable generation, the actual non-hydroelectric renewable share of generation needed to meet the target is 8.8 percent.

Fundamentally, 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 slight decline in natural gas and coal prices that partially offsets the higher costs of the new renewables. The retail price of electricity, shown in Figure 5, is projected to be only slightly above the Reference case in the last few years of the projections when the renewable credit price is expected to reach 1.5 cents per kilowatt-hour (0.8 cents in 2003 dollars). In 2025, the nation's electricity bill is projected to be $1.5 billion higher in the RPS case than in the Reference case. The nominal 1.5-cent cap is reached in 2016 and beyond because, with decreasing time left when the credit will be available (it sunsets in 2030), and declining real value it provides insufficient subsidy to spur additional investment in renewables.



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. Over the 2000 to 2025 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 payments to the government for renewable credits, are projected to be $3.6 billion higher in the RPS than in the Reference case. Relative to the total resource costs of the industry over the 2003 to 2025 time period, this change is small, a 0.6 percent increase from the Reference case.

Figure 6. Credit and Allowance Cost with RPS



Source: National Energy Modeling System. ml_brpssm.d051203d

The market for renewable credits that retail electricity suppliers will have to hold for generation for non-qualifying generators is expected to grow as the RPS share increases over time. Although, as shown in Figure 6, the real cost in year 2001 dollars declines after 2020, as the required share of generation remains constant, and the credit cap price does not keep pace with inflation. In 2025 with the RPS, the renewable credit market together with allowance costs paid by retail electricity suppliers to the government is projected to reach $3.6 billion ($2.5 billion in credits and $1.1 billion in allowance payments to the government). For existing coal, nuclear and oil facilities who are not projected to see significantly lower fuel prices or higher electricity prices with the RPS, 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 to be offset by lower natural gas costs.

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. Wellhead natural gas prices in the Reference case are $3.95 per thousand cubic feet in 2025 (year 2001 dollars), and $3.89 per thousand cubic feet with the RPS. In 2025 the total residential natural gas bill is projected to be $290 million (0.5 percent) lower with the RPS than in the Reference case. For the commercial and industrial sectors the bills in 2025 are, respectively, $200 million (0.6 percent) and $200 million (0.4 percent) lower with the RPS than in the Reference case.

In the Reference case, total residential electricity costs were $137.5 billion (year 2001 dollars) in 2025. With the RPS, this increases to $138.1 billion. As a result, total residential expenditures on electricity in 2025 increase by $540 million with the RPS, an increase of 0.4 percent. Electricity costs for the commercial sector in 2025 increase by $700 million (0.5 percent). Electricity costs for the industrial sector increase by $290 million (0.4 percent).

Comparison With Earlier EIA RPS Analysis

In February, 2002, EIA released a report analyzing a proposed 10 percent RPS, in response to a December, 2001, request by Senator Frank Murkowski, then Ranking Minority Member of the Senate Committee on Energy and Natural Resources. That report is entitled, "Impacts of a 10-Percent Renewable Portfolio Standard" (SR/OIAF/2002-03). The assumptions in the two proposed bills are different and thus the projected impacts are somewhat different although the directions of results are generally the same.

In the 2002 analysis, the RPS target was similar, 2.5 percent in 2005, increasing to 10 percent by 2020. The earlier study's lower exemption cutoff – exempting utilities with sales below 0.5 billion kilowatthours per year - combined with inclusion of new hydroelectric power, raised the effective requirement in 2020 to 9.5 percent of sales rather than the 8.8 percent target that results under the Bingaman request. The earlier analysis also included double credits for new renewable energy facilities built on Indian lands and inclusion of credits for customer-sited qualifying generators providing power to the grid. Also, rather than capping the credit price at 1.5 cents per kilowatthour (nominal), the earlier request set a real 3.0 cent per kilowatthour credit cap. In real terms, this compares a credit price cap of 3.0 cents per kilowatthour in 2020 with one that is slightly less than 1 cent. While the Bingaman request includes extension of the PTC, the earlier analysis assumed the PTC to end on December 31, 2003. The RPS had a sunset date of December 31, 2020 in the earlier request, much sooner than the 2030 sunset date in the Bingaman request. The earlier analysis was based on the assumptions used for the *Annual Energy Outlook 2002* (AEO2002) rather than the *Annual Energy Outlook 2003* used for the response to Senator Bingaman.

Overall, the results of the 2 analyses reflect the differences in RPS assumptions. In both cases, the sunset and civil penalty provisions have a significant impact on the amount of renewables stimulated. As the sunset date approaches, generators prefer paying penalties to building additional renewable energy capacity for which they would not get credits beyond the sunset date. As a result, in the earlier analysis, by 2020 utilities reach 8.4 percent of sales provided by qualified new renewables, 88 percent of the targeted 9.5 percent, a larger share than projected in the current analysis. In the analysis done for Senator Murkowski, wind, biomass, and to a much lesser extent, geothermal resources increase to meet the RPS. Geothermal resources are less responsive to the RPS program analyzed in this report since fewer renewables are needed to meet the target. Both analyses see reductions in natural gas generation and consequently lower natural gas prices. Cumulative resource costs to the industry from 2000 to 2020 are $7 billion ($2000) in the earlier analysis, compared with $3.6 billion ($2001) through 2025 in the Bingaman analysis. Similarly the total value of credits under the earlier proposed RPS reach approximately $12 billion ($2000), compared with $2.5 billion ($2001) under the recent work, reflecting the much higher cap on credit costs specified in the earlier proposal.

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 analyzed 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 2025 in the Reference case. If the historical growth rate 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.

Since natural gas plants are expected to account for much 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 to make renewables competitive 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. Non-hydroelectric 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 assumed to occur and 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.

For both wind and biomass the level of development called for in the RPS comes with some uncertainty. The RPS case shows wind capacity increasing from approximately 4.3 gigawatts in 2001 to 41 gigawatts in 2020 – about a 900 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. Elsewhere, developers or grid operators may have to pay to build or upgrade long transmission lines from the remote areas with ample wind resources to the cities with significant demand. 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 power 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 20 percent of a region's total generation. As this limit is approached, the ability of wind capacity to contribute to regional reliability requirements, already low compared with most other generation resources, gets progressively smaller, requiring additional backup capacity and other mitigating technologies (energy storage, improved grid monitoring and control, and improved power conversion on the wind turbine). At these high penetration levels, significant wind generation, especially in off-peak hours, may have to be curtailed to avoid the expensive shut-down and restart cycling of coal or nuclear plants. Because such penetration levels have not been achieved on power systems of comparable size and function as modeled by EIA[11], the magnitude of these effects is still somewhat uncertain.

As with wind, data suggest that there are sufficient biomass resources to fuel the increased biomass generation projected in the RPS 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 case, the infrastructure to reliably 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. Substituting additional wind or dedicated biomass technology for the biomass cofiring would either result in higher costs or more payments to the government to ensure compliance with the cap.

[11] Wind penetration levels of 15% have been achieved in Denmark and some other areas. However, these systems are interconnected with larger regions that provide significant capability for ensuring reliability. These larger regions are more analogous to the regions modeled in NEMS.

Appendix A

United States Senate

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

ENERGY.SENATE.GOV

May 8, 2003

The Honorable Guy Caruso
Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue S.W.
Washington, DC 20585

Dear Mr. Caruso:

As you know the Congress is considering comprehensive legislation to update the U.S. national energy strategy. I am requesting that the EIA analyze the potential costs and benefits of a proposed Renewable Portfolio Standard (RPS). The assumptions of such an RPS are:

- The facilities subject to the RPS include all electric utilities that sell electricity to retail consumers. Electric utilities with sales less than 4,000 GWh are exempt. In addition Hawaii is exempt.
- The base is defined as all electric utility retail sales in a given calendar year. This excludes existing renewables. Existing and new hydropower are excluded.
- The definition of renewable energy is electricity generated at a facility placed in service on or after the date of enactment that uses solar, wind, ocean, geothermal, biomass (as defined in section 504(b), landfill gas, incremental hydro, and MSW (excluding recyclable paper).
- The RPS includes a tradable credit system in which one renewable energy credit will be distributed for each kWh of electricity generated from renewable sources in excess of the amount needed to meet the standard. The cost of the credit is a maximum of 1.5 cents per kWh. Penalties will be assessed by multiplying each kilowatt-hour of generation in violation by the lesser of 1.5cents/kWh or 200% of the average market value of the credit in the year.

- The timetable for the RPS is:

Calendar Year	Minimum Annual Percentage
2008 through 2011	2.5
2012 through 2015	5.0
2016 through 2019	7.5
2020 through 2030	10.0

Please include the impact of the following amendment to the production tax credit:

- The placed in service date for wind energy, closed-loop biomass and poultry waste facilities is before January 1, 2007.
- In addition to wind energy, closed-loop biomass and poultry waste facilities, the qualifying facilities include open-loop biomass (including agricultural livestock waste nutrients), geothermal energy, solar energy, small irrigation power (<5W), municipal biosolids and recycled sludge as qualifying facilities. The placed in service date for the additional facilities is after the date of enactment and before January 1, 2007.
- The credit will be 1.8 cents per kilowatt hour with no adjustment for inflation for production in years after 2003. In the case of a biomass facility placed in service before the date of enactment, the ten-year credit period is reduced to a five-year period and commences after December 31, 2003 and the credit is reduced to 1.0 cent per kilowatt hour.

I ask that the requested information be made available as soon as possible. I also ask that my staff be briefed prior to any release of information.

If you have any questions regarding this request, or need clarification, please contact Leon Lowery with my Senate Energy and Natural Resources Committee staff at 202-224-2209. I thank you in advance 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,

Jeff Bingaman
Ranking Member