A Powerful Opportunity

Making Renewable Electricity the Standard

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Executive Summary

Congress has a powerful opportunity for making renewable electricity the standard in the United States as it considers deregulating the electricity industry. Lawmakers from both houses and both parties have introduced proposals specifying that a gradually increasing percentage of the nation's electricity be generated from renewable resources. These proposed renewable portfolio standards (RPS) range from 4 percent in 2010 to 20 percent in 2020. This report examines the costs and benefits of achieving the proposed RPS targets.

The most aggressive of the proposals, offered by Senator James M. Jeffords (R-Vermont), would require a nonhydro renewables target of 20 percent by 2020. Achieving this target would accomplish the following:

- Result in the development of renewable technologies in every region of the country, with the Plains, Western, and Mid-Atlantic states generating 20 percent or more of their electricity from a diverse mix of renewable technologies.
- Stabilize carbon dioxide (CO_2) emissions from electricity generation at year 2000 levels through 2020 at a cost of $18 per ton of CO_2 reduced. (See figure ES1)
- Result in average electricity prices falling 13 percent by 2020 instead of 18 percent under a business-as-usual scenario. (See figure ES2)
- Reduce a typical (500 kWh/month) household's expected average electric bill savings of $5.90 per month between 1998 and 2020 under a business-as-usual scenario by $1.33. (See figure ES3)
- Lower the projected growth in average natural gas prices by 5% in 2020. As a result, households that heat with natural gas would pay 13 cents less per month on their combined electricity and natural gas bills in 2020 than without an RPS.

Figure ES1. CO_2 Emissions from Electricity Generators

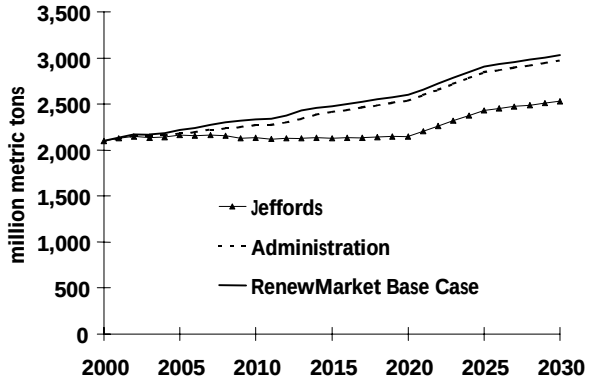


Figure ES2. Average Consumer Electricity Prices

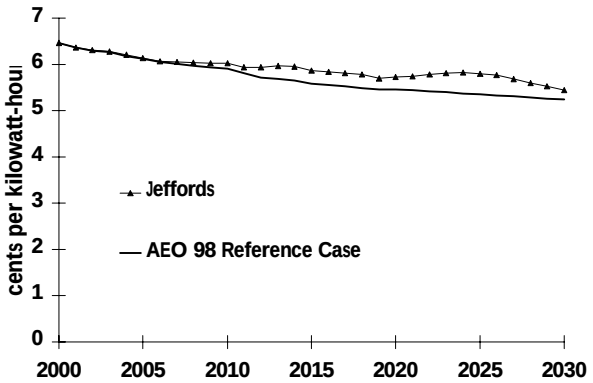
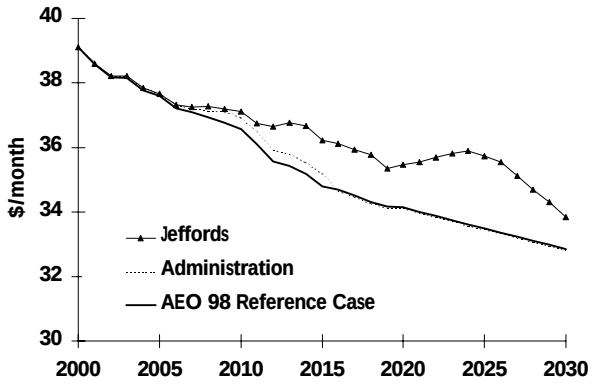


Figure ES3. Average Monthly Electricity Bill for a Typical Nonelectric Heating Household



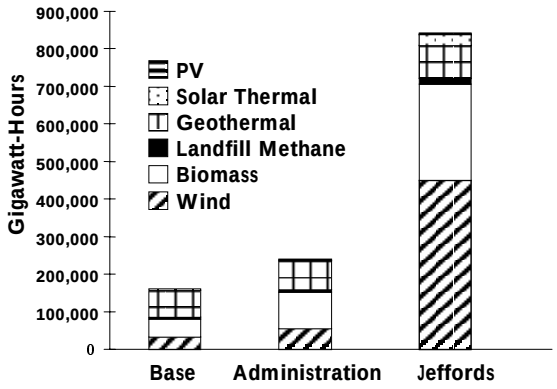
A proposal offered by the Clinton Administration would increase renewables to 5.5 percent of total generation in 2010. Meeting this target would do the following:

- Result in the development of renewable technologies in most regions of the country, with the Western, New England, Mid-Atlantic and High Plains states generating 5 percent or more of their electricity from non-hydro renewables.
- Reduce CO_2 emissions from electricity generation 2 percent below projected levels at a cost of $7 per ton of CO_2 reduced.
- Result in average electricity prices falling 15 percent by 2015 instead of 16 percent under a business-as-usual scenario. After the Administration's RPS ends in 2015, electricity prices would be lower than projected levels due to lower gas prices for electricity generators.
- Reduce a typical (500 kilowatt-hours per month) household's expected average electric bill savings of $5.23 per month between 1998 and 2015 under a business-as-usual scenario by 36 cents.
- Lower the projected growth in average natural gas prices by 1 percent in 2020. As a result, households that heat with natural gas would pay 24 cents less per month on their combined electricity and natural gas bills than without an RPS.

Based on these results, we conclude that a minimum national renewable generation requirement would accomplish the following:

- **Provide considerable environmental benefits**. By displacing fossil fuels, renewables would help the United States reduce heat-trapping gases and other pollutants that harm the environment and human health. An aggressive renewables target that increases about 1 percent each year to 20 percent in 2020 would be needed to eliminate the growth in CO_2 emissions in the electricity sector and reduce coal generation below current levels.
- **Reduce CO_2 emissions at a low cost**. Our analysis clearly shows that renewables can reduce CO_2 emissions at a much lower cost than indicated in some recent studies funded by the fossil fuel and electric power industries, government and non-governmental energy research organizations. These studies predict that reducing CO_2 emissions 7 percent below 1990 levels, as specified in the Kyoto Protocol, will cost between $60 and $95 per ton of CO_2 reduced through domestic actions only. Our analysis, which indicates that the United States could achieve a renewables target of 20 percent in 2020 at a cost of $18 per ton of CO_2 reduced, clearly shows that an RPS is a relatively inexpensive domestic policy for helping the United States meet the Kyoto targets. Furthermore, these cost projections do not take into account the considerable cobenefits society would reap from lowering emissions that cause acid rain, smog, and respiratory problems.
- **Diversify the nation's electricity mix.** Under the RPS proposals, nonhydro renewable resources would provide up to five times more electricity than the projected business-as-usual levels. Biomass, wind, and geothermal would provide the vast majority of the total renewable generation. Solar and landfill methane would also experience significant growth, but provide a relatively small share of total generation (See figure ES4). Greater fuel diversity from a variety of renewable technologies would help insulate the US economy from fossil-fuel price increases and supply shortages. It would also provide an important opportunity for the United States to build a strong domestic renewable energy industry with a large export potential, while creating jobs in high-tech industries and rural economies.

Figure ES4. Breakdown of Total Nonhydro Renewable Generation in 2020 with and without an RPS



- **Expand renewable energy development throughout the nation.** Current nonhydro renewable energy generation in the United States is concentrated in California, the Northeast, and the Southeast. As the RPS targets increase, renewable energy development will spread across the United States, and particularly in the Great Plains, Western, and Mid-Atlantic states.

- **Have only a modest impact on electricity prices**. Average electricity prices are projected to fall 13 to 17 percent between 1997 and 2020 under the RPS proposals, compared with an 18 percent decline without an RPS. According to the results of national polls, most households would be willing to pay more than $2 extra per month for renewables, and would thus appear willing to support a renewables target of 20 percent in 2020. Furthermore, the incremental cost of meeting the renewables targets falls over time, as the costs of renewable technologies decline through mass production and improved performance.

- **Lower natural gas prices**. By displacing some of the projected growth in natural gas use for generating electricity, renewables would put competitive pressure on fossil-fuel prices, and reduce the projected growth in natural gas prices for all gas consumers. For the over 50 percent of households that heat with natural gas, gas savings completely offset the slightly higher electricity costs over time. Industry, which consumed 40 percent of all the natural gas used in 1996, would also reap significant savings. Even with an aggressive renewables target of 20 percent in 2020, however, total natural gas generation would still nearly quadruple from 1997 levels.

A number of other studies have shown similar results. For example, an analysis by the Energy Information Administration (EIA) found that achieving a 10 percent penetration of nonhydro renewables in 2010 would result in a 3 percent higher average electricity price compared with no RPS—but the price would still be 17 percent lower in 2020 than it was in 1996. The study also found a 10 percent drop in projected electricity sector carbon emissions and a 8 percent drop in projected total nitrogen oxide emissions in 2020. Furthermore, a close examination of the EIA study revealed major savings for consumers that were not made explicit in the report. First, higher electricity prices are projected to encourage investments in more efficient technologies and reduce the demand for electricity. Second, average natural gas prices are projected to drop 6 percent in 2020, yielding savings for gas consumers. Including these effects reduces the projected cost of the RPS in the EIA study from $10.5 billion to $1.8 billion in 2020.*

The results of our analysis provide the following important insights into designing an effective RPS policy:

- To maximize the development of a diverse mix of new renewable technologies, to achieve a greater regional distribution of development, and to produce meaningful environmental improvement, RPS targets should be set near the high end of the range of proposals studied.

- To provide a stable and predictable market for renewable developers, reduce potential price volatility, and eliminate the need for a cost cap, the RPS targets should increase gradually over a long period of time.

- If a cost cap is desired, it should be set just above the expected market price of renewable energy credits. A cap that is set too low can result in a shortage of renewable generation relative to the target, increase administrative costs, and reduce market efficiencies.

- To encourage the development of new renewable technologies, existing hydropower and municipal solid waste incineration should not be eligible for credits under an RPS. Our analysis indicates that these facilities do not need additional income to continue operating. Including them in the RPS therefore raises its costs unnecessarily, limits the participation of emerging renewable technologies with a greater potential for cost reductions, and produces no environmental benefits.

If anything, the actual cost of the RPS is likely to be less than our analysis indicates. First, if designed properly, an RPS would provide a stable market for renewable technologies, which could lower financing costs. Second, the historical record of forecasting fossil fuel prices shows that most such forecasts have been wrong. With higher fuel prices, renewables would be even more valuable, ensuring that there will be a ready supply of advanced technologies not subject to fossil fuel price escalation. Third, our analysis does not include the benefits renewables provide in reducing the environmental and other societal costs of fossil fuels and nuclear power that are not reflected in energy prices.

Ideally, the RPS would be combined with other renewable energy and energy efficiency policies that have been enacted in a number of states and proposed at the federal level. For example, renewable energy funds could be used to lower the costs and encourage the development of emerging technologies like photovoltaics, which participate at relatively low levels under an RPS. Requiring electricity providers to disclose their fuel sources and emissions on electricity bills—like nutrition labels—would allow consumers to make an informed decision about purchasing cleaner electricity. Requiring all power plants to meet the same emission standards would put renewables on a more equal footing with fossil fuels. Allowing customers who own renewable technologies to sell any excess electricity generated back to their electricity providers at a fair rate, would encourage the development of small generation, increase the reliability of the electricity system, and reduce the need for costly investments in power lines. Enacting rules that would allow renewable generators equal access to the transmission system would also facilitate the development of renewables under an RPS.

Our analysis clearly shows that creating a minimum national standard for electricity generated from clean renewable resources is an powerful mechanism for capturing some of the public benefits of renewables. As electricity generation becomes increasingly competitive and greater emphasis is placed on short-term prices, an RPS will be especially important for capturing the long-term environmental and economic benefits of renewables.

A Powerful Opportunity

Making Renewable Electricity the Standard

The Renewable Portfolio Standard (RPS) is a powerful policy to encourage the use of renewable energy sources in the United States. It sets minimum targets for the production of electricity generated from renewable resources. The aim is to guarantee a minimum market for the renewable energy industries, thus allowing them to make the investments needed to bring down costs and eventually attain full competitiveness. If designed properly, an RPS can help maintain and enhance the public benefits of renewable energy that are at risk under electric industry restructuring. These benefits include building a domestic renewable energy industry; reducing pollution and greenhouse-gas emissions; improving human health; and increasing domestic energy sources, national security, and the diversity of the US generation mix.[1]

As of December 1998, five states have passed Renewables Portfolio Standards as part of electricity restructuring legislation or regulations—Maine, Nevada, Arizona, Massachusetts and Connecticut—with a number of other states considering the policy.[2] Two states—Iowa and Minnesota—had previously adopted minimum renewable energy requirements. Wisconsin also included a minimum renewable energy requirement as part of electricity reliability legislation passed this year.

At the federal level, Congress has introduced six RPS proposals. These proposals have been introduced by Representative Dan Schaefer (R-Colorado), Senator Dale Bumpers (D-Arkansas), Representative Edward J. Markey (D-Massachusetts), Senator James M. Jeffords (R-Vermont), Representative Dennis Kucinich (D-Ohio), and the Clinton Administration.[3] Each bill proposes different targets spanning different time periods and with different eligibility criteria. The bills specify that a minimum percentage of US electricity generation or sales be obtained from renewables. This percentage ranges from 4 percent in 2010 under the Schaefer bill to 20 percent in 2020 under the Jeffords bill, representing an increase in renewable energy use ranging from 10 percent to more than five times the projected business-as-usual levels.

One feature common to all the federal bills is the proposal to create a national renewable energy credit-trading market to implement the RPS. The market would allow electricity generators or retail suppliers to meet the RPS targets by purchasing credits from certified renewable generators rather than physically generating the power themselves or purchasing the power directly. This design is meant to help ensure that the RPS targets are met in the least expensive manner by creating an incentive to develop renewable resources where they would have the highest value (i.e., where the difference between the price of renewable generation and the electricity it displaces is the lowest). Such a credit-trading market would also

[1] For a more thorough discussion of the benefits of supporting renewable energy development, and a variety of potential support mechanisms, see Alan Nogee, Steven Clemmer, Brent Haddad and Bentham Paulos, *Powerful Solutions*; *7 Ways to Switch America to Renewable Electricity*, Union of Concerned Scientists, January 1999.

[2] Pending bills or regulatory proposals in Nebraska, Wisconsin, Vermont, Kansas, New Mexico, and Delaware include RPSs.

[3] Senator Slade Gorton (R-Washington) cosponsored the Bumpers bill. The Kucinich bill is not analyzed in this report because it was introduced after our analysis was completed. However, the impacts would be similar to Jeffords proposal through 2020.

help keep administrative costs low. The market proposal is patterned in some ways after the market for sulfur dioxide emissions allowances created under the 1990 Clean Air Act Amendments. Establishing a *national* renewable standard and credit-trading market is appropriate since the entire country would share many of the benefits of increasing renewables—such as increased national security and reductions in greenhouse-gas emissions.

A few other studies have attempted to analyze the impacts of a national RPS, with targets ranging from 4 percent to 10 percent in 2010 (We compare these studies with our analysis in the *Results* section below). Our analysis goes beyond these studies by presenting a more comprehensive assessment of the range of impacts and implications that are likely to occur under different assumptions and RPS designs. This includes an analysis of a more aggressive RPS of 20 percent in 2020. In particular, we examine

- national electricity and natural gas price impacts
- costs to consumers
- renewable energy credit prices
- carbon dioxide emission reductions
- the increased market share and regional distribution of renewable energy technologies

This study does not address additional impacts of an RPS, which may be examined in future research. For example, while we do examine the direct costs to consumers and where renewable facilities are likely to be located in relation to the demand for credits, we do not evaluate the effects on regional employment or indirect effects on income. The overall economic impact of the RPS will also depend on how the competitive market for electricity evolves in the future. The costs of financing renewable generation may either rise or fall, depending on the availability of long-term power-purchase contracts, market perceptions of technology risk, and market perceptions of the risk that the RPS policy itself might be abandoned or scaled back. How the targets are designed and implemented will also have a significant impact. For example, legislation might require that a certain portion of each state's or region's RPS target be met using locally produced renewable resources. And certain renewable technologies might be given a guaranteed minimum market share to make certain they are not left out.

We also did not examine the interaction between the RPS and other policies and programs that have been passed or proposed at both the national and state levels. Among these policies are carbon dioxide or other emissions caps, taxes, or performance standards; public benefits funds for energy efficiency and renewable energy; state RPSs; net metering (which allows customers with small renewable energy systems to sell excess electricity back to their electricity providers); and green marketing and utility green pricing programs. These policies are likely to increase renewable generation. Depending on how they are structured, they could either raise or lower the incremental cost of meeting a federal RPS.

The first section of the report outlines the provisions of each federal RPS proposal. The second section describes the main features and key assumptions of our electricity planning model and the methodology used to calculate the costs and benefits of a national RPS with tradable credits. The third section illustrates the results of the analysis. Finally, the conclusion discusses the implications of enacting a national RPS and describes the most important elements for designing an effective RPS policy.

The Federal RPS Proposals

The six federal RPS proposals differ in several significant ways, as table 1 shows. The most important differences are:

- the percentage of renewables generation required
- the ramp-up period for the standard
- the type of renewables eligible to meet the standard
- on what entities the renewables standard is imposed
- the duration of the requirement
- the imposition or omission of a cost cap

They also differ in the government agency designated to administer the program.

Table 1. Renewable Portfolio Standards Included in Federal Legislation

Bill Sponsor	Standard and Duration	Basis	Eligible Resources
Schaefer (H.R. 655)	2% 2000-2004 3% 2005-2009 4% 2010-2015 sunsets in 2015	All electricity generated for sale, except hydro, from preceding year.	Organic waste, biomass, dedicated energy crops, landfill gas, geothermal, solar, tidal, & wind.
Clinton Administration (S. 2287)	5.5% 2010-2015 sunsets in 2015 (DOE Secretary sets targets for 2000-2004 and 2005-2009)	Retail electricity sales from preceding year.	Wind, solar, biomass, & geothermal. (not specified if MSW is eligible)
Bumpers & Gorton (S. 1401)	5% 2003-2007 9% 2008-2012 12% 2013-2019 sunsets in 2019	Retail electricity sales from preceding year.	Solar, wind, biomass, hydro, geothermal, MSW, & landfill gas.
Markey (H.R. 1960)	3% in 1998 10% in 2010 onwards (DOE Secretary sets annual targets in intervening years)	All electricity generated for sale from preceding year.	Solar, wind, geothermal, & biomass (excludes MSW)
Jeffords (S. 687)	2.5% in 2000 rising 0.5%/year to 5% in 2005 rising 1%/year to 20% in 2020 onwards	All electricity generated for sale, except hydro, from preceding year.	Solar, wind, biomass, geothermal, & landfill gas (excludes MSW)
Kucinich (H.R. 4798)	Base = 1997 renewable generation Base in 2000 rising 0.5%/yr to Base + 3% in 2005 rising 1%/yr to Base + 8% in 2010 rising 1%/yr onwards	Retail electricity sales from preceding year.	Organic waste biomass (excludes MSW and black liquor), dedicated biomass energy crops, landfill gas, geothermal, solar, & wind.

Targets and Ramp-Up Period. All of the RPS proposals start with targets that are close to existing levels of renewable generation and increase to a maximum percentage of total US electricity generation or retail electricity sales of

- 4 percent in 2010 under the Schaefer bill
- 5.5 percent in 2010 under the Administration bill
- 10 percent in 2010 under the Markey bill
- 12 percent in 2013 under the Bumpers bill
- 20 percent in 2020 under the Jeffords bill

The Kucinich targets are nearly identical to the Jeffords bill until 2020, except the target continues to increase by one percent each year thereafter. While all the proposals establish targets in preceding years that gradually increase to these levels, only the Jeffords and Kucinich bills set annual targets. The other bills specify targets over multiyear intervals and, in some cases, require the program administrator to set gradually increasing targets for the intervening years. For this analysis, we assumed that targets would increase linearly between identified years for the Schaefer, Administration, Markey, and Bumpers proposals.

The percentage targets set forth in the six bills are not directly comparable, however, because they embody differing assumptions about which renewable resources would be counted and how (in the

numerator) and on what entities the standard would be imposed (in the denominator).

Eligible Renewables. All the bills include wind, solar, biomass, landfill methane, and geothermal energy as eligible renewable sources. In addition to these, the Schaefer bill includes municipal solid waste (MSW) and tidal power, and the Bumpers bill includes MSW and hydropower.

All the bills except Bumpers give equal credit to existing and new renewable generation. The Bumpers bill calculates the required renewable generation using a formula that gives half a credit to each unit of large-scale hydro generation 80 MW and above, one credit to each unit of existing renewable generation including hydro under 80 MW, and two credits to new renewable generation (other than large hydro).

None of the bills except Kucinich specifies whether biomass electricity generated by businesses for their own use (self-generation or cogeneration)—which is about equal to the amount of nonhydro renewable generation sold in 1996—could be sold into the electricity market and counted toward meeting the targets. Presumably, this electricity would be sold in the credit market if the credit price were high enough to make it financially attractive to do so.[4] We assume that all biomass self-generation would meet this test. This generation (along with hydro generation for Bumpers) would contribute so much that neither the Schaefer nor the Bumpers bills would require any additions beyond the base renewable projections in the early years—not before 2008 under the Schaefer bill or before 2011 under the Bumpers bill. In contrast, the Kucinich bill excludes a form of biomass called "black liquor," which is used for electricity generation mainly in the pulp and paper industry and constitutes a large portion of current biomass self-generation.

Entities Required to Meet the Standard. The Schaefer and Jeffords bills place the RPS requirement on all generators—except hydropower—that produce electricity for sale. The Markey bill places the requirement on all such generators, including hydropower. The Bumpers, Administration, and Kucinich bills place the RPS requirement on retail electricity suppliers and the targets are calculated as a fraction of total retail sales.[5]

Duration of the Standard. Three of the proposals include a sunset provision. The Schaefer and Administration standards sunset in 2015, and the Bumpers standard sunsets in 2019. Thus renewable plant owners would receive no income from credit sales after this time. Any above-market costs of new renewable plants built just before the sunset would have to be recovered in the first few years of operation, resulting in higher prices for consumers in the short term but lower prices over the long term.

In contrast, the Markey, Jeffords, and Kucinich proposals do not include a sunset. This would allow renewable developers more time to recover their above-market costs and thereby reduce potential credit-price volatility unless the incremental cost of renewable generation fell to zero and remained there. If the latter happened, the standards would in effect "self-sunset."

Administrator. The Schaefer, Bumpers, and Jeffords bills indicate that the Federal Energy Regulatory Commission (FERC) would administer the RPS. The Administration and Markey bills designate the US Department of Energy as the RPS administrator. All the bills specify that the administrator would be responsible for issuing, recording, and tracking the sale and exchange of renewable credits; imposing and collecting fees to cover administrative costs; collecting information to verify that the standard has been met; as well as enforcing the standard and imposing penalties for noncompliance.

Other Provisions. The Administration proposal includes two additional provisions. First, it includes a cost cap, in which the price of renewable energy credits cannot exceed 1.5 cents per kilowatt-hour. Under this cap, retail electricity providers subject to the RPS requirement have the option of purchasing renewable credits from the program administrator (DOE) at the cap price rather than buying credits on the open market. The bill states that any proceeds the administrator collects are to be placed in the national

[4] For a self-generator to participate in the renewable energy credit market it would have to sell the power it generates into the wholesale market and buy back what it needed for its own use. This would make financial sense only if the income from credit sales were more than sufficient to cover the difference between the selling price and the purchase price.

[5] All of the bills specify that the previous year's generation or retail sales should be used to establish the target rather than current-year figures.

public benefits trust fund, also created in the Administration proposal. The proceeds would be added to federal matching funds to the states for investments in renewable energy, energy efficiency, and low-income energy programs. While the bill does not specify, for the purposes of this analysis we assume that the proceeds collected from the sale of renewable energy credits would be used to support investments in new renewable generation. Changes in the language of the bill would be needed to ensure this occurs.

Second, the Administration proposal allows electricity providers to bank credits that are purchased in excess of their requirement in a given year to use in subsequent years. This could help moderate fluctuations in credit prices from shortages and surpluses in renewable generation, thereby increasing the flexibility with which electricity providers comply with the standard and encouraging early resource development. However, the effects of credit banking were not modeled in our study.

Method and Assumptions

To estimate the impacts of the federal RPS proposals, we created an electricity market model, called RenewMarket, patterned after the Electricity Capacity Planning (ECP) submodule of the National Energy Modeling System (NEMS).[6] RenewMarket—although less sophisticated and less detailed than the ECP in some respects—produces similar results under test conditions and has the advantages of greater flexibility, transparency, and ease of use.

RenewMarket shares many of the features of the ECP. The main function of both models is to determine what power plants are likely to be built in 13 regions of the country (the North American Electric Reliability Council, or NERC, regions, minus Alaska and Hawaii—see map, page 24). They do this by comparing the long-term costs of competing technologies and assigning the largest market share to the lowest-cost technology. Both models take as inputs the costs and performance characteristics of generating technologies and region-specific projections of electricity demand, plant retirements, fossil-fuel prices, renewable resource potential, and financing costs.

There are some significant differences between the models, however. Most importantly, RenewMarket uses different projections of renewable technology costs and includes one renewable technology not covered in the ECP: the cofiring of biomass with coal in existing coal-steam plants. It also applies different constraints to wind resources, makes different assumptions about technology learning (the tendency of technologies to become less expensive with greater cumulative installed capacity), and draws on a smaller data base of existing plants to estimate annual fuel use and pollutant emissions. Finally, RenewMarket's forecast period extends to 2030, whereas the ECP makes forecasts only to 2020.

In this section we summarize the assumptions and basic features of RenewMarket, its similarities with and differences from the ECP, and the method used to calculate the costs and benefits of the various federal RPS proposals.

Assumptions. The assumptions used in our analysis that are most important in determining the costs and benefits of achieving the national RPS targets are

- projected fuel prices
- the characteristics of existing and new fossil fuel and renewable power plants
- the regional supply, cost, and quality of renewable resources
- financing costs

Fuel Prices. RenewMarket uses projected regional fuel prices for oil, coal, natural gas, and wood fuel from the NEMS *Annual Energy Outlook–1998* (*AEO 98)* reference case.[7] The national average price of coal decreases slightly over time, while the price of natural gas rises at an average annual rate of 0.7 percent from 2000 to 2020. The model adjusts the wellhead gas price to reflect changes in gas consumption relative to the base case, as described in the *Model Features* section below. Wood fuel prices do not escalate with time but rather with increasing use of

[6] Unless explicitly stated otherwise, NEMS and the ECP refer to the versions of those models used to produce the *AEO 98* reference case.

[7] We are grateful to Jeff Jones, Tom Petersik, Alan Beamon and Roger Diedrich of the Energy Information Administration for providing us with these and other data from NEMS.

biomass resources (see the *Renewable Resources* section below).

Electricity Demand and Capacity Need. RenewMarket uses projections of regional electricity demand from the NEMS *AEO 98* reference case. We also adopted the ECP's projected rates for retirement of existing plants and the ECP's assumption of a 15 percent reserve margin (the excess of capacity over predicted peak demand). As a result, RenewMarket projects the same amount of new generating capacity in each region and year as projected by the ECP in the *AEO 98* reference case.

Characteristics of Existing Plants. RenewMarket uses a set of standard unit types to characterize existing power plants. We derived the heat rates and the variable and fixed operating costs of the standard unit types from the Tellus Institute's power plant data base. A typical region contains three types of existing coal units (ranging from less to more efficient and more to less costly) and one type each of existing oil-fired steam, gas-fired steam, gas-fired combustion turbine, gas-fired combined-cycle, hydro, and nuclear units. In contrast, the ECP draws on an extensive data base of power plants in the United States to estimate fuel use and operating costs of existing power plants.

Characteristics of New Fossil-Fuel Plants. RenewMarket adopts the ECP's projected capital and operating costs and heat rates for new fossil-fuel plants used in *AEO 98*. Three main new plant types are incorporated into the model: gas-fired combustion turbines, gas-fired combined-cycle units, and coal-fired steam power plants.[8] For each type, there is a conventional and an advanced option.

Characteristics of Renewable Technologies. Both RenewMarket and the ECP model the following renewable technologies: wind, solar thermal, photovoltaic, biomass, municipal solid waste (MSW), and geothermal. RenewMarket divides the MSW category into two technology types: conventional waste-to-energy and landfill methane.[9] RenewMarket adds one further technology option that the ECP does not include: the cofiring of biomass in existing coal facilities. This option is important in our analysis both because it is relatively inexpensive (especially in comparison with new biomass power plants) and because it directly displaces existing coal generation, which is the leading source of carbon dioxide emissions from the electricity sector.

RenewMarket does not adopt the ECP's projections of renewable technology cost and performance. The ECP's assumptions are pessimistic compared with those of the most recent assessment of renewable electric technologies produced through a collaboration between the Electric Power Research Institute (EPRI), the Department of Energy (DOE), and a variety of other government, industry, and utility experts.[10] We believe the EPRI/DOE projections are more consistent with historical experience and more accurately reflect the likelihood of further gains resulting from research and development and continued industry expansion. Consequently, we incorporated the EPRI/DOE projections into RenewMarket (albeit with some modifications to account for technology learning, as described in the *Model Features* section).

Renewable Resources. In both RenewMarket and the ECP, regional resource constraints limit the amount of renewable capacity that can be added. In addition, the quality of renewable resources varies by region and declines with increasing resource use. The definition of resource quality differs with each resource type. For solar and wind technologies, the capacity factor (the average output divided by the maximum output) defines the quality of the resource. For biomass technologies, it is the price of biomass fuel. For geothermal technologies, quality is based on

[8] The ECP allows for additions of new nuclear plants beyond those already planned or under construction; however, the cost of this option is so high that none is likely to be built. RenewMarket does not consider the nuclear option.

[9] In the ECP, municipal solid waste generation does not compete for market share; instead, the expansion of MSW capacity is "hard-wired" into the model. In RenewMarket, conventional waste to energy is similarly hard-wired, but landfill methane is allowed to compete against other technologies.

[10] Electric Power Research Institute and US Department of Energy, *Renewable Energy Technology Characterizations,* EPRI TR-109496 (December 1997). The EIA also used these projections to conduct an alternative base case run in NEMS for *AEO 98* called the "high renewables" case. Previous versions of the EPRI/DOE report have been used in the development of a number of DOE inter-laboratory studies and of the national energy strategy for the past several years. For example, see Interlaboratory Working Group for the Office of Energy Efficiency and Renewable Energy, US Department of Energy, *Scenarios of US Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond,* ORNL-444, Oak Ridge, Tenn.: Oak Ridge National Laboratory, September 1997; and National Laboratory Directors, *Technology Opportunities to Reduce US Greenhouse Gas Emissions,* prepared for the US Department of Energy (October 1997).

the capital and operating costs of the plants, which depend on the temperature of the geothermal reservoirs being exploited.

With the exception of wind and geothermal energy, the resource constraints and cost-supply curves applied to renewable technologies in RenewMarket are the same as those applied in the ECP. In the case of wind, we determined that the "elasticities" assumed by the ECP—which raise the capital cost of wind in proportion to the amount of windy land exploited—overly constrain the amount of wind capacity that could practically be built in the model. We therefore dropped these elasticities and instead reduced the estimated windy land area by an average of 60 percent to reflect anticipated siting costs and restrictions. We also added a new, lower-quality wind resource class to allow for the possibility of greater use of wind energy (where economically justified) under the more ambitious RPS scenarios.

In the case of geothermal energy, we were only able to approximate the limitations on regional growth imposed by the geothermal submodule of the ECP. These limitations appear to restrict the average annual increase in geothermal capacity nationwide to about 300 MW per year. In our opinion, this limitation is overly restrictive, especially considering the incentives to increase geothermal capacity that an RPS would provide. We therefore increased the amount of capacity that could be built in a given year to 1000 MW.

Financing Costs. The cost of financing new power-plant construction is an important factor in determining the cost of meeting an RPS target. Since most renewable technologies are more capital intensive (but have lower operating costs) than competing fossil-fuel technologies, higher financing costs tend to discourage renewable energy development and raise the cost of an RPS. RenewMarket uses the ECP's assumed financing costs—which vary by region and over time—for both conventional and renewable technologies. The range is significantly higher than in previous versions of NEMS (a 10–15 percent annual fixed charge rate as opposed to 7.5–10 percent in the version of the model used to produce AEO 97). EIA staff introduced this change to reflect the different financial structures and greater financial risks that are likely to appear in a competitive, deregulated electricity market.

Model Features. In this section we describe the key features of the RenewMarket model that were used to calculate the costs and benefits of achieving the federal RPS proposals. It describes the methods used to determine

- which power plants will be built in a given region and year and at what times they will operate
- the reduction in costs of advanced fossil fuel and renewable technologies that occurs over time as more capacity is installed and as more experience is gained
- the reduction in gas prices that result from lower gas consumption
- constraints on the amount of wind power that could occur at higher levels of installed capacity

Build Decisions. In determining which plants to build in a given region and year, RenewMarket seeks to minimize the current value of long-term plant capital and operating costs. The model first calculates the increase in system-wide annualized capital and operating costs that would result from the addition of each competing plant type to the generating system. It then applies a market-sharing algorithm to distribute shares of the required new capacity among the competing options. The least-cost option receives the largest share (within resource limitations), while other options receive progressively smaller shares in order of increasing cost. The market-sharing algorithm, which is the same as that used by the ECP, peaks sharply, so that only those options that are very close in cost to the least-cost technology receive a share.

Intermittent resources such as wind and solar are assigned a capacity credit, which determines how much conventional capacity they displace per unit of intermittent capacity added. Thus, for example, if wind receives a capacity credit of 30 percent, 100 MW of wind will displace 30 MW of fossil-fuel capacity. As in the ECP, the capacity credit is determined by the average output of the resource during each region's peak demand periods. Unlike the ECP, however, RenewMarket assumes that the capacity credit for wind plants declines with increasing wind

penetration, with combustion turbines making up the deficit. The result is to increase the cost of meeting ambitious RPS targets with wind and to shift the renewable energy mix toward biomass and other technologies.

Unlike the ECP, RenewMarket does not distinguish between generating technologies with short or long lead times. Nor—with the exception of minimum reserve margin requirements—does it incorporate external constraints, such as a pollution cap, that can affect build decisions. RenewMarket can incorporate pollution and fuel taxes, however, if desired.

Plant Dispatch. The aim of the plant dispatch module is to minimize current total operating costs while satisfying electricity demand. To do this, RenewMarket first ranks the available plants in order of increasing operating cost (including both fuel and variable operations and maintenance). Next, it dispatches each plant in rank order until it meets the expected demand in each load period. RenewMarket uses the nine load periods defined in the ECP, including summer peak, winter peak, and so on. Intermittent solar and wind plants are treated as "must run" units, with their output predetermined by a set of capacity factors for each region and load period. The factors RenewMarket uses are those the National Renewable Energy Laboratory developed for the EIA.

Technology Learning. A significant feature of both models is that the costs of advanced fossil-fuel and renewable technologies decline over time. In the ECP, this decline is assumed to be entirely the result of accumulated experience in plant construction and installation. That model applies a capital cost reduction, or learning factor, for each doubling of a technology's installed capacity. The learning factor for the first five units built (with the unit size varying by technology) is 10 percent. After the first five units, the learning factor declines to 5 percent. After 40 units, the learning factor declines to 2.5 percent, where it remains thereafter.

RenewMarket takes a somewhat different approach. According to the EPRI/DOE report cited above, most renewable technologies are likely to experience cost reductions as a result not only of learning in the domestic industry but also of research and development and of growth in the international market. For technologies such as photovoltaics, solar thermal, and biomass gasification combined-cycle, these exogenous factors are likely to be much more important in driving down costs than domestic growth in installed capacity.[11] Therefore, we "hard-wired" the EPRI/DOE cost projections for these technologies into the model. For wind and geothermal— which are closer to technological maturity and for which a substantial domestic market already exists—we split the cost reductions more or less equally between technology learning and exogenous factors. This was done by applying half the projected annual rates of cost reductions from the EPRI/DOE report and half the learning factors from the ECP.

The result of these assumptions is to slow the rate of penetration of wind and geothermal technology, while increasing the use of solar and biomass technologies, compared with projections from the ECP learning factors alone.

Gas Price Elasticity. Under an RPS, renewables are likely to displace some of the projected growth in natural gas use, which will in turn cause a drop in gas prices. The ECP adjusts gas price projections for changes in gas consumption using a price function that depends on the projected lifetime of domestic gas reserves. RenewMarket employs a price elasticity for each year that was calculated by dividing the projected change in gas prices by the change in cumulative gas consumption relative to the reference case for several NEMS runs (the High Renewables case and two RPS cases). As an example, the derived price elasticity in 2020 is $0.015/MMBtu per quadrillion Btu. Under the Markey RPS, the projected decline in cumulative gas consumption by 2020 is 4.4 quads (2.6 percent). That implies a drop in the gas price of $0.07/MMBtu (about 2 percent of the projected national average price for natural gas used for electricity generation in that year). The price elasticity function starts in 2005; before that time, changes in

[11] Rapid growth in sales of photovoltaic modules has occurred overseas in response to demand for village power in developing countries. Such sales, along with R&D investments, are likely to be the critical cost drivers in the near term. R&D is likely to be the most important factor bringing the costs of solar thermal technology nearer to competitive levels in the next several years. As for biomass gasification/combined-cycle technology, R&D investments and improvements in conventional combined-cycle technology are likely to be the important drivers of cost reductions.

cumulative gas consumption are assumed to have no effect on price.

We also assumed that gas prices would decrease by the same amount for electricity generators as well as for residential, commercial, and industrial consumers. Since the reductions in consumer gas prices predicted in the NEMS runs resulted in a very small increase in consumer gas use—and because RenewMarket does not include this demand feedback effect or project consumer gas use—we multiplied the consumer gas-use projections from the *AEO 98* reference case by the decrease in gas prices predicted by RenewMarket for each RPS proposal to derive consumer gas savings.

The effect of the gas price elasticity is to lower the projected costs of the RPS. Increased use of renewable energy decreases gas consumption, which in turn lowers gas prices. Although the drop in gas prices makes further renewable additions relatively more expensive, this effect is more than offset by the drop in expenditures for natural gas in both the electricity sector and the wider economy.

Constraints on Wind Growth. Because wind is relatively inexpensive and because there is a large amount of land area in the United States suitable for wind development, wind energy use can become quite high under ambitious RPS scenarios. At lower levels of penetration, wind turbines can be incorporated into the electricity system with little difficulty. At higher levels of penetration, several factors could constrain further growth in wind energy, among them its intermittent and dispersed nature, the wind industry's ability to ramp-up production, access to transmission capacity, and potential siting limitations.[12] To address these issues, RenewMarket includes four features that constrain wind capacity as wind energy use increases:

- an industry growth-rate penalty, which raises the cost of wind energy when the average rate of growth of wind capacity in the preceding three years exceeds 25 percent per year
- a decline in wind capacity credit with increasing wind penetration on regional electricity grids, which increases the amount of combustion turbine capacity needed to meet reliability requirements
- a reduction in the wind capacity factor with increasing wind penetration to reflect the probability that wind output will exceed electricity demand during high-wind, low-load periods
- a reduction in the windy land area, averaging 60 percent in each wind resource class, to reflect potential siting costs and constraints beyond the environmental and urban exclusions already considered in the wind resource data

The effect of these changes is to limit the penetration of wind energy in any single region, increase the proportion of biomass, geothermal, and solar resources in the capacity mix, and increase the overall cost of the RPS.

Calculating the Net Costs of the RPS. The net cost of the RPS equals the increase in the electricity bills minus the savings from lower gas prices.

Renewable Energy Credit Prices. RenewMarket models the RPS by progressively lowering the operating costs of qualifying renewable plant types until the RPS target is met. The amount by which the cost must be reduced is called the shadow price. By applying the same shadow price to all qualifying units—and allowing the model to choose the mix of units to be added to minimize the current value of long-term costs—this approach ensures that the RPS target is met at the lowest cost under the assumptions and within the limitations of the model.

The shadow price works in two ways. First—and most importantly—it lowers the annualized (or levelized) cost of new renewable units that are competing to be built. Second, it lowers the operating costs of both new and existing renewable plants in the dispatch module. In both cases, the shadow price is applied only when needed to boost renewable energy generation to the level required by the targets.

The shadow price calculated by the model directly measures the amount of economic stimulus required to achieve the RPS target. Thus, it should relate in some fashion to the price renewable credits would command in a credit market. However, the shadow price (as used in the build decision) is a levelized quantity that applies over the lifetime of units built in a particular year, whereas the credit-trading

[12] Most of these constraints also apply to solar technologies, but in practice they are constrained by cost to a relatively low level of market penetration.

price should equal the value the market places on the last kilowatt-hour of renewable generation required to meet the target in a single year. How the two quantities might be related depends on characteristics of the market that are difficult to predict.

Consider the perspective of a generator interested in building a renewable plant. Suppose that RenewMarket accurately estimates the shadow price the plant owner would require to justify going ahead. At what actual price would the generator have to sell its renewable credits in its first year of operation? The answer depends on the plant owner's expectations of income from future credit sales, as well as the owner's perceptions of the risks to that future income stream. The problem is similar to that encountered in the stock market, where buyers and sellers set the current price of stock on the basis of expectations of the stock's future price and earnings.

The issue is further complicated by the fact that markets for renewable credit futures and options could arise, or renewable plant owners could enter long-term contracts with electricity providers to sell their credits on a fixed price schedule. In addition, power companies might choose to spread their own costs of meeting RPS targets over a number of years to reduce the customer impact. All of these factors could affect how much consumers ultimately pay for the RPS and when they pay it.

Our solution to this set of challenges is to assume that the credit-trading price in any given year equals *either* the current value of the levelized credit in that year minus the current value of expected income from future credit sales, *or* the shadow price, whichever is larger. The first term kicks in when the credit price is falling, the second when it is rising. By starting at the end of the study period and working backward, we are able to calculate a stream of credit prices that will provide the economic stimulus required by the model.

Credit prices estimated in this fashion can appear highly volatile. This is especially true before the RPS target levels off or a sunset provision takes effect, since then the current value of expected income from future credit sales is reduced (perhaps even to zero) and the renewable generators are forced to recover a larger share of their above-market costs in the current year.[13] To smooth out the peaks and valleys, we assumed that renewable credit sellers and buyers would enter into fixed-price contracts to spread the costs over a seven-year period. This period is meant to reflect an average of likely credit contract terms, which could range anywhere from one year to fifteen years or longer.

Modeling the Administration's RPS proposal, which calls for a price cap of 1.5 cents per kilowatt-hour, required adjustments to this method. To model the price cap, we first calculated the funds that would be available in every year of the RPS, assuming that electric utilities paid the maximum (the price cap times the target generation) into the public benefits trust fund. Then we converted this amount to its levelized equivalent (i.e., the amount that could be spent every year over 30 years and yield the same present value). Next, we instructed RenewMarket to raise the shadow price in each year until *either* the total amount of renewable generation equaled the target, *or* the total funding required (the shadow price times the predicted renewable generation) equaled the amount of funding available. From the resulting stream of shadow prices, we recalculated the credit-trading prices using the method described above and then repeated the process.

Limitations of the Method. Both RenewMarket and the ECP have limitations. Foremost among these is that neither is designed to model a fully competitive electricity market. Both models seek to minimize the long-term costs of providing electric power, not to maximize the profits of plant owners—the driving force in a competitive market. In a perfectly efficient market, minimizing costs and maximizing profits should go hand in hand. However, the emerging regional electricity markets may turn out to be far from optimally efficient. For example, some markets may be dominated by a few suppliers able to control prices and limit competition to some degree. Furthermore, strategic factors not considered in the models, such as

[13] An effect very much like this occurred in the first two rounds of bidding in the United Kingdom's Non-Fossil-Fuel Obligation (NFFO) program, which like the RPS set targets for renewable energy generation. Under the NFFO rules in the early 1990s, renewable generators were allowed to receive a subsidy only through 1998. This created a high premium price, prompting the UK electricity regulator to allow generators to recover their above-market costs over a longer period in subsequent solicitations.

consumer demand for "green" power and policies that provide incentives for renewables, may affect decisions about building and retiring plant capacity. Given these uncertainties, it is difficult to predict the full effects of competition and deregulation on the costs of meeting the RPS.

A further limitation of both models is that they oversimplify the method of determining the market shares of different technologies in two respects. First, the method assumes that the distribution of costs around the mean is identical for every technology—a questionable premise for resources as disparate as gas-fired combustion turbines and wind power plants. This tends to work against renewable technologies, as there is probably a broader distribution in their cost and performance than in the cost and performance of fossil-fuel technologies. Second, it gives a greater market share to technologies with high capital costs when the combined capital and operating costs of competing technologies are the same. This tends to favor coal, biomass, solar, and geothermal technologies over wind and gas technologies. On balance, we believe this limitation raises the apparent cost of the RPS.

Another limitation applies only to RenewMarket. Unlike the ECP, RenewMarket does not allow for bulk power purchases and sales between regions. Imports are a significant part of the capacity mix of several regions, especially New York, which imports 30 percent, mostly from Canada, and California, which imports 27 percent. However, an analysis by the Department of Energy of the Clinton Administration's electricity restructuring proposal shows that total intra-regional electricity trading in the United States only represents 2 to 3 percent of total electricity sales in 2010.[14] Regardless, shifts in electricity exchanges could affect the development of renewable resources under the RPS. Furthermore, many believe that transmission capacity will increase as the generation market becomes increasingly competitive and as the control and pricing of transmission becomes more regional in nature to facilitate the transfer of greater amounts of electricity over longer distances. If the rules are designed to allow renewable developers fair and equal access to the transmission system, it may be economical to build additional renewable generation in regions with high quality resources and fewer people in order to sell electricity to more populous regions with lower quality resources. Therefore, the absence of exchanges in RenewMarket should raise the apparent cost of the RPS by causing a less than optimal change in the distribution of resources relative to the base case, but the size of the effect cannot be determined.

Finally, neither RenewMarket nor the ECP models decentralized or distributed generating sources. This is a significant drawback in modeling photovoltaic systems, which are better suited to small-scale, decentralized applications such as rooftop panels and transmission grid support. Thus, not including distributed renewable resources would also raise the apparent cost of the RPS, but the effect is likely to be small.

Taking all of these limitations into consideration, we believe that RenewMarket overestimates the likely costs of the RPS.

Results

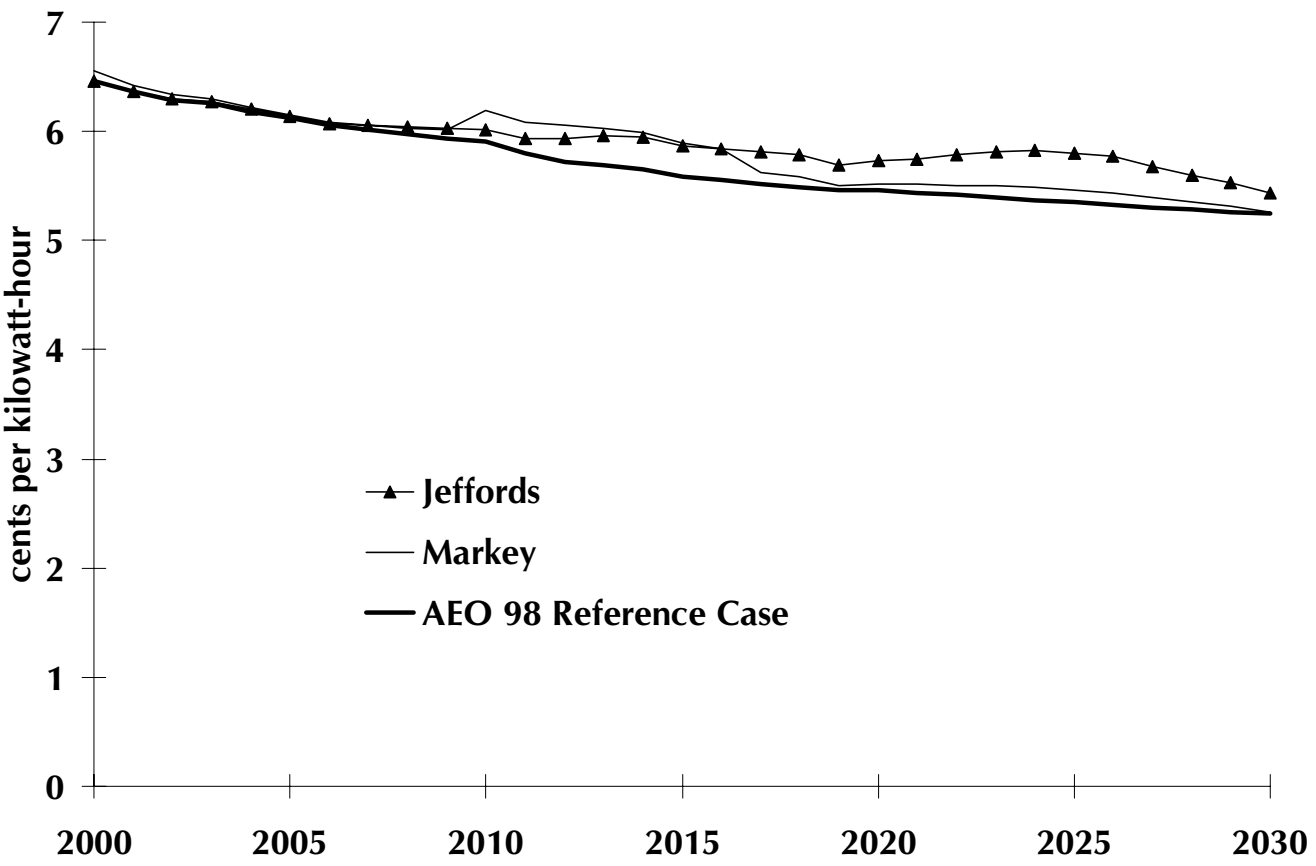
In this section we present the national and regional costs and benefits of meeting the proposed RPS targets. First, we present the results of the Administration, Markey, and Jeffords proposals, which reflect the range of impacts under a relatively modest, midrange, and aggressive RPS. We then look briefly at the key results for the Schaefer and Bumpers proposals; our analysis indicates that little additional renewable generation is needed above the base case to meet their RPS targets. Finally, we compare our findings with the results of other recent studies.

National Results. We will start by examining the national level impacts of the RPS proposals on electricity and natural gas prices and costs, renewable energy credit prices, carbon dioxide emissions, and the market share of renewable technologies.

Electricity prices and costs. Average consumer (residential, commercial and industrial) electricity prices under the Jeffords and Markey RPS targets relative to EIA's reference case projection from

[14] US Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis and the Office of Policy and International Affairs, *Comprehensive Electricity Competition Act: Supporting Analysis*, July 1998. On line at www.doe.gov/ceca/ceca.htm

Figure 1. Average Consumer Electricity Prices



AEO 98 are shown in figure 1.[15] The figure does not show average prices under the Administration RPS proposal because the changes are too small to see on the scale shown. Average electricity prices in the *AEO 98* reference case and RPS proposals are translated into the average monthly electricity bill for a typical non-electric heating household using 500 kilowatt-hours per month in figure 2.[16] The RPS scenarios include the effects of lower gas prices to electricity generators compared with the *AEO 98* reference case as renewables displace some of the growth in natural gas for generating electricity (see next section).

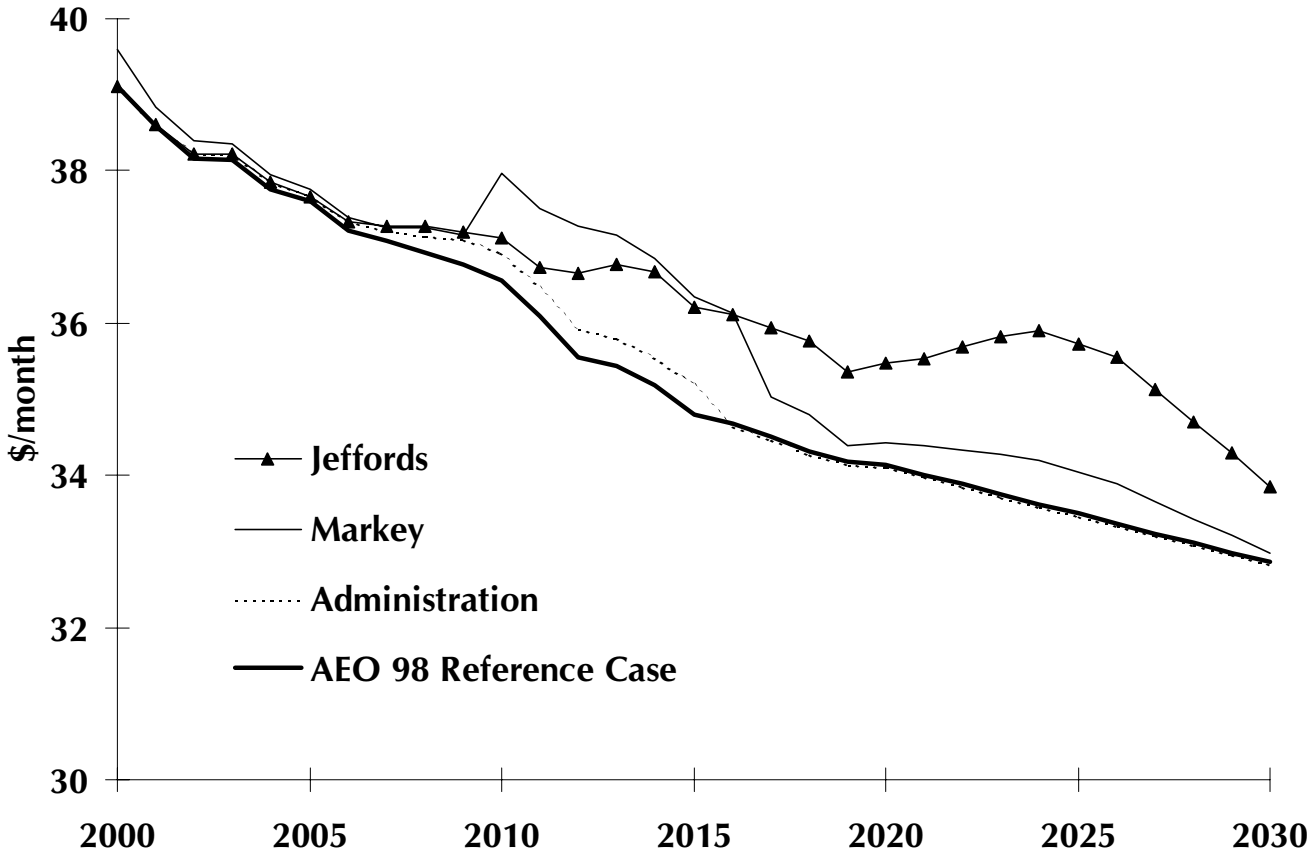
Business as usual. The overall trend shows electricity prices falling over time in every scenario. The *AEO 98* reference case projects average electricity prices to fall by 1.1 cents per kilowatt-hour (¢/kWh) or 18 percent between 1998 and 2020 in a business-as-usual scenario. For a typical household, monthly electricity bills would fall nearly $6 by 2020 or an average of 27 cents each year, from $40 per month in 1998 to $36.56 per month in 2010 and $34.14 per month in 2020. According to the EIA, electricity prices are projected to fall as electricity generators "depreciate their high cost existing capacity, reduce their operating costs, and build less expensive new capacity to meet future demand."[17] These falling prices are not the result of new policies to increase

[15] Since our model calculates only the change in generation costs, we adopted the consumer electricity price projections out to 2020 from EIA's *Annual Energy Outlook—1998* (*AEO 98*). We extrapolated prices between 2020 and 2030 based on growth rates between 2015 and 2020. All prices and costs are presented in real (inflation-adjusted) 1996 dollars.

[16] The level of usage is based on industry standards for a non-electric heating household and assumed to remain fixed throughout the forecast period. Nonelectric households represented about 70 percent of all households in 1997 (Energy Information Administration, *1997 Residential Energy Consumption Survey*).

[17] Energy Information Administration, Office of Integrated Analysis and Forecasting, *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997,* (SR/OIAF/98-01) February 1998.

Figure 2. Average Monthly Electricity Bill for a Typical Nonelectric Heating Household



competition in the industry. However, an analysis by the US Department of Energy for the Clinton Administration indicates that introducing competition into the electricity industry could reduce prices even further—by an additional 12 percent below the *AEO 98* reference case projection in 2010.[18]

All of the RPS scenarios would reduce the savings customers are expected to realize from lower electricity prices in the business-as-usual case, but in every RPS scenario, customers would still be paying less each year than they are paying today, as shown in table 2.

Jeffords. Under the Jeffords RPS, average electricity prices would still be 13 percent lower in 2020 than they are today. Average monthly electricity bills for the typical household would decline from $40 per month in 1998 to $37.12 per month in 2010 and $35.47 per month in 2020.[19] On average, the Jeffords RPS would reduce expected monthly savings in the business-as-usual case by one-third or 9 cents each year between 2000 and 2024. In other words, in the first year, the RPS would reduce the expected savings of 27 cents per month by 9 cents. In the second year, the RPS would reduce the expected savings of 54 cents per month by 18 cents. By 2020, the Jeffords RPS would reduce savings by $1.33 per month from the reference case, but the typical customer would still be paying $4.60 per month less than today.[20]

[18] US Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis and the Office of Policy and International Affairs, *Comprehensive Electricity Competition Act: Supporting Analysis*, July 1998. Online at www.doe.gov/ceca/ceca.htm

[19] Average monthly household electricity bills are calculated by adding the change in average electricity prices under the RPS proposals to the projected national average electricity price in the residential sector from *AEO 98* and then multiplied by 500 kilowatt-hours per month.

[20] Customers who use more electricity than a typical household using an average 500 kilowatt-hours per month, including those using electric heat, would have higher total monthly

Table 2. Average Monthly Electric Bills for a Typical Household[a] (1996$)

Scenario	1998	2010	2020	2030
AEO 98 Reference	$40.04	$36.56	$34.14	$32.86
Administration	$40.04	$36.93	$34.11	$32.83
Markey	$40.04	$37.97	$34.42	$32.97
Jeffords	$40.04	$37.12	$35.47	$33.85

[a]Based on an average use of 500 kilowatt-hours per month.

The cost of the Jeffords RPS relative to the reference case continues to grow slightly through 2024, when it reaches a peak of $2.28 per month for the typical household. After 2024, however, the gap between the Jeffords scenario and the reference case narrows each year. By 2030, the Jeffords RPS would cost only 0.2 cents per kWh more than the reference case or $1.00 per month for the typical household. Average monthly bills in the Jeffords case would be $33.85 per month in 2030, compared with $40 per month in 1998 and $32.86 per month in 2030 in the reference case. Over the entire period, the Jeffords bill effectively dedicates 20 percent of the expected household electricity savings to diversifying the fuel mix to 20 percent clean renewables.

Markey. Under the Markey RPS, average electricity prices would still be 6 percent lower in 2010 and 17 percent lower in 2020 than they are today. Average monthly electricity bills for the typical household would decline from $40 per month in 1998 to about $38 per month in 2010 and $32.42 per month in 2020. On average, the Markey RPS would reduce expected monthly savings in the reference case by 13 cents each year between 2000 and 2013, reaching a peak of $1.73 per month in 2013, and then falling rapidly to a range of 15 to 50 cents per month between 2017 and 2030. Thus, under the Markey RPS in 2020, the typical household would still be paying $5.58 per month less than today.

Average monthly bills in the Markey case would be $32.97 per month in 2030, compared with $40 per month in 1998 and $32.86 per month in 2030 in the reference case. Thus, over the entire period, the Markey bill effectively dedicates 16 percent of the expected household electricity savings to diversifying the fuel mix to 10 percent clean renewables.

Administration. Under the Administration RPS, average electricity prices would still be 10 percent lower in 2010 and 18 percent lower in 2020 than they are today. Average monthly electricity bills for the typical household would decline from $40 per month in 1998 to about $36.93 per month in 2010, $34.11 per month in 2020, and $32.83 per month in 2030. On average, the Administration RPS would reduce expected monthly savings in the reference case by 15 percent or 4 cents each year between 2000 and 2009. Between 2009 and 2015, the Administration RPS would reduce expected savings by 36 cents per month from the reference case, but the typical household would still be paying $3.07 per month less in 2010 than today. Prices are 0.07¢/kWh or 1 percent higher than the reference case in 2015 at its peak cost, but still 15 percent below 1998 levels. After the Administration RPS targets end in 2015, costs are projected fall below the reference case and the typical household would actually save money on its electricity bills due to lower gas prices to electricity generators. Over the entire period, the Administration bill effectively dedicates 3 percent of the expected household electricity savings to meeting the RPS targets.

Natural gas prices and costs. To the extent that renewables displace some of the projected growth in natural gas use for generating electricity, natural gas prices are projected to decline for electricity generators and gas consumers. As discussed in the *Model Features* section, we incorporated the average sensitivity of natural gas prices to changes in gas consumption in the electricity sector from EIA's RPS analyses. Relative to the *AEO 98* reference case projection, average natural gas prices for all gas consumers steadily fall by 5 percent in 2020 and 9 percent in 2030 under the Jeffords RPS and by 1.3 percent in 2010 under the Administration RPS.

savings compared to what they are currently paying for electricity, but they would also experience a larger monthly impact from the RPS.

Figure 3. Electricity Generator Gas Prices

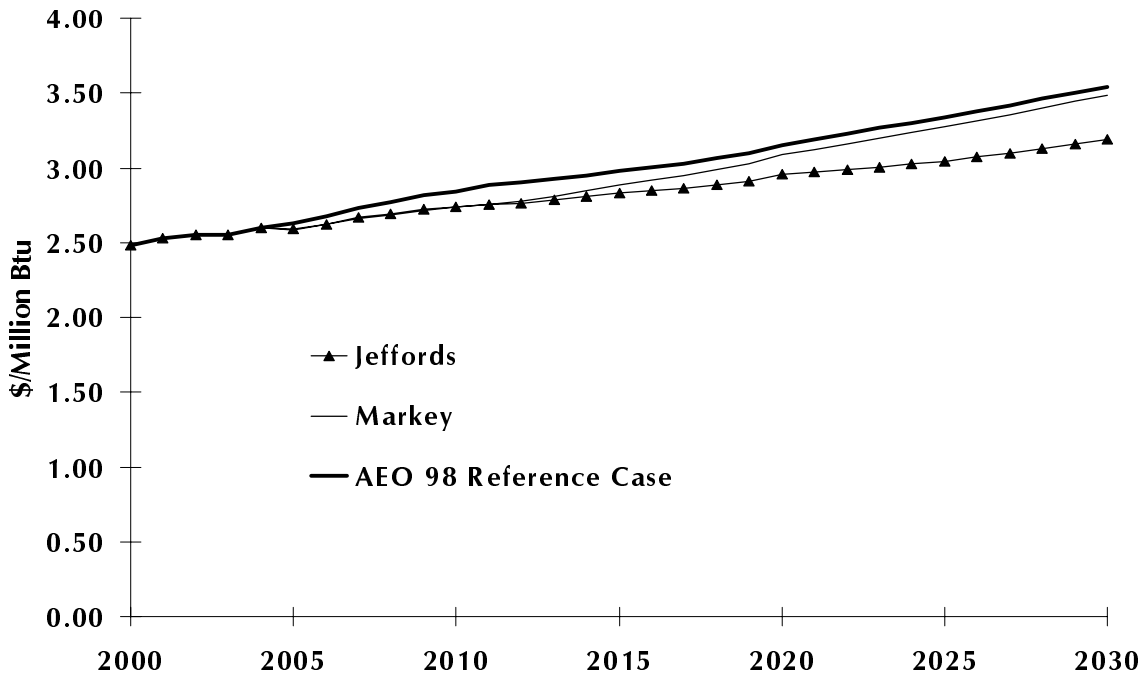


Figure 4. Change in Average Monthly Electricity and Natural Gas Bills for an Average Natural Gas Heating Household under the RPS Proposals Relative to *AEO 98* Reference Case

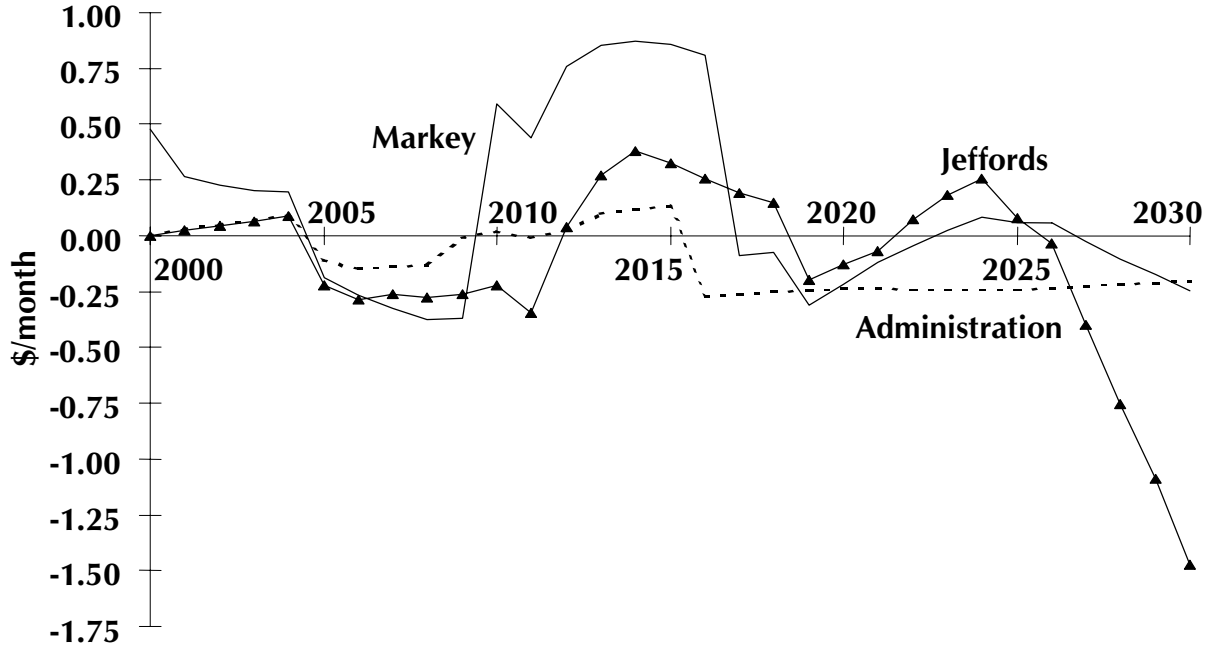
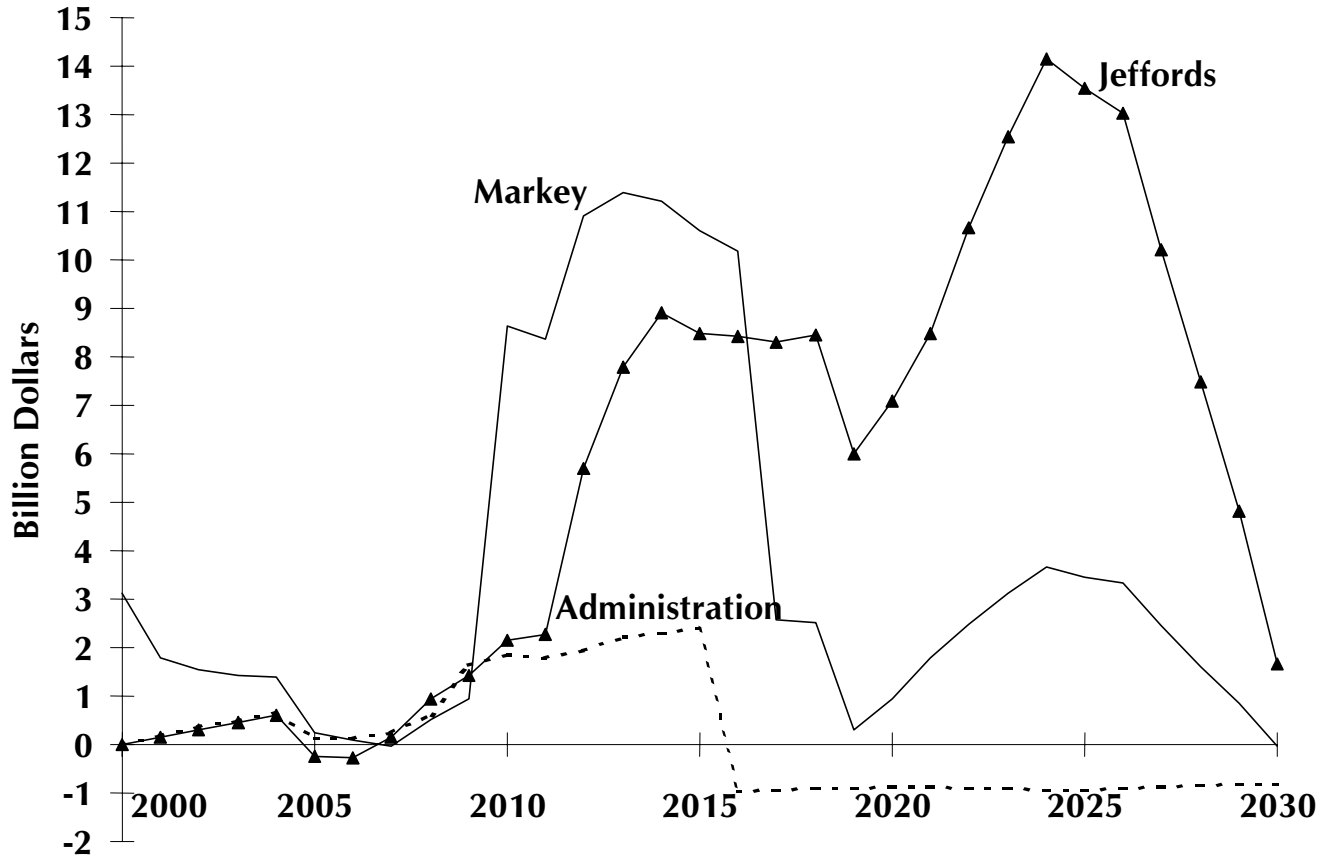


Figure 5. Net Cost of Jeffords, Markey and Administration RPS Proposals



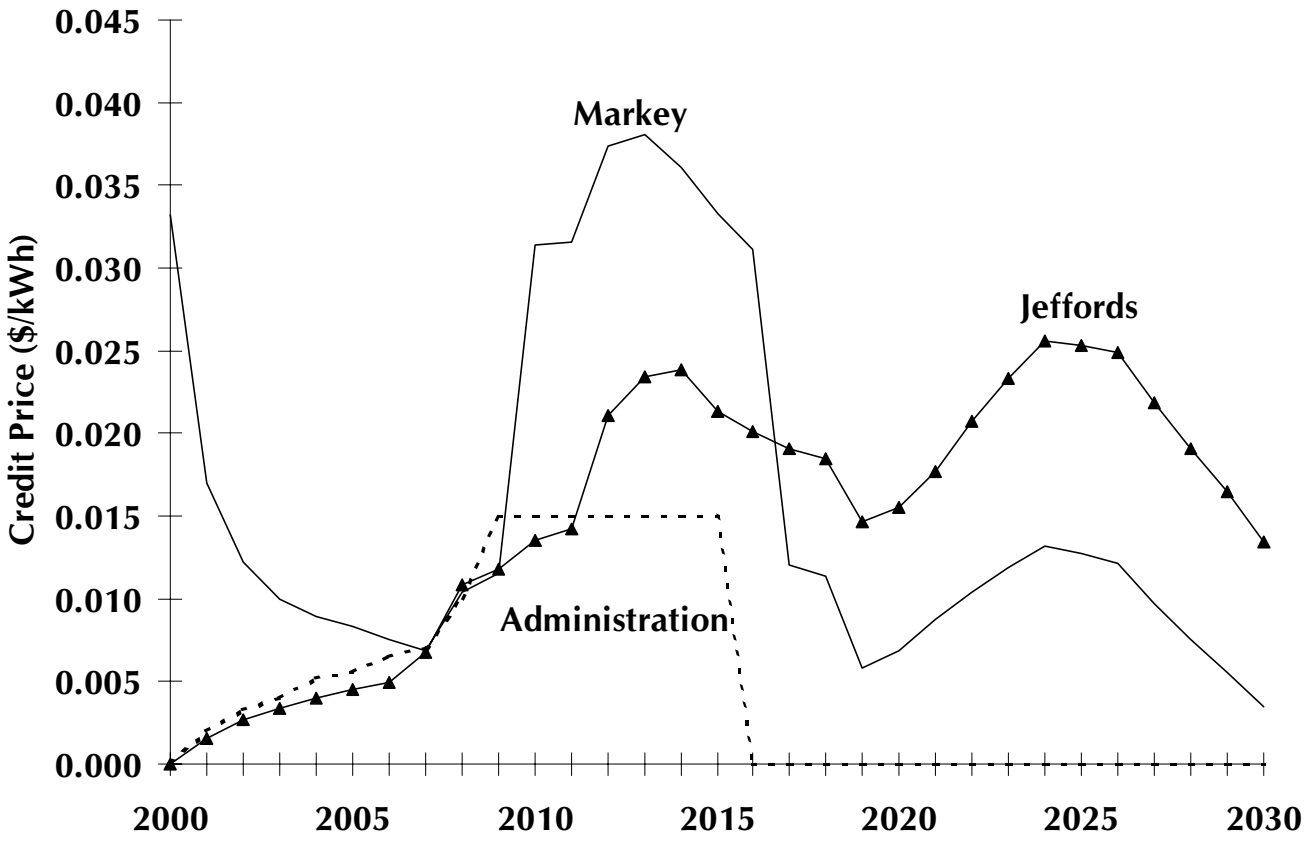
Average electricity generator gas prices under the RPS proposals and the *AEO 98* reference case, which we use in our model, are illustrated in figure 3.[21] Renewables displace enough new gas generation under the Jeffords RPS to steadily lower generator natural gas prices 11 percent below the reference case in 2030. Under the Markey RPS, generator gas prices would be 4 percent lower than the reference case in 2010, as less new gas generation is displaced. While not shown in the figure, the Administration RPS also reduces generator gas prices 1.6 percent below the reference case in 2010.

Consumer gas prices would also fall relative to the reference case, providing additional savings for households and businesses. For the more than half of all US households that heat with natural gas, the savings completely offset the increase in electricity costs over time under all of the RPS proposals, as shown in figure 4. Industry, which used 40 percent of the total natural gas in 1996, would also reap significant savings, ranging from $540 million in 2010 under the Administration RPS to $2.3 billion in 2020 and $4 billion in 2030 under the Jeffords RPS.

Net Cost of RPS. The total net cost of the RPS proposals, taking into account the change in electricity costs and total natural gas savings to the entire economy, is illustrated in figure 5. Under the Jeffords RPS, total net costs increase by an average of $590 million per year between 2000 and 2024, and then fall rapidly by $2 billion per year until 2030 as gas savings grow and as renewable developers have recovered most of their above market costs. Total net costs under the Markey RPS increase by an average of $880 million per year between 2000 and 2013, and then decline rapidly by $1.5 billion per year to near zero in 2019. Costs temporarily rise then fall to zero between 2019 and 2030, as electricity demand

[21] *AEO 98* forecasts prices only out to 2020. We extrapolated gas prices out to 2030 based on the average annual growth rate between 2015 and 2020.

Figure 6. Average Renewable Energy Credit Price



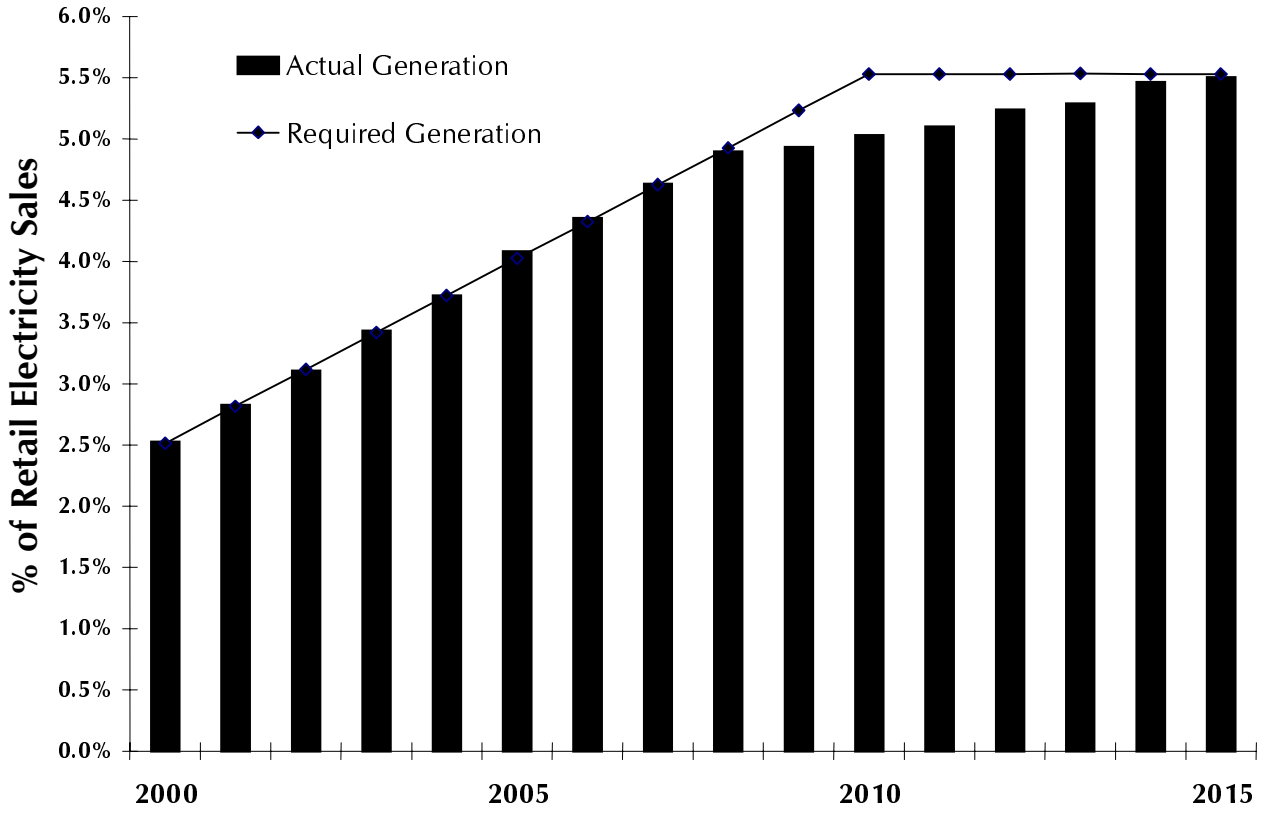
increases and more renewable generation is needed to meet the fixed 10 percent target. Under the Administration RPS, total net costs gradually increase by an average of $160 million per year between 2009 and 2015. After the RPS sunsets in 2015, net savings of nearly $1 billion per year are realized due to lower natural gas prices.

Renewable energy credit prices. Average credit prices under the RPS proposals, assuming that the credits are sold in seven-year fixed-price contracts as explained in the *Methods* section, are illustrated in figure 6. The average is taken over the contracts in effect at any given time. Despite having higher targets, the Jeffords RPS has lower renewable credit prices than the Administration RPS through 2011 and a lower peak credit price than the Markey RPS peak price. The reason is that, under the Jeffords RPS, renewable generators can expect credit prices to remain higher over a longer period as the target continues to increase through 2020, so they can charge less in the earlier years. In contrast, under the Markey RPS, the credit price is likely to drop fairly quickly after the target levels out at 10 percent after 2010, thereby forcing renewable producers to charge a higher price around 2010. This demonstrates that it is important to have the RPS gradually increase over a longer period of time to reduce credit price volatility.

The Markey RPS also has a high credit price in 2000 because a significant amount of new generation is needed in the first year to raise the renewables share of total generation from 2.3 percent under the base case to 3 percent under the RPS. During the first few years after 2000, only a small amount of new generation is needed to meet the gradually increasing target, which drives credit prices down and causes developers who install plants in 2000 to charge higher prices. This shows that it is important to set the initial target as close to the level of existing market share of renewable generation as possible.

Credit prices under the Administration RPS reach the proposal's price cap of 1.5 cents per kilowatt-hour between 2009 and 2015. The target reaches 5 percent

Figure 7. Shortfall in Renewable Generation Under Administration RPS Price Cap Actual vs. Required Generation to Meet RPS Target



in 2010 and 5.5 percent in 2015, delaying reaching the intended target by five years, as illustrated in figure 7. This temporary shortfall in renewable generation occurs because renewable developers do not receive enough economic stimulus to build the generation needed to meet the target and recover their above market costs until 2015, the last year before the target sunsets. However, once the target levels off in 2010, the credit is sufficient to encourage enough growth in renewable generation to attain the desired target in 2015.

According to the Administration's proposal, during the years when a shortfall in renewable generation occurs, retail electricity providers would purchase proxy credits from the program administrator (the DOE) for 1.5¢/kWh to meet their requirement. Proceeds from the sale of these proxy credits would be placed into a national public benefits fund for renewable energy, energy efficiency, and low income energy assistance programs, also created under the proposal. In this analysis, we assume the proceeds would be used to purchase as much renewable generation as possible, which is reflected in the actual generation shown in figure 7. However, since the bill does not specify how the proceeds should be used, there is no guarantee this would occur without changes to the language of the bill.

While the sunset provision in the Administration proposal would artificially force credit prices to fall to zero, our model projects that credit prices would be zero by this time anyway because only a small amount of additional renewable generation is needed to meet the fixed targets as the demand for electricity grows.[22] Credit prices do not decline to zero under the Jeffords and Markey RPSs because some biomass

[22] This also holds true for the Schaefer and Bumpers proposals, which also contain sunset provisions.

generation with relatively high operating costs needs a continuing credit to compete with the drop in real coal prices projected by EIA in *AEO 98,* which we use in this study.[23] Even if credit prices fell to zero at some point, the targets would remain in effect, so as electricity generation grows the credit price might rise again.

These results suggest that credit price spikes—and peak program costs—could be reduced by increasing the duration of the RPS requirement and by ensuring that credit trading continue for a sufficient period beyond the rising RPS requirement, so that developers could recover their incremental costs over a reasonable period.

Because we were unable to consider a number of potential low-cost options and potential benefits of an RPS, we believe that our input and modeling assumptions are generally conservative and more likely to err on the side of overestimating the incremental cost of meeting the federal RPS proposals. In particular, we did not model:

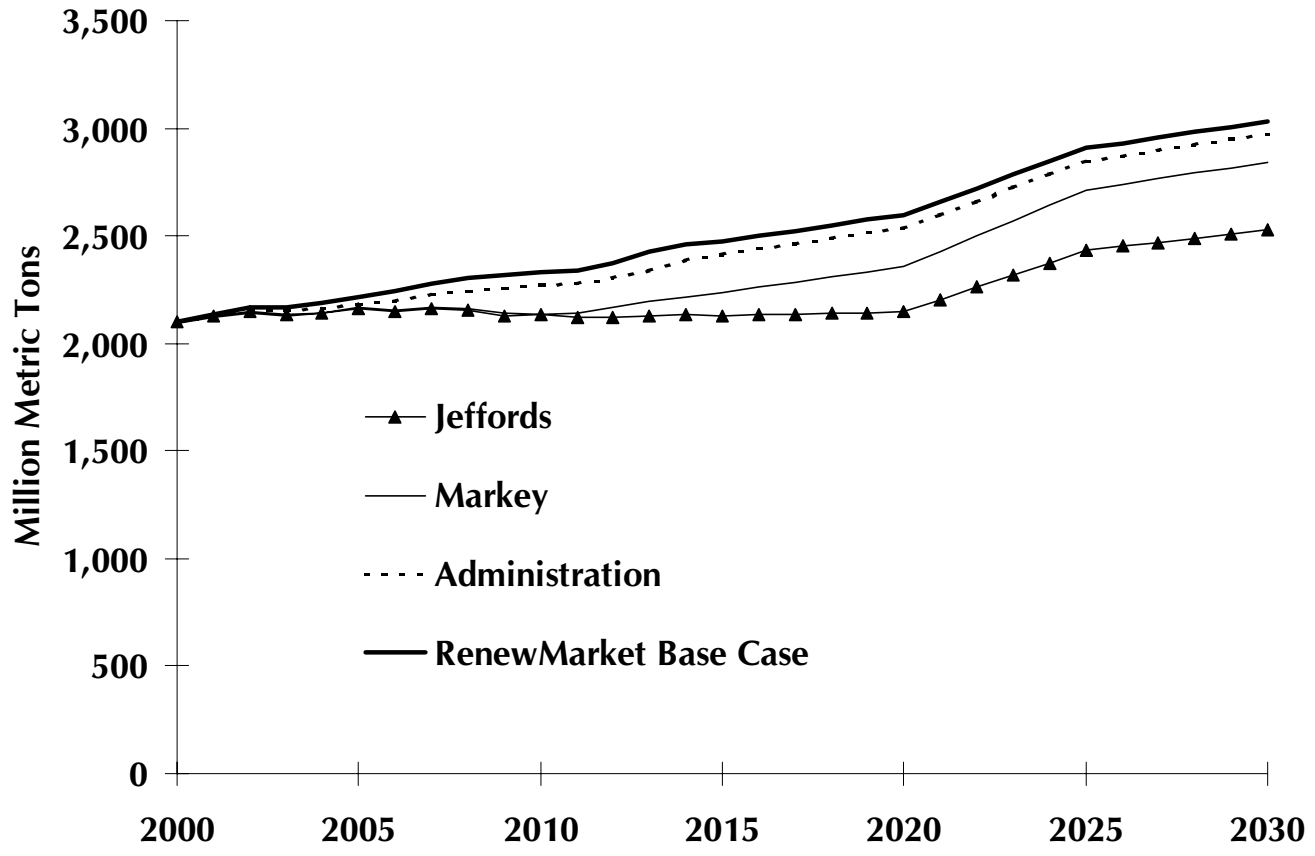
- The dynamic effects of the interaction between different types of credit-trading markets that would most likely exist under an RPS, including short-term spot markets, medium- and long-term bilateral contracts, and futures markets. Through a combination of these markets, buyers and sellers are likely to make arrangements at prices below the marginal cost or market clearing price of the last renewable unit installed to meet a given RPS target.
- The likelihood that electricity providers that own renewable generation and are subject to the RPS requirement would only charge their customers an amount sufficient to recover their incremental costs to minimize rate impacts and to enhance their competitive position. Any credits they possess in excess of their requirement would most likely be sold at the marginal credit price.
- The potential for renewable energy development in Alaska and Hawaii, both of which have plentiful resources and average electricity prices that are 50 to 100 percent higher than the national average. Renewable developers in these states could obtain and sell renewable energy credits to electricity providers in other states, which would be likely to lower the marginal cost of meeting the national RPS targets.
- Distributed resources, such as photovoltaics, which are likely to gain some share of the RPS because of their value in avoiding retail electricity purchases and transmission and distribution costs, and in providing premium power services, such as emergency backup power.
- State renewables support policies, such as system benefit charges and state portfolio standards.[24]
- "Green marketing," the selling of renewable generation at higher prices to customers willing to pay more for cleaner generation.[25]
- Environmental externality benefits from avoiding health and environmental costs associated with displaced fossil-fuel generation.
- The reduction in electricity sales that would result from higher electricity prices under the RPS proposals, which would stimulate investments in energy efficiency and fuel-switching measures and reduce the amount of renewables needed to meet the targets over time. An RPS analysis by EIA for Senator Jeffords showed that this feedback effect could reduce the cost of the RPS by as much as 40 percent (see *Study Comparison* section below).

[23] This analysis does not model any policies that might restrict the projected growth in coal generation, such as carbon or other emission caps. The Jeffords bill includes emission caps on carbon dioxide, sulfur dioxide, and nitrous oxide emissions, which could reduce the cost of the RPS, but we did not model these features of the bill.

[24] As a number of states implement renewable support policies, the incremental cost of meeting the federal standards would probably decline. However, the overall costs to consumers of both the state and federal actions could be the same, lower, or higher than the costs estimated in this study, depending on how the policies are structured and how they relate to each other.

[25] For example, if the green market has already exceeded the level of renewables required to meet an RPS target in a given year, and if this generation is eligible for credits under the federal standards, then the incremental cost of meeting the federal targets would be zero.

Figure 8. CO_2 Emissions from Electricity Generators



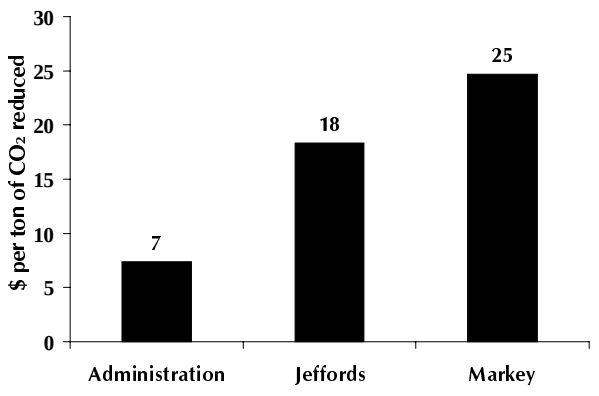
Carbon dioxide emissions reductions. By displacing fossil fuel use, the RPS proposals would reduce carbon dioxide (CO_2) emissions from electricity generators compared to the RenewMarket base case projection, as shown in figure 8. Under the RenewMarket base case, CO_2 emissions are projected to increase by 24 percent between 2000 and 2020. The sudden rise in base CO_2 emissions after 2015 is the result of increased coal and natural gas generation to help meet growth in demand and to replace generation from retiring nuclear plants, whose licenses are scheduled to expire by 2025.

The results illustrate that an RPS that gradually increases from existing levels to 10 percent in 2010 and 20 percent in 2020 is needed to approximately stabilize CO_2 emissions at 2000 levels through 2020. In 2020, CO_2 emissions drop 2.4 percent, 9 percent, and 17 percent below the RenewMarket base case projections under the Administration, Markey, and Jeffords RPSs, respectively.

The average cost per ton of CO_2 reduced for each RPS proposal is shown in figure 9.[26] Total costs include natural gas savings to the entire economy from lower gas consumption and prices. The Administration RPS reduces carbon emissions at the lowest cost because the majority of new generation added to meet the RPS target is biomass cofiring, which directly displaces coal, and because after the RPS sunsets in 2015, renewables continue to reduce CO_2 emissions at a net monetary savings as a result of lower gas prices. The Jeffords and Markey RPSs also reduce carbon emissions at a relatively low cost. The main reasons for this are that a significant amount of biomass cofiring is added, which reduces coal generation at a relatively low cost, combined with a significant reduction in natural gas use and prices, which lowers the cost of reducing CO_2 emissions.

[26] This is derived by dividing the total present value costs of each proposal between 2000 and 2030, by the total present value of CO_2 emission savings over the same period, using a 5 percent discount rate.

Figure 9. The Cost of Reducing CO_2 Emissions



By displacing coal and some oil-fired generation, the RPS proposals would also reduce emissions of criteria pollutants such as nitrogen oxides (NO_x), sulfur dioxide (SO_2) and particulate matter. An RPS would also help fossil-fuel generators lower their cost of complying with regulations on SO_2 emissions, which are subject to cap under the Clean Air Act Amendments of 1990.

Existing fossil-fuel generation is characterized in our model according to standard unit types by region, as described in the *Assumptions* section. Because emission rates vary greatly for individual power plants of the same type within region, we were not able to determine how much electricity was being displaced from specific power plants to accurately estimate reductions in criteria pollutants. However, recent analyses by the Energy Information Administration and the US Department of Energy using NEMS, which contains a detailed data base of existing power plants, found that an RPS would reduce nitrogen oxide (NO_x) emissions. EIA's analysis of an RPS of 10 percent in 2010 predicted that NO_x emissions from electricity generators would be reduced by 530,000 tons or 8 percent below 2020 levels.[27] The DOE analysis of the Administration's restructuring proposal, which includes an RPS of 5.5 percent in 2010, projected electricity generator NO_x emissions to fall 230,000 tons or 4 percent below projected 2010 levels.[28] A more detailed comparison of our results to the findings of these studies is provided below in the *Study Comparison* section.

Growth in Nonhydro Renewable Generation. The mix of total (new and existing) nonhydro renewable generation in 2010 and 2020 for the base case and the RPS proposals is shown in figure 10. Under the base case, nonhydro renewable generation is projected to grow from 2.3 percent of total US electricity generation in 2000 to 3.5 percent in 2020. New wind and geothermal plants are projected to meet most of this increase. Except for the retirement of about 750 MW of geothermal capacity, existing renewable generation is projected to continue at 1997 levels throughout the forecast.

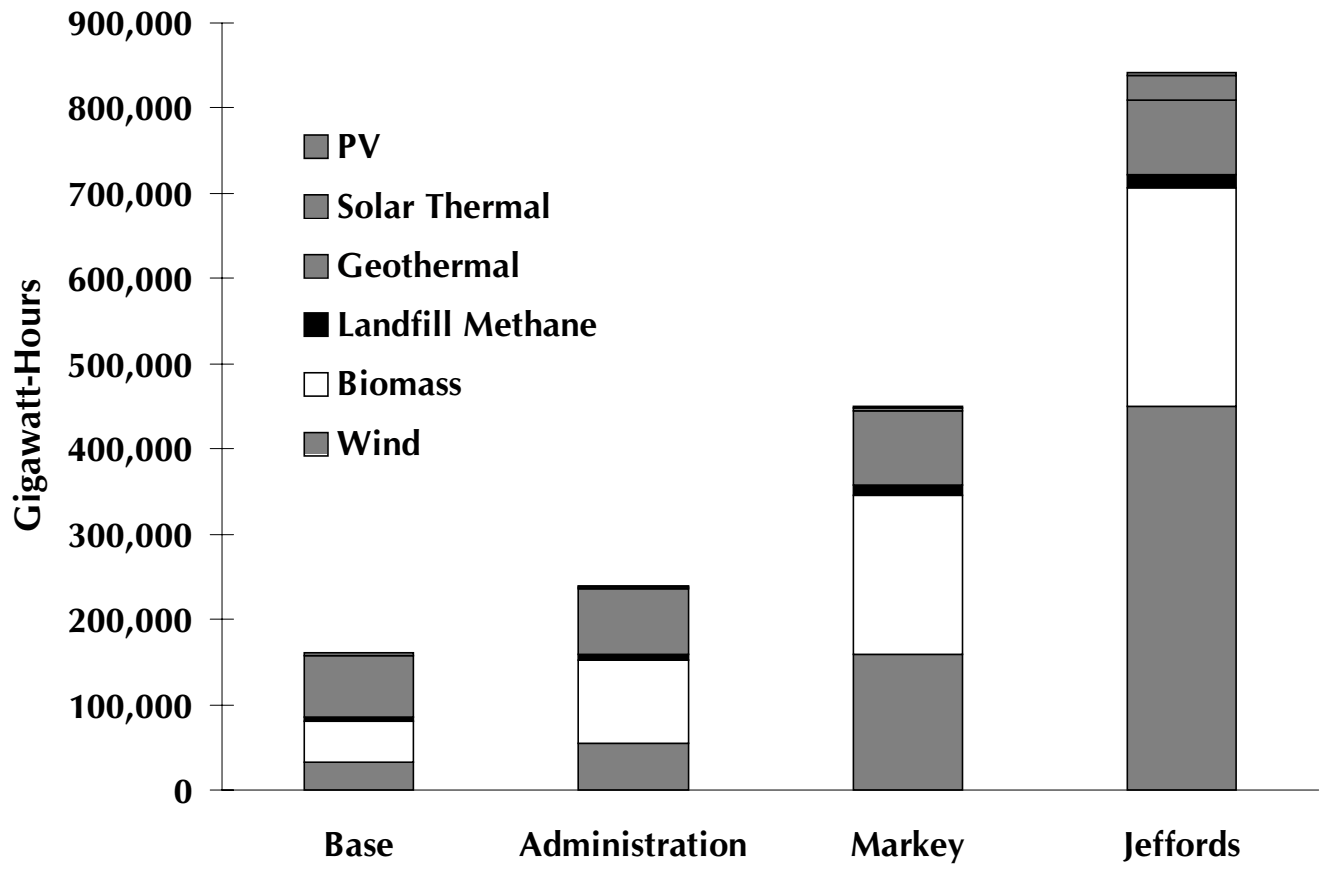
It is possible that increasing competitive pressures in the generation sector and uncertainties caused by electricity restructuring will result in our base case producing less renewable capacity than projected. In particular, our model may underestimate the retirement of some existing biomass plants with high operating costs because we assume average operating costs and performance for all biomass plants in the United States as well as regional biomass fuel costs. For example, some biomass plants in California and Maine are already idle as a result of high operating costs and competitive pressures. Under the Administration RPS, nonhydro renewables provide 71 percent more than the baseline in 2010. In contrast, nonhydro renewable generation more than triples in 2010 under the Markey and Jeffords RPS proposals and expands by more the five times in 2020 under the Jeffords RPS.

Figure 10 also shows that biomass, wind, and geothermal sources provide the vast majority of the total generation under the base case and the growth in generation under the RPS proposals. Wind also captures an increasing market share over time under the higher Jeffords and Markey RPS targets, as the low-cost biomass and geothermal resources become fully utilized. Under the Jeffords RPS, wind supplies about 53 percent of the total renewable generation needed to meet the 2020 target. Furthermore, landfill methane fills a significant niche under the Markey and Jeffords proposals. Solar thermal and photovoltaics

[27] Energy Information Administration, Office of Integrated Analysis and Forecasting, *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997* (SR/OIAF/98-01) February 1998.

[28] US Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis and the Office of Policy and International Affairs, *Comprehensive Electricity Competition Act: Supporting Analysis*, July 1998. On line at www.doe.gov/ceca/ceca.htm

Figure 10. Breakdown of Total Nonhydro Renewable Generation in 2020 with and without an RPS



experience significant growth above the base case under the Jeffords RPS, but provide a relatively small share of total nonhydro generation. In every other case, solar thermal and photovoltaics provide little extra capacity beyond the base case—an indication that these resources are uncompetitive as sources of bulk power competing with the central station alternatives modeled in RenewMarket.[29]

The projected contribution of renewables and fossil fuels to the *new* generation added between 1997 to 2020 under the base case and the RPS proposals is illustrated in figure 11. Under the base case, natural gas and coal provide 94 percent of the new generation, with new geothermal and wind making up most of the remaining share. Except for a small amount of new biomass and wind, fossil fuels still account for 89 percent of new generation under the Administration RPS.

Under the Markey RPS, the fossil-fuel share of new generation drops to 77 percent, mainly from the displacement of coal. Total wind generation increases by a factor of five and total biomass generation more than triples.

The Jeffords RPS displaces a significant amount of both new coal and natural gas generation, as the renewable market share climbs to nearly half of new generation. However, natural gas still leads all new generation, capturing 54 percent of the market. Biomass cofiring and contributions from other renewable technologies actually reduce coal generation below 1997 levels. Increased generation from all other renewable technologies, and particularly new wind turbines, reduces the market share of new natural gas

[29] All additions of photovoltaics in the base case are input into the model and reflect the expectations of EIA analysts. Photovoltaics would probably do better than projected since the model ignores the potential market for small-scale, distributed applications, which are typically more economic than large, central-station photovoltaic applications.

generation by 20 percent compared with the base case. However, even with the significant increase in renewables under the Jeffords RPS, total natural gas capacity grows by 295,000 megawatts and total gas generation grows by a factor of 3.6 between 1997 and 2020. This translates into a market share for gas of 27 percent of total generation in 2020 compared with 34 percent under the base case.

Regional Results. The regional distribution of renewable energy development varies greatly under the RPS proposals. For the purposes of this analysis, we show the regional distribution of total nonhydro renewable generation in 2020 under each RPS proposal as a percent of total regional electricity generation by North American Electric Reliability Council (NERC) region, minus Alaska and Hawaii, as illustrated in figure 12. While California and the Northwest supply the largest amount of renewable generation under the Administration RPS, the New England, Mid-Atlantic, Southwest, and Northern Plains states also contribute significantly, as shown in figure 13. Under the Markey RPS (figure 14), the same regions supply most of the renewable generation but at a higher level, with significant growth in wind generation in the Plains states. Wind generation continues to grow in most regions and especially in the plains states to meet the higher Jeffords RPS (figure 15), as five regions obtain more than 20 percent of generation from renewables in 2020, while 10 regions obtain more than 10 percent of generation from renewables. Renewable energy development occurs at a fairly high level in nearly all regions under the Jeffords RPS because regional limits on high-quality renewable resources force the model to look elsewhere.

Note that projections of technology mix and regional distribution are inherently much more uncertain and sensitive to changes in assumptions than

Figure 11. Contribution to New Generation, 1997-2020

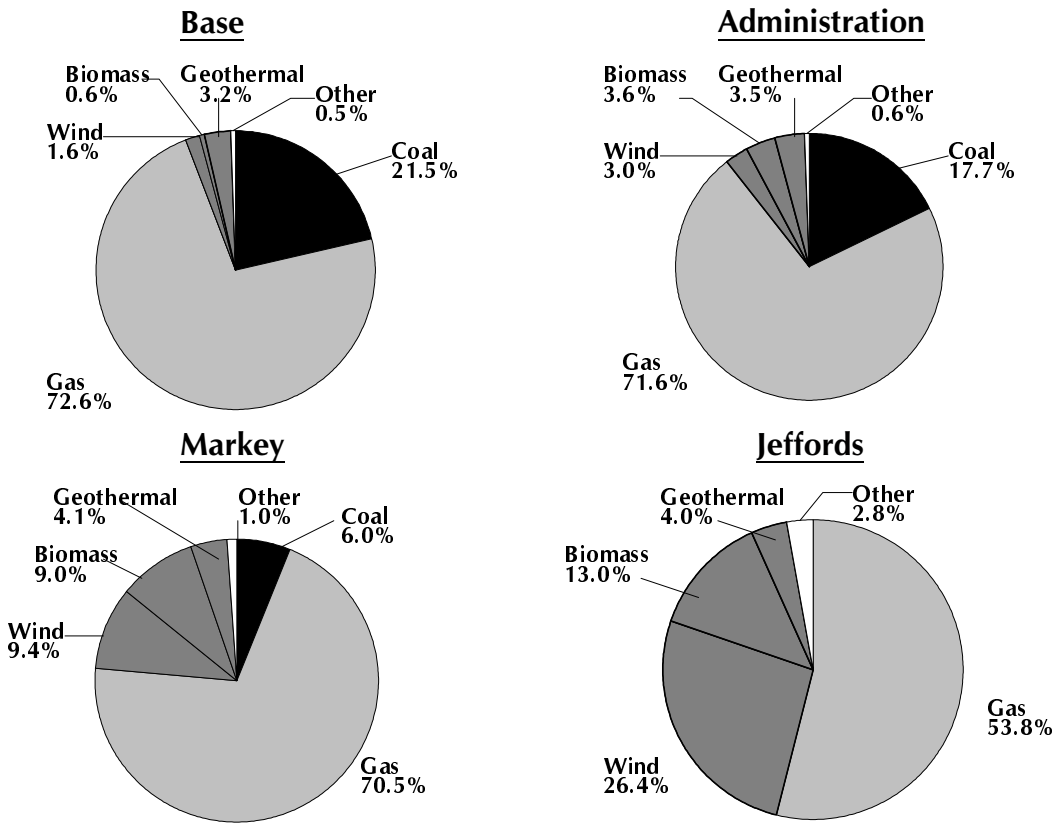
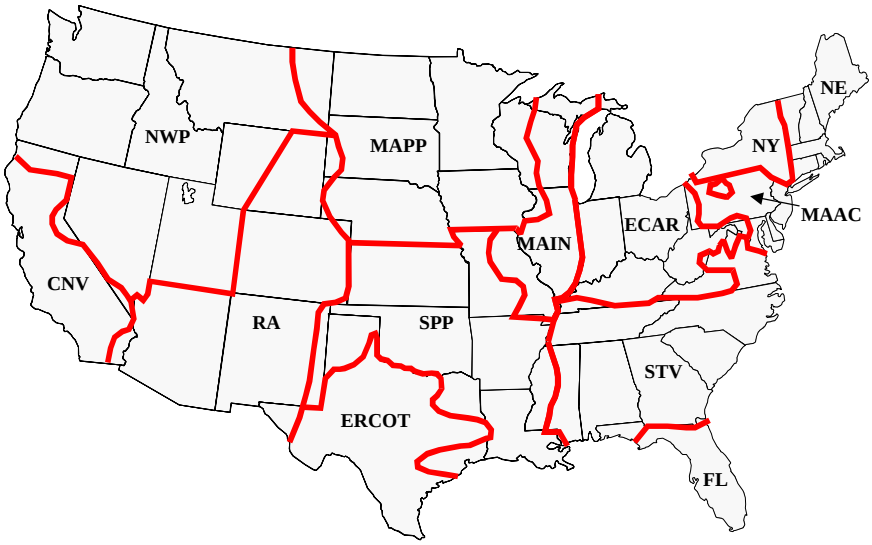


Figure 12. North American Electric Reliability Council (NERC) Regions



ECAR East Central Reliability Coordination Agreement Region
ERCOT Electric Reliability Council of Texas
MAAC Mid-Atlantic Area Council
MAIN Mid-America Interconnected Network
MAPP Mid-Continent Area Power Pool
NY New York Power Pool
NE New England Power Pool
FL Florida subregion of Southeastern Electric Reliability Council (SERC)
STV SERC excluding Florida
SPP Southwest Power Pool
NWP Northwest Pool subregion of the Western Systems Coordinating Council (WSCC)
RA Rocky Mountain and Arizona-New Mexico Power Areas subregion of WSCC
CNV California-Southern Nevada Power Area subregion of WSCC

Figure 13. Administration RPS Renewable Energy Generation % of Total Generation in 2020, by Region

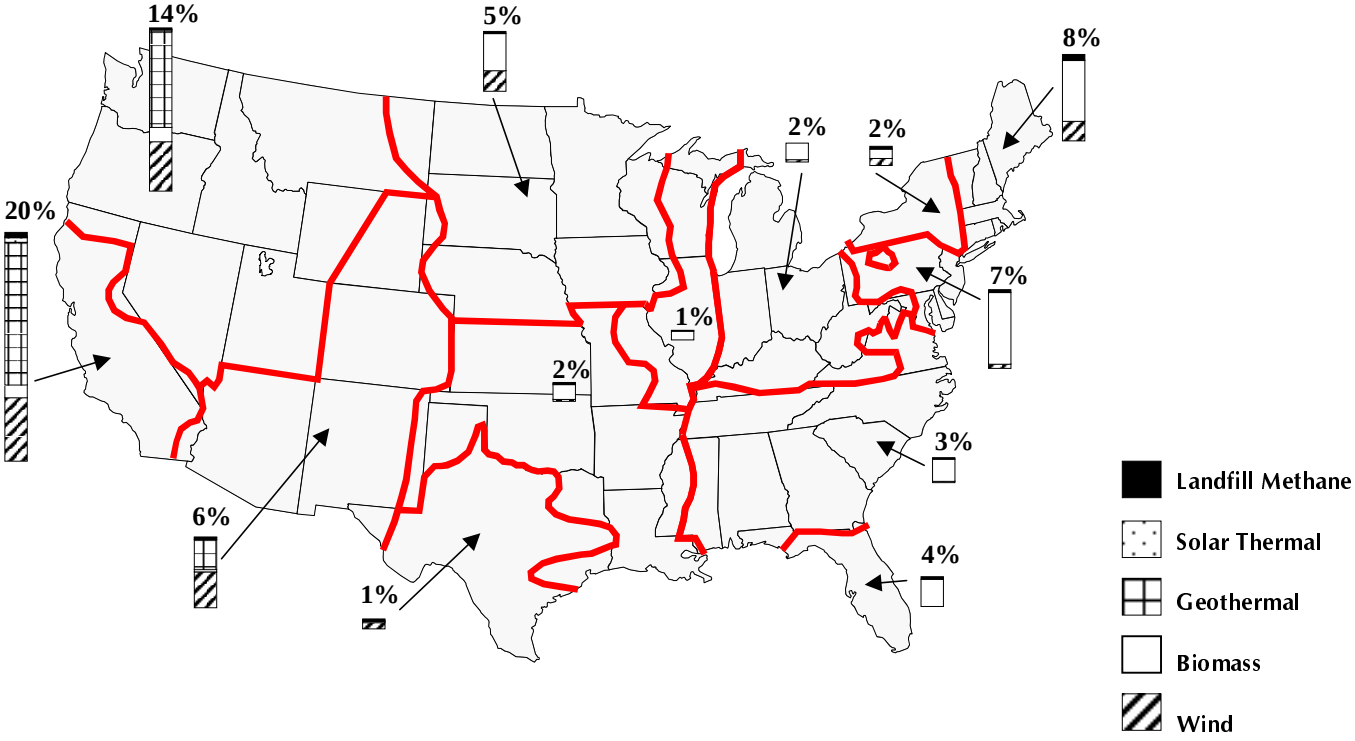


Figure 14. Markey RPS Renewable Energy Generation % of Total Generation in 2020, by Region

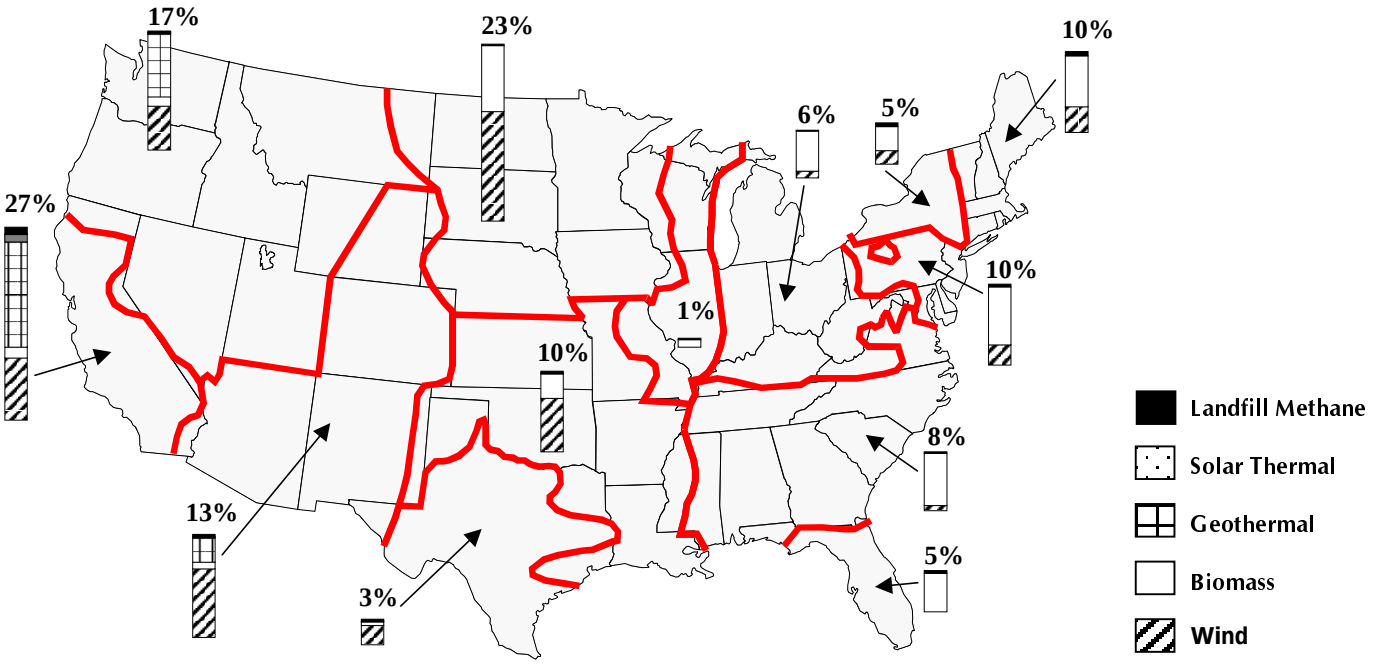
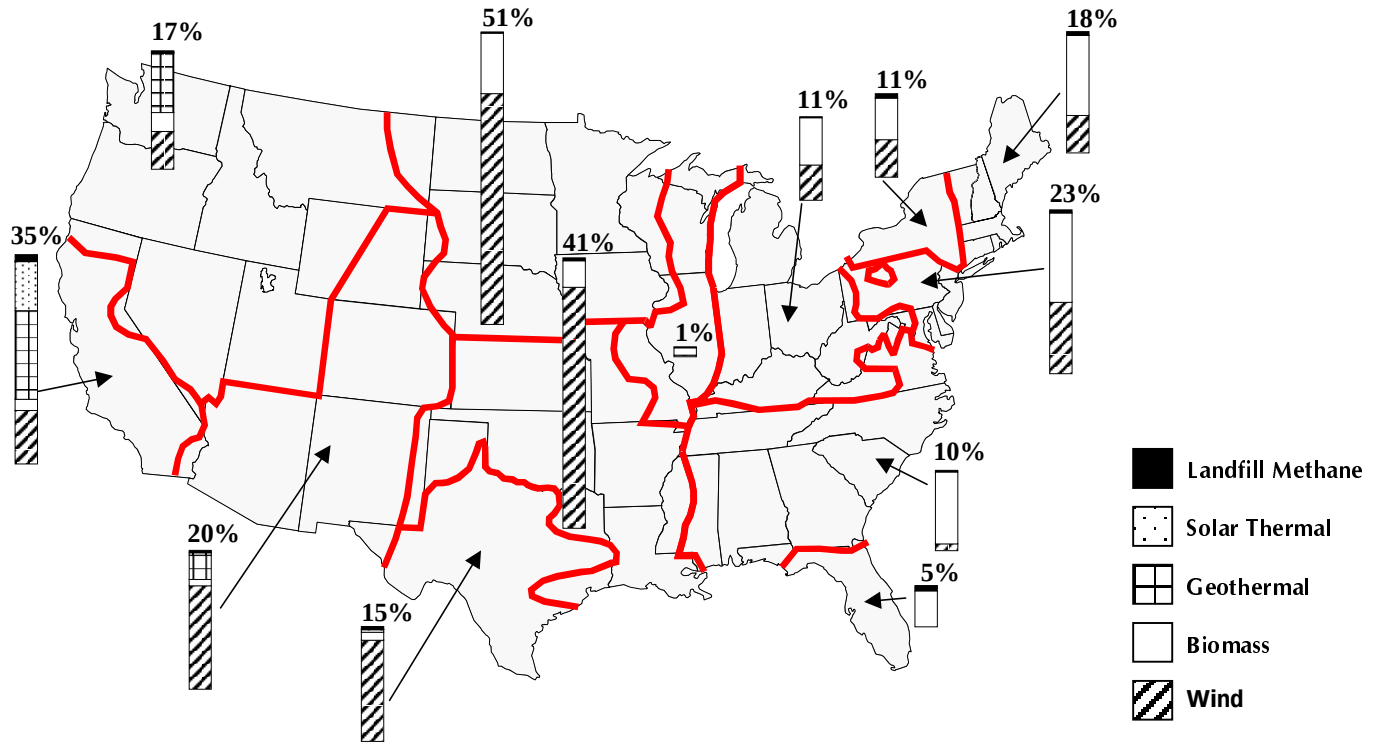


Figure 15. Jeffords RPS Renewable Energy Generation % of Total Generation in 2020, by Region



findings on national costs and benefits of the RPS. Many factors will influence the actual technology and regional development under a national RPS, among them state and regional policy decisions, the rate of technology development, interregional electricity trading, and so forth. Because the RPS creates strong competition among technologies for credits at a marginal credit price, the total program cost results are much more robust than specific projections of technology and regional development.

Small changes in assumptions could lead to large shifts in resource development in one region to a different resource in another region with very minor impacts on overall costs. For example:

- A small decrease in the cost of biomass relative to wind and geothermal could lead to substantially more biomass development in regions with abundant biomass resources at the expense of wind development in windy regions without affecting the overall program costs. Changes in relative costs could result not only from technology and resource developments, but also from state and regional policies to promote indigenous renewable resources, such as state portfolio standards, system benefit charges, or tax credits.
- Siting and permitting barriers to developing some technologies in some regions may constrain the pace or level of penetration of those technologies and lead to development of more expensive resources in other regions.
- Not including distributed resources, such as photovoltaics, makes it likely that we have underestimated the probable development of these technologies. Including them could lead to resource and regional development shifts and lower total costs.

Furthermore, while our assumptions and constraints for wind are reasonable and technically achievable, the projected levels of wind development, especially in the Jeffords scenario, go beyond existing experience. It is possible therefore, that actual wind penetration will be lower in some regions, which could result in higher-cost resources being developed. We believe that any such overestimate will be more than outweighed by our conservative assumptions, as set out in the *Assumptions* section.

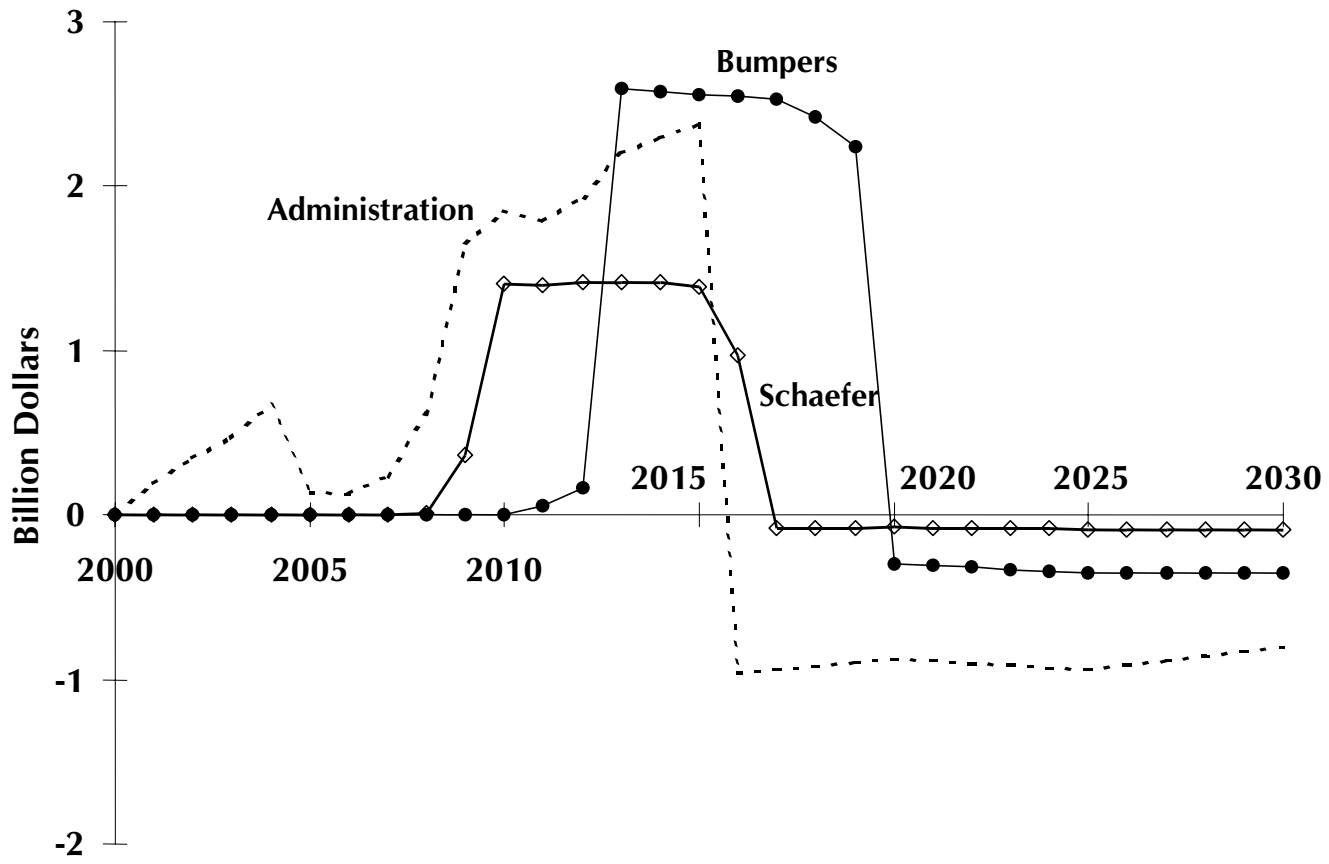
Key Impacts of the Schaefer and Bumpers RPS Proposals. Our analysis indicates that little new renewable generation is needed over baseline projections to meet the Schaefer and Bumpers RPS targets, as existing renewable generation and new renewables installed in the base case receive a large share of the available credits under both bills. In fact, no additional renewable generation above the base case is needed to meet the Schaefer targets until 2008 and the Bumpers targets until 2011. The Schaefer bill would provide a 13 percent increase in renewable generation in 2010, while the Bumpers bill would provide a 28 percent increase in 2013. Most of the new generation needed to meet the Schaefer and Bumpers targets comes from biomass cofiring, and small amounts of wind and geothermal. At a minimum, these proposals would preserve the existing and new renewables projected under the base case that are potentially at risk due to electricity restructuring.

The most obvious reason why the Schaefer RPS results in such a small amount of additional renewable generation is that the targets are the lowest of all the proposals. Another reason is that existing generation from municipal solid waste (MSW) incineration, which is eligible under both the Schaefer and Bumpers bills but not under the other bills, accounts for 15 percent of the credits needed to meet the Schaefer targets in 2010.

In addition to including MSW, there are two main reasons why the Bumpers targets result in little new renewable generation above the base case. First, low-cost generation from existing hydropower facilities literally "swamp" the credit market. While Bumpers attempts to limit the amount of income large hydropower facilities (80 MW and above) can receive by giving them only a half credit for each unit of electricity generated, hydro still receives enough credits to exceed the Bumpers targets between 2003 and 2007, 57 percent of the required credits in 2008 and 40 percent of the required credits in 2013.[30] This does

[30] Hydropower facilities of 80 MW and above accounted for about 76 percent of the total hydro generation in 1995, according to information submitted by electric utilities to the Energy Information Administration (Form EIA-759: Monthly Power Plant Report and Form EIA-860: Annual Electric Generator Report). Both our model and NEMS fix hydropower and MSW capacity and generation at 1996 levels, except for

Figure 16. Net Cost of Bumpers, Schaefer, and Administration RPS Proposals



not include hydropower generated in Canada, which could be sold in the United States and further swamp the US credit market, unless prohibited in the legislation. Second, eligible new renewable generation is entitled to receive two credits for each unit of electricity generated, which effectively cuts in half the amount of new generation needed to meet the target.

Our analysis indicates that hydro and MSW facilities (as well as industrial biomass cogeneration) do not need additional income to continue operating. Therefore, setting higher targets to accommodate these facilities *and* to ensure that new renewable generation is developed raises the cost of meeting the RPS targets unnecessarily since all eligible renewable generation would receive income from the sale of renewable credits. This explains why the Bumpers proposal costs slightly more than the Administration proposal, as shown in figure 16, despite the fact that the Administration's targets results in two and a half times more renewable generation above the baseline than the Bumpers targets. The Bumpers and Schaefer proposals also result in much lower gas savings because only a small amount new gas generation is being displaced.

Costs fall to zero under both proposals immediately after each RPS sunsets. Like the Administration proposal, the sunset provision in the Schaefer and Bumpers proposals would artificially force credit prices to fall to zero. However, our model projects that credit prices would be zero by this time anyway because of the small amount of new renewable generation needed to meet the targets.

The Schaefer and Bumpers proposals also result in the lowest CO_2 savings and the highest cost per ton of CO_2 reduced of all the proposals. The Schaefer targets lower CO_2 emissions by a maximum of

a small amount of planned MSW capacity addition. We assume that environmental and relicensing constraints would limit new hydropower development. In reality, hydropower and MSW capacity could increase in response to the RPS, but a large increase is unlikely.

0.5 percent in 2010 at a cost of $49/ton of CO_2 reduced. The Bumpers targets reduce CO_2 emissions by a maximum of 1.2 percent at a cost of $42 per ton of CO_2 reduced. This modest reduction and high cost compared with the other RPS proposals occur because the existing renewables and new renewables installed under the base case receive credits and add to the cost of the RPS, but do not result in additional CO_2 reductions.

Comparison with Other Studies. In this section we compare our results to five studies completed in 1997 and 1998 that analyzed the impacts of a national RPS. These studies include

- Two analyses by the Tellus Institute—one of the Schaefer proposal and the other of an RPS equivalent to the Markey proposal.[31]
- An analysis by the US Department of Energy (DOE) that modeled the Administration's RPS proposal as part of a comprehensive assessment of the Administration's electricity restructuring bill.[32]
- An analysis by the Energy Information Administration (EIA) for Senator Jeffords of an RPS gradually increasing to 10 percent in 2010 and remaining constant in subsequent years.[33]
- *Energy Innovations*—a study by UCS and others, which modeled an RPS of 10 percent in 2010 as part of a comprehensive set of policies to achieve a 10 percent reduction in carbon emissions below 1990 levels. This analysis was updated by the Tellus Institute and the World Wildlife Fund in a 1998 study *Policies and Measures to Reduce CO_2 in the United States: An Analysis of Options Through 2010*.[34]

Table 3. Comparison of the Nonhydro Renewable Share of Total Generation under Base Case Projections

	2000	2010	2020
UCS	2.9%	3.2%	4.1%
DOE	2.8%	2.7%	n.a.
EIA—*AEO 98* Reference	2.7%	2.6%	2.5%
Energy Innovations	1.8%	2.6%	n.a.
Tellus	1.9%	2.4%	n.a.

Because the information available from these studies varies considerably, a detailed comparison of these studies was not possible. Where information is available, we summarize the results of each study as well as the key similarities and differences in the assumptions and methods used to derive the results. In particular, we compare results for renewable energy credit prices, electricity and natural gas price impacts, CO_2 emission levels and reductions, and the cost per ton of reduced CO_2.

One important similarity between these studies is that they all used the National Energy Modeling System (NEMS) or RenewMarket, which was patterned on the Electricity Capacity Planning module of NEMS. However, while the basic modeling framework of NEMS did not change significantly, a number of key assumptions did change under the different studies; these changes affect the relative cost and market share of renewable technologies.[35] These assumptions include fossil-fuel price projections,

[31] Steve Bernow, William Dougherty, and Max Duckworth, "Quantifying the Impacts of a National, Tradable Renewables Portfolio Standard, "*The Electricity Journal*. 10 (4): 42–52, May 1997. The same authors analyzed the Schaefer and Markey targets, as well as an RPS of 8 percent in 2010, in "Analysis of Renewable Portfolio Standards," prepared for the American Wind Energy Association's *Windpower '97* Conference, June 1997.

[32] US Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis and Office of Policy and International Affairs, *Comprehensive Electricity Competition Act: Supporting Analysis*, July 1998. On line at www.doe.gov/ceca/ceca.htm.

[33] Energy Information Administration, Office of Integrated Analysis and Forecasting, *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997* (SR/OIAF/98-01), February 1998. Senator Jeffords asked the EIA to model this RPS target, instead of increasing the target to 20 percent as proposed in the bill. EIA also analyzed two additional RPS targets of 5 percent and 10 percent of total generation in 2020 for *Annual Energy Outlook—1998*. On line at www.eia.doe.gov/oiaf/aeo.html. We do not include the results from this analysis because the targets are different from the targets modeled in our study.

[34] Alliance to Save Energy, American Council for an Energy Efficient Economy, Natural Resources Defense Council, Tellus Institute, and Union of Concerned Scientists, *Energy Innovations: A Prosperous Path to a Clean Environment*, Washington, D.C.: Alliance to Save Energy, 1997. On line at www.ucsusa.org/cgi-bin/AT-ucssearch.cgi. A more detailed comparison of these and other studies is presented in *A Small Price to Pay: US Action to Curb Global Warming Is Feasible and Affordable*, prepared by UCS and the Tellus Institute, July 1998.

[35] EIA's analysis used the *AEO 98* version of NEMS, while the DOE's analysis used the AEO 97 version along with another model, and *Energy Innovations* and the Tellus analysis used the AEO 96 version. Our model, RenewMarket, adopted many of the assumptions from *AEO 98* .

technology costs, financing costs, technology learning curves, and renewable resource costs and supply constraints. Furthermore, the studies often replaced or supplemented the NEMS assumptions with outside assumptions, as well as using other models and methods in conjunction with NEMS to calculate the impacts of an RPS. We created the RenewMarket model precisely for this reason—to allow us to better understand the impacts of an RPS under a range of assumptions.

The studies also evaluate somewhat different RPS designs. *Energy Innovations*, the Tellus analyses, and our analysis of the Schaefer and Markey proposals place the requirement on all generators; the UCS and DOE analyses of the Administration proposal place the requirement on retail electricity providers; and the EIA analysis places the requirement on all generators except hydropower facilities. Furthermore, electricity generation from municipal solid waste facilities is eligible under the RPSs modeled in *Energy Innovations*, the Tellus studies, and the UCS analysis of the Schaefer proposal, but not the EIA and DOE studies or the UCS analyses of the Administration and Markey RPS proposals. In addition, instead of modeling credit trading like the other studies, *Energy Innovations* modeled a hybrid RPS/public benefits fund, in which funds were assumed to be collected from consumers through a charge of 0.2c/kWh on all electricity sales. These funds would be used to buy down the capital cost of renewable technologies to a level competitive with the least expensive conventional generating option in the year of installation to meet the RPS target. The study also assumed that no single renewable technology could capture more than half of the total market share.

Base case projections. Much of the difference in projected impacts is attributable to differences in base case projections. In general, a higher level of renewable generation projected to be economically viable in the base case is likely to result in lower costs in the RPS runs, as less additional renewable generation is needed to meet a given target. A higher level of renewable generation in the base case may also result in fewer emission reductions in the RPS runs, but it depends on which resources the renewables displace, since the carbon content of coal is about twice as high as that of natural gas. Furthermore, differences in energy price projections, economic growth rates, and other key variables will affect the level of generation and carbon emissions projected under the base case.

Our analysis projects that nonhydro renewable generation will represent a higher and growing share of total generation under the base case than all of the other RPS studies, as shown in table 3. There are two main reasons for this. First, our analysis includes biomass electricity generated by businesses for their own use (self-generation or cogeneration), which adds about 1 percent to the renewable share of total generation. This is also included in the EIA and DOE base case projections, but not in the Tellus and *Energy Innovations* analyses, which explains the differences in the projected renewable share in 2000.

Second, our analysis assumes a lower cost and higher performance for renewable technologies than the other studies, which explains why the share of renewable generation grows at a faster rate over time than the other studies. As explained in the *Assumptions* section, our assumptions for renewable technologies were taken from a recent comprehensive analysis by the Electric Power Research Institute (EPRI) and the US Department of Energy. EIA completed an alternative reference case run for *AEO 98* called the "high renewable energy case," which also used the EPRI/DOE assumptions. For comparison, the high renewables case projected the renewable share of total generation would increase from 2.7 percent in 2000 to 3.7 percent in 2010 and 6 percent in 2020. Thus, our projection falls in between the two EIA projections.

Electricity and natural gas price impacts. A comparison of renewable energy credit prices, and the change in average electricity prices and natural gas prices for electricity generators for the RPS studies is shown in table 4.

The studies project similar credit prices despite using different methods. The reason our analysis predicts slightly higher credit prices under the 10 percent RPS case is because we assume that renewable developers will adjust their credit prices according to their expectation of future income from credit sales (see *Methods* chapter). Consequently, under the Markey RPS proposal, credit prices tend to rise fairly quickly around 2010 as the target reaches its maximum level and then fall quickly after the target levels off (see figure 6 above). We assume that developers will need to charge higher prices before the target levels off to ensure that they will recover their above market costs in anticipation of the drop in credit prices after 2010. In contrast, under our analysis of the Jeffords RPS proposal, which also reaches 10 percent in 2010, we project the credit price to be about 1.4 cents per kilowatt-hour or less than half as much as the Markey proposal (see figure 6 above). The credit price is lower and more stable under the Jeffords proposal because the target continues to increase gradually after 2010, so renewable developers can expect additional income in the future. Furthermore, we assume that developers will spread their costs of period of seven years to reduce the impact to consumers that might occur from unusually high prices in certain years.

All of the other studies, except *Energy Innovations*, calculate credit prices based on the annualized (or levelized) incremental cost needed over the life of renewable technologies (usually 30 years) installed in a particular year to meet the RPS target. This price is likely to differ from the actual credit-trading price, which should equal the value the market places on the last kilowatt-hour of renewable generation required to meet the target in a single year. Furthermore, this approach does not reflect the likely volatility in credit prices or the fact that developers are likely to need to recover their costs more quickly than over the life of the facility. The EIA study does attempt to account for some of the change in credit prices over time by using a five-year rolling average of levelized credit prices.[36]

The studies also predict a similar change in average electricity prices relative to the base case for each RPS target, despite using different methods for calculating the costs. The slightly higher price in our study for the Markey RPS of 10 percent in 2010 is largely due to the method used for calculating credit prices discussed above. For comparison, our analysis of the Jeffords proposal shows a 0.11 c/kWh increase in average electricity prices relative to base case projections to reach the 10 percent target, because of lower credit prices in 2010 compared to the Markey proposal.

In addition, the UCS, EIA and DOE studies all use a marginal cost approach, in which the most expensive unit needed to meet a given RPS target sets the price for all renewable generation. This approach reflects how renewable energy credits and electricity generation would be priced under a competitive market and is similar to the way sulfur dioxide emission allowances are currently traded.

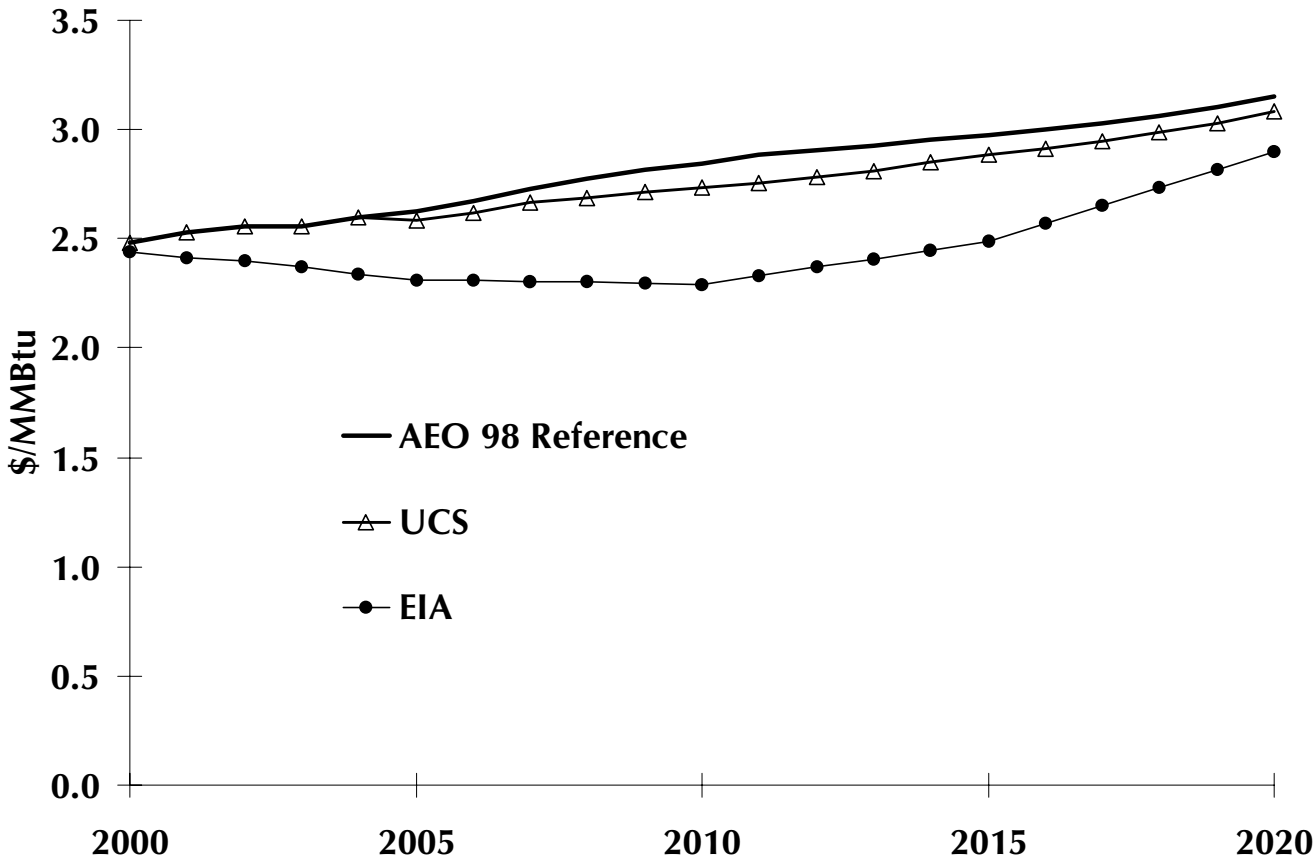
Table 4. Renewable Energy Credit Prices and Electricity and Natural Gas Price Impacts in 2010 for Six RPS Studies

RPS Target and Study	Renewable energy credit price (¢/kWh)	Increase in average electricity prices (¢/kWh)	Reduction in generator natural gas prices ($/MMBtu)
4% in 2010			
UCS	1.01	0.04	0.003
Tellus	1.03	0.03	n.a.
5.5% in 2010			
UCS	1.5	0.07	0.05
DOE	n.a.	0.10	0.08
10% in 2010			
UCS-Markey	3.1	0.28	0.11
UCS-Jeffords	1.4	0.11	0.10
EIA	2.5	0.25	0.46
Tellus	2.6	0.26	n.a.
Energy Innovations	n.a.	0.20	n.a.

¢/kWh = cents per kilowatt-hour
MMBtu = Million British Thermal Units
n.a. = not available.

[36] Personal communication with Peter Whitman, Energy Information Administration, July 15, 1998.

Figure 17. Electricity Generator Gas Prices Under an RPS of 10% in 2010



While the Tellus analyses also use a marginal cost approach to calculate the renewable energy credit price, they do not multiply this value by the total renewable generation needed to meet the RPS target to get the total marginal costs. Instead, they calculate the net resource costs of the RPS, which reflects the incremental capital and operating costs of building the renewable facilities instead of conventional generating plants under traditional utility accounting practices. This method is a more accurate reflection of the actual incremental cost of renewables because it removes the transfer payments from consumers to renewable developers for plants that cost less to operate than the most expensive unit. However, it also underestimates the actual costs that consumers are likely to pay under a national RPS with credit trading. Our model, which is capable of calculating costs using either method, indicates that marginal costs are roughly 2 to 5 times higher on average than net resource costs.

Another factor that may contribute to the slightly lower electricity price impact in the EIA analysis is that it projects a much larger decline in natural gas prices to electricity generators than our results, as shown in table 4 and figure 17. This is because renewables displace more new natural gas generation and less coal generation in the EIA study. The main reason our analysis shows greater coal displacement is because we include biomass cofiring in existing coal plants as a technology option in our model, while the other studies do not. The DOE study also predicts a slightly larger reduction in generator gas prices and gas use than our study. Tellus and *Energy Innovations* did not model this effect.

The EIA analysis also showed average electricity prices falling 17 percent between 1996 and 2020, compared with 20 percent in the base case. As a result, annual electricity expenditures were $10.6 billion higher than the base case in 2020. However, closer examination of the results shows that the

slightly higher electricity prices under the RPS reduced the projected demand for electricity, which lowered the cost to $7.1 billion. Furthermore, the results of the analysis showed lower natural gas prices for all consumers, which reduced consumer natural gas costs by $5.7 billion in 2020. Including these effects reduced the net cost of the RPS to $1.8 billion in 2020 and actually produced a net savings of $1.8 billion in 2010.[37]

Carbon dioxide emission reductions. A comparison of electricity sector carbon dioxide (CO_2) emissions levels and reductions in 2010 for the RPS studies is shown in table 5. Compared with the Tellus, DOE and EIA studies, our results show slightly lower overall CO_2 emissions levels, despite fewer CO_2 emission reductions. There are two main reasons for this. First, we project a higher level of renewables in our base case, which reduces overall emission levels in the base case and results in fewer emission reductions in the RPS cases. Second, our analysis shows a smaller displacement of natural gas and a larger displacement of coal—which has a higher carbon content per unit of electricity generated than natural gas—than the other studies.

Energy Innovations has the lowest CO_2 reductions and the lowest electricity sector CO_2 emissions because this study used an earlier version of NEMS that had a different base case projection with lower economic growth, electricity sales, and renewable generation needed to meet the target. The Tellus study also used this version of NEMS, which could explain its slightly lower emission reductions.

The EIA and DOE studies also found that an RPS would reduce nitrogen oxide (NO_x) emissions in the electricity sector. EIA predicted NO_x emissions reductions of 530,000 tons or 8 percent below 2020 levels, while the DOE analysis projected NO_x emissions to fall 230,000 tons or 4 percent below the baseline levels in 2010.

Table 5. Comparison of Electricity Sector CO_2 Emission Levels and Reductions in 2010 for Six RPS Studies

RPS Target and Study	CO_2 emission level in 2010 (MMT)	CO_2 emission reductions in 2010 (MMT)	(%)
4% in 2010			
UCS	2,321	12	0.5
Tellus	n.a.	33	n.a.
5.5% in 2010			
UCS	2,273	59	2.5
DOE	2,328	92	3.8
10% in 2010			
UCS-Markey	2,135	197	8
EIA	2,191	231	10
Tellus	n.a.	161	n.a.
Energy Innovations	1,987	140	7

MMT = Million Metric Tons
n.a. = not available

Cost of carbon dioxide reduced. The cost per ton of CO_2 reduced with and without consumer natural gas savings is shown in table 6 for the 10 percent RPS case. For our analysis, the cost of CO_2 reduced is calculated by dividing the present value increase in electricity costs relative to the base case between 2000 and 2030, by the present value of CO_2 savings over the same period. This was calculated in the same fashion in the EIA study between 2000 and 2020[38] and in *Energy Innovations* and the Tellus analysis between 2000 and 2010.

We show slightly higher costs per ton of CO_2 reduced under the Markey RPS than the Tellus analyses and *Policies and Measures* when natural gas savings to consumers are not included, mainly because of differences in the way credit prices and the costs of

[37] While the EIA analysis did project a $16 billion decline in revenue to the natural gas industry in 2010 relative to the reference case, it does not explain that a large portion of these lower revenues were due to lower gas prices for electric generators and consumers because of renewables displacing gas for electricity generation under the RPS. Gas savings to consumers and the effect on electricity sales from higher electricity prices under the RPS were not quantified in the EIA report. We calculated these impacts using the detailed results of EIA's analysis generated with the National Energy Modeling System (NEMS) and provided to us by EIA staff.

[38] Costs and CO_2 reductions were extrapolated linearly between five year increments for the EIA analysis.

the RPS are calculated as described above. Our projected cost per ton of CO_2 reduced is slightly higher under the Markey RPS than the EIA analysis because we capture a larger portion of the costs of meeting the RPS earlier in the forecast period and because the EIA analysis projects much higher gas savings for electricity generators, which offsets some of the increase in electricity prices relative to the reference case. The impact of lower gas prices to electricity generators is evident in the Jeffords RPS proposal of 20 percent in 2020, which projects a cost of $29 per ton of saved CO_2 reduced without including consumer gas savings.

When natural gas savings to consumers are included, the cost of reduced CO_2, falls by a large amount in the EIA and UCS analyses. Only our study explicitly included the benefit of lower gas prices for electricity generators and consumers in reducing the cost of the RPS. Our analysis shows that the net cost of the Jeffords RPS proposal drops to $18 per ton when consumer gas savings are included.

All of the RPS analyses predict relatively low costs of reducing CO_2 compared with some recent studies by industry, government and nongovernmental energy research organizations. The projected cost of $2-$34 per ton of CO_2 reduced for the RPS studies is lower than the most expensive measures needed to meet or exceed the Kyoto targets of reducing US CO_2 emissions 7 percent below 1990 levels in *Energy Innovations* and *Policies and Measures*.

And it is significantly lower than the costs projected in industry and government studies that argue that Kyoto compliance will be cost prohibitive. A recent study by EIA claims that it will cost $95 per ton of CO_2 ($348 per metric ton of carbon) to reduce CO_2 emissions 7 percent below 1990 levels, based only on domestic actions.[39] Even at this relatively high cost, the EIA's Kyoto study projects that nonhydro renewable generation would provide only 5.3 percent of total US generation in 2010, and 14 percent in 2020. This result is inconsistent with their RPS analysis, which shows that nonhydro renewables can provide 10 percent of the nation's electricity in 2010 for a much lower cost.

[39] Energy Information Administration, *Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity*, October 9, 1998. On line at www.eia.doe.gov/oiaf/kyoto/kyotorpt.html)

Table 6. The Cost of CO_2 Reduced, Under an RPS of 10 percent in 2010

RPS Target and Study	Cost of saved CO_2 without consumer natural gas savings[a]	Cost of saved CO_2 with consumer natural gas savings
	($ per ton)	
UCS-Markey	34	25
UCS-Jeffords*	29	18
EIA	32	2
Tellus	30	n.a.
Policies and Measures	26	n.a.

*The Jeffords RPS continues to increase one percent per year after 2010 to 20 percent in 2020.

[a] Includes natural gas savings to electric generators.

EIA's Kyoto study also compares its results with six other studies funded by the fossil fuel and electric power industries as well as other government agencies and research organizations.[40] These predict costs ranging from $60 to $80 per ton CO_2 reduced ($221 to $295 per metric ton of carbon). All of these studies assume the equivalent of a carbon tax, imposed at these levels, will be needed to meet the Kyoto targets. And few analyze specific policies for achieving the targets and overcoming market barriers to encourage the development of energy-efficient and low-carbon technologies.

Our RPS analysis as well as EIA's own RPS analysis and the other studies reviewed above clearly show that an RPS is a relatively inexpensive domestic policy for helping the United States meet the Kyoto targets. Furthermore, none of the projected costs of reduced CO_2 consider the cobenefits society would reap from lowering emissions that cause acid rain, smog, and respiratory problems.

[40] These studies were conducted by Wharton Econometrics Forecasting Associates, and funded by the American Petroleum Institute, the Electric Power Research Institute, Charles River Associates, the Massachusetts Institute of Technology, the Pacific Northwest National Laboratory, and Data Resources Inc. See the EIA report for references and a more thorough review of the studies.

Conclusions

Our analysis clearly shows that creating a minimum national standard for clean electricity generated from renewable resources is an effective way to capture some of the public benefits of renewables that are currently not reflected in energy prices. As electricity generation becomes increasingly competitive and greater emphasis is placed on short-term prices, an RPS will be especially important for capturing the long-term environmental and economic benefits of renewables.

Meeting a national renewables target of up to 20 percent in 2020 as proposed by Congress would accomplish the following:

- **Provide considerable environmental benefits**. By displacing fossil fuels, renewables would help the United States meet its commitment to reduce heat-trapping gases and other pollutants that harm the environment and human health. An aggressive renewables target that increases about 1 percent each year to 20 percent in 2020 would be needed to eliminate the growth in CO_2 emissions in the electricity sector and reduce coal generation below current levels.
- **Reduce CO_2 emissions at a low cost**. Our analysis clearly shows that renewables can reduce CO_2 emissions at a much lower cost than indicated in some recent studies funded by the fossil-fuel and electric power industries, government and non-governmental energy research organizations. These studies predict that reducing CO_2 emissions 7 percent below 1990 levels, as specified in the Kyoto Protocol, will cost between $60 and $95 per ton of CO_2 reduced through domestic actions only. Our analysis, which indicates that the United States could achieve a renewables target of 20 percent in 2020 at a cost of $18 per ton of CO_2 reduced, shows that an RPS is a relatively inexpensive domestic policy for helping the United States meet the Kyoto targets. Furthermore, these cost projections do not take into account the considerable cobenefits society would reap from lowering emissions that cause acid rain, smog and respiratory problems.
- **Diversify the nation's electricity mix.** Under the RPS proposals, nonhydro renewable resources would provide up to five times more electricity than the projected business-as-usual levels. Biomass, wind and geothermal would provide the vast majority of the total renewable generation. Solar and landfill methane would also experience significant growth, but provide a relatively small share of total generation. Greater fuel diversity from a variety of renewable technologies would help insulate the US economy from fossil-fuel price increases and supply shortages. It would also provide an important opportunity for the United States to build a strong domestic renewable energy industry with a large export potential, while creating jobs in high-tech industries and rural economies.
- **Expand renewable energy development throughout the nation.** Current nonhydro renewable energy generation in the United States is concentrated in California, the Northeast, and the Southeast. As the RPS targets increase, renewable energy development will spread across the United States, and particularly in the Great Plains, Western, and Mid-Atlantic states.
- **Have only a modest impact on electricity prices**. Average electricity prices are projected to fall 13 to 17 percent between 1997 and 2020 under the RPS proposals, compared with an 18 percent decline without an RPS. According to the results of national polls, most households would be willing to pay more than $2 extra per month for renewables, and would thus appear willing to support a renewables target of 20 percent in 2020. Furthermore, the incremental cost of meeting the renewables targets falls over time as the costs of renewable technologies decline through mass production and improved performance.

[41] See Energy Information Administration, Office of Integrated Analysis and Forecasting, *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997*, SR/OIAF/98-01, February 1998.

- **Lower natural gas prices**. By displacing some of the projected growth in natural gas use for generating electricity, renewables would put competitive pressure on fossil-fuel prices and reduce the projected growth in natural gas prices for all gas consumers. For the over 50 percent of households that heat with natural gas, gas savings completely offset the slightly higher electricity costs over time. Industry, which consumed 40 percent of all the natural gas used in 1996, would also reap significant savings. Even with an aggressive renewables target of 20 percent in 2020, however, total natural gas generation would still nearly quadruple from 1997 levels.

The results of our analysis also provide the following important insights into designing an effective RPS policy:

- To maximize the development of a diverse mix of new renewable technologies, to achieve a greater regional distribution of development, and to produce meaningful environmental improvement, RPS targets should be set near the high end of the range of proposals studied.
- To provide a stable and predictable market for renewable developers, reduce potential price volatility, and eliminate the need for a cost cap, the RPS targets should increase gradually over a long period of time.
- If a cost cap is desired, it should be set just above the expected market price of renewable energy credits. A cap that is set too low can result in a shortage of renewable generation relative to the target, increase administrative costs, and reduce market efficiencies.
- To encourage the development of new renewable technologies, existing hydropower and municipal solid waste incineration should not be eligible for credits under an RPS. Our analysis indicates that these facilities do not need additional income to continue operating. Including them in the RPS therefore raises its costs unnecessarily, limits the participation of emerging renewable technologies with a greater potential for cost reductions, and produces no environmental benefits.

If anything, the actual cost of the RPS is likely to be less than our analysis indicates. First, if designed right, an RPS would provide a stable market for renewable technologies, which could lower financing costs. Second, the historical record of forecasting fossil fuel prices shows that most such forecasts have been wrong. With higher fuel prices, renewables would be even more valuable, ensuring that there will be a ready supply of advanced technologies not subject to fossil-fuel price escalation. Third, our analysis does not include the benefits renewables provide in reducing the environmental and other societal costs of fossil fuels and nuclear power that are not reflected in energy prices.

Ideally, the RPS would be combined with other renewable energy and energy efficiency policies that have been enacted in a number of states and proposed at the federal level. For example, renewable energy funds could be used to lower the costs and encourage the development of emerging technologies like photovoltaics, which participate at relatively low levels under an RPS. Requiring electricity providers to disclose their fuel sources and emissions on electricity bills—like nutrition labels—would allow consumers to make an informed decision about purchasing cleaner electricity. Requiring all power plants to meet the same emission standards would put renewables on a more equal footing with fossil fuels. Allowing customers who own renewable technologies to sell any excess electricity generated back to their electricity providers at a fair rate, would encourage the development of small generation, increase the reliability of the electricity system and reduce the need for costly investments in power lines. Furthermore, enacting rules that would allow renewable generators equal access to the transmission system would also facilitate the development of renewables under an RPS.

Congress has a powerful opportunity for making clean electricity the standard in the US. By insuring that a gradually increasing share of the nation's electricity comes from renewable energy, a renewable portfolio standard would help establish a viable market for America's renewable energy industries and place the nation on course toward a sustainable energy future.