2. Projected Effects of Electricity Competition

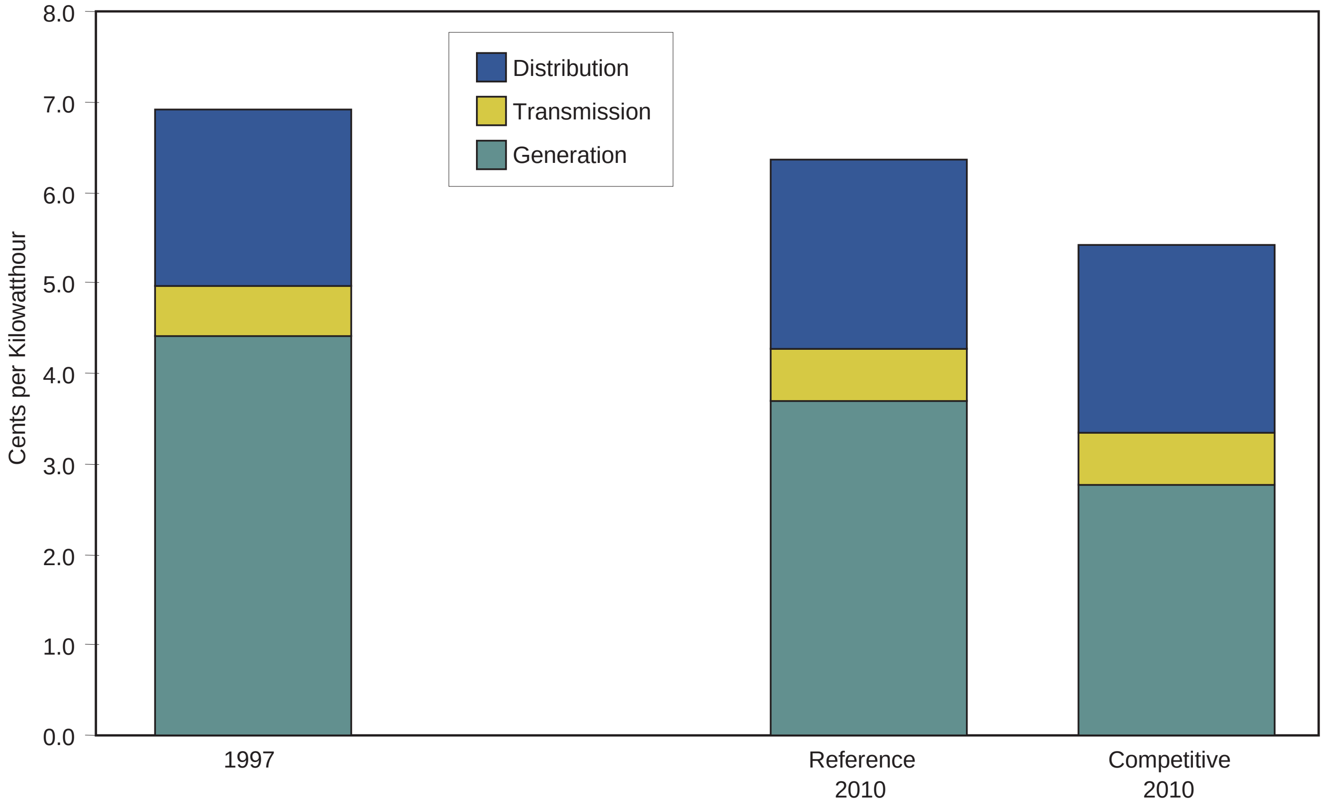
This chapter reviews the impacts of the Administration's electricity competition plan, using information derived from the Policy Office Electricity Modeling System (POEMS). It focuses on impacts of key interest to policymakers, such as effects on electricity prices, the fuel mix for electricity generation, environmental emissions, and benefits to rural communities. Appendix A includes detailed output tables for the Reference and Competitive scenarios that provide insights into some issues not explicitly addressed in this chapter.

Electricity Prices and Stranded Costs

The introduction of retail competition is projected to lead to lower electricity prices for consumers. In the Competitive Scenario, the costs of generating, transmitting, and distributing electricity are projected to decline relative to the Reference Scenario (Figure 4). Although the transmission and distribution segments will continue to be regulated, increased visibility and competitive pressures are expected to result in greater efficiencies and, therefore, lower costs. For example, costs for billing and metering activities may be reduced through contracting with more efficient providers or aggregating to achieve economies of scale.

Although electricity prices decline in both scenarios, the rate of decline is faster in the Competitive Scenario. In 1997, the national average delivered price was 6.9 cents per kilowatthour. With

Figure 4. Cost-of-Service and Competitive Electricity Prices
(1997 Cents per Kilowatthour)



Note: For the Competitive Scenario, the distribution component includes a recovery charge for net stranded generation assets.
Source: Office of Policy, U.S. Department of Energy, POEMS model analysis (May 1999).

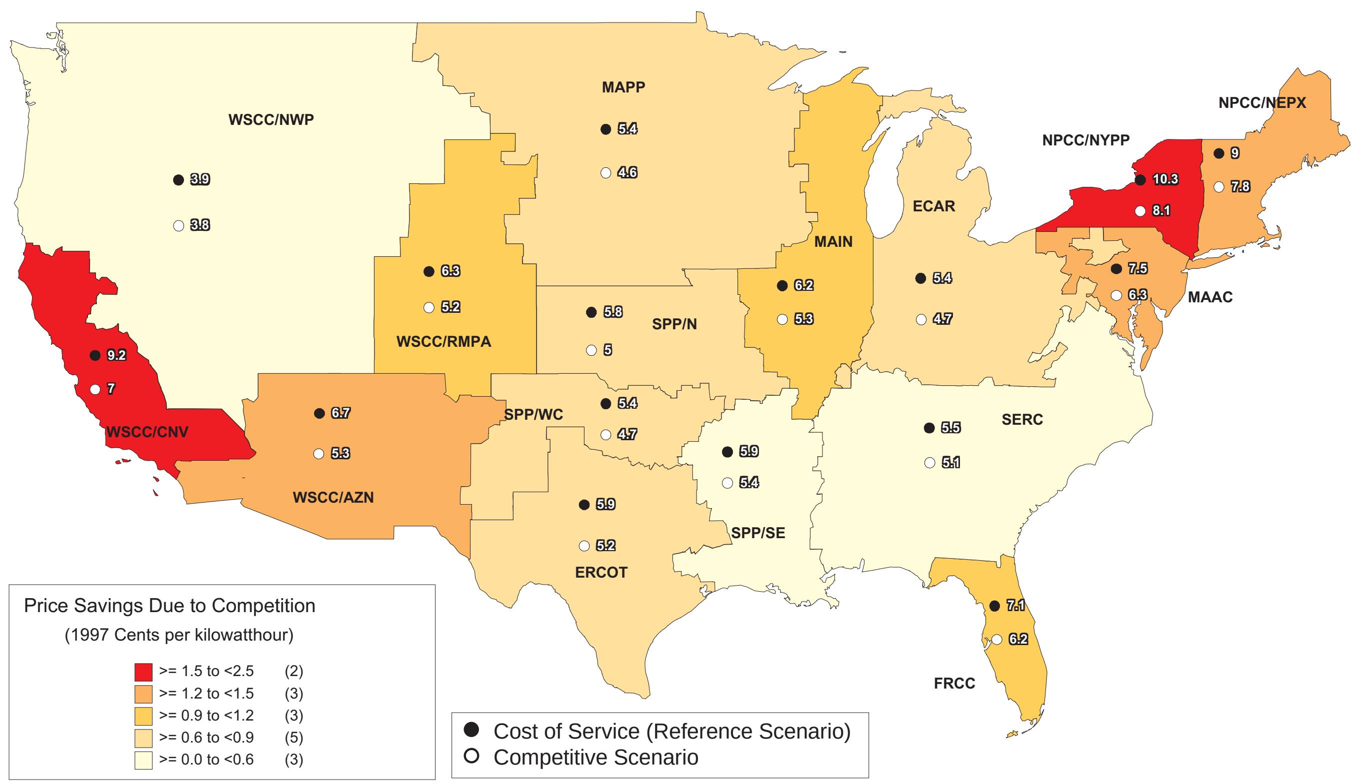
continued cost-of-service regulation, the price in 2010 is projected to be 6.3 cents per kilowatthour. The decline is the result of depreciation of existing high-cost plants, as well as the continued entrance of more efficient capacity. With retail competition, greater efficiencies and marginal-cost pricing lead to larger price reductions. The national average price is projected to be 5.5 cents per kilowatthour in 2010 in the Competitive Scenario, about 14 percent lower than in the Reference Scenario.

As shown in Figure 5, there is a wide range of projected prices with continued cost-of-service regulation, ranging from 3.9 cents per kilowatthour in the Pacific Northwest to 10.3 cents per kilowatthour in New York. With competition, the variation in price is likely to be smaller, ranging from 3.8 cents per kilowatthour in the Pacific Northwest to 8.1 cents per kilowatthour in New York.[6] Note that POEMS covers only the continental United States, so that the analysis presented in this report does not include projections for Alaska and Hawaii.

In general, the regions projected to have the highest prices under cost of service regulation are those that are likely to see the largest decrease in prices under competition. The remaining regional variation results from differences in fuel prices, operating costs, transmission costs, transmission constraints, distribution costs, and stranded costs. Differences in transmission and distribution costs are the most important factors.

Examining projected prices at the State level yields the same conclusion—that customers in almost all States are expected to see lower electricity prices under competition, as shown by the change in average price in Figure 6 (see also Appendix A). In three States with currently very low electricity prices (Oregon, Washington, and Montana) some

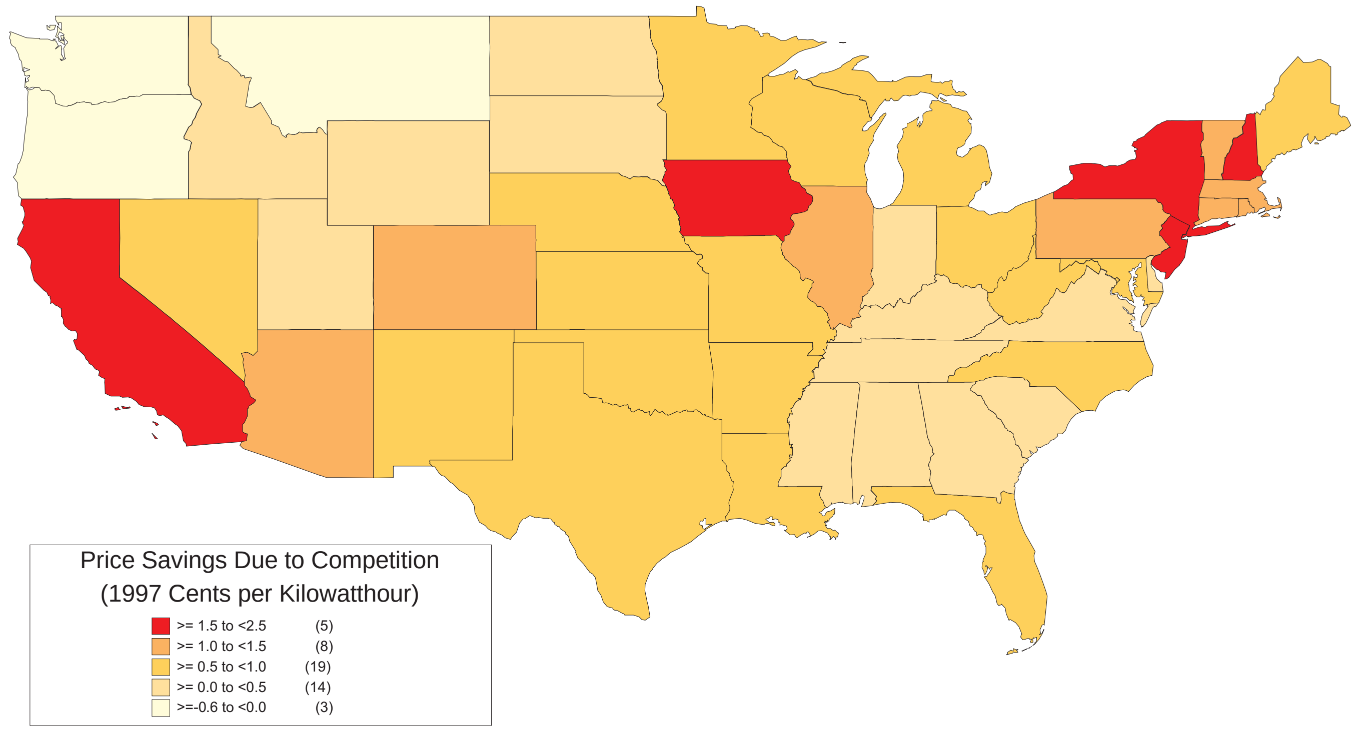
Figure 5. Projected Average Retail Electricity Prices in 2010
(1997 Cents per Kilowatthour)



Note: The Competitive Scenario reflects cost-of-service rates for Federal preference power customers.
Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

[6] Consistent with the Administration's proposed legislation, the Competitive Scenario maintains existing mechanisms for pricing and allocating power produced at Federal facilities.

Figure 6. Average Price Savings in the Competitive Scenario, 2010



Source: Office of Policy, U.S. Department of Energy, POEMS model analysis (May 1999).

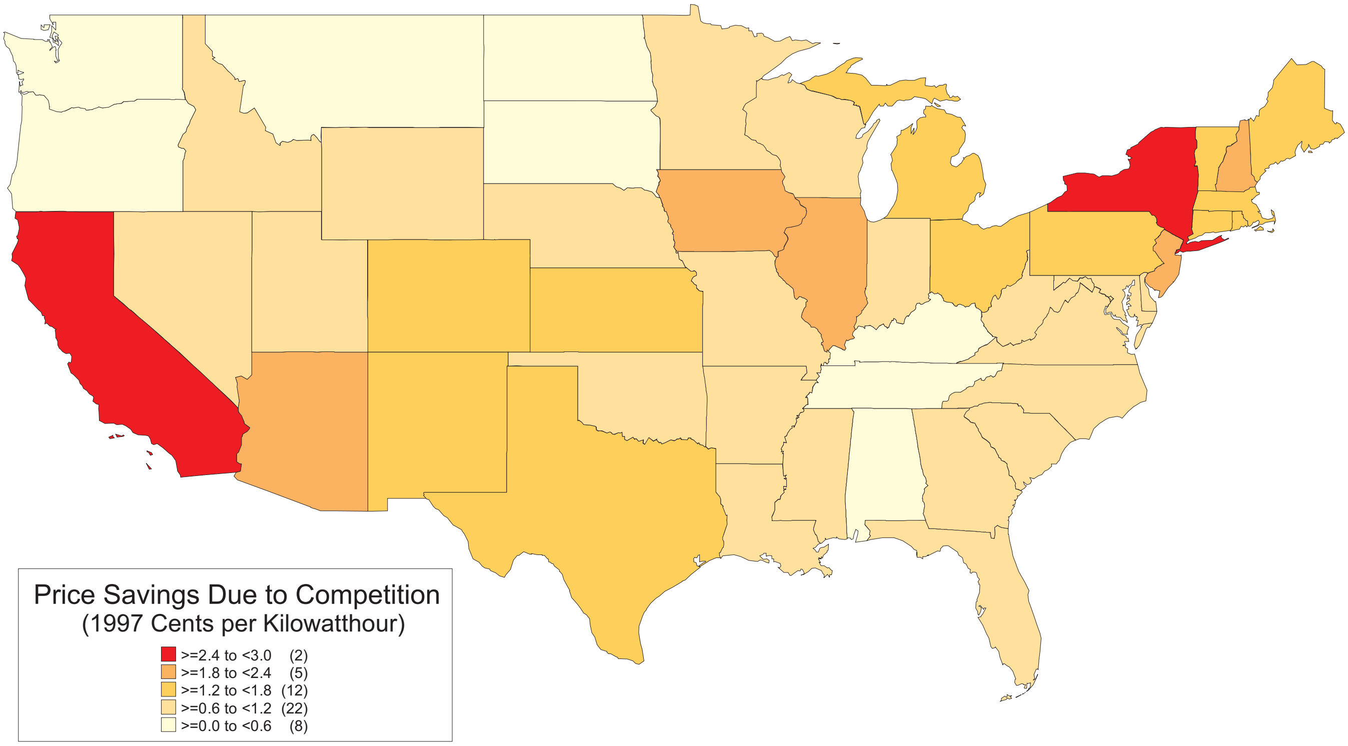
customers may pay higher prices under competition. As described below, however, residential customers are projected to benefit from larger than average price reductions because of the manner in which rates have been determined historically. Residential customers in all States are expected to experience savings (Figure 7). Not surprisingly, the States with some of the highest cost-of-service rates will reap the greatest benefits from competition, even though their geographic and other circumstances may lead them to continue to have prices higher than the national average.

Nationally, savings are projected for all classes of customers: residential, commercial, and industrial. A comparison of 2010 national cost-of-service and competitive rates by customer class is shown in Figure 8. Among customer classes in 2010, residential buyers are projected to see the largest price decreases with retail competition. In part, this is because historical capacity costs were allocated to customer classes on the basis of their contribution to peak demand. Residential customer demand tends to have more variation by time of day and season than industrial and commercial; therefore, it receives a relatively greater share of the costs under peak demand allocation than it would if costs were allocated on the basis of sales.

Although the energy costs associated with peak demands are generally high, the capital costs for peaking turbines are relatively low in comparison with those for baseload units. In the competitive market, higher marginal costs at peak periods will lead to higher average generation prices for residential customers than for customer classes with flatter load profiles, but the average premium will be less than under the typical method of allocating capital costs under cost-of-service regulation.

Total expenditures for electricity by all consumers are projected to be $240 billion in the Reference Scenario in 2010. In the Competitive Scenario, expenditures are projected to drop to $203 billion in 2010. Although most of the reduction is the result of lower electricity prices, a small portion is also the result of reduced purchases. Energy efficiency improvements and greater use of combined heat and

Figure 7. Residential Price Savings in the Competitive Scenario, 2010



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Figure 8. Electricity Prices by Customer Class, 2000-2015

Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

power technologies lower demands for centrally generated power. If only the price difference between the scenarios is considered at the Reference Scenario level of electricity demand, total savings in 2010 are $32 billion.

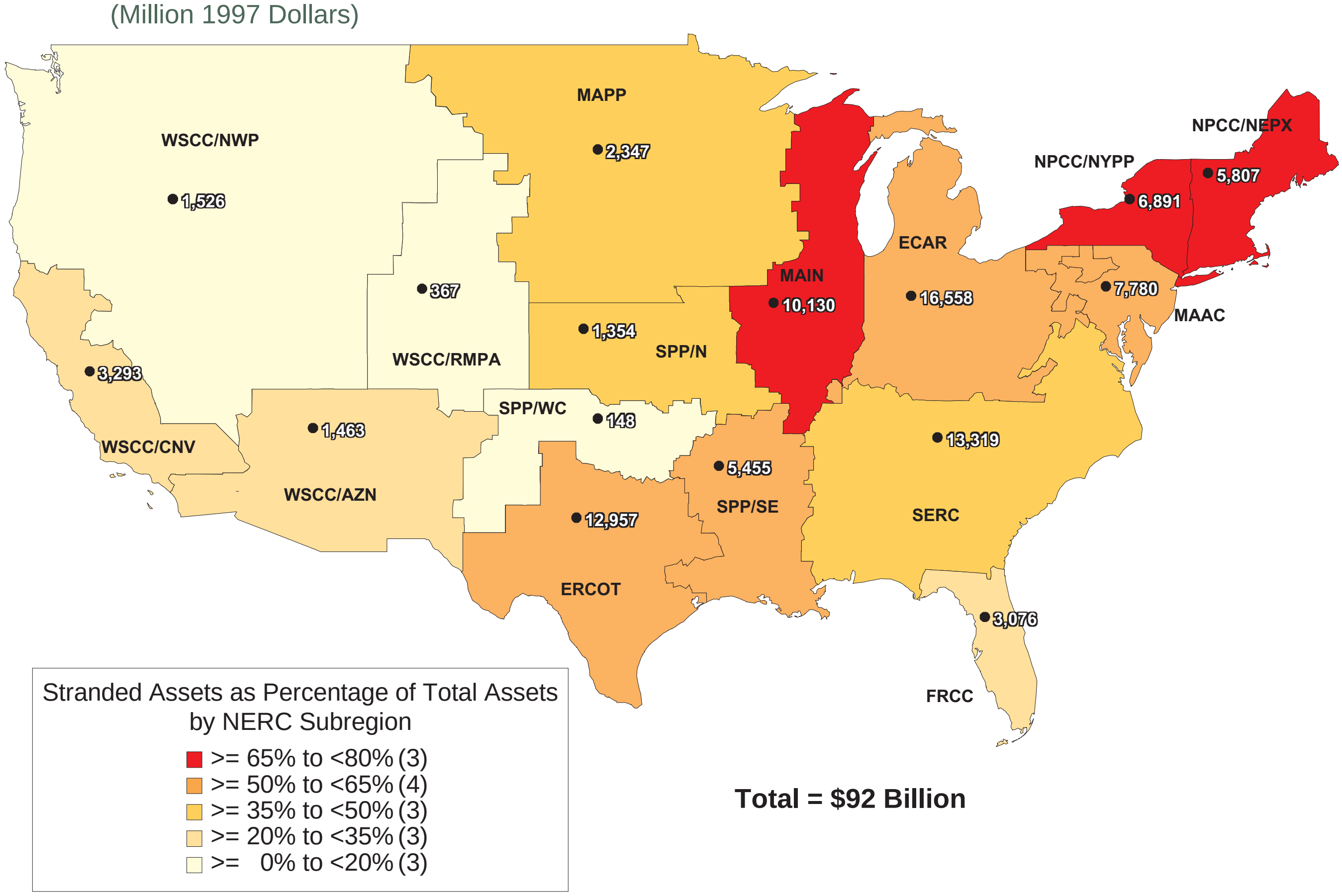
The competitive prices include the recovery of a projected $92 billion in stranded costs of generators (Figure 9) and flowback to consumers of $15 billion in surplus valuations for existing and productive generating assets. When stranded costs for existing and productive generating assets are recovered over a 10-year period, as described below, the national average additional charge to the average electricity price is 0.3 cents per kilowatthour in 2010. On a regional average basis, stranded cost recovery factors are projected to range from 0.02 to 0.5 cents per kilowatthour. Within regions, stranded cost recovery factors will vary across individual utilities because of differences in generating asset portfolios and price differences across power control areas. Similarly, the flowback to consumers of a portion of the surplus values for generating assets reduces prices by 0.03 cents per kilowatthour on average.

The Competitive Scenario also provides for recovery of regulatory assets and decommissioning costs. The pace of recovery in these categories for both scenarios reflects recent State-level practices, and it is assumed to be similar in the two scenarios. Provision for recovery of regulatory assets and decommissioning costs adds 0.1 cents per kilowatthour to the estimated national average price of electricity in 2010.

Electricity Demand

The Reference Scenario electricity demand forecast averages 1.5 percent growth annually from 1997 to 2010, reaching 3,794 billion kilowatthours in 2010. Several elements of the Act would affect the demand for electricity. Lower prices resulting from competition are likely to stimulate additional

Figure 9. Stranded Productive Generating Assets in the Competitive Scenario, 2000
(Million 1997 Dollars)



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

demand. The proposed provision for a Public Benefits Fund and the expectation that competition will spur efforts to package energy efficiency (and other energy service products) with power sales are projected to reduce demands. In addition, competitive markets— together with the provisions in the Bill that would provide interconnection standards and remove economic barriers—are projected to stimulate distributed generation by combined heat and power (CHP) facilities. A portion of the electricity generated from CHP facilities is assumed to be used internally and the remainder sold over the grid. The net result is slightly higher electricity demand in the near term and lower demand as the plan comes into full effect. In 2010, the projected demand for electricity purchased from distribution companies is 88 billion kilowatthours (2.3 percent) lower in the Competitive Scenario than in the Reference Scenario.

Generation Capacity

Most of the generation capacity used in 2010 will be capacity that exists today. As of December 31, 1997, net summer capability was 751 gigawatts,[7] and it is projected to increase to 823 gigawatts in the Reference Scenario by 2010. New additions make up only 27 percent of the projected total capacity in 2010. Currently, coal-fired plants account for the largest share of all capacity (42 percent). Other major types of capacity are oil- and gas-fired boilers (19 percent), nuclear (13 percent), hydroelectric (13 percent), and combustion turbines (8 percent). Combined-cycle plants and non-hydroelectric renewables have relatively small shares (4 percent and 1 percent, respectively). In the future, the generating mix is projected to shift toward gas turbine technologies and away from coal and nuclear plants.

In both the Reference and Competitive scenarios, the greatest share of new construction is projected to be natural-gas-fired plants, reflecting the combined effect of high efficiencies, short construction periods, modularity, and modest projected increases in natural gas prices. In the Reference Scenario, natural-gas-fired plants account for 90 percent of capacity additions between 1995 and 2010. Specifically, combined-cycle plants serving base or intermediate loads are projected to represent 49 percent of the new capacity additions from 1995 to 2010, with gas-fired combustion turbines that serve peaking requirements capturing an additional 41 percent of total capacity additions.

The most significant change in the mix of future generating capacity in the Competitive Scenario relative to the Reference Scenario is the increase in the share of renewable capacity (Figure 10) that results from both the renewable portfolio standard (RPS) included in the Administration's proposal and from consumers' interest in green power. Less capacity of other types of plants is needed as a result. However, much of the additional renewable capacity is intermittent. For example, wind turbines, which generate only when the wind is blowing, operate less than plants that can be reliably run 24 hours a day. As a result, much of the renewable capacity added receives only a partial credit toward meeting capacity requirements, leading to more installed capacity under the Administration's proposal than in the Reference Scenario, even though demand is slightly lower.

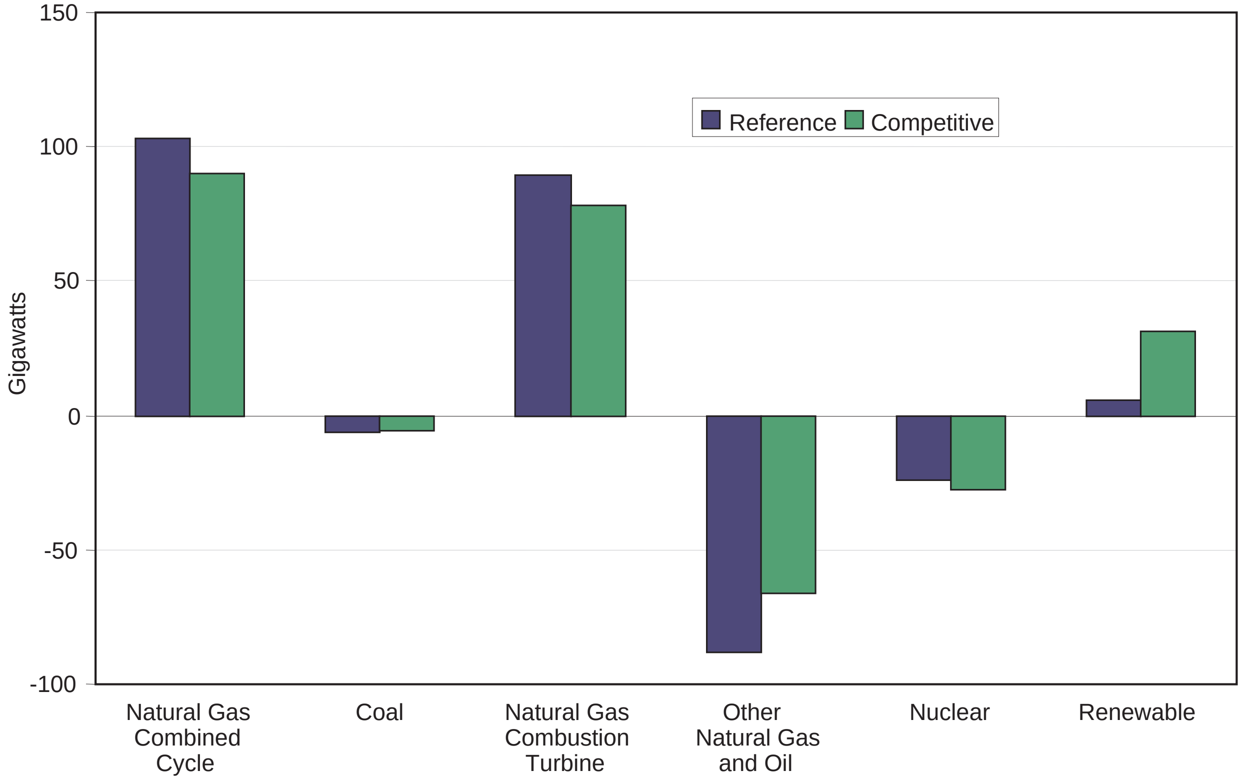
Electricity Generation

The differences in generation by fuel type across the Reference and Competitive scenarios (Figure 11) do not directly track the differences in capacity additions outlined above. Because competition will provide strong incentives to run low-cost plants more efficiently and to shorten scheduled outage periods, existing coal and nuclear plants are run more often in the Competitive Scenario.

The change in non-hydroelectric renewable generation under the Administration's proposal is significant (Figure 12). The renewables eligible to meet the requirements of the RPS include: solar thermal, photovoltaic, wind, biomass, landfill gas, other miscellaneous renewable sources, and the renewable share (61.4 percent) of electricity generation from municipal solid waste by electric utilities, independent power producers, and cogenerators.

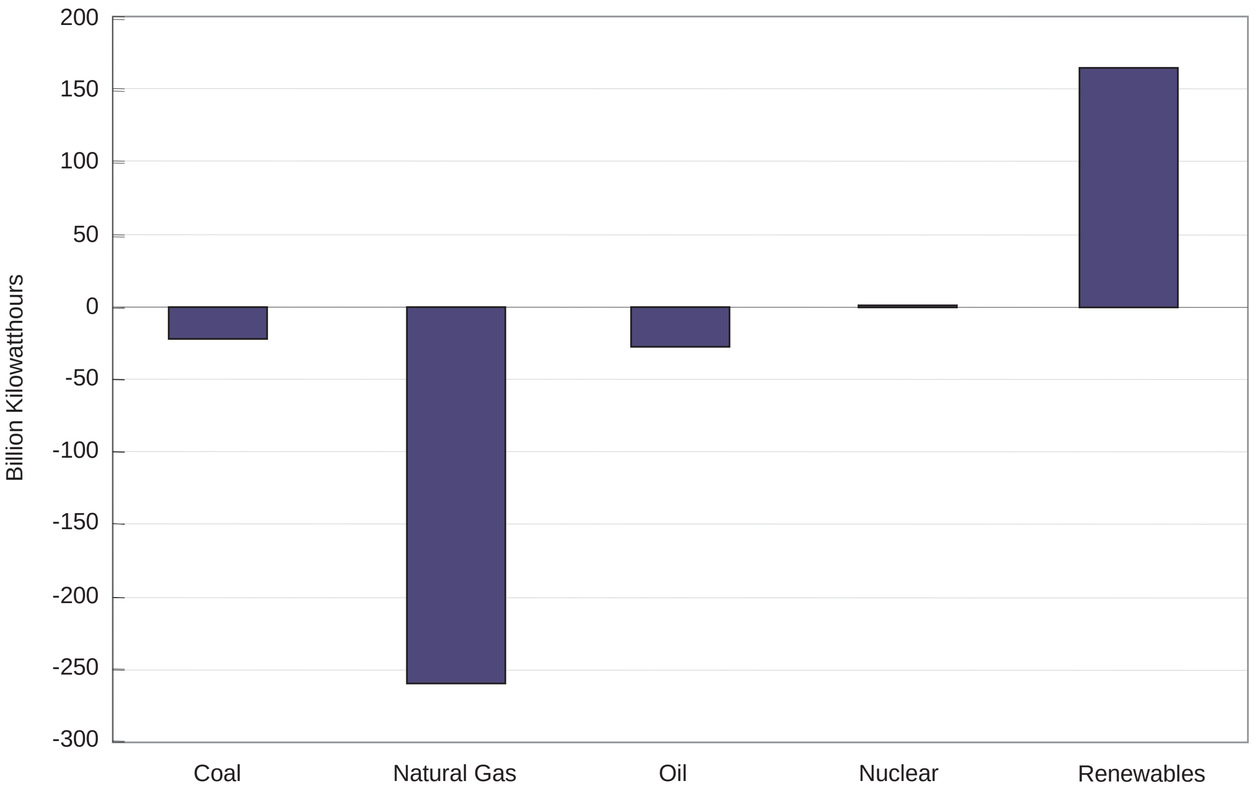
[7]Includes all generating capacity except traditional (industrial and commercial) cogeneration.

Figure 10. Cumulative Change in Capacity by Plant Type, 1995-2010



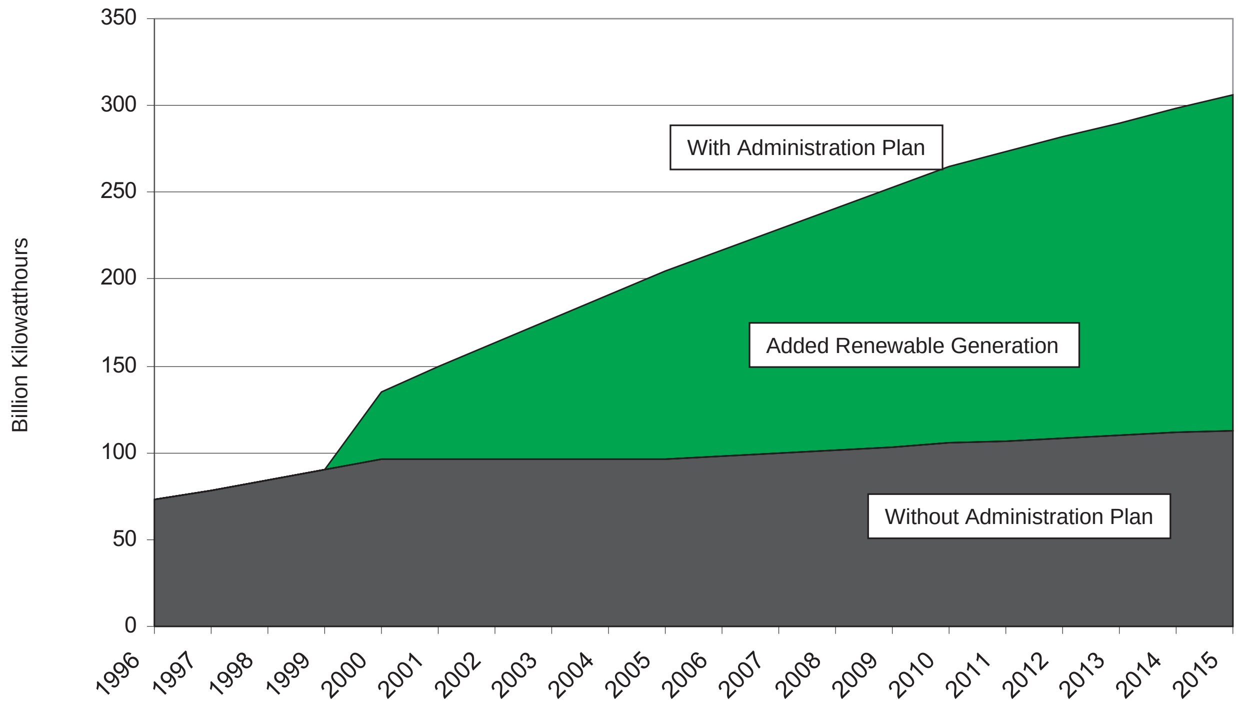
Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Figure 11. Change in Generation by Fuel from the Reference Scenario to the Competitive Scenario, 2010



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Figure 12. RPS-Eligible Generation in the Competitive Scenario, 1996-2015



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Because of consumers' interest in green power and the proposed RPS, generation from non-hydroelectric renewables in 2010 is projected to be 7.1 percent of total generation in the Competitive Scenario, as compared with 2.3 percent in 1997. In 2010, it is projected that retail sellers of electricity subject to the RPS requirement will make some purchases of proxy renewable credits at the cost cap level of 1.5 cents per kilowatthour. Cost reductions for renewable energy technologies that are more rapid than anticipated—or higher-than-projected prices for fossil fuels—would reduce, possibly to zero, the purchase and use of proxy credits in the RPS program.

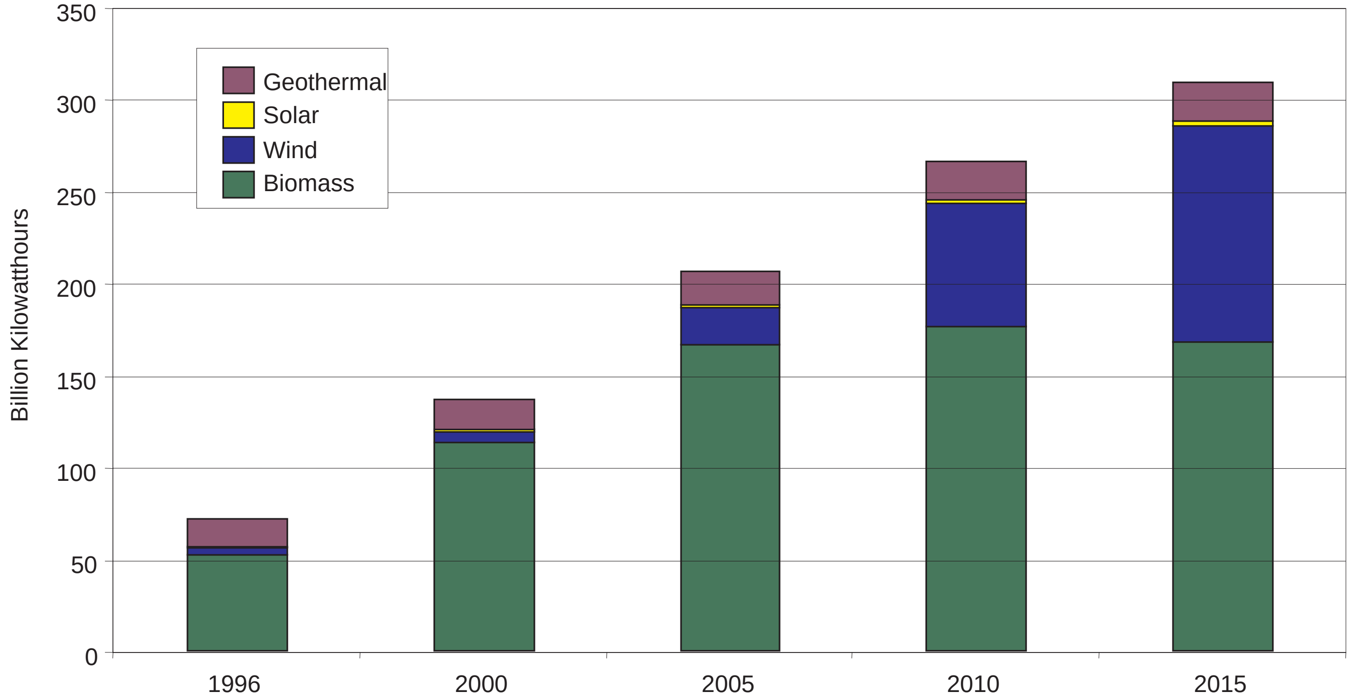
Figure 13 shows the projected mix of renewable generation in the Competitive Scenario. The major new sources introduced as a result of the Administration's plan are projected to be biomass and wind power. Biomass—including co-firing applications in coal plants, direct-fired generation, and cogeneration—is projected to make up 62 percent of the incremental non-hydroelectric renewable generation above the Reference Scenario level in 2010. Wind power is projected to contribute 37 percent in 2010, growing even more further into the future.

Wind capacity is projected to increase steadily over time, eventually replacing some higher cost biomass. Higher capital costs associated with a rapid expansion of the wind power industry prevent wind capacity from increasing more quickly before 2010. In addition, as more experience is gained and economies of scale are achieved, the cost of wind turbines is projected to decline, making them more attractive in the later years of the forecast.

Carbon Dioxide Emissions

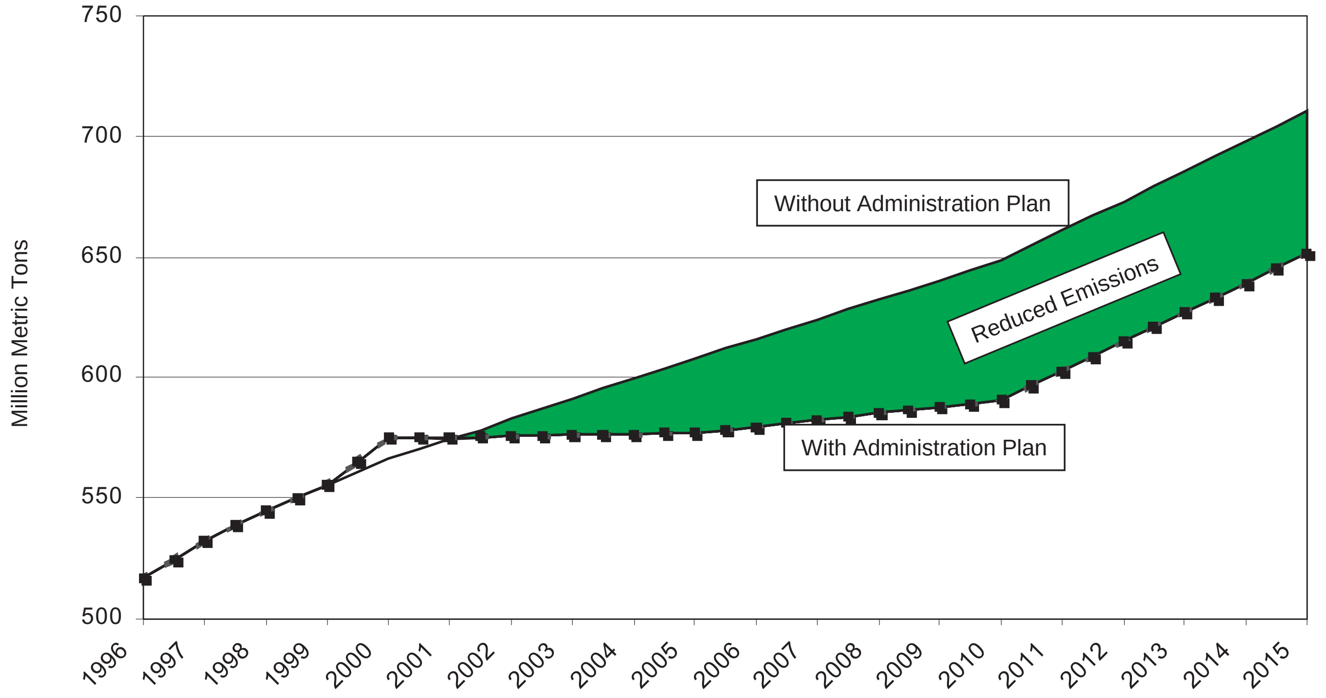
Carbon dioxide emissions from electricity generation, measured as carbon equivalent, are projected to increase by 116 million metric tons between 1997 and 2010 in the Reference Scenario. In the Competitive Scenario, carbon dioxide emissions in 2010 are projected to be lower by 59 million metric tons carbon equivalent than in the Reference Scenario (Figure 14). Carbon dioxide emissions may rise slightly in the early years of competition compared to the Reference Scenario, due to more intensive use

Figure 13. RPS-Eligible Generation by Type in the Competitive Scenario, 1996-2015



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Figure 14. Carbon Dioxide Emissions from Electricity Generation, 1996-2015



Note: Emissions from electricity generators are net of changes in emissions from other sectors, which result from increases in distributed generation or price responses.

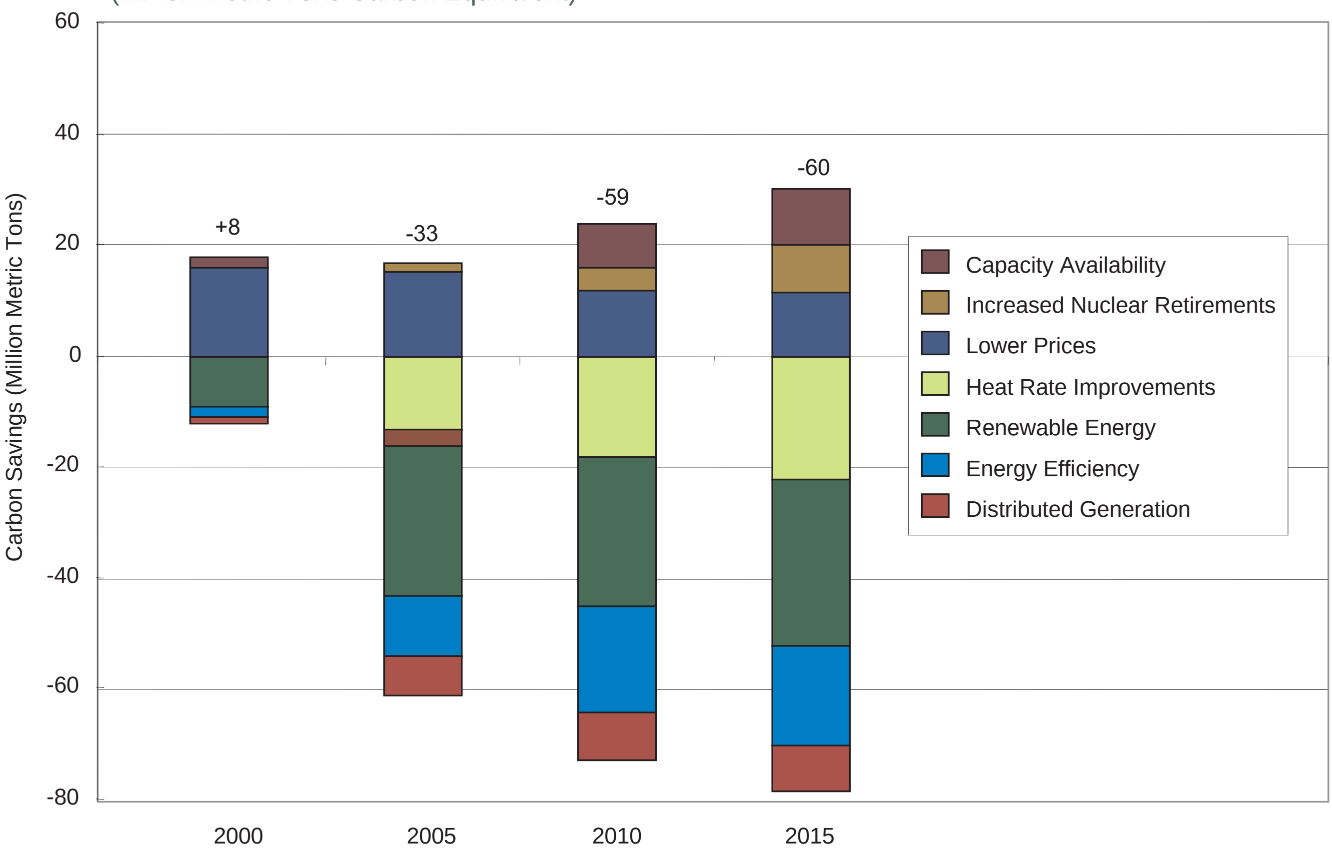
Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

of coal-fired capacity. Over time, however, emissions grow more slowly in the Competitive Scenario than in the Reference Scenario as the potential for increased utilization of existing coal plants decreases, the RPS requirements increase, and additional investments are made in energy efficiency. Another factor leading to lower emissions is the improved efficiency in power generation, as generators faced with competition have a direct financial incentive to reduce their input costs.

Recognizing the inherent uncertainty of future market developments, the Administration estimates that its proposal will lead to carbon dioxide emissions reductions (measured as carbon equivalent) of between 40 and 60 million metric tons in 2010. This approach parallels that used in evaluating economic benefits, which recognizes that the impacts of the Administration's proposed legislation and those of competition itself are not easily separated. Emissions reductions in this range are likely to be achieved even if most of the uncertainties discussed below are ultimately resolved in a direction that tends to increase emissions beyond the modeled level.

Carbon dioxide emissions are affected by many factors associated with the Administration's proposal. Figure 15 illustrates the estimated impacts of the various elements; however, this decomposition is only approximate, because all the elements interact. Factors leading to higher emissions include higher electricity demand due to lower prices, increased availability of coal-fired power plants, and the increased likelihood of nuclear retirements. On the other hand, emissions will be reduced by higher availabilities of the remaining nuclear plants, improved energy efficiency stimulated by competitive energy service companies and the public benefits fund, greater penetration of efficient combined heat and power systems, and increased use of renewables. Some of the key uncertainties are discussed below.

Figure 15. Elements Contributing to Carbon Dioxide Savings, 2000-2015
(Million Metric Tons Carbon Equivalent)



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Key Uncertainties Affecting Carbon Dioxide Emissions

Demand Price Response. Retail competition that lowers electricity prices to final consumers will, by itself, tend to result in greater consumption of electricity. However, there is a wide divergence of opinion as to how electricity consumption responds to changes in prices (often called "price elasticity"). POEMS uses the demand modules of the National Energy Modeling System to calculate the consumer response to lower electricity prices. The reduction in electricity prices is expected to result in an increase in demand that raises carbon dioxide emissions by 12 million metric tons carbon equivalent in 2010.

Heat Rate Improvements. Competition will force electric power generators to operate more efficiently. Generation efficiency is expected to increase by 4 percent by 2010, reducing projected carbon dioxide emissions by 18 million metric tons carbon equivalent. Analysis of existing units shows a wide range of operating efficiencies. If greater efficiency improvements are achieved, carbon dioxide emissions will be lower. If smaller efficiency improvements are achieved, carbon dioxide emissions will be higher.

Renewable Generation. One of the significant policies affecting carbon dioxide emissions in the Administration's proposal is the RPS requirement. In addition, some customers have shown an interest in purchasing green power. Together, these factors are projected to reduce emissions by 27 million metric tons carbon equivalent. If renewables are more or less expensive than projected, however, emissions will be affected as the amount of proxy credits purchased from DOE in lieu of actual generation changes. The degree to which consumers are willing to purchase additional renewables in the form of green power is uncertain, although early evidence from several States suggests that it could be considerable. To the extent that green power purchases have been underestimated in this analysis, emissions savings might be greater.

Capacity Availability Improvements. In a competitive market for electricity, electric power generators that are able to have their plants available more often than their competitors will be more profitable, even with similar production costs. Powerplant operators are refining maintenance and scheduling techniques that allow them to reduce outage periods. Coal powerplant availabilities are expected to increase by 4 percentage points by 2010, and nuclear powerplant availabilities are expected to improve by an average of 3 percentage points. These increases result in a net increase in carbon dioxide emissions of approximately 8 million metric tons carbon equivalent in 2010. Powerplant availabilities are affected by both environmental and economic factors that can result in either greater or lesser improvement in availability.

Powerplant Retirements. The move to competition will force the retirement of some powerplants that can not cover their operating costs and future capital expenditures. Powerplant retirements will be affected by a number of economic and non-economic factors, including electricity prices at peak and off-peak times, environmental factors, other regulatory factors, post-construction capital expenditures and fixed costs, and the marginal cost of producing electricity. Retirements of nuclear units will increase carbon dioxide emissions, whereas retirements of coal units will decrease emissions. Overall, economic retirements are expected to increase carbon dioxide emissions by 4 million metric tons carbon equivalent by 2010. However, competition may actually result in an increase in nuclear availability that reduces carbon dioxide emissions compared to the Reference Scenario.

Combined Heat and Power (Distributed Generation). The Administration's plan includes several actions that will remove market barriers to the implementation of cost-effective CHP and distributed power projects. Specifically, it proposes the development of a Federal standard for interconnection, clarification of tax depreciation schedules applicable to distributed generation equipment, a tax credit for investment in facilities prior to 2002, and State-level consideration of approaches to stranded cost recovery that do not penalize efficient CHP projects. Together with ongoing Federal programs to stimulate CHP and distributed generation, these initiatives could result in much higher penetration of the technologies and a concomitant reduction in carbon emissions due to their inherent efficiencies. Although this analysis projects a reduction in carbon dioxide emissions of 7 million metric tons carbon equivalent by 2010 due to these initiatives, larger reductions are possible.

Other State-Level and Private Decisions Under Competition. Decisions that could result in lower-than-modeled emissions include higher spending on energy efficiency, resulting either from competition among retail electricity suppliers, from expenditures through the public benefits fund (the results presented here assume an incremental $2 billion annually in efficiency spending due to the public benefit fund), or from more consumer interest in green power. Energy efficiency improvements are projected to lead to a reduction in carbon dioxide emissions of 19 million metric tons carbon equivalent by 2010.

Emissions of Nitrogen Oxides and Sulfur Dioxide

The Administration's proposal includes provisions that clarify the authority of the U.S. Environmental Protection Agency (EPA) to require a cost-effective interstate trading system for nitrogen oxide (NO_x) pollutant reductions, addressing the regional transport contributions needed to attain and maintain the ozone ambient air quality standard. However, no change is proposed to existing EPA authority to determine geographic coverage or level of reductions required in addressing regional transport contributions.

Consistent with these provisions, the projected level of nitrogen oxide emissions will be determined primarily by past, pending, and future actions taken by EPA under its existing regulatory authorities. For example, the emissions levels in 2000 and beyond are significantly below the 1995 level in both the Reference and Competitive scenarios due to the Phase 2 Clean Air Act NO_x standards, which were included in both cases. In addition the NO_x SIP Call for the 22 Eastern States has been included in both scenarios, which leads to reductions in summer NO_x starting in 2003. Annual NO_x emissions in the Competitive Scenario are projected to be slightly higher in 2000 and then virtually the same as the projected levels in the Reference Scenario in 2010 (Figure 16).

An annual nationwide cap on sulfur dioxide emissions from the electric utility sector has been established pursuant to the 1990 Clean Air Act Amendments. This cap is not modified by the Administration's restructuring proposal. Consequently, emissions of this pollutant are projected to be the same in both scenarios.

Benefits to Rural America

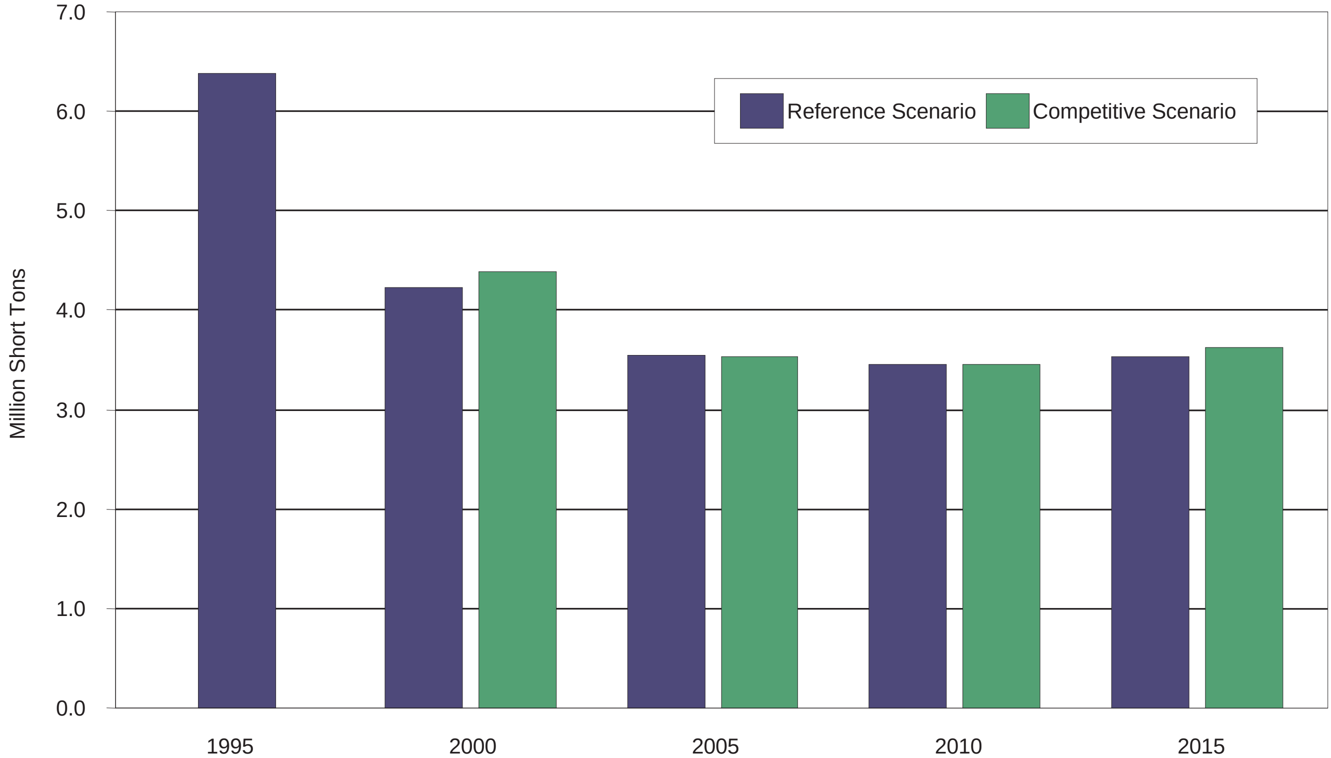
The POEMS results provide considerable insight into the likely implications of the Administration's proposal for rural America. The discussion below focuses on impacts of competition on electricity prices and rural benefits from the proposed RPS. The section closes with a brief analysis of the proposed rural safety net.

Projected Impact of Competition on Prices Paid by Rural Consumers

The projections of Reference and Competitive scenario prices at the beginning of this chapter indicate that competitive prices are lower to residential consumers in all regions and States throughout the projection period. The State- and regional-level results do not directly address impacts on particular groups within States, such as customers in rural areas. However, a review of some of the major issues and arguments surrounding restructuring provide no reason to expect that rural consumers will be systematically disadvantaged under the Administration's plan.

First, in considering the risks to customers of a scenario in which wholesale market prices rise unexpectedly with competition, many rural consumers are likely to face reduced risk due to their direct or

Figure 16. Annual NO_x Emissions, 1995-2015



Note: Phase 2 NO_x standards and the Ozone Transport Rule are assumed.
Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

indirect ownership of generation or their access to Federal power at cost-based rates. The ownership of generation and transmission (G&T) cooperatives by rural electric distribution cooperatives, a common arrangement, provides the distribution cooperatives (and the individual customer/owners whom they in turn serve) with a physical hedge against financial harm in such a scenario. A similar hedge against high wholesale market prices exists for rural consumers who receive power from Federal projects, which under the Administration proposal would continue to be provided at cost-based rates rather than market prices.

Second, while some have suggested that rural residential customers would face significant price risks in a hypothetical scenario where the introduction of competition results in massive bypass by existing industrial customers of rural electric systems, both economic factors and existing laws and regulations at the State level make such a scenario unlikely. The economic motivation for bypass as a result of retail competition is far from clear, because retail competition does not generally allow for customers to leave their distribution provider. Competition does not give industrial customers additional leverage to plan (or threaten) to relocate or self-generate to secure price concessions, inasmuch as they already have those options under cost-of-service rates. Moreover, distribution, unlike generation, is still considered to be a natural monopoly, making it difficult to erect new distribution lines that would compete with incumbent distribution cooperatives even if there were no legal impediments to doing so.

In fact, the latest (December 1996) compilation prepared by the National Association of Regulatory Utility Commissioners (NARUC), provided as Appendix B, suggests that existing State laws present a barrier to physical bypass over and above the economic hurdles noted above. The NARUC compilation notes that 37 out of 50 States have the authority to assign exclusive service territories. In addition, in more than half the States, laws require that private entities seeking to serve new customers obtain a certificate of convenience and necessity, and many States impose this requirement before any construction of transmission and distribution lines takes place. Where the web of rules is insufficient to preclude distribution bypass, State commissions with ratemaking authority over rural cooperatives can assure that any charges to recover stranded costs cannot be bypassed, even by customers who manage to accomplish physical bypass. In sum, the NARUC information suggests that only 2 of the 50 States lack both the authority to prevent duplicative service and the authority to regulate rural cooperative rates.

Finally, the Administration proposal includes an opt-out provision under which a State or an unregulated rural cooperative could choose to implement competition in a manner that reflects its own unique circumstances, or even to maintain the current regime for providing electric service. In effect, the opt-out provision assures that the Administration plan will not require the introduction of competition in the unlikely scenario where it might be damaging to consumers within a particular State or within the service territory of an unregulated electricity cooperative.

The Administration proposal recognizes that the potential for adverse rural impacts stemming from the interaction of competition with other factors can never be completely ruled out. In some cases, competition could affect such activity that might occur within the confines of State-level laws and regulations. Notwithstanding our expectation that competition will provide important net benefits to rural America, prudence dictates the need for a rural safety net.

Projected Rural Benefits of the Renewable Portfolio Standard

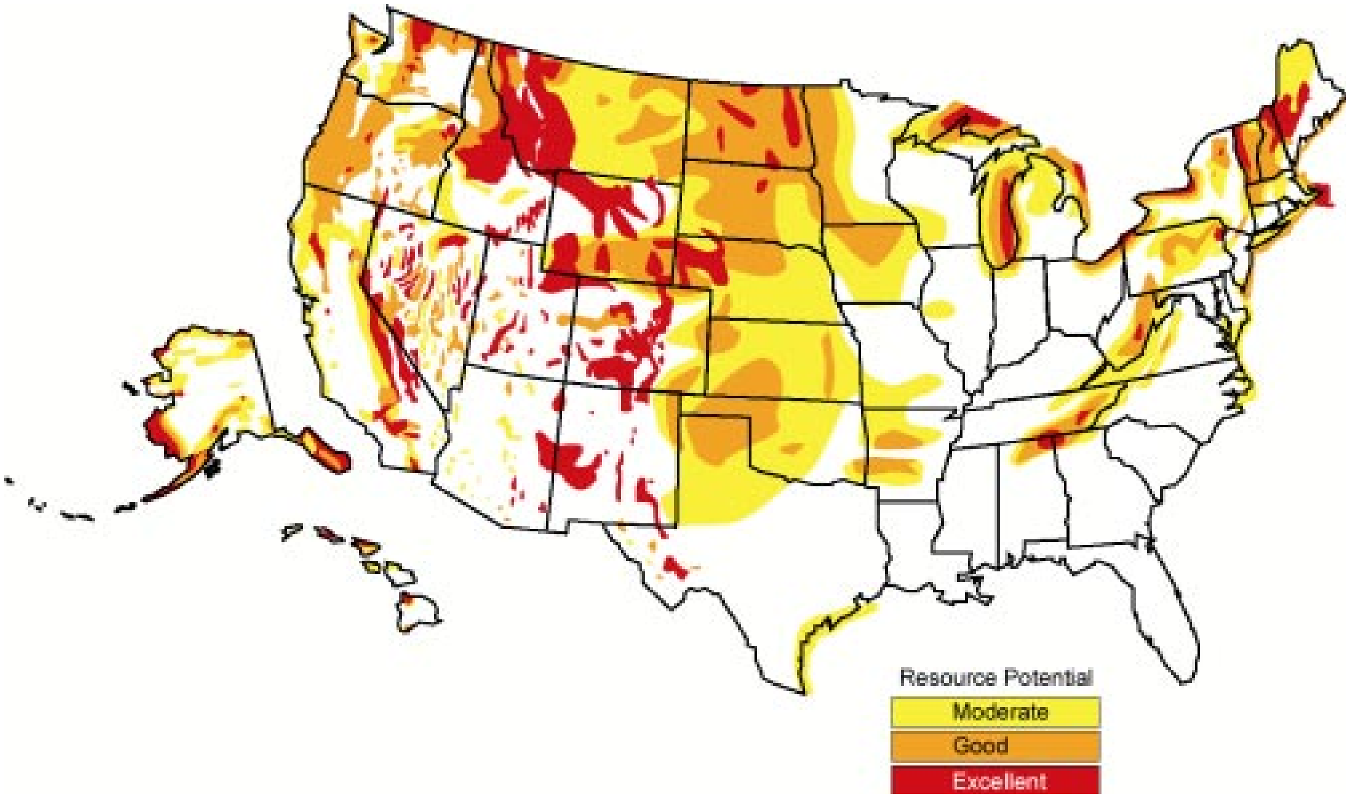
A complete economic assessment of the rural impacts of the Administration's electricity restructuring plan necessarily involves consideration of the benefits of the proposed RPS to rural communities. The POEMS results indicate that biomass and wind energy resources will account for the vast majority of renewable electricity produced in response to the Administration's proposed RPS program. The wind and biomass resources that will be tapped to meet the proposed RPS standard are located almost exclusively in rural America. For example, rural areas clearly have the bulk of the Nation's wind power potential (Figure 17) and its biomass potential. Figure 18, which compares non-hydroelectric renewable generation in the Reference and Competitive scenarios, illustrates the major impacts of the Administration plan by region. Likely rural impacts include increased economic development, job creation, higher local property tax revenues, enhanced agricultural production, and increased land values.

While the Department of Energy lacks the expertise to provide a full economic analysis of direct and spillover benefits to rural economies, information from projects currently under development and from previous analyses indicates that such benefits are likely to be significant. A preliminary analysis by USDA economists found that the role of biomass in the 5.5 percent RPS in the Administration's 1998 legislative proposal would have raised net farm income by almost 0.8 percent per year after the standard was fully implemented. USDA economists have indicated that growth in net farm income due to biomass activities would be somewhat higher under the 7.5 percent RPS included in the Administration's latest proposal.

The impacts of wind power development on rural income were not considered in this analysis and remain a subject for future study. The POEMS results show an increase of 58 billion kilowatthours in wind power generation relative to the Reference Scenario in 2010—a development that would lead to more than 2,000 direct (permanent) jobs to run the wind farms and more than 8,000 person-years of direct employment to build them. None of these estimates reflects multiplier effects on local employment or fees paid to landowners.

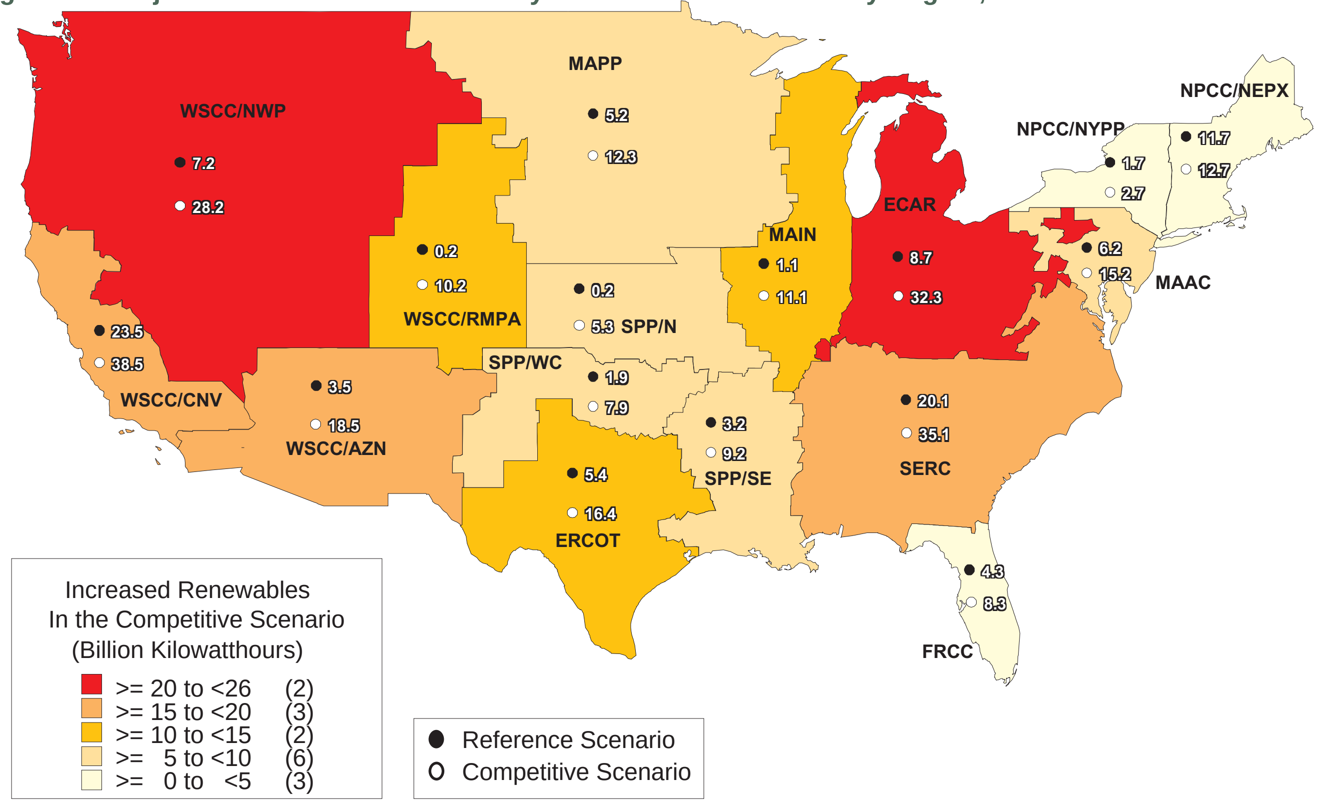
Wind projects will also make an important contribution to the local tax base, easing the burden on other taxpayers. A single 35-megawatt project now under construction in Culbertson County, Texas, will produce over $400,000 in annual tax revenue, or approximately 10 percent of the county's total property tax revenue. More than 650 wind projects of the same size would be needed to provide the increase in wind generation projected in the POEMS analysis of the Administration plan.

Figure 17. U.S. Wind Resources



Note: Class 4 and above areas are prime candidates for wind development.
Source: Energy Information Administration, *Renewable Energy Annual 1998: Issues and Trends*, DOE/EIA-0628(98) (Washington, DC, March 1999).

Figure 18. Projected Generation from Non-hydroelectric Renewables by Region, 2010



Source: Policy Office, U.S. Department of Energy, POEMS model analysis (May 1999).

Biomass energy development also has important rural benefits. A recent study suggests that the land impact for 8 to 12 gigawatts of co-firing would be approximately 2 million acres.[8] The POEMS analysis suggests an increase of biomass use under the Administration plan equivalent to 13 gigawatts of biomass co-firing in 2010.

The Rural Safety Net

The Administration anticipates that rural interests will benefit from its restructuring proposal. However, recognizing the Administration's commitment to rural America, the proposal includes added insurance in the form of a rural safety net provision that could provide up to $650 million in aid to rural consumers by 2010 in the unanticipated event that they should suffer an adverse impact in the transition to competition.

In combination with other rural-friendly policies included in the Administration proposal, the rural safety net provides an amount of protection that is appropriate compared to standard indicators of rural electricity expenditures. Rural distribution cooperatives currently sell roughly $16 billion worth of electricity annually. According to data collected by the Rural Utilities Service, approximately one-third of this value represents the distribution function that is directly affected by retail competition. Thus, at its ceiling level, the rural safety net would have enough resources to cover more than 15 percent of the total distribution costs of all rural electric cooperatives within the United States.

There are, of course, many alternative measures of rural electricity expenditures. For example, the Energy Information Administration's latest Residential Energy Consumption Survey reports over $18 billion in electricity expenditures by residential electricity consumers classified as rural, without regard to the type of utility providing service. However, since the adverse impacts of competition, if any, are likely to be highly localized, the resources provided in the Administration's proposed safety net would be sufficient to meet all reasonably foreseeable contingencies regardless of how the rural electricity expenditure base is defined.

Next Steps

This analysis is intended to inform discussions of restructuring policy by comparing a generic cost-of-service scenario to a retail competition scenario that is consistent with the main elements of the Administration's Comprehensive Electricity Competition Act. Further analyses can provide additional insights as the discussions unfold. While some future analyses will be driven by the specific elements of alternative proposals, some issues that have already been identified as potential subjects of future analysis are briefly summarized below.

- **Transmission Constraints.** Transmission plays an important role in the modeling of competition, because only in the presence of transmission constraints will wholesale power prices in adjacent competitive markets differ by more than the transmission fee plus line losses. Electricity flows on the transmission system do not generally follow the contract path, and the available capacity between two market areas may be influenced by power flows throughout the system. Thus it is important to verify the POEMS representation of transmission constraints, using tools that can follow physical flows. Some progress has been made in this area, and work with the North American Electric Reliability Council and other transmission experts on the transmission representation in the POEMS model is continuing.
- **Timing and Scope of Competition.** Notwithstanding the difficulty of separating the projected effects of the CECA from those attributable to other steps toward competition, sensitivity scenarios addressing this issue could provide useful

[8] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Scenarios of U.S. Carbon Reduction" (Washington, DC).

insight into the likely impact of alternative transition paths.

➢ **Renewable Generation.** Because of the potential roles of green power and the RPS in competitive markets, the cost of incremental renewable generation is of great interest. Refinements to POEMS have been made to include the economic evaluation of biomass co-firing. However, further improvements in the representation of biomass resources and their use by electricity generators could be made. In addition, sensitivity scenarios to examine alternative biomass and wind resource estimates could refine the projections of the extent to which generators will purchase credits to meet the RPS requirements.