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National Renewable Energy Laboratory

Innovation for Our Energy Future

Evaluating a Proposed 20% National Renewable Portfolio Standard

Technical Report
NREL/TP-6A2-45161
February 2009

Jeffrey Logan, Patrick Sullivan,
Walter Short, Lori Bird, Ted L. James,
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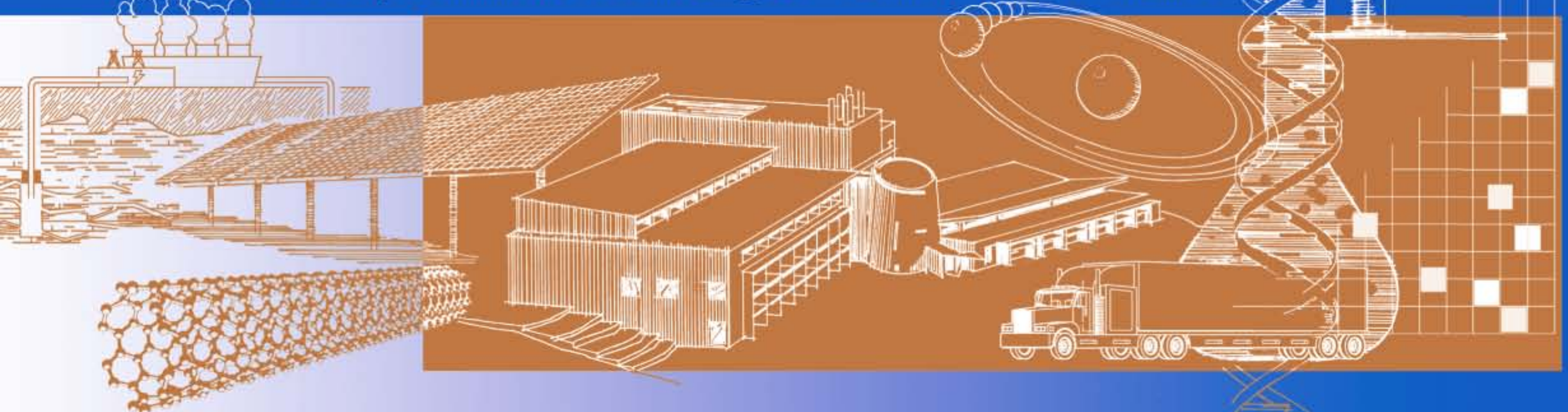

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Executive Summary

This paper provides a preliminary analysis of the impacts of a proposed 20% national renewable portfolio standard (RPS) by 2021, which has been advanced in the U.S. Congress by Senator Jeff Bingaman of New Mexico. The paper was prepared before the American Recovery and Reinvestment Act was signed into law by President Barack Obama on February 17, 2009, and thus does not consider important changes in renewable energy (RE) policy that need to be addressed in follow-on analysis.

A renewable portfolio standard is a mandate requiring certain electricity retailers to provide a minimum specified share of their total electricity sales from qualifying renewable power generation. The draft legislation analyzed here exempts small electricity providers—those selling less than 4 billion kilowatt hours (kWh) per year—and allows up to 25% of the RPS total to be met through qualifying energy efficiency (EE) projects. Existing hydropower and municipal solid-waste generation resources do not qualify under the proposed RPS, but are deducted from retail electricity providers' retail sales to calculate their renewable energy compliance obligations. The RPS would allow affected electricity providers to use any combination of the following to achieve the target: 1) generate their own renewable energy, 2) purchase renewable energy certificates (RECs), or 3) pay an "alternative compliance payment" of 3 cents per kilowatt hour (an effective safety-valve on the price of RECs). Distributed generators, such as rooftop photovoltaic systems, would earn triple credits for every kilowatt hour produced. The proposed RPS ramps up in a series of steps from 4% in 2011 to 20% in 2021 and continues at that level through 2039, before "sunsetting" (i.e., returning to zero). The legislation aims to prevent preemption of, or interference with, existing state RPS mandates that meet or exceed the federal requirement.

We used NREL's Regional Energy Deployment System (ReEDS) model to evaluate the impacts of the RPS requirements on the energy sector and considered design issues associated with renewable energy certificate (REC) trading markets.

Preliminary findings include:

- After removing the small-utility exemptions and assuming that the maximum 25% energy efficiency allowance is fully used, the 20% RPS has an effective renewable requirement equal to 12% of total U.S. retail sales in 2021. The assumption that the energy efficiency component of the target would be fully used before adding new renewable energy supply, due to its cost-effective nature, will be further evaluated in follow-on work.
- The base case scenario estimates that qualifying renewable generators will provide about 9% of the national load in 2021, much of that due to existing state RPS mandates. Thus, the proposed national legislation would require about 3% more generation from qualifying renewables beyond the state RPS mandates by 2021. In this sense, the proposed legislation does not represent a significant stretch beyond existing state policy in aggregate, although ramp-up additions in years that transition from one RPS level to another can present challenges.
- Based on the assumptions used in this analysis, wind power capacity expands to approximately 129 gigawatts (GW) in 2030 in the RPS scenario, up from about 117

GW in the base case. Concentrating solar power (CSP) capacity remains virtually unchanged at 32 GW that year, while distributed photovoltaics increase from about 4 GW in the base case to more than 7 GW in the RPS case.

- The federal RPS results in a modest 200 million metric ton (MMT) annual reduction in carbon dioxide (CO_2) emissions in 2030, compared to the base case. This is primarily because significant renewable energy additions are projected to occur even in the base case scenario.
- Western states, endowed with wind and solar resources, exceed their RPS requirements based on renewable energy deliveries, while states in the Southeast generally rely on purchasing RECs.
- Consumer electricity prices are estimated to increase approximately 1% in 2030, compared to the base case.

Implementers must also address complex REC market design issues to encourage investment in renewable generation, capture the economic benefits of credit trading across states and regions, and prevent double-counting or other unintended use of credits.

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1. Background

A renewable portfolio standard (RPS) is a mandate requiring certain electricity retailers to provide a minimum specified share of their total electricity sales from qualifying renewable power generation.[1] At the beginning of 2009, 28 states had an RPS and an additional five states had goals for renewable energy deployment.[2] Firms that generate power from qualifying renewable facilities receive renewable energy certificates (RECs) that can be applied to their annual requirements or sold to others.

The 20% federal RPS bill analyzed in this report has the following provisions:

- The program includes incremental steps to reach a 20% RPS by 2021, with a "sunset" after 2039. The proposal mandates the following minimum RPS levels over time: 4% by 2011, 8% by 2013, 12% by 2016, and 16% by 2019.

- Utilities generating less than 4 million megawatt hours (MWh) per year and those in Hawaii are exempt. Existing hydroelectric power (including pumped hydro) and municipal solid waste (MSW) do not earn federal compliance credits. The amount of qualifying renewable generation required per year is calculated by applying the percentage targets to total retail electricity sales minus existing hydropower, MSW generation, and electricity sales by exempt utilities.

- New renewables, existing renewables, and energy efficiency savings can be used to meet the federal requirement. New renewable energy is defined as electricity generated from solar, wind, geothermal, ocean, biomass, landfill gas, and incremental hydropower facilities placed in service on or after January 1, 2006. Existing renewable energy generated from facilities installed prior to January 1, 2006, can be used to meet the standard; however, the RECs provided to existing generators must be assigned directly to the entity purchasing the power and cannot be traded.

- Energy efficiency improvements may be used to meet up to 25% of the RPS requirement in each calendar year, but only by petition from a state governor. Eligible energy savings include reductions in end-use electricity at consumer facilities (compared to a base year) as well as reductions in distribution system losses by a retail electricity distributor. New combined heat and power (CHP, also known as cogeneration) efficiency gains are also eligible (with savings based on comparison of the combined system to separate thermal and electrical requirements). The bill calls for measurement and verification standards to be enacted by 2010.

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[1] For more background on existing state RPS policies in the United States, see R. Wiser and G. Barbose, "Renewable Portfolio Standards in the United States: A Status Report with Data Through 2007," Lawrence Berkeley National Laboratory, April 2008; and D. Hurlbut, "State Clean Energy Practices: Renewable Portfolio Standards," National Renewable Energy Laboratory, July 2008.
[2] A map summarizing state RPS mandates and targets is available on the DSIRE Web site at http://www.dsireusa.org.

- A system of federal RECs would operate as a separate commodity from state RECs. Federal credits can be banked for up to three years from the date issued. Distributed generation (less than 1 megawatt – MW) receives triple credits, and installations on American Indian lands receive double credits; however, no facility can exceed triple credits. Compliance with state RPS obligations through RECs or other mechanisms will, in certain circumstances, also count toward a utility's federal RPS. The "secretary"[3] may delegate administration of the REC tracking system to a third party.

- Alternative compliance payments can be made at a rate of 3 cents per kilowatt hour (adjusted for inflation) in lieu of RECs. Utilities failing to meet RPS requirements by purchasing RECs or using alternative compliance payments are penalized by multiplying the number of kilowatt hours (kWh) sold in violation by two times the value of the alternative compliance payment rate. For circumstances not under a utility's reasonable control, penalties or requirements may be waived for up to five years. Federal penalties may be reduced by the amount of state penalties if the state requirement is greater than the federal RPS. Implementers would put revenues from noncompliance into a fund for states to promote renewable energy production.

[3] The draft legislation does not specify which agency "secretary" is authorized in this statement.

2. Methodology and Assumptions

The Regional Energy Deployment System (ReEDS) model, the capacity expansion and dispatch tool used for this analysis, was created to compare national policy scenarios; it also has built-in capabilities for implementing a renewable portfolio standard (RPS) policy. To appropriately model the proposed RPS scenario in ReEDS, however, the modelers needed to make simplifying assumptions. First, the target RPS—which reaches 20% from 2021 to 2039—was prorated to 16%-17% because small utilities, which provide more than 20% of national load, are exempt from the requirement. The fraction of load met by large utilities is expected to increase slightly between 2020 and 2040 to above 80%.

Second, all balancing areas were assumed to use their full efficiency allotment, 25% of the RPS, because efficiency measures are usually more cost-effective than adding renewable power supply.[4] That further reduced the effective RPS to about 12% of total U.S. retail sales, from 2021 to 2039. The effective 12% RPS is the minimum amount of renewable power that would be required; in reality, not all states would use the entire 25% efficiency carve-out or allow their excess RECs to count toward the federal obligation.

Technologies that may contribute to the RPS include wind, concentrated solar power (CSP), geothermal, biopower, and distributed photovoltaics (PV)—hydropower and municipal solid waste are not counted. As in the proposed legislation, distributed renewable energy systems are permitted to claim triple credits toward the RPS; i.e., 1 kWh from a rooftop PV system counts as 3 kWh for RPS accounting purposes. PV is the only distributed technology considered in this analysis.

The model applies the RPS to the nation as a whole, and allows states, regions, or individual utilities to purchase renewable energy certificates to meet local shortfalls. In the case that the whole country falls short of the RPS, an alternative compliance payment of 3 cents per kilowatt hour is assessed.

There are other assumptions made in ReEDS that are not specific to this analysis but can be significant drivers in the model and are therefore worth mentioning. These include:

- Technology cost and performance parameters and projections are from Black and Veatch as estimated for the *20% Wind Energy by 2030*[5] study (see **Figure 1**).

[4] This simplification was assumed primarily because ReEDS does not explicitly represent efficiency savings. Follow-on analysis should evaluate cases where efficiency measures might not meet the entire 25% RPS allowance.
[5] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply*, July 2008.

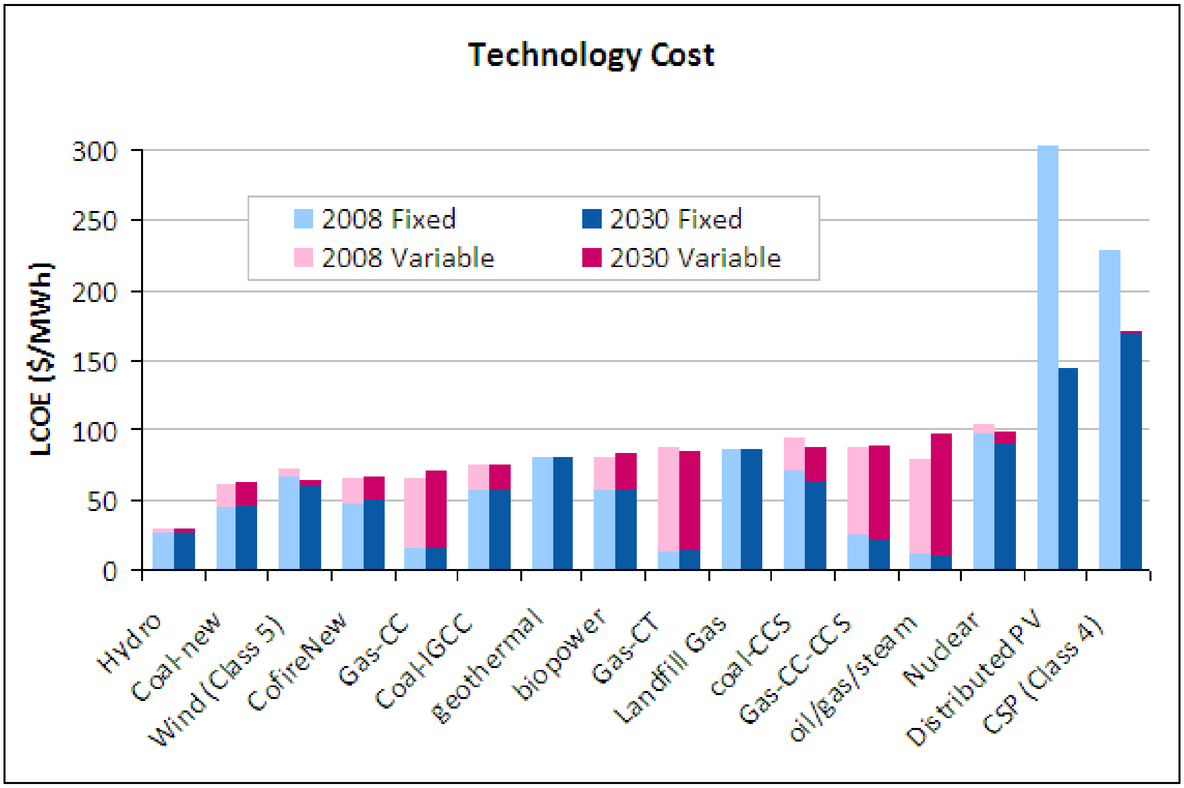

Figure 1. Levelized cost of electricity inputs used in ReEDS

- Fuel cost projections are from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2008 high gas price case. The price of natural gas, in particular, can have a large impact on both investment and dispatch decisions in the model.
- Wind receives a production tax credit (PTC) of 2.1 cents per kilowatt hour through 2009. With the signing of the American Recovery and Reinvestment Act on February 17, 2009, the PTC was extended through 2012. Follow-on analysis will evaluate the impacts of this extension and other incentives for renewable energy.
- CSP receives an investment tax credit (ITC) of 30% through 2016, after which it drops to 10%.
- Nuclear capital costs have been multiplied by 1.5 times from the Black and Veatch projections (i.e., from $3,000/kW to $4,500/kW) to represent recently publicized cost-estimate increases and the current social political climate of uncertainty toward the technology.
- Load growth rates are from the EIA Annual Energy Outlook 2008, and seasonal and diurnal load curves are from Platts, an energy information service.
- There is no price, cap, or tax of any kind on CO_2 or other greenhouse gases; sulfur dioxide (SO_2) is subject to the Clean Air Interstate Rule caps.

- All existing state-level RPS targets with enforceable penalties are met in the baseline case. Most state RPS programs run through 2020 or 2025 before expiring.[6]
- The analysis explicitly accounts for the cost of new transmission for all power generation options by determining when new transmission lines are needed and evaluating factors in the cost of building them.
- Other assumptions are outlined in **Appendix A** (ReEDS documentation) and in the *20% Wind Energy by 2030* study.

Although the above inputs and assumptions have been vetted for reasonableness, some aspects of the future most likely will differ from the projections made in the model.

[6] See the DSIRE database for information on specific state RPS mandates (http://www.dsireusa.org).

3. Impacts

We ran two scenarios, with and without the proposed RPS. The scenarios will be referred to here as the "base case" and the "RPS case." In the RPS case, the bulk of the renewable generation share (after accounting for exempt utilities and allowing efficiency savings) is met by wind power. CSP is the second-largest contributor, with biopower, geothermal, and distributed PV being minor players (see **Figures 2 and 3.**)

The dotted line in Figure 2 shows the penetration rate over time of qualifying renewable energy sources. If read from the top down, it shows that approximately 12% of total eligible load is met through qualifying renewable sources in 2022. To meet reserve requirements, natural gas-fired capacity increases substantially over time, but actual generation from gas declines. New coal plants continue to come online after 2030 due largely to the decommissioning of nuclear power plants. Again, the results assume that there are no requirements to mitigate carbon dioxide.

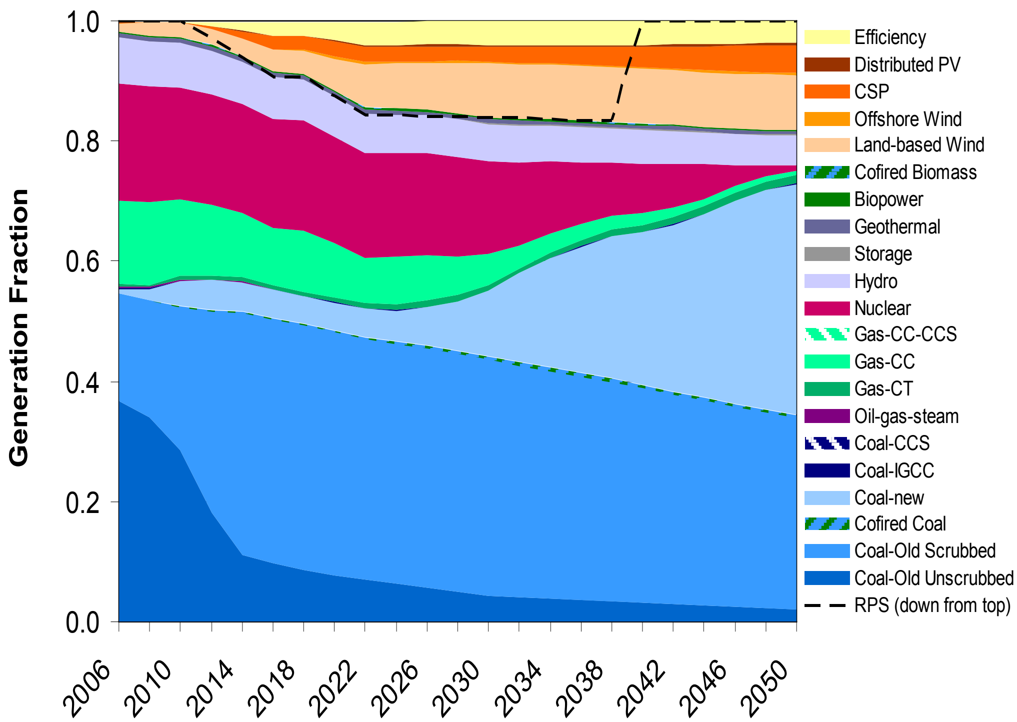

Figure 2. Contributions to meeting total load in the RPS case

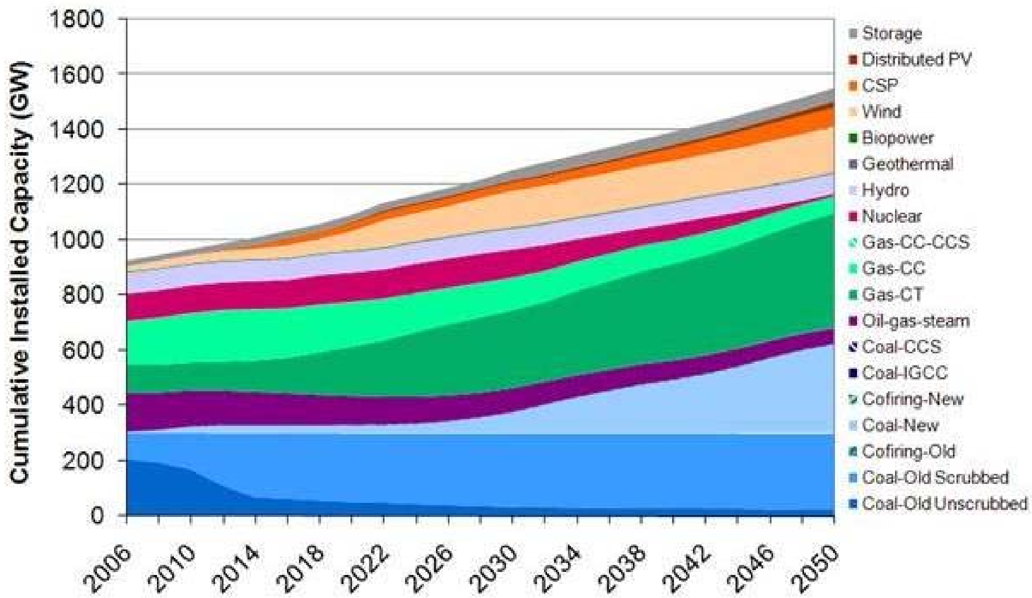

Figure 3. Contributions to power generation capacity in the RPS case

Notably, the capacity differences between the base case and RPS case are small, as shown in **Table 1**. The base case, with state renewable standards implemented as currently legislated, builds nearly as much wind as (and slightly more CSP than) the RPS case. Coal capacity decreases, while natural gas capacity increases in the RPS case vs. the base case.

Table 1. Capacity Differences (in GW) in 2030 between the Base and RPS Scenarios

	Base Case	RPS Case	Difference
Gas	363	398	36
Coal	415	379	-36
Nuclear	102	102	0
Hydropower	76	76	0
Wind	117	129	11.5
CSP	32.7	32.2	-0.5
Distributed PV	3.7	7.2	3.5
Geothermal	2.9	3.6	0.7
Biopower	2.0	2.1	0.1

The similarity of the two scenarios reflects the fact that the federal RPS is largely met through assumptions about efficiency and existing state RPS programs. As mentioned earlier, the RPS nominally peaks at 20% from 2021 to 2039, but exempt utilities reduce it to 16%-17%. If the efficiency allowance is fully used, 12% of load is met by renewable power. The base case provides 10.6% of its load from renewable sources in 2030, not a large difference from the 12% in the RPS case.

Assumed efficiency savings account for the bulk of the generation differences; although, around 2022, wind and CSP replace gas to a noticeable degree. After peaking in 2022—the first year of the full RPS—the difference in renewable generation between the RPS case and base case shrinks steadily as shown in **Figure 4**. (The graph shows generation in the RPS case minus generation in the base case in a given year—reductions in generation from a particular source appear below the x-axis, and increases in generation are above the x-axis.) The RPS case continues to build renewables: The gap closes because the base case is building slightly more renewables in later years than in the RPS case. In the figure, the dashed line represents the difference in load between the two cases, primarily due to the assumption on the efficiency allowance. Most years see a reduction in coal-fired generation between the two cases, and an increase in wind and co-fired biomass generation.

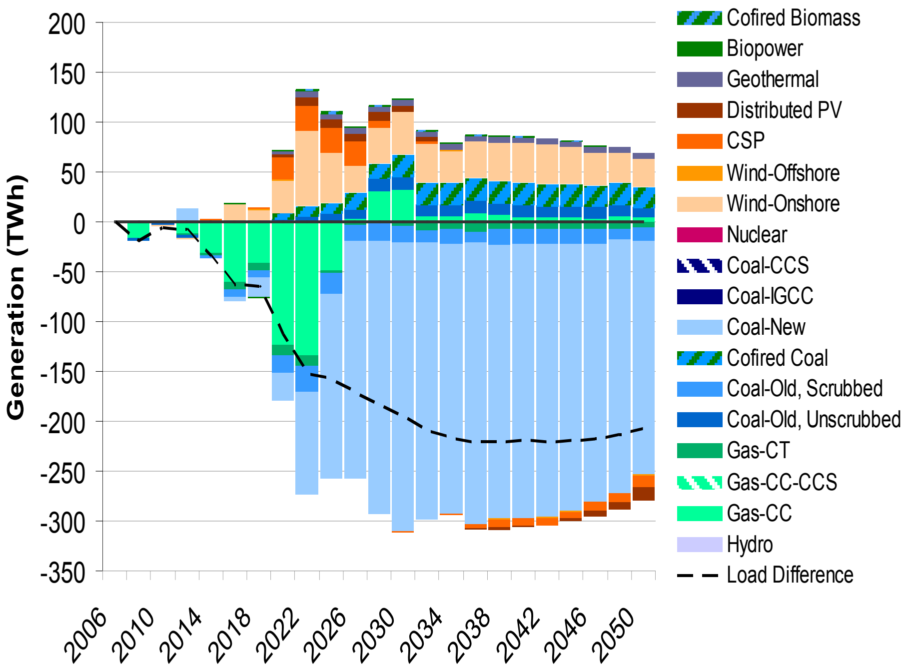

Figure 4. Differences in generation between the RPS and base cases

There are noticeable, though not large, incremental carbon reductions in the RPS case—they are mostly due to the load reduction from efficiency savings. **Figure 5** indicates that CO_2 emissions in the 2030 RPS case decline by approximately 220 million metric tons (MMT) compared to that in the base case. Much of the reduction is due to the assumed efficiency measures because renewables do not replace large quantities of fossil fuel generation. Cumulative CO_2 emissions of the RPS case decline by about 2,500 MMT by 2030.

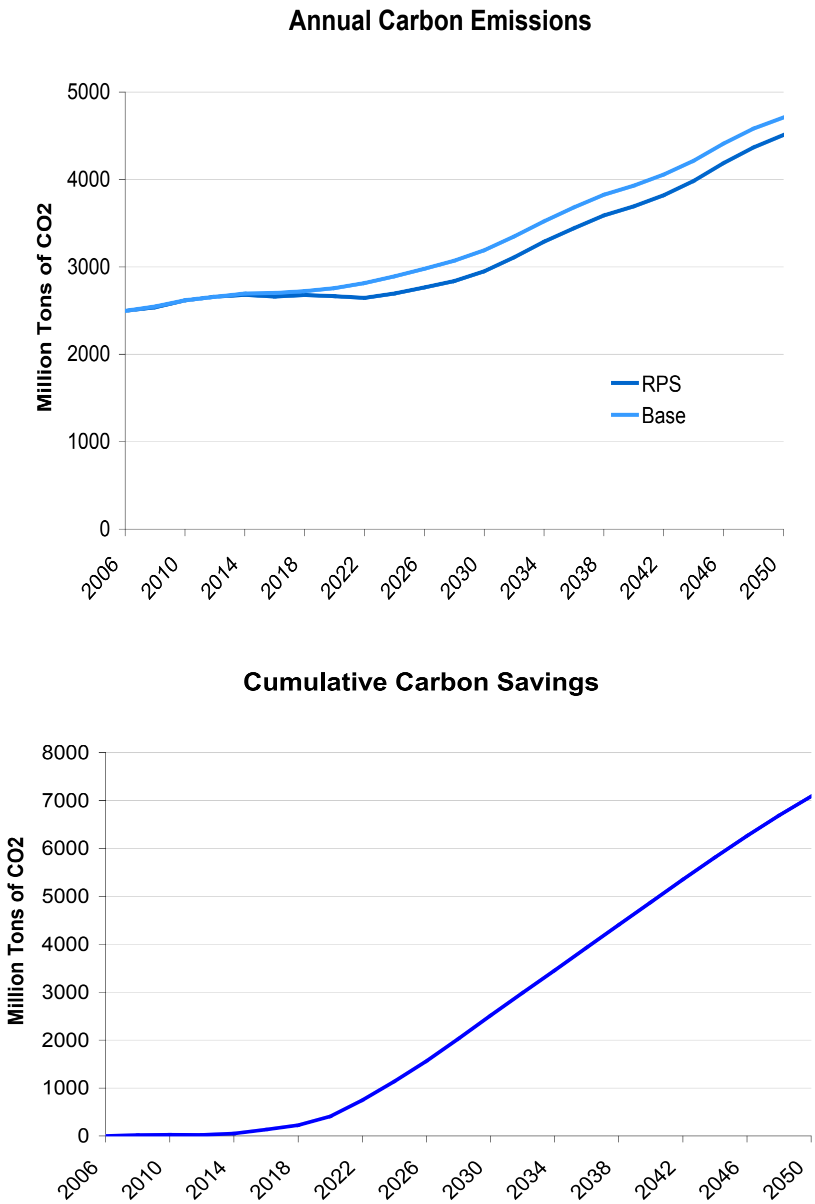

Figure 5. Annual and cumulative changes in CO_2 emissions between the base and RPS cases

Wind capacity expansion is similar between the two cases (**Figure 6)**, with the notable exception of an increase in wind built in the 2018-2022 period in the RPS case. This increase in capacity meets the increase in the RPS in 2021.[7] The base case catches up somewhat in the following two periods and parallels the RPS case from then on. The smoother expansion plan simulated in the base case would be healthier for the wind industry than the spike in the RPS case.

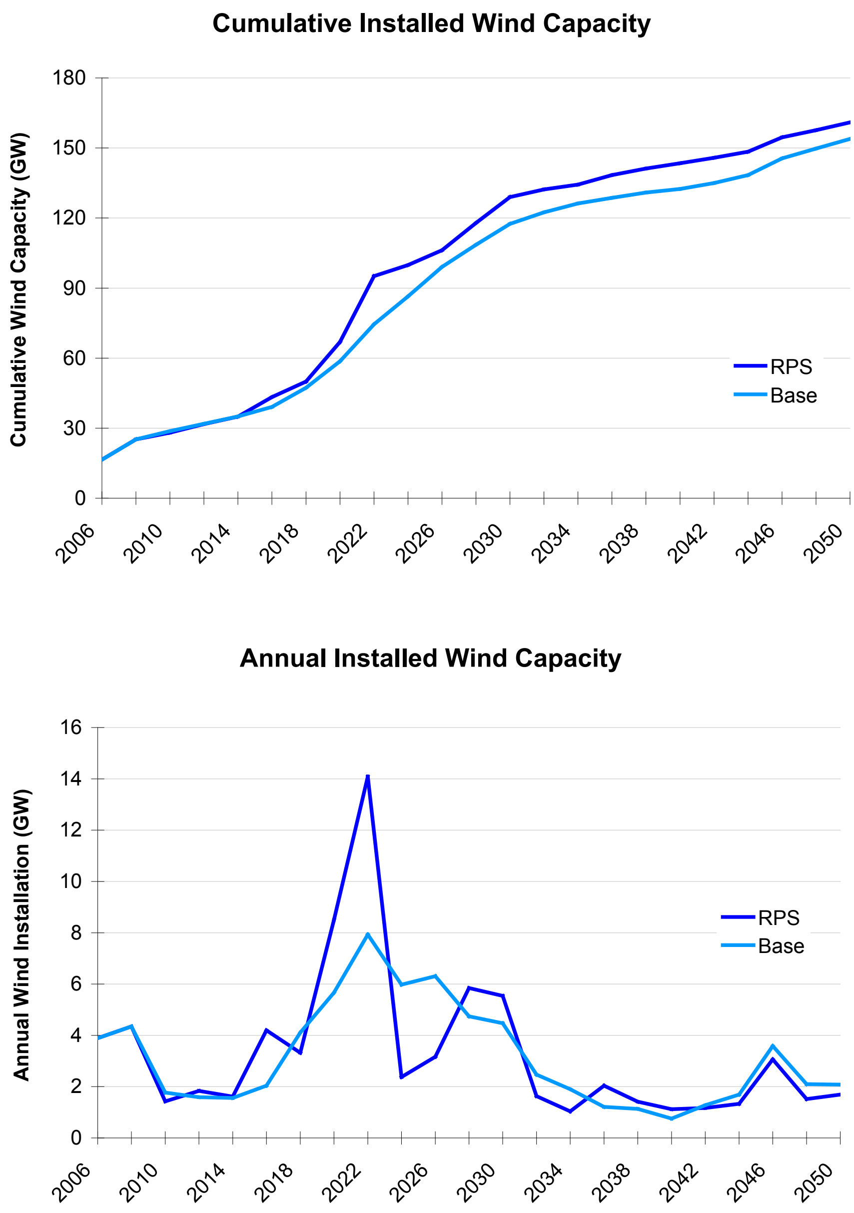

Figure 6. Cumulative and annual installations of wind power

[7] ReEDS runs two-year periods, so the 2021 standard is first seen in 2022.

The western half of the country, endowed as it is with wind and solar resources, provides more than its share of renewable energy toward the RPS target. In California, for example, renewable power options generate more than half of the state's total electricity (**Figure 7**). Some states in the Southeast, on the other hand, are projected to buy RECs to make up for regional shortfalls.[8] The country as a whole, however, always meets the RPS target, never opting for the 3 cents per kilowatt hour alternative compliance payment. Details of the contributions to the RPS at the national level are shown in **Figure 8**.

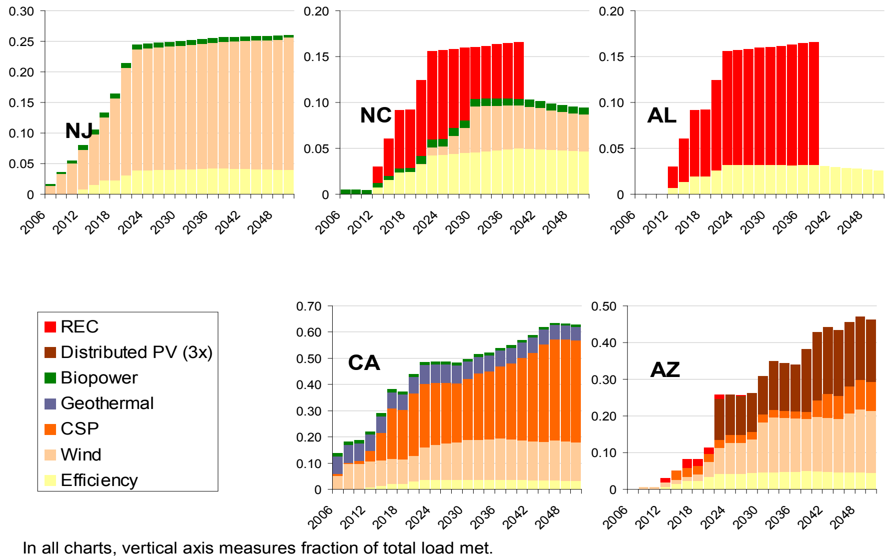

Figure 7. Selected state-level contributions to the RPS

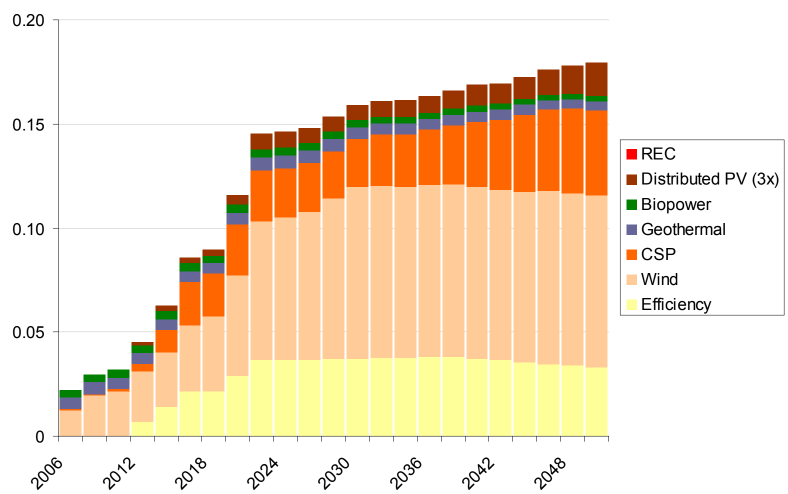

Figure 8. Contributions to the national-level RPS

[8] This finding differs from past EIA modeling of federal RPS legislation, which project relatively large amounts of biopower in the Southeast. See Section 5 for more on this topic.

Because differences between the two scenarios are small, we do not anticipate an RPS of this sort to have major impacts on supply, transmission, or prices. Calculated electricity price differences between the scenarios are small, with prices in the RPS case being slightly more expensive, as shown in **Figure 9**. In 2030, for example, electricity prices are about 1% higher than in the base case. In later years, the estimated increase grows to about 2%.

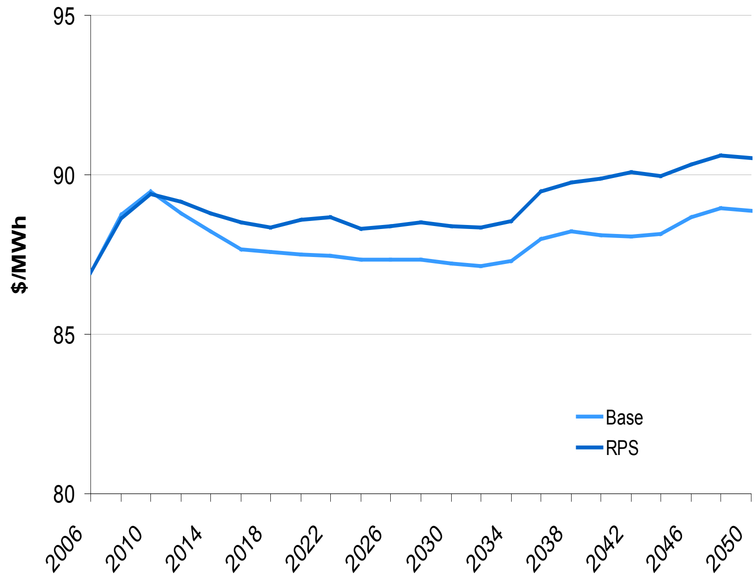

Figure 9. Preliminary assessment of RPS on average national electricity prices

4. Policy Design and REC Market Issues

The proposed legislation raises some questions regarding trading of renewable energy certificates (RECs) as well as the overall design of the REC trading market. In cases where potential ambiguity exists, or conflict appears between existing state and federal RPS requirements, options are presented that could help address uncertainties.

A. Dual RECs System: The draft legislation creates a dual RECs system, with federal RECs separate from state RPS RECs. While this method may be required based on other elements of the draft legislation, it may also create tracking problems and confusion over appropriate claims, because there could be two RECs (federal and state) issued for a single megawatt hour of renewable generation. Because states generally specify that RECs contain renewable energy attributes and establish a basis for claiming renewable energy, the federal REC cannot also contain these attributes. The legislation does not clearly define a REC—the federal REC should be defined in a way to avoid confusion. Alternatively, legislators may want to consider employing a single RECs system; however, that would require other necessary changes to the draft bill.

B. State RPS Interaction: The bill could present difficulties for states to set RPS standards that are more stringent than the federal standard. For example, utilities in states with higher RPS targets (e.g., 25%) than the federal 20% target may be allowed to sell "excess" RECs to utilities in other states for federal compliance. Without further clarity, if this is allowed, state targets would not necessarily be more stringent than the federal RPS. Language could be included to ensure that utilities are not able to trade federal RECs that are used to meet a higher state RPS standard; or, alternatively, the language would more-clearly give states the authority to decide how to treat this issue.

Similarly, small utilities that are exempt from the federal RPS—but may be subject to state RPS policies—could also sell RECs they use for state compliance to entities in other states for federal compliance. Again, this would mean that state standards are not additional to the federal standard.

The legislation calls for state penalties to be applied to the federal penalty in cases where a utility is in noncompliance of both a state and federal RPS. Further clarity of implementation authority and rights would alleviate ambiguities and potential implementation challenges.

C. REC Issuance to Utilities Subject to State RPS: Under the draft legislation, federal RECs will be issued to electric utilities to match compliance with state renewable portfolio standards pursuant to subsection (610h4Ai). Upon an initial review of the legislation, this language seems to imply that federal RECs could be provided to both the generator and the electric utility for the same megawatt hour of renewable generation, creating the possibility of double-counting. Managing this situation consistently with other provisions of the draft—and to ensure no double-counting—would require the federal REC tracking system to associate generator-awarded federal RECs with their corresponding state RECs, and to ensure that the generator-awarded federal RECs automatically transfer with the state REC to the entity that uses the state

REC for state RPS compliance. If this is indeed the intent (i.e., to ensure that the federal REC is conveyed with the state REC for the purpose of state RPS programs), then the language should be clarified. The current language is unclear, and absent clarification, regulatory implementation may be a challenge.

D. Double-Counting: The double-counting language in the bill addresses only double-counting of the same megawatt hours for federal compliance. Counting state compliance toward federal compliance is contemplated generally. The potential gaming between federal RPS compliance and voluntary sales by means of state RECs also is not addressed. The draft, which would permit assigning state RECs and federal RECs to the same generation, allows a utility to apply federal RECs to its federal compliance, and then use the state RECs associated with the same megawatt hour for voluntary sales. This is potentially harmful to consumers who expect voluntary REC purchases to represent use of renewable power beyond what would have occurred without the voluntary purchase. The definition of double-counting would be clearer if it were to exclude RECs used for federal RPS compliance from being sold to voluntary purchasers of renewables. This could be accomplished if the law were to state explicitly that such gaming constitutes a deceptive trade practice and may be prosecuted as such by the Department of Justice and the Federal Trade Commission.

E. REC Tracking: The bill calls for a new, separate federal REC-tracking system. It does not use the existing regional REC-tracking systems, although there is authority in the bill to do so. Given the significant effort in developing these systems, a pragmatic approach to the development of a federal system would use these systems to the extent feasible. The regional systems have established protocols for obtaining and verifying meter data for verification purposes, and that effort should not be duplicated.

F. Treatment of Existing Renewable Generation: The provision in the legislation that establishes nontradable RECs for existing generation may be difficult to implement. For example, generators that came online prior to 2006 may have already traded RECs (and potentially any future federal RECs) in transactions conducted for state RPS compliance. It also may be unclear what “nontradable” actually means regarding implementation. Exempting REC trading from existing renewable generation requires additional renewable generation to be built (that is eligible for tradable RECs). This provision may slightly drive up pricing and requires further detail in the REC tracking systems. Consideration of a provision to make all RECs tradable, with no distinctions between existing and new, may be worth evaluating.

G. Treatment of Distributed Generation: The bill defines distributed generation as no larger than 1 MW. Given the trend toward larger distributed PV systems in recent years, a definition greater than 1 MW could be considered. Several states offer net metering for systems larger than 1 MW.

H. Treatment of EE Credits: The legislation does not clearly define an energy efficiency (EE) credit. Also, there is no date established for qualifying energy efficiency measures. If the goal is to incentivize new efficiency investments, the legislation should specify a date after which efficiency investments would be eligible to receive federal credits.

In many states, entities other than electric utilities administer energy efficiency incentive programs. In some cases, the administrator is a state agency; in others, it is a nonprofit organization. The legislation does not clearly indicate whether EE credits could be generated by these incentive programs and, if so, to whom they would be issued. Evaluating the option for allocating energy efficiency credits in these instances to the state or nonprofit incentive program administrator would clarify the impact of this provision. The bill currently would only allow a state agency to receive the EE credits if that agency directly installed the EE system.

The bill states that EE credits will be issued for "qualified electricity savings achieved by an electric utility" and "qualified electricity savings achieved by other entities." It is unclear what is meant by "achieved": Does it refer to the source of the funding or the administrator of the efficiency program? (In some states, efficiency programs are funded through a surcharge on utility bills, but the programs themselves are administered by other entities.) Some clarification on this issue would be helpful.

I. Standards for EE Measurement and Verification: The bill calls for the Department of Energy to issue measurement and verification (M&V) standards by January 2010. This timeline may be too aggressive, given the complexity of developing such standards.[9]

J. State EE Credit Interaction: The bill is silent on the issue of whether energy efficiency used to meet a state standard can also be used to meet the federal requirement. It appears that utilities that meet their state EE requirements could sell federal credits for the same efficiency to utilities in other states.

[9] The Department of Energy supported the International Performance Measurement and Verification Protocol (IPMVP) in the 1990s. The M&V standards developed are voluntary. Details are available at http://www.evo-world.org/.

5. Comparison with EIA 15% RPS Evaluation

In June 2007, the Energy Information Administration (EIA) released an analysis of the impacts of a 15% RPS using the National Energy Modeling System (NEMS).[10] NEMS and the Regional Energy Deployment System (ReEDS) model have some fundamental differences (see **Appendix B)** and differing baseline assumptions, which explains why they arrive at different estimates.[11]

Although this analysis uses a 20% RPS instead of the 15% in the EIA analysis, the effective targets are similar because energy efficiency credits can account for up to 25% of the RPS in this analysis. Many of the other legislative requirements are also similar: Existing hydropower cannot be used to meet the target, small electricity providers are exempt, and distributed PV systems earn triple credits.

Biomass generation is the largest contributor to the EIA's analysis of the 15% RPS, with wind and solar contributing as well. A detailed analysis would be required to fully explain these differences with the ReEDS results. However, the basic difference is that NEMS uses a more expensive supply curve to capture transmission, siting, and intangible costs associated with wind; while ReEDS directly assesses these costs in line with industry practice. This results in the lower cost for wind as the NEMS supply curve would suggest. Consequently, ReEDS results emphasize wind, while the NEMS model meets the RPS with other renewable resources—namely, biomass. By 2030, solar installations produce about 8% of qualifying renewable generation in the EIA analysis due to the triple-crediting; this is more than the ReEDS simulation estimates.

Relative to the reference case, retail electricity prices increase by about 2% in the EIA scenario in 2030, while the ReEDS analysis estimates a 1.3% increase. This is due to lower overall costs of the required renewable generation in ReEDS compared to EIA. Annual carbon dioxide emissions decline by 222 million metric tons (MMT) in the EIA 15% RPS scenario, compared to approximately 220 MMT in the ReEDS analysis.

[10] Available at http://www.eia.doe.gov/oiaf/servicerpt/prps/index.html.
[11] Documentation on NEMS is available at http://www.eia.doe.gov/oiaf/aeo/overview/index.html.

6. Potential Follow-on Work

As noted previously, this analysis is preliminary and should not be considered comprehensive or final. Potential follow-on work could include:

- **Conducting sensitivity analysis on the draft 20% RPS legislation**. Key sensitivities that could be run on the draft legislative bill include different energy efficiency allowance penetrations, gas price trajectories, nuclear power plant costs, RE technology improvements over time, and policy assumptions on PTC extensions and/or carbon caps/taxes. Additionally, it might be useful to explore the extent to which excess federal RECs, accrued as a result of state RPS compliance, are retired rather than sold. As noted previously, a substantial change to national tax credits for renewable energy occurred just after this analysis was completed and follow-on work should consider this new legislation.

- **Comparing past and ongoing work.** Several other organizations, including the Union of Concerned Scientists, Lawrence Berkeley National Laboratory, and the Energy Information Administration have published findings from similar RPS analyses. Follow-on work could include more comprehensive comparisons of these findings with those from other organizations.

- **Analyzing other proposed RPS legislation**. This work would look at proposals such as the 25% target by 2025 introduced by Rep. Edward Markey of Massachusetts.

Appendix A – ReEDS Model Description

The Regional Energy Deployment System (ReEDS) model is a multiregional, multitime-period, geographic information system (GIS), and linear programming model of capacity expansion in the electric sector of the United States. The model, developed by NREL's Strategic Energy Analysis Center (SEAC), is designed to conduct analysis of the critical energy issues in today's electric sector with detailed treatment of the full potential of renewable electric technologies.

The principal issues addressed include access to and cost of transmission, access to and quality of renewable resources, the variability of wind and solar power, and the influence of variability on the reliability of the grid. ReEDS addresses these issues through a highly discretized regional structure, explicit accounting for the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Qualitative Model Description

ReEDS minimizes system-wide costs of meeting electric loads, reserve requirements, and emission constraints by building and operating new generators and transmission in 23 two-year periods from 2006 to 2050. The primary outputs of ReEDS are the amount of capacity and generation of each type of prime mover—coal, natural gas, nuclear, wind, etc.—in each year of each two-year period.

Time in ReEDS is also subdivided within each two-year time period; each year is divided into four seasons, and each season into four diurnal time-slices. There is also one super-peak time-slice. These 16 annual time-slices (spring has only three time-slices) allow ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year both with conventional and renewable generators.

While ReEDS includes all major generator types, it has been designed primarily to address the market issues of greatest significance to carbon-constrained scenarios—carbon taxes or caps. As a result, renewable and carbon-free energy technologies are a focus.

Diffuse resources, such as wind and solar power, come with concerns that conventional dispatchable power plants do not have—particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much higher level of geographic disaggregation than other models: 356 different regions in the continental United States. These 356 resource supply regions are then grouped into four levels of larger regional groupings—balancing authorities, regional transmission operators (RTO), North American Electric Reliability Council (NERC) regions, and national interconnect regions.

Much of the data inputs to ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources allows ReEDS to calculate transmission distances, as well as the benefits of dispersed wind farms or CSP plants supplying power to a demand region. Both the wind and solar supply curves are divided into five resource classes, based on the quality of the resource—strength and dependability of wind or solar insolation—that are further described in ReEDS reference documentation.

Regarding resource variability and grid reliability, ReEDS also allows electric storage to be built—either co-located with wind farms or sited at load centers—and used for load shifting, resource firming, and ancillary services. Three varieties of storage are supported: pumped hydropower, batteries, and compressed air energy storage.

Along with wind and solar power, ReEDS has supply curves for biomass and geothermal resource and allows biopower and geothermal plants to be built in each balancing authority. The geothermal supply curve is in megawatts (MW) of recoverable capacity while the biomass supply curve is in MMBtu (one million British Thermal Units) of annual feedstock production. Other carbon-reducing options are considered as well. Nuclear power is an option, as is carbon capture and sequestration (CCS) on some coal and natural gas plants. For now, CCS is treated simply, with only an additional capital cost for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation process. In the future, it is intended that ReEDS will have geographically varying costs for CCS as well as piping and sequestering constraints on the CO_2.

The major conventional electricity-generating technologies considered in ReEDS include: hydropower, both simple and combined-cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by their:

- equipment lifetime (years)
- capital cost ($/MW)
- fixed and variable operating costs ($/MWh)
- fuel costs ($/MMbtu)
- heat rate (MMbtu/MWh)
- escalation in operating costs and heat rates with plant aging (%/year)
- construction period (years)
- financing costs (nominal interest rate, loan period, debt fraction, debt-service coverage ratio)
- tax credits (investment or production)
- minimum turndown ratio (%)
- quick-start capability and cost (%, $/MW)
- operating-reserve capability
- planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters, accounting for fundamental differences, of course. For instance, heat rate is replaced with round-trip efficiency for storage technologies, and the dispatchability parameters—fuel cost, heat rate, turndown ratio, quick-start, and operating reserve capability—are not used for non-dispatchable wind and solar.

The model considers distinguishing characteristics of each conventional generating technology. For example, there are several types of coal-fired power plants within ReEDS, including gasification, biomass co-firing, and CCS options. Any of these plants can burn either high-sulfur or, for a cost premium, low-sulfur coal. Generation by coal plants is restricted to be base and intermediate load with cost penalties (representing ramping/spinning costs) if power production during peak-load periods exceeds production in shoulder-peak hours.

New coal plants are assumed to be able to provide more spinning reserve capability than older units. Combined-cycle natural gas plants are considered to be able to provide some operating/spinning reserve and quick-start capability, while simple-cycle gas plants can be cheaply and easily used for reserves and quick-starts. Nuclear power is considered to be base load. Hydroelectricity is not allowed to increase in capacity, due to resource and environmental limitations. Hydropower is also energy-constrained, due to water resource limitations, but is assumed to be able to provide both quick-start capability and operating/spinning reserve.

Retirements of conventional generation can be modeled either through exogenous specification of planned retirements (currently used for nuclear, hydro, and oil/gas steam plants), economic retirements, or as a fraction of remaining capacity each period. All retiring wind turbines are assumed to be refurbished or replaced immediately—because the site is already developed with transmission access. Similarly, any storage at the wind site is assumed to be replaced immediately upon retirement while grid-sited storage retires automatically when its assumed lifetime has elapsed but is not automatically replaced.

ReEDS tracks emissions from both generators and storage technologies of carbon, sulfur dioxide, nitrogen oxides, and mercury. Caps can be imposed at the national level on any of these emissions. There is also the option of applying a carbon tax instead of a cap; the tax level and ramping pattern can be exogenously defined.

ReEDS is a national electric capacity expansion model, not a general equilibrium model. To define each time period of the optimization, the model requires that the scenario be exogenously specified in terms of fuel costs and electric loads for each NERC region over the 44-year time horizon of ReEDS. To allow for the evaluation of scenarios that might depart significantly from the scenario used to develop the input fuel prices and electricity demands, there are price elasticities of demand and demand elasticities of fuel prices integrated into the model. For demand, the exogenously defined demand escalation is adjusted up or down based on the price of electricity; while for coal and natural gas, the price is adjusted based on how the calculated fuel use compares to the use assumed in the inputs.

Qualitative Details on Transmission

ReEDS considers the availability of capacity on existing transmission lines, the cost of accessing and using those lines, and the cost of building new transmission lines for new generation (e.g., dedicated to new wind or CSP farms) when existing lines are not available. To determine how much wind or CSP can access existing transmission lines and the cost of building a line from the wind site to the grid, we use a GIS database to develop a four-step supply curve for each class of wind/solar in each supply region, which presents the amount of capacity that can access the grid at each of four different costs. (The supply curve is formed of discrete steps, with each step represented by a different variable within the linear program.)

The costs increase with increasing distance from the resource to an existing transmission line that has adequate remaining capacity available to accommodate the generation. Although the lines are usually carrying generation from other sources, at any given instant, they may or may not have the capacity to transmit additional power from new wind or CSP generators. It is practically impossible at the national level to assess the capacity available at any given time on each line in the country. Thus, ReEDS requires that the user input the fraction of the capacity of each line that will be available for wind or CSP; the default fraction is set at 10% for all lines.

This transmission availability constraint severely limits the amount of wind or CSP that can be transmitted on existing lines, well below that found in previous studies[12] that required only that the wind resource be within 20 miles of an existing transmission line.

In addition to the cost of building a line from the wind/CSP site to the grid, ReEDS also allows the user to input a cost for the use of the grid. That cost can be based on the distance the power is transmitted or on the number of power control areas that the electricity must pass through (called a "pancake rate"). ReEDS also verifies that the existing transmission lines crossing the border of a supply/demand region have enough capacity to carry the wind and CSP generation into and out of the region. In addition, all generation (from both renewable and conventional generators) is constrained from flowing between any two balancing authorities in each time-slice by the capacity of lines that connect the two balancing authorities. ReEDS does not account for loop-flows, contingencies, etc. that could further restrict transmission on existing lines.

While new transmission lines dedicated to renewables are not constrained by the remaining transmission capacity available, they do have additional cost. For lines built to serve remote sites, the entire cost of constructing and maintaining a new line is attributed to the wind or CSP capacity at that site. This means that the lines are used only when the wind is blowing (or sun is shining), and their costs must be amortized over that intermittent power. The costs of new transmission lines can vary significantly based on terrain, congestion, labor costs, etc. Currently, ReEDS assumes a single cost for new lines expressed in $/MW-mile, which is increased for rough terrain and population congestion. In the future, we anticipate modifying ReEDS to vary the new transmission line cost per mile with the length of the transmission line and the amount of renewable capacity potentially available within the supply region.

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[12] See, for example, B. Parsons and Y. Wan, *U.S. Wind Reserves Accessible to Transmission Lines*. IEEE Power Engineering Review. Vol. 15(9), September 1995; pp. 5-6; NREL Report No. 21239.

New transmission lines dedicated to wind or CSP can be built either between supply/demand regions as described above or within a region. Dedicated in-region transmission lines are assumed to transport the electricity generation directly from the wind/CSP site to a load center within the region, bypassing the transmission grid and connecting to the distribution system within the load center. As with the construction of lines connecting renewables to the grid described above, the GIS is used to develop supply curves for each resource class in each supply region for the cost of building these intraregional transmission lines directly to load centers.

New transmission lines are also built in ReEDS to transmit power from one balancing authority to another. These lines can be accessed by either conventional or renewable generators. ReEDS builds these lines when it is cost-effective and when there is a need for more transmission capacity between the balancing authorities in one or more of the 16 time-slices in each year; or when it is needed to ensure capacity reserve margins are met in the different balancing authorities, NERC regions, or interconnection regions.

Transmission losses are modeled in ReEDS as a linear function of the distance the power is transmitted. These losses apply to the transmission of both renewable and conventional generation, and are currently specified using the fraction of power lost per MW-mile.

Qualitative Details on Wind Variability

Wind power—because the resource is variable and unpredictable and neither the resource nor the resulting electricity can readily be stored—is complicated to model. ReEDS, in an attempt to capture the peculiarities of wind power, has a detailed stochastic treatment of wind power that is unique among power sources. Solar power, were it not assumed in ReEDS to have six hours of thermal storage, would have similar issues; as it is, for now, only wind has such involved variability calculations. The variability of the wind resource can impact the electric grid in several ways. One useful way to examine these impacts is to categorize them by time, ranging from multiyear planning issues to small instantaneous fluctuations in output.

At the longest time interval, a utility's capacity expansion plans may call for the construction of more nameplate generation capacity. To meet this need, the planners can plan to build conventional dispatchable capacity or wind. The variability of wind precludes the planners from considering a MW of nameplate wind capacity to be the same as a MW of nameplate dispatchable capacity: Wind capacity availability cannot be counted on when peak demand for electricity occurs; and, actually, conventional capacity also cannot be considered 100% reliable.

The difference is in the degree of reliability; conventional generators experience forced outages on the order of 2%-20% of the time, while wind energy is available at varying levels that average about 30%-45% of the time depending on the quality of the wind site. For planning purposes, this lack of reliability is handled in the same way—a statistical treatment that calculates how much more load can be added to the system for each MW of additional nameplate wind capacity, or effective load carrying capability (ELCC).

Effective load carrying capability is less for wind than for conventional capacity; first, because the wind availability is less than that of conventional generators. And second, because at any given instant, the generation from a new wind farm can be heavily correlated with the output from the existing wind farms—if the wind isn't blowing at one wind site, there is a reasonable chance it is also not blowing at another nearby site. On the other hand, there is essentially no correlation between the outputs of any two conventional generation plants.

Fortunately, there are ways to partly mitigate both the low availability of the wind resource and its correlation between sites. In the past 20 years, there has been considerable improvement in wind capacity factor (the ratio of actual output over a period of time to its output if it had operated at full capacity over that same interval) of new wind installations. This is attributable to both better site exploration/characterization and to improvements in the wind turbines themselves (largely higher towers).

The correlation in wind output between sites also can be reduced. Increasing the distance between sites and the terrain aspects that separate them reduces the chances that two sites will experience the same winds at the same time. With its multiple regions, ReEDS is able to approximate the distance between sites and, therefore, the correlation between their outputs. ReEDS uses the correlation between sites to estimate the variation in wind output from the total set of wind farms supplying power to a particular region.

Between each two-year-period optimization and for each demand region, ReEDS updates its estimate of the marginal ELCC associated with adding wind of each resource class in each wind supply region to meet demand within an RTO. This marginal ELCC is a strong function of the wind capacity factor and the distance from the existing wind systems to the new wind site for which the ELCC is being calculated. It is also a weak function of the demand region's load-duration curve as well as the size and forced outage rates of the conventional capacity. This marginal ELCC is assumed to be the capacity value of each MW of that wind class added in the next period in that wind supply region to serve the RTO's demand. Everything else being equal, when expanding wind capacity, ReEDS will select the next site in a region that is as far from the existing sites as possible to ensure the lowest correlation and the highest ELCC for the next wind site. (More practically, everything else is never "equal," and ReEDS considers the tradeoffs between ELCC and wind site quality, transmission availability/cost, and local siting costs.)

Generally, for the first wind site supplying a demand region, these capacity values (ELCC) are almost equal to the capacity factor. However, as the wind penetrates to higher levels, the ELCC can decline to almost zero in an individual wind supply region. The next time frame of major interest is the day-ahead time frame. Utilities generally make decisions on which generating units to commit to generation a day ahead of time. To comply with these unit-commitment procedures, independent power plant owners may be expected to provide a bid for firm capacity a day ahead. Obviously, this can be problematic for operators of wind farms. For example, if the wind operator bids to provide firm capacity, and the wind does not blow as forecast, the operator may have to make up the difference by purchasing power on the real-time market. If that power costs more per kilowatt hour than he is being paid for his day-ahead bid, he will lose money on those kilowatt hours he is forced to purchase.

Not all of today's electric-grid systems operate day-ahead and real-time markets, as described in the preceding paragraph. California, for example, allows a monthly balancing of bid and actual generation for wind that is much more tolerant of the inaccuracies in forecasting wind a day ahead of time. No matter the market structure, however, the imbalances must be offset with adequate operating reserves. Therefore, to capture the essence of the unit-commitment issue, ReEDS estimates the impact of wind variability on the need for operating reserves (includes quick-start and spinning reserves) that can rapidly respond to changes in wind output. The operating reserves are assumed to be a linear function of the variance in the sum of generation (both wind and conventional) minus load. Because the variability of wind is statistically independent of the load variability and forced outages, the total variance with wind can be calculated as the sum of the variance associated with the normal (i.e., no wind) operating reserve and the total (all the wind supply regions) variance in the wind output over the reconciliation period. Before each two-year optimization, ReEDS calculates the marginal operating reserve additions required by the next unit of wind (added in a particular wind supply region from a particular wind class) as the difference between the operating reserve required by the total system with that new wind and the operating reserve required by the total system, if there were no new wind installations in that wind supply region. This value is then used throughout the next two-year linear program optimization as the marginal operating reserve requirement induced by the next MW of wind addition in that region of that wind resource class.

At the shortest time interval, regulation reserves must compensate for instantaneous changes in wind output. Regulation reserves are normally provided by automatic generation control of conventional generators whose output can be automatically adjusted to compensate for small changes in voltage on the grid. Fortunately, these instantaneous changes in wind output do not all occur at the same time, even from wind turbines within the same wind farm.

This lack of correlation over time and the ease with which conventional generators can respond allows us to reasonably ignore this second order cost. ReEDS assumes that any wind generation delivered to a specific demand region in a specific time-slice that exceeds the total electric load in that region/time-slice will be lost. In addition, as mentioned above, ReEDS also statistically accounts for surplus wind lost within a time-slice due to variations in load and wind within the time-slice. ReEDS has three endogenous options for mitigating the impact of variability. The first is to add conventional generators that can provide spinning reserve (e.g., gas combined-cycle) and quick-start capabilities (combustion turbines). The second, and usually least costly, is to allow the dispersion of new wind installations reducing the correlation of the outputs from the different wind sites. The third, and usually most costly, is to allow for storage of electricity at the wind site. If it is cost-effective, ReEDS will build storage capacity at an onshore wind site that can be used during peak electric demand periods to generate electricity when the wind is not blowing to its full capacity. Storage options available in

ReEDS are pumped hydro, compressed air, and batteries. ReEDS endogenously selects the capacity of the turbines at a site, the transmission capacity to the site, and the capacity of the storage. It assumes that all output from wind turbines is used either to provide power directly to the grid or to charge storage. ReEDS also assumes that power can be delivered to a wind site from the grid (with industrial power-purchase retail markups) to charge storage even when the onshore wind turbines are not generating power.

This allows the power capacity (and, therefore, the capital cost) of the storage facility to be reduced without compromising its ability to provide adequate energy. The energy stored at a wind site can be discharged in any time-slice. ReEDS also allows the electricity storage technology to be placed at the load centers rather than at wind sites. General storage at the load centers would have greater capacity value than that located at an onshore wind site because it would not be constrained by the availability of transmission capacity from the wind site. On the other hand, as mentioned above, storage at an onshore wind site allows for the downsizing of transmission-line capacity.

To keep the number of variables in the linear program of ReEDS to a minimum, storage at offshore wind sites is not simulated. Such systems are assumed to be less likely, due to the relatively higher costs of offshore wind and storage.

Appendix B – Attributes of Modeling Renewable Electricity: ReEDS vs. NEMS

[Most important differences are in bold.]

Attribute	Details	ReEDS: Electric-Sector ONLY (Capacity Expansion Model)	NEMS: ALL Energy Sectors (Energy-Economic Model – EMM)
Costs dominated by capital costs	Finance, depreciation, materials costs, learning/decreasing costs	ReEDS base case capital costs are intended to represent “mainstream” industry expectations (largely from Black and Veatch)	EIA staff draws on various sources of expert opinion to select capital cost assumptions
Operating costs are fixed and small	Risks, variability	Does not address risk	Does not address risk
Modular plant size	Reduces over/under capacity problems and transmission requirements	Assumes all plants (including conventionals) can be built in a modular fashion	Assumes all plants (including conventionals) can be built in a modular fashion
Environmental impacts are generally minimal	Air emissions, life-cycle analysis of materials	Includes air emissions	Includes air emissions
Resource sites vary in quality	Resource level, time of availability, access to infrastructure, terrain	Models resource site-quality issues at relatively fine geographic resolution (more than 350 regions); models use of existing grid and new transmission construction necessary to obtain resource	**Applies long-term multipliers**, based in part on geospatial analysis of access to infrastructure and in part on expert judgment. Geographic resolution at NEMS region level (13). Due to coarse geographic resolution, **it is not possible to model transmission**

Conversion to usable energy must occur near the resource site	Transmission, siting	High spatial resolution enables relatively detailed modeling of transmission and siting (see above)	Transmission cost is represented by a regional adder to the cost of every KWh, e.g., wind transmission cost is same as gas-fired power transmission cost
Resource variability	Backup requirements, ancillary service requirements, curtailments, forecasting, diversity	**Represents variability and diversity through stochastic treatment of capacity value, operating reserve requirements, and curtailments.**	Represents variability in resource and has some decrease in capacity value as a function of amount of wind installed, but not as a function of diversity
Distributed capability - solar, biomass, wind	Competition at the retail level, interaction with owner's loads	Represents distributed PV on buildings at the 350+ regional resource variation level	Represents load at the 13 region levels of the EMM and distributed PV.
Immature industry	Comfort/experience of investors, uncertainty in future cost and performance, supply/demand imbalances	Includes learning. Includes growth penalties (rapid growth causes price increases)	Includes learning. Includes growth penalties.

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14. ABSTRACT *(Maximum 200 Words)*
This paper provides a preliminary analysis of the impacts of a proposed 20% national renewable portfolio standard (RPS) by 2021, which has been advanced in the U.S. Congress by Senator Jeff Bingaman of New Mexico, The paper was prepared before the America Recovery and Reinvestment Act was signed into law by President Barack Obama on February 17, 2009, and thus does not consider important changes in renewable energy (RE) policy that need to be addressed in follow-on analysis. We use NREL's Regional Energy Deployment System (ReEDS) model to evaluate the impacts of the RPS requirements on the energy sector and consider design issues associated with renewable energy certificate (REC) trading markets.

15. SUBJECT TERMS
NREL; renewable portfolio standard; RPS; Regional Energy Deployment System model; ReEDS; renewable energy certificates; RECs; generation capacity; National Energy Modeling System; NEMS; federal 20% RPS by 2021

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