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Publication Date
2016-10-01

DOI
10.1016/j.apenergy.2016.07.023

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Long-term Implications of Sustained Wind Power Growth in the United States: Direct Electric System Impacts and Costs

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Abstract
This paper evaluates potential changes in the power system associated with sustained growth in wind generation in the United States to 35% of end-use demand by 2050; Wiser et al. (forthcoming) evaluates societal benefits and other impacts for this same scenario. Under reference or central conditions, the analysis finds cumulative wind capacity of 404 GW would be required to reach this level and drive 2050 incremental electricity rate and cumulative electric sector savings of 2% and 3%, respectively, relative to a scenario with no new wind capacity additions. Greater savings are estimated under higher fossil fuel costs or with greater advancements in wind technologies. Conversely, incremental costs are found when fossil fuel costs are lower than central assumptions or wind technology improvements are more-limited. Through 2030 the primary generation sources displaced by new wind capacity include natural gas and coal-fired generation. By 2050 wind could displace other renewables. Incremental new transmission infrastructure totaling 29 million MW-miles is estimated to be needed by 2050. In conjunction with related societal benefits, this work demonstrates that 35% wind energy by 2050 is plausible, could support enduring benefits, and could result in long-term consumer savings, if nearer-term (pre-2030) cost barriers are overcome; at the same time, these opportunities are not anticipated to be realized in their full form under "business-as-usual" conditions.

Keywords:
Wind energy
Wind Vision
Scenario modeling
Wind integration
Transmission

1. Introduction

Wind power is one of the fastest-growing sources of new electricity supply globally and the largest source of new renewable power generation added in the United States since 2000. As of year-end 2015, there were nearly 74 gigawatts (GW) of installed wind capacity in the United States, and wind generation totaled 4.7% of 2015 U.S. electricity generation (AWEA 2016). While historical growth in wind power has been significant, interest in continued and sustained growth in wind is stimulated by its abundant resource potential (more than 10,000 GW of gross land-based wind and 4,000 GW of gross offshore wind in the United States [Lopez et al. 2012]); competitive long-term stable pricing (Wiser and Bolinger 2014); economic development opportunities (Brown et al. 2012); and favorable environmental attributes, relative to other sources of electricity (Siler-Evans et al. 2013). At the same time, historically low natural gas prices, low wholesale electricity prices, and reduced demand for electricity could depress future wind investments (DOE 2015). Moreover, the intrinsic variability, uncertainty, and location-dependence of wind can create transmission and grid integration challenges associated with greater levels of wind deployment (Milligan 2015).

To support policy development and public decision making, this paper and Wiser et al. (forthcoming) explore many of the costs, benefits, and related impacts associated with future wind power deployment as identified in the recent U.S. Department of Energy (DOE) *Wind Vision Study* (DOE 2015).[1] While we do not analyze a specific policy in this analysis, the quantifications of cost, benefits, and impacts of all future

1 The *Wind Vision Study* (DOE 2015) represents a technical update and expansion of an earlier DOE report (DOE 2008). It involved a broad-based collaboration among DOE, national laboratories, industry, academia, and non-governmental organizations and seeks to document the accomplishments of wind power to date, evaluate the overall economic proposition for wind power, and chart a future path for the technology.

U.S. wind deployment are intended to help inform policy decisions. This research uses a scenario analysis approach where we model scenarios of the future U.S. electricity system, including ones where 10%, 20%, and 35% of end-use electricity demand is met by wind-generated electricity in 2020, 2030, and 2050, respectively. These Wind Vision "*Study Scenarios*" are compared with "*Baseline*" scenarios under which no new wind is deployed post-2013 in order to assess the cost, benefits, and impacts of *all incremental* wind deployment beyond 2013. Incremental cost and wind deployment impacts of a traditional "business-as-usual" (BAU) scenario are also presented to further inform the amount and impact of potential future policy support.

In this paper we describe the electric-sector modeling approach and key input assumptions used to develop the scenarios; the envisioned transitions to a future power system based on the scenario results; direct electric sector costs and impacts on electricity consumers; and transmission expansion and grid-integration-related issues identified for the *Study Scenarios*. In Wiser et al. (forthcoming), these costs and electric-sector impacts are compared with social, environmental, and other benefits and impacts associated with the same scenarios. The impacts assessment in Wiser et al. (forthcoming) includes those associated with avoided greenhouse gas (GHG) emissions, other avoided air pollution emissions, water use, energy diversity and risk reduction, workforce and economic development, and land use and local impacts. The *Wind Vision* (DOE 2015) provides further detail on the assumptions and results for both papers.

Our approach builds on past research and substantially contributes to this literature. The existing literature has found that the size of the global (Marvel et al. 2012) and U.S. (Lopez et al. 2012) wind resource coupled with the increasing maturity of wind technology (Wiser et al. 2011) might yield a robust role for wind energy (Barthelmie and Pryor 2014; Cochran et al. 2014; IPCC 2014; Luderer et al. 2014; Zhang et al. 2016). Future wind deployment, however, can be strongly affected by the extent of continued wind energy cost reductions, the scale of greenhouse gas emission policies, competitiveness of other generation technologies, and other factors (IPCC 2014; Luderer et al. 2014; Mai et al. 2014; Zhang et al. 2016). Some of the scenario analysis literature focused specifically on future U.S. wind (MacDonald et al. 2016, DOE 2008).

Other past research, which is oftentimes separate from the detailed research on wind energy's impacts on the electricity system, has explored a subset of the potential environmental or societal benefits of wind energy. For example, Yang and Chen (2016) evaluate the sustainability of wind power systems. McCubbin and Sovacool (2013) compare the health and environmental impacts of wind to natural gas, Siler-Evans et al. (2013), Buonocore et al. (2016), and Cullen (2013) explore regional health and climate benefits, while Arent et al. (2014) assess a small subset of benefits associated with a high-penetration renewable energy scenario in the U.S.

Our research, including that presented in this paper and that described in Wiser et al. (forthcoming), extends the prior research in multiple significant ways. Ours includes a comprehensive assessment of arguably the most-significant impacts, costs, and benefits associated with all new wind deployment under a high penetration wind future. This comprehensive assessment uses a myriad of state-of-the-art methods needed to quantify the diverse key effects – spanning wind industry and grid infrastructure requirements, electricity system and ratepayer impacts, and environmental, public health, and other economic impacts – of a high-penetration wind energy future. We rely on an electric sector model that contains the spatial and temporal detail necessary to accurately assess high wind energy penetration futures, and on state-of-the-art methods to assess the benefits and impacts that derive from that future. We also use recent assumptions about wind and fossil energy costs to ensure that our results are current

and relevant to inform decision-makers. In addition, to reflect the uncertainties involved in the future market, technology, and policy conditions as well as in the underlying methods, we use multiple sets of assumptions to estimate plausible ranges of future impacts. We clearly present uncertainties, limitations, and caveats so that researchers and decision-makers can properly understand and evaluate the results described. Finally, in addition to the national-scale impacts reported and of focus in much of the existing literature, we present many of our key findings regionally to inform local as well as national stakeholders. Section 2 of this paper describes the modeling methodology, particularly the Regional Energy Deployment System (ReEDS) model, the scenario construct, and the key input assumptions used for the *Wind Vision* scenarios. Section 3 presents the scenario results, including U.S. wind industry impacts, cost and price impacts, implications for the evolution of the U.S. electricity sector, and transmission and integration related results. We conclude in Section 4.

2. Modeling and Assumptions

2.1. Regional Energy Deployment System (ReEDS) Model

The primary analytic tool used for the *Wind Vision* scenario development and impacts assessment is the National Renewable Energy Laboratory's (NREL's) ReEDS model (Short et al. 2011). ReEDS is an electric sector capacity expansion model that relies on system-wide least cost optimization to estimate the type and location of fossil, nuclear, renewable, and storage development; the transmission expansion requirements; and the generator dispatch and fuel needed to satisfy regional demand requirements and maintain grid system adequacy. ReEDS considers technology, resource, and policy constraints, and models scenarios of the continental U.S. electricity system from 2010 to 2050. ReEDS is specifically designed, through the use of high spatial resolution and statistical methods that estimate impacts of renewable variability and uncertainty, to represent the unique characteristics of wind and other renewable generation and their impacts on the broader electric system. In particular, ReEDS explicitly and dynamically estimates the need for new transmission and increases in operating reserve requirements, renewable curtailments, and changing contributions to planning reserves that may be driven by increases in renewable generation. Many of the features are not available in other large-scale capacity expansion models.

While ReEDS represents many aspects of the U.S. electric system, like any model, it has certain limitations. Some of these limitations include a system-wide optimization perspective that does not accurately reflect all market inefficiencies; limited industry and manufacturing constraints in the model; and a narrow focus on the U.S. electricity system. One consequence of these model limitations—which also exist in most long-term capacity-expansion models—is that estimated system expenditures may be understated, as the practical realities associated with planning electric system investments and siting new generation and transmission facilities are not fully represented in the model. Another limitation of the model is that it does not explicitly include detailed systems operation modeling needed to more fully consider wind grid integration. In addition, transmission modeling in ReEDS is designed to capture the basic economics of accessing remote resources and to conceptually inform future transmission layouts, but is not intended for detailed transmission planning.

Notwithstanding the above limitations, we use ReEDS for our analysis because of its sophisticated ability to capture many of the traits of wind technologies described previously, in the appendix, and in the model documentation (Short et al. 2011). High spatial resolution in ReEDS enables it to consider the relative economics among generation resources and the trade-offs between different spatial distributions of wind and other technologies, including the cost of transmission expansion. For example,

ReEDS models many more regions and has greater renewable technology-specificity than other large-scale capacity expansion models including the U.S. Energy Information Administration's National Energy Modeling System (NEMS) model or global Integrated Assessment Models (IAMs). In addition, in a similar manner to production cost models, ReEDS estimates the operational impacts of higher levels of wind. ReEDS' representation of systems operation includes lower temporal resolution than production cost models; however previous research (Brinkman 2015, NREL 2012) applied hourly and sub-hourly modeling directly based on ReEDS capacity expansion scenarios, including those with similar or greater wind penetration levels explored in the present analysis, and have found that ReEDS' representation of renewable grid integration is adequate. Other analyses (Lew et al. 2013, EnerNex 2011) have also used production cost simulations with similar wind penetration levels to those presented herein without conflicting findings to those from ReEDS. Because of these prior results and the lack of ability for production cost models to reflect capacity expansion, we use ReEDS for the current work as opposed to these other models. We also use a range of scenarios, described in Section 2.2, to quantify a range of possible future impacts.

Additional detail on the ReEDS model is provided in the article appendix and the ReEDS documentation (Short et al. 2011). Recent publications using ReEDS include the *SunShot Vision* study (DOE 2012), the *Renewable Electricity Futures* study (NREL 2012), and other papers (Mai et al. 2014a; Mai et al. 2014b; Clemmer et al. 2014; Mignone et al. 2013; Lantz et al. 2014; Logan et al. 2013). An earlier version of the ReEDS model was also used to develop scenarios for the *20% Wind Energy by 2030* report (DOE 2008). We also use the NREL SolarDS model (Denholm et al. 2009), which simulates future rooftop solar photovoltaic (PV) deployment.

2.2. Scenario Framework

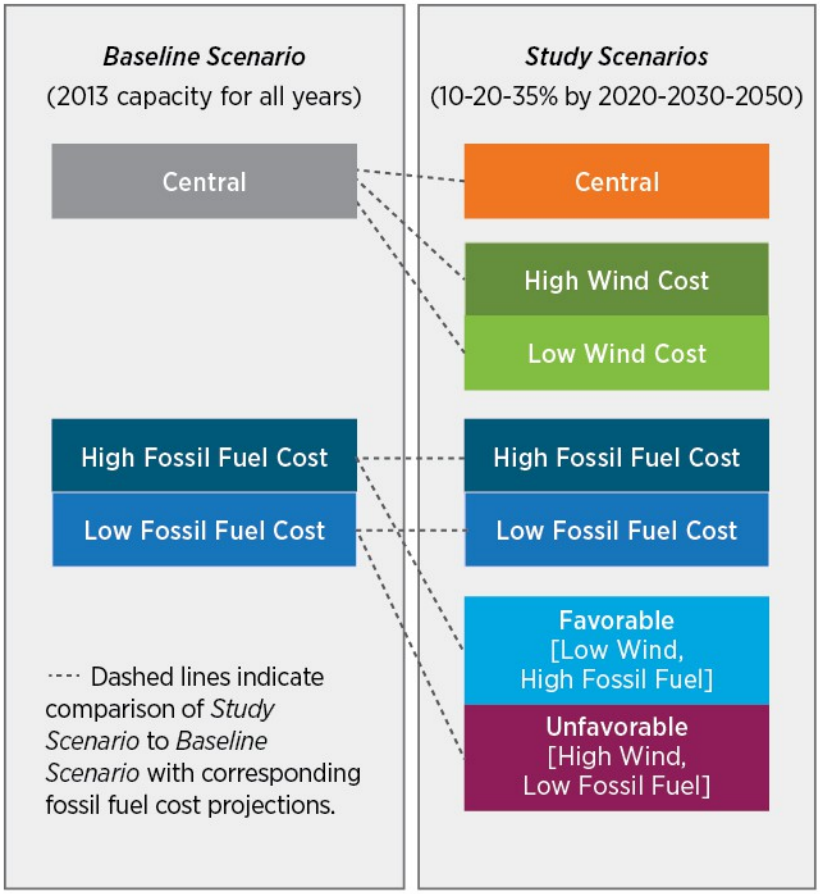
The *Wind Vision* modeling analysis is focused on two sets of scenarios: *Study Scenarios* and *Baseline Scenarios*. The level of wind generation is exogenously defined under both sets of scenarios and none of the scenarios represents the economically optimum amount of future wind power. The *Study Scenarios* reflect predetermined growth in wind penetration in the U.S. electricity system through 2050. In contrast, the *Baseline Scenarios* serve as reference scenarios by reflecting the opposite future for wind; wind capacity is artificially prevented from deploying in the model after 2013 under the baseline. This type of reference scenario differs from a traditional BAU reference where artificial limitations on wind or other generation types are not generally applied. We design our *Baseline Scenario*s such that differences in results between them and the *Study Scenarios* reflect the impact of <u>all</u> new wind deployment after 2013. The *Study Scenarios* can be conceptually viewed as including a national wind-specific energy standard although we do not intend to analyze this or any other particular policy. Instead, the valuation assessment is designed to inform any policy that might be considered to support new wind deployment.

Under the *Study Scenarios*, annual wind power electricity generation is prescribed to reach predetermined levels of 10% of annual end-use electricity demand by 2020, 20% by 2030, and 35% by 2050. (No predetermined capacity requirements from wind power are modeled in the *Study Scenarios*. Instead, the total wind capacity required to reach the wind penetration levels is determined by the assumed future performance of wind technologies, the quality of the wind resource in sites accessed for each ReEDS scenario, and the amount of wind curtailment estimated by ReEDS.) Included within these total wind penetration levels, offshore wind generation is prescribed to be 3% of wind's electricity share (0.3% of annual end-use demand) by 2020, 10% of wind generation (2% of end-use demand) by 2030, and 20% of wind generation (7% of end-use demand) by 2050. The offshore wind levels include regional specificity for five separate offshore regions: the North Atlantic, South Atlantic, Gulf, Pacific, and Great

Lakes. We note that assumed technology costs for offshore wind are higher than land-based wind (see Section 2.3) and that we apply additional constraints in the optimization model to reflect the desired regional offshore wind generation prescriptions. As a result, our reported electric system cost estimates – which are based on scenarios *with* the offshore prescriptions – are likely higher than they might otherwise be. However, offshore wind offers unique potential benefits that may not be fully captured in the modeling analysis—including the scale of available offshore wind resource for high cost coastal markets, reduced transmission requirements, potential fuel diversity and wholesale price benefits, and possibly higher capacity value.

In developing the specific wind penetration scenarios and percentages, scenario design considerations included the ability of those scenarios to: maintain recent industry growth trends and support demand for the existing domestic wind power manufacturing base; achieve future wind energy penetration levels that are consistent with the range of prior estimates anticipated to support substantial future carbon emissions reductions (Wiser et al. 2012, Clarke et al. 2014); be technically feasible and economically plausible with aggressive wind technology cost reductions (e.g., Low Wind Cost assumptions, see Section 2.3.1), relatively high fossil fuel prices, or some combination of the two, even absent policy support. See DOE (2015) for further details on the justification for these specific wind penetration targets.

Given uncertainties associated with future market conditions, multiple scenarios are modeled as sensitivities. Two sets of key future market variables are evaluated: wind cost and performance and fossil fuel costs. Three trajectories of future wind cost—central, high, and low wind cost—and three trajectories of future fossil fuel costs from the EIA's 2014 Annual Energy Outlook (AEO)—central, high, and low fuel cost—are considered. While most sensitivities vary only one of these market variables at a time, we also model combined sensitivities including under favorable (low wind costs coupled with high fuel cost) and unfavorable (high wind costs coupled with low fuel cost) conditions. All other input data assumptions are identical across sensitivities and are summarized below. Figure 1 shows the scenario framework, including *Study* and *Baseline Scenarios* and all sensitivities.



Note: Fossil Fuel Costs (Low, Central, High) are based on Annual Energy Outlook (AEO) 2014 scenarios. Wind costs (Low, Central, High) were derived from a literature review.

Figure 1. Scenario framework of the *Wind Vision* analysis.

For the *Baseline Scenarios*, we artificially fix total installed wind capacity at year-end 2013 levels. These scenarios are exclusively used as references from which the incremental impact of all future wind deployment and generation can be assessed. Because of the artificial limit on post-2013 wind deployment, this *Baseline* differs from a traditional BAU scenario. The *Central Baseline Scenario* provides a reference for the three *Study Scenarios* that rely on the central fossil fuel cost case, and the *Baseline Scenarios* under high and low fuel cost assumptions provide references for the *Study Scenarios* with the corresponding fuel cost assumptions. *Baseline Scenario* sensitivities with different wind technology improvement trajectories are not needed because no new wind capacity is installed. None of the scenarios within either of these categories—*Study* or *Baseline*—represents a forecast or prediction. Instead, they provide the framework for understanding impacts in a future that includes high levels of wind power.

For reference and to further inform potential policy development, we also present results relative to a more traditional BAU scenario in Section 3.5.

Other market factors, such as demand growth or different non-wind technology projections, can also impact results and introduce uncertainty; however, modeling the sensitivity of results to these factors is

outside the scope of the present study. In addition, other than the prescribed wind penetration levels in the *Study Scenarios*, the modeling analysis only considers existing policies as enacted as of January 1, 2014. Proposed or new legislation or regulations that would impact future wind deployment are excluded from the results and analysis reported here. For example, the U.S. Environmental Protection Agency's Clean Power Plan was not modeled as the final rules for this power sector carbon regulation were not available at the time the analysis was complete, and remain unclear given legal challenges.

It is important to note that—while the *Wind Vision* analysis is policy-agnostic and focused entirely on the U.S. electric sector—the impacts, costs, and benefits of the *Study Scenarios* will be dependent on the policy and market factors used to yield wind deployment levels consistent with the *Wind Vision* as well as broader economic interactions. The impacts, costs, and benefits presented here are driven by the approach to implementing the *Study Scenarios* in ReEDS: prescribed wind generation levels in the electric sector. Alternative approaches to reaching the same deployment levels, through policy drivers or market dynamics, would be expected to yield somewhat different results. We also note that research has generally found that policies that are specifically intended to internalize so-called "external" costs (e.g., environmental taxes) are likely to be more cost effective and/or deliver greater social returns than will technology- or sector-specific policy incentives. This is, in part, due to economy-wide rebound and spillover effects, which are not explicitly modeled in *Wind Vision*.

2.3. Major Assumptions

Data sources, methods, and core major assumptions, including wind and non-wind technology cost and performance, fossil fuel costs, electricity demand, and retirement assumptions are described briefly in the following sections. Further detail on these and descriptions of other assumptions can be found in DOE (2015) and the underlying references.

2.3.1. Technology Cost and Performance

We develop technology cost and performance assumptions, including region-specific capital costs, estimated operations and maintenance (O&M) expenditures, performance or capacity factor data, and transmission spur line costs (i.e., transmission costs to move the power to local load, another transmission line with available capacity, or a centralized export point) for land-based and offshore wind for current and future years, through 2050. Assumptions for current land-based wind technologies are grounded in market data (Wiser and Bolinger 2014) and modeled performance of current commercial technology (e.g., Wiser et al. 2012). Future projections for land-based wind are developed, using a process consistent with that from Lantz et al. (2012), based on 23 projections from 15 independent studies. Starting from a 2014 cost range of approximately $50/MWh to $85/MWh, under the Central Wind Cost projection, the levelized costs of electricity (LCOEs) for land-based wind technologies decline from 2014 levels 9% by 2020, 16% by 2030, and 22% by 2050. Under the Low Wind Cost projection, the percent reductions are 24%, 33%, and 37% for the same time periods, respectively. We assume no technology improvement for land-based wind under the High Wind Cost projection.

Offshore wind inputs were developed in a similar manner. However, a greater diversity of technology (i.e., marine sub-structures), limited data, a less mature industry, and fewer long-term projections necessitated some key differences. Starting-point cost data were derived from the published data of the global offshore wind industry as well as estimates from recent development activity on the Atlantic coast of the United States (Tegen et al. 2011; Tegen et al. 2010). Analyses of independent literature-based projections were used to inform estimates of cost reduction through the mid-2020s. From the mid-2020s

to 2050, offshore wind projections rely on three independent learning rate estimates (DOE 2015). In addition, offshore wind costs included estimates of offshore export cables and incremental construction costs associated with sites further from shore. Reductions to 2014 offshore wind LCOEs (estimated at approximately $170/MWh to $230/MWh) are assumed to be 16% by 2020, 32% by 2030, and 37% by 2050 under our Central Wind Cost projection. In comparison, offshore LCOEs decline by 22%, 43%, and 51% under the Low Wind Cost projection and 5%, 18%, and 18% under the High Wind Cost projection, by 2020, 2030, and 2050, respectively. Further detail on the methods used to develop current and future wind technology cost projections and the specific parameters can be found in the *Wind Vision* (DOE 2015).

Expected cost and performance estimates for new solar PV, concentrating solar power, geothermal, biomass, and hydropower were also developed from empirical market data and literature projections, where such data were available. Non-renewable electric generation technologies, including coal, natural gas combined cycle, natural gas combustion turbine, and nuclear technologies, rely on capital cost and performance estimates resulting from the AEO 2014 Reference Case (EIA 2014). DOE (2015) provides further detail on those assumptions.

Three explicit trajectories of fossil fuel costs are considered—Low Fuel Costs, Central Fuel Costs, and High Fuel Costs—to reflect the substantial uncertainty in future fuel cost projections and the sensitivity of modeling outcomes to changes in the projected fossil fuel prices. Central Fuel Costs are extracted from the AEO 2014 Reference Case. Low Fuel Costs are extracted from the High Oil and Gas Resource and the Low Coal Cost scenarios in the AEO, whereas High Fuel Costs are extracted from the Low Oil and Gas Resource and High Coal Cost scenarios in the AEO (EIA 2014). Because the AEO data extend only through 2040, fossil fuel costs for each specific trajectory are assumed to be constant in real dollar terms from 2040 to 2050. While the AEO data provides the base fuel prices for natural gas, ReEDS endogenously accounts for the sensitivity of fuel costs (prices) to changes in regional electric sector fuel usage.

2.3.3. Load Growth and Retirements

The *Wind Vision* applies a single load growth trajectory, extracted from the AEO 2014 Reference Case for the time period of 2013 to 2040 and extrapolated through 2050. Regional differences reflected by the AEO are also represented in ReEDS. The overall change in electricity demand is approximately 34% from 2013 (3,700 terawatt-hours [TWh]) to 2050 (4,900 TWh), with an average annual load growth rate of 0.8%.

Generation plant retirements in ReEDS are primarily a function of plant age and assumed lifetimes. Fossil fuel-fired plant ages are derived from data reported by Ventyx.[2] Coal plants less than 100 MW in capacity are retired after 65 years; coal plants greater than 100 MW in capacity are retired after 75 years. Natural gas- and oil-fired capacity is assumed to have a 55-year lifetime. Nuclear plants are assumed to be approved for a single service life extension period, giving existing nuclear plants a 60-year life. No refurbishment costs or increased O&M costs are applied to extend the nuclear or fossil plant life. Plant lifetimes are also estimated for other generation sources. Respective assumed lifetimes are: wind power plants, 24 years; solar and geothermal facilities, 30 years; and battery storage, 12 years. All other technologies (e.g., hydropower, biopower) are assumed to have lifetimes extending beyond 2050.

2 http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite.

Plant retirement decisions in reality are more complex and would likely require weighing revenues with ongoing fixed and variable costs instead of simple lifetimes. To partially reflect economic decision-making considerations, we model utilization-based retirements in addition to age-based retirements described above. Moreover, near-term coal retirements are reflected in the modeled scenarios by incorporating announced retirements (Saha 2013). In total, as a result of all retirement assumptions, cumulative (starting in 2013) coal retirements in the *Central Study Scenario* total 43 GW by 2020, 67 GW by 2030, and 186 GW by 2050. From 2013 to 2050, 97 GW of nuclear capacity, 86 GW of natural gas combustion turbine (NG-CT) and combined cycle (NG-CC) capacity, and 96 GW of oil- or gas-based steam capacity are assumed to retire. A majority of the nuclear, NG-CT, and NG-CC capacity retires after 2030. The amounts of fossil and nuclear capacity retirements under the *Central Baseline Scenario* are slightly less than but similar to the values reported for the *Central Study Scenario*. While significant uncertainties exist with respect to future plant retirements, we note that because of these similar retirement estimates between scenarios, costs and impacts that are derived based on differences between scenarios would not likely be sensitive to different retirement assumptions, so long as they are applied consistently between scenarios.

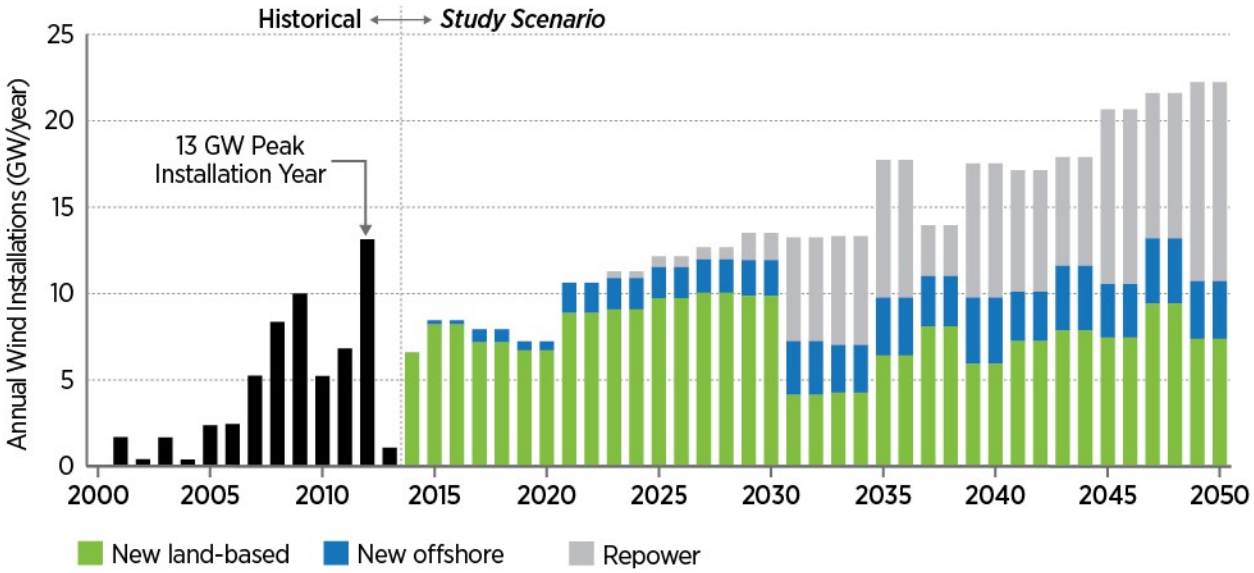
3. Results

Transitioning to a future electricity system where wind plays a more prominent role will have direct impacts to the wind industry, cascading effects through the rest of the electricity system, and implications to local and global environments, human health, and the broader economy. In this section, we describe an envisioned 35% wind by 2050 scenario, in terms of wind capacity distribution and growth, impacts to electric sector and consumer costs, impacts to other electricity generation industries, transmission expansion, and grid integration. DOE (2015) and Wiser et al. (forthcoming) supplements this analysis by presenting some of the environmental, social, and other impacts associated with the same scenarios.

3.1. Future Wind Capacity and Investments

In the *Central Study Scenario*, total installed wind capacity increases from 61 GW at year-end 2013 to approximately 113 GW by 2020, 224 GW by 2030, and 404 GW by 2050. This growth represents nearly three doublings of installed capacity. Of these installed capacity amounts, offshore wind comprises 3 GW, 22 GW, and 86 GW for 2020, 2030, and 2050, respectively. The amount of installed wind capacity needed to meet the deployment levels considered in the *Study Scenarios* will depend on future wind technologies. For example, with improvements in wind technology yielding higher capacity factors (i.e., Low Wind Cost), 382 GW of wind capacity is needed to reach the 35% penetration level in 2050. Conversely, 459 GW would be required using today's technologies with limited advancements (i.e., High Wind Cost).

The *Study Scenarios* support new wind capacity additions at levels comparable to recent historical levels (U.S. average annual wind growth between 2009 and 2013 was 7 GW/year) but drives higher levels of total demand for wind turbine equipment as a function of repowering needs—that is, the replacement of turbine equipment at the end of its useful life with new state-of-the-art equipment. Considering both new additions and repowering, demand for wind turbines averages approximately 8 GW/year from 2014 to 2020 and 12 GW/year from 2021 to 2030 and increases to 18 GW/year from 2031 to 2050. While aggregate demand trends upward (Figure 2), it is primarily concentrated in the new land-based segment in the near term. Deployment of offshore plants and repowering become more significant in the 2031–2050 timeframe.



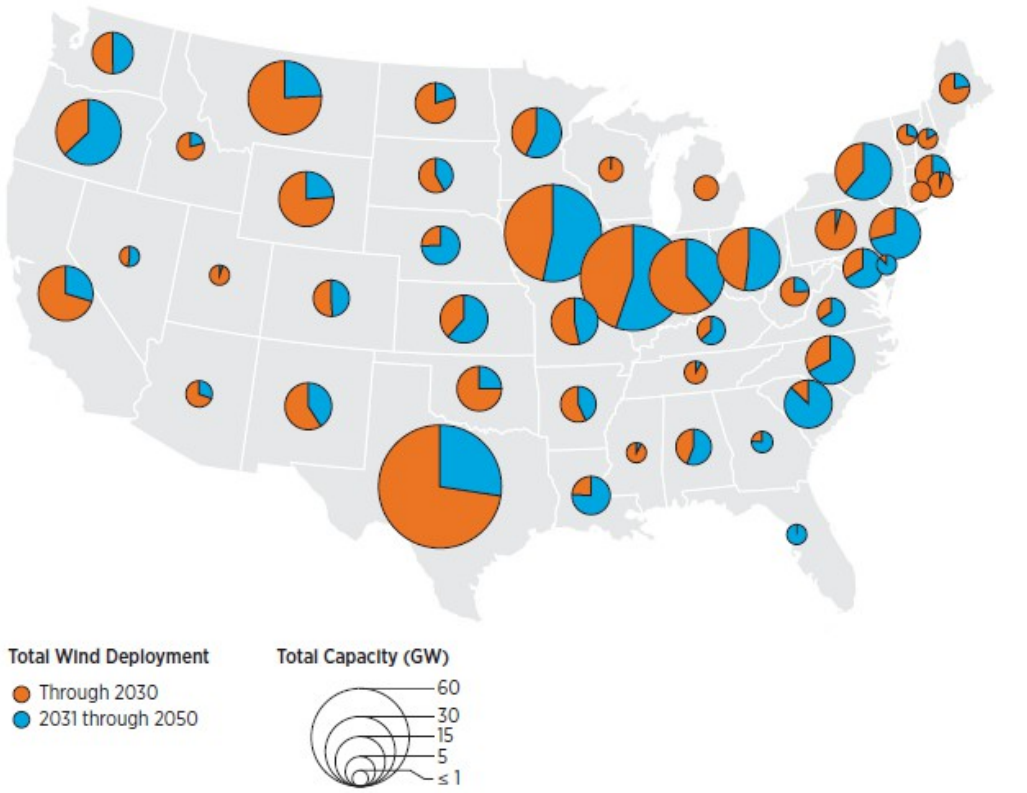
Note: New capacity installations include capacity added at a new location to increase the total cumulative installed capacity or to replace retiring capacity elsewhere. Repowered capacity reflects turbine replacements occurring after plants reach their useful lifetime. Wind installations shown here are based on model outcomes for the *Central Study Scenario* and do not represent projected demand for wind capacity.

Figure 2. Historical and forward-looking wind power capacity growth in the *Central Study Scenario*.

Wind industry expenditures (new capital and development expenditures, annual operating expenditures, and repowered capital expenditures) grow to more than $30 billion/year from 2020 to 2030 and are estimated at approximately $70 billion/year by 2050 for the *Central Study Scenario*.[3] In 2050, annual expenditures exceed $20 billion/year for operations, $25 billion/year for repowering, and $25 billion/year for new greenfield development. For comparison, new investments in U.S. wind plants averaged $13 billion/year between 2008 and 2013.

Figure 3 illustrates the state-level distribution of utility-scale wind capacity (land-based and offshore) in 2030 and 2050 under the *Central Study Scenario*. By 2030, installed wind capacity exists in all but one state. By 2050, wind capacity is present in all 50 states, with at least 40 states having more than 1 GW of installed wind capacity.[4] Variations in wind resource quality, relative distances to load centers, and existing infrastructure drive regional differences in modeled wind penetration levels. In addition, while Figure 3 shows regional distributions of wind for a single scenario, state wind deployment exhibits a wide range across the broad set of scenarios modeled. Nonetheless, we find diverse geographic distribution of future wind power deployment across all *Study Scenarios*.

3 Unless otherwise specified, all monetary results reported are in real 2013 U.S. dollars.
4 As of 2015, wind installations of 62 MW and 203 MW exist in Alaska and Hawaii, respectively (AWEA 2016). While future wind deployment in these states is expected and could potentially grow beyond 1 GW, these states are not counted among the states with more than 1 GW because the modeling analysis was restricted to the 48 contiguous states.



Note: Results presented are for the *Central Study Scenario*. Across *Study Scenario* sensitivites, deployment by state may vary depending on changes in wind technology, regional fossil fuel prices, and other factors. ReEDS model decision-making reflects a national optimization perspective. Actual distribution of wind capacity will be affected by local, regional, and other factors not fully represented here. Alaska and Hawaii already had wind deployment in 2013. However, future deployment estimates are limited to the 48 contiguous United States due to modeling limitations.

Figure 3. Distribution of wind capacity in 2030 and 2050 under the *Central Study Scenario*.

3.2. Costs of the *Wind Vision Study Scenarios*

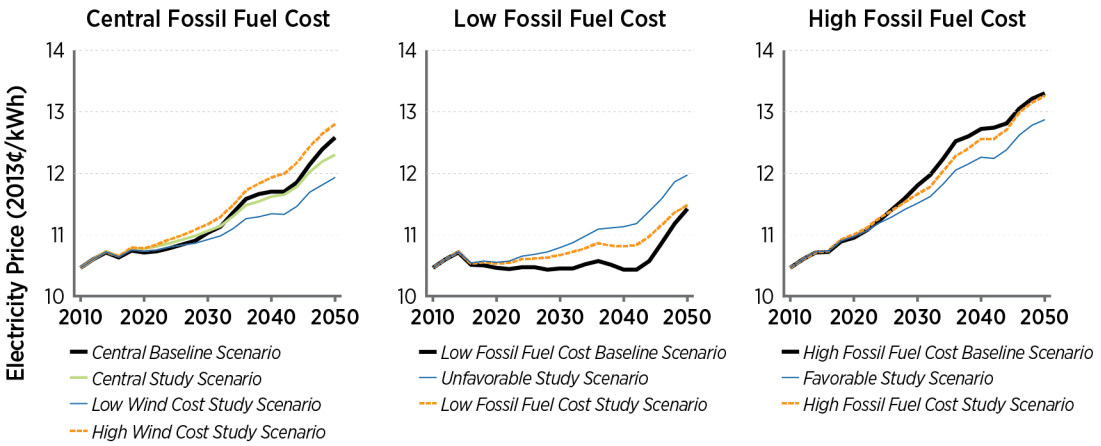
We assess the cost of the scenarios by using two metrics: national average retail prices to all electricity consumers in the United States and the net present value of direct electric system expenditures. Both metrics consider costs associated with all capital, operating, and fuel expenditures for new and existing generation, transmission, and storage capacity. *Incremental* costs of the *Study Scenarios* are measured with respect to the corresponding fuel cost *Baseline Scenario*.

3.2.1. Electricity Prices

Average retail electricity prices across all regions and all sectors (residential, commercial, and industrial) for both the *Baseline Scenarios* and the *Study Scenarios* are estimated to grow (in real terms) between 2013 and 2050. Through 2030, retail electricity prices in the *Central Study Scenario*, relative to the *Baseline Scenario*, are less than 1% higher. In the long-term (2050), retail electricity prices are expected to be *lower* by 2% compared to the "no-new-wind" *Baseline Scenario*. A wider range of future costs and savings are possible as estimated by the sensitivities. In 2020, retail electricity rates range from nearly zero cost difference up to a 1% cost increase when comparing the *Study Scenarios* to the respective

Baseline Scenarios. In 2030, incremental costs are estimated to be as high as 3% under the most unfavorable conditions for wind (low fossil fuel prices combined with high wind power costs). Under the most favorable conditions in 2030, the *Study Scenario* results in a 2% reduction in retail electricity prices relative to the *Baseline Scenario*. By 2050, incremental electricity prices across the *Study Scenarios* are estimated to range from a 5% increase to a 5% reduction in electricity prices relative to the corresponding *Baseline Scenario*. For the *Central Study Scenario*, we find reductions in 2050 electricity prices of about 2%.

The electricity price results demonstrate the importance that fossil fuel prices have on future electricity prices in absolute terms as well as in relative terms between high and low wind scenarios. In addition, incremental electricity prices of the *Wind Vision* can be strongly affected by advancements in wind technologies. Figure 4 shows estimated national average retail electricity prices across all *Study* and *Baseline Scenarios*.



Note: Electricity price scale does not start at 0.

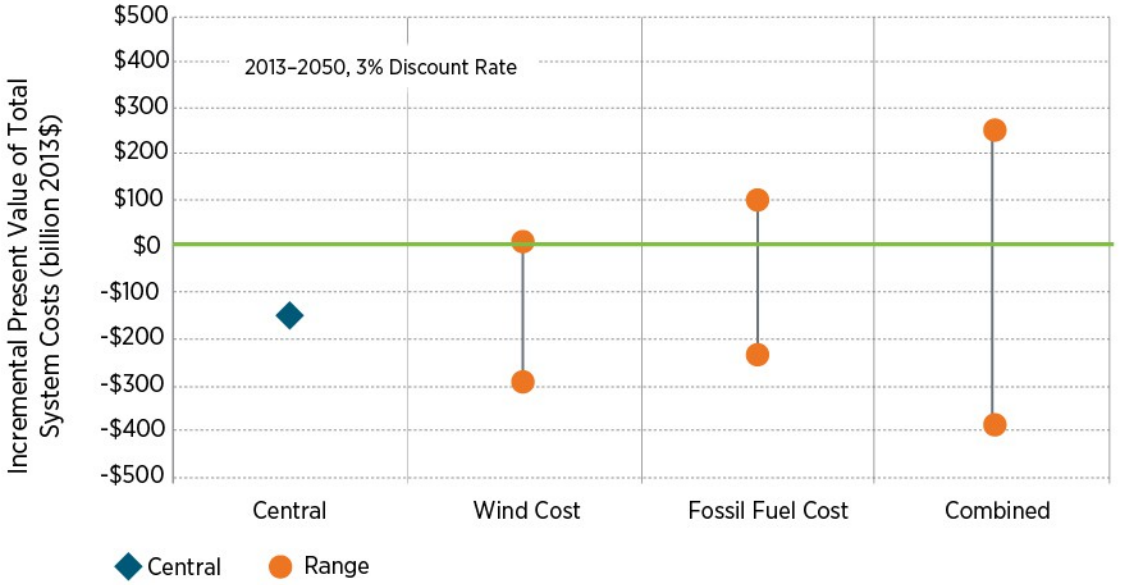
Figure 4. National average retail electricity prices for the *Study* and *Baseline Scenarios* (across sensitivities).

3.2.2. Electric System Costs

In present value terms (3% real discount rate, 2013–2050),[5] cumulative electric sector expenditures (fuel, capital, operating, and transmission) are lower for the *Study Scenarios* than for the *Baseline Scenarios* under central conditions and many sensitivities. Such a result is consistent with the long-term reduction in retail electricity rates found for the *Study Scenarios* and is a function of the value after 2030 of including large amounts of new wind in the system, as fuel prices increase and retired capacity requires replacement, relative to a scenario that holds wind capacity at current (2013 levels). In particular, the net present value of system cost for the *Central Study Scenario* is approximately $149 billion (-3%) lower than the *Central Baseline Scenario*. As shown in Figure 5, potential incremental electricity sector expenditures range from savings of $388 billion (-7%) to a cost increase of $254 billion (+6%), depending on future wind power cost trends and fossil fuel prices.

5 A 3% real discount rate is used reflecting a "social" discount rate that is commonly used to assess long-term costs and benefits by the U.S. Energy Information Administration, International Energy Agency, and Intergovernmental Panel on Climate Change and is consistent with the White House Office of Management and Budget guidance for "cost-effectiveness" analysis that spans more than 30 years. This discount rate differs from the higher investment discount rate used internal to ReEDS in its investment decision-making.

Trends in total electric system costs are a direct result of the trade-off between wind capital investments versus fuel costs, primarily associated with natural gas-fired generation but also with coal-fired generation. Other system changes associated with the *Study Scenarios* are also captured in the cost comparisons. For example, additional costs associated with the greater transmission and storage capital investments (Section 3.4) are captured in these figures, but reduced capital investments for non-wind technologies (including solar and natural gas) and reduced fuel costs mitigate these increases. The net results of these impacts are shown in Figure 5 and result in cost savings associated with the *Central Study Scenario*, and a wide range of possible impacts across the sensitivity scenarios.



Note: Ranges reflect the incremental prices for the *Study Scenario* relative to the comparable *Baseline Scenario*. Categories of results reflect the specific sensitivities considered. *"Wind Cost"* reflects the change in impact across the *Low Wind Cost* and *High Wind Cost Scenarios, "Fossil Fuel Cost"* reflects the change in impact across *High Fossil Fuel Cost* and *Low Fossil Fuel Cost Scenarios*, and "Combined" refers to the change in impact across the *Favorable* and *Unfavorable Scenarios* in which low wind costs are combined with high fossil fuel costs and high wind costs are combined with low fossil fuel costs, respectively.

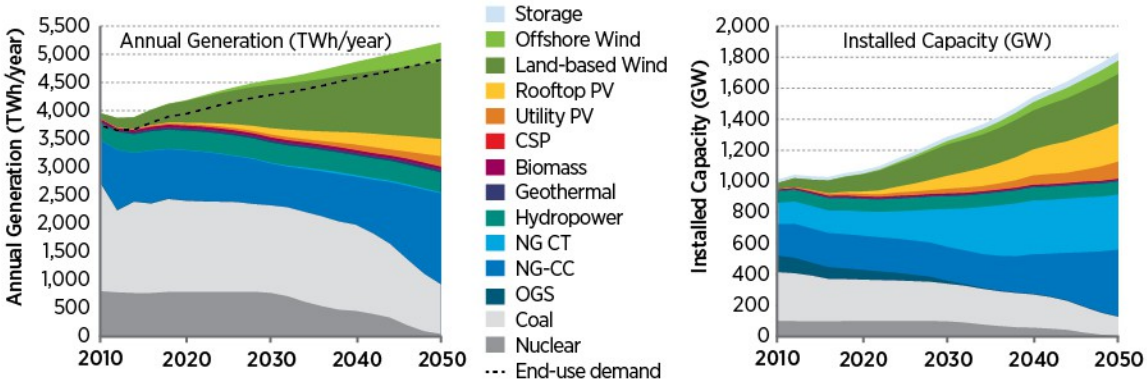
Figure 5. Incremental system costs of *Study Scenarios* relative to the *Baseline Scenario*.

3.3. Evolution of the Electricity Sector under the *Wind Vision Study Scenario*

Electricity generated in the United States in 2013 totaled approximately 4,058 TWh. Of this, coal-fired generation comprised the largest share at 39%, followed by natural gas-fired generation at 28%. Nuclear and hydropower power plants contributed 19% and 6.6%, respectively. Generation from wind power plants totaled 4.1% of 2013 generation. Other renewable technologies, including solar, geothermal, and biomass, contributed 2.1%.[6] There are approximately 941 GW in total installed capacity in the 2013 U.S.

6 Values for 2013 are taken from the EIA electric power monthly (www.eia.gov/electricity/monthly). Reported natural gas generation values here and throughout this paper include oil-fired steam generators. Hydropower generation values include electricity produced by domestic hydropower plants only—excluding net generation from pumped hydropower storage. The scenario results presented include net imports from Canada, which the Canadian National Energy Board notes totaled 42 TWh in 2013 and are assumed to be 34–52 TWh annually in future years. Solar generation represents all grid-connected solar facilities, including utility-scale concentrating solar power and PV and distributed PV.

electricity generation fleet, of which 61 GW are from wind turbines. From this current point, the *Study Scenarios* envision some significant changes (see Figure 6), particularly in the long term.



Note: Total generation exceeds end-use demand due to transmission and distribution losses. Technology category acronyms: PV = photovoltaic, CSP = concentrating solar power (with and without thermal energy storage), NGCT = natural gas-fired combustion turbines, NGCC = natural gas-fired combined cycle, OGS = oil and gas steam turbines. Biomass includes dedicated biopower, co-fired biomass with coal, and landfill gas or municipal solid waste capacity; hydropower includes all net Canadian imports.

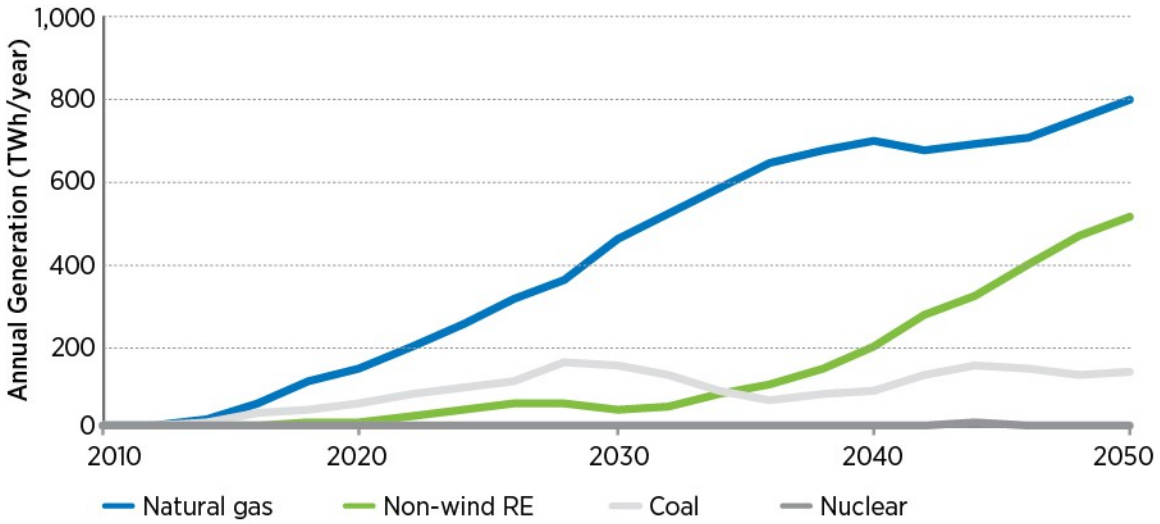
Figure 6. Annual generation (left) and installed capacity (right) by technology type and year under the *Central Study Scenario*.

Growth in electricity demand through 2030 is primarily met or exceeded by the expansion of wind under the *Study Scenarios*. This growth reduces aggregate generation from other energy sources. Reductions in fossil fuel-based generation on absolute and percentage bases are observed. Under the *Central Study Scenario*, fossil fuel-based generation comprises about 64% and 54% of end-use demand in 2020 and 2030, respectively, compared to about 70% in 2013. While annual electricity generated from non-wind renewable and nuclear technologies does not exhibit a similar decline by 2030, its growth is limited under the *Study Scenarios*. From 2030 to 2050, assumed retirements combined with load growth begin to have a more dramatic effect on the generation mix. During this time period, growth in wind generation under the *Study Scenarios* continues to exceed growth in electricity demand. Nonetheless, by 2050, natural gas-fired generation equals 33% of end-use demand, representing significantly higher absolute natural gas-fired generation than historical totals. In effect, along with wind generation, natural gas replaces declining coal and nuclear generation. In 2050, coal generation makes up only 18% of end-use demand, and nuclear comprises less than 1% in the *Central Study Scenario*. Growth in solar generation continues relatively steadily and reaches about 10% in 2050. Hydropower and other renewable energy generation remain largely at current levels, making up 7% and 2% of total 2050 end-use demand, respectively.

The capacity expansion trajectory largely follows the same trends as the generation trajectory with three important differences. First, while coal generation is observed to hold relatively steady in the near term, coal capacity actually declines by about 66 GW between 2013 and 2030. Second, while oil and gas steam capacity also declines over this time period, growth in natural gas combustion turbine capacity more than makes up for this decrease. These natural gas units provide peaking and reserve capacity needs and, thus, play an important role for the power sector that is not observed in the annual generation values. Third, the rate of growth in installed capacity is observed to be higher than the rate of growth in annual generation, primarily as a result of rapid growth in wind and solar PV capacity and their associated lower capacity factors and capacity values. Among the non-wind renewable technologies,

solar technologies exhibit the greatest capacity increases, reaching 33 GW by 2020, 116 GW by 2030, and 357 GW by 2050.

In the *Study Scenarios*, relative to the *Baseline*, wind primarily displaces fossil fuel-fired generation, especially natural gas, with the amount of displaced gas growing over time. In the long term (after 2030), wind in the *Study Scenarios* also affects the growth of other renewable generation, coal, and—in some scenarios—growth of nuclear generation. Figure 7 shows the avoided generation as a result of the *Central Study Scenario* compared with the *Central Baseline Scenario*. The avoided generation mix will ultimately depend on uncertain future market conditions, including fossil fuel prices and technology costs.[7] Displaced fossil fuel consumption leads to avoided emissions and other impacts (DOE 2015; Wiser et al. forthcoming). With wind penetration increasing to the levels envisioned under the *Study Scenarios*, the fossil fleet's role to provide energy declines while its role to provide reserves increases.



Note: The positive values indicate there was greater generation from these sources under the *Baseline Scenario* compared with the *Study Scenario*. The "natural gas" category includes oil-fired generation. Non-wind RE refers to non-wind renewable energy.

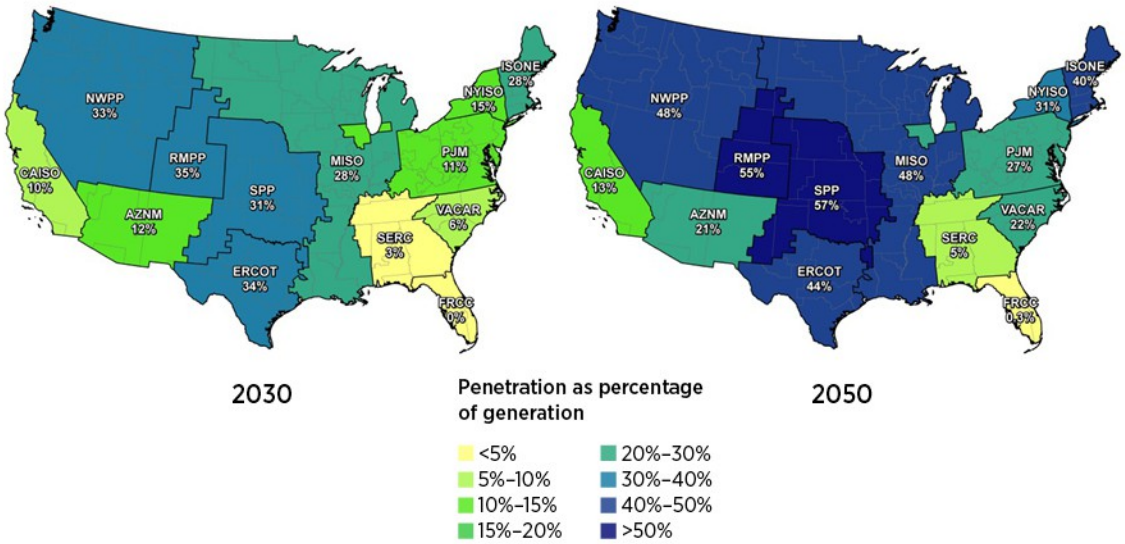
Figure 7. Difference in annual generation between the *Central Study Scenario* and *Baseline Scenario* by technology type.

3.4. Transmission and Grid Integration

The primary role of electric system operators and planners is to ensure reliable delivery of electricity at the lowest cost to meet demand. Challenges in serving this role result from variability and uncertainty that exists at all timescales, and that relate to all supply side resources as well as electricity load. Increasing wind penetration adds to this variability and uncertainty. In addition, the location-dependence and often remoteness of wind resources can lead to increased transmission needs associated with greater wind deployment.

7 Under the fossil fuel and wind technology sensitivities, displaced generation differs from what is shown in Figure 7; however, we did not estimate the benefits and impacts of these different avoided generation mixes. In addition, other market factors such as different future non-wind renewable, nuclear, and fossil technology advancements or different demand growth futures would yield different costs and avoided generation of achieving the wind penetration levels modeled (e.g., 35% by 2050).

Based on model outcomes from the *Study Scenarios*, most of the western and central parts of the United States have wind penetration levels that exceed the 20% nationwide level by 2030, with some regions approaching or exceeding 30% penetration. By 2050, wind penetration levels exceed 40% across much of the West and Midwest, with less substantial—but still sizeable—levels in other parts of the country. In the Southeast, wind penetration levels are lower than in other regions but are significantly higher than levels found in that region in 2013, particularly for coastal areas. Figure 8 shows the regional wind penetration levels across the continental United States found in the *Central Study Scenario*. Here, penetration refers to wind generation divided by total regional generation, whereas in other sections wind penetration is defined with respect to national end-use electricity demand.



Note: The percentages shown reflect the percentage of in-region wind generation to in-region total generation. They do not take into account imports or exports of electricity, including any imports from Canada. The regions depicted represent approximate boundaries of existing regional transmission organizations/independent system operators (RTOs/ISOs) and other reliability areas to illustrate regional wind penetration distributions only. They do not reflect future expected market, energy balancing or reserve sharing boundaries. Acronyms used in this map. Northwest Power Pool (NWPP); California ISO (CAISO); Western Electricity Coordinating Council / Southwest (AZNM); Rocky Mountain Power Pool (RMPP); Electric Reliability Council of Texas (ERCOT); Southwest Power Pool (SPP); Midcontinent ISO (MISO); SERC Reliability Corporation (SERC); Virginia-Carolinas Region (VACAR); PJM Interconnection (PJM); New York ISO (NYISO); ISO New England (ISONE); Florida Reliability Coordinating Council (FRCC).

Figure 8. Regional annual wind penetration for 2030 (left) and 2050 (right) under the *Central Study Scenario*.

The levels of wind penetration examined in the *Study Scenarios* increase variability and uncertainty in electric power system planning and operations. From the perspective of planning reserves, we estimate wind power's aggregated capacity value in the *Study Scenarios* to be about 10%–15% in 2050 (with lower marginal capacity value), thereby reducing the ability of wind compared to other generators to contribute to increases in peak planning reserve requirements. In addition, the uncertainty introduced by wind in the *Study Scenarios* increased the level of operating reserves that must be maintained by the system. Transmission constraints and system inflexibility result in average curtailment of 2%–3% of potential wind generation, modestly increasing the threshold for economic wind deployment. All of these costs are embedded in the system costs and retail rate impacts reported earlier in Section 3.2.

The challenges of wind integration can be addressed by various means, including increased system flexibility, greater electric system coordination, faster dispatch schedules, improved forecasting, demand response, greater power plant cycling, and storage options. For example, we find about 54 GW of total installed storage capacity in 2050 under the *Central Study Scenario* representing a growth of 32 GW over the existing (as of 2013) 22 GW of operating storage capacity in the United States and compared with 24 GW total (new and existing) installed storage capacity by 2050 under the *Baseline Scenario*.[8] Specific circumstances dictate the optimal solution to increase system flexibility and continued research is expected to provide more specific and localized assessments of impacts.

Required new transmission capacity for the *Central Study Scenario* is 2.7 times greater by 2030 than for the *Baseline Scenario* and about 4.2 times greater by 2050. However, transmission expenditures make up a small fraction (less than 2%) of total electric sector costs in the *Central Study Scenario*. Incremental cumulative (from 2013) transmission needs of the *Central Study Scenario* relative to the *Baseline Scenario* amount to 10 million MW-miles by 2030 and 29 million MW-miles by 2050. Assuming only single-circuit 345-kilovolt lines (with a 900-MW carrying capacity) are used to accomplish this increase, an average of 890 circuit miles/year of new transmission lines would be needed between 2021 and 2030, and 1,050 miles/year between 2031 and 2050. This is comparable to the average of 870 circuit miles added each year since 1991 (as of 2013). New transmission capacity in the *Study Scenarios* is primarily concentrated in the Midwest and Southern Central regions of the United States (see Figure 9).

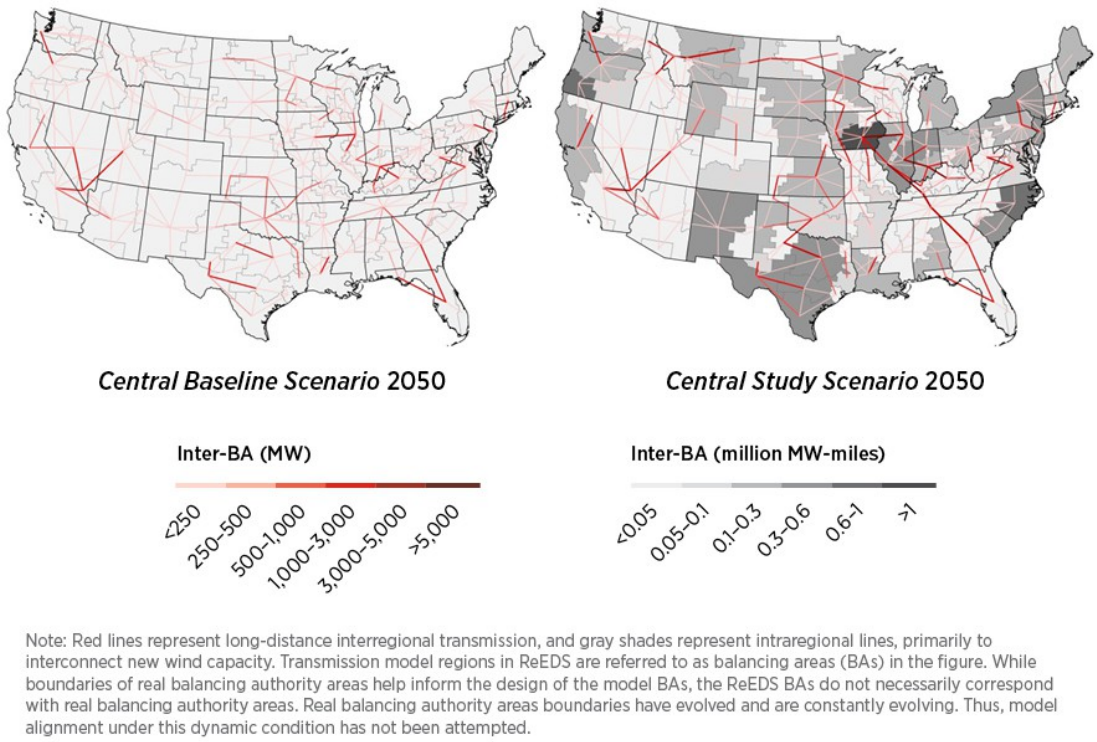


Figure 9. New (2013–2050) transmission expansion under the *Central Baseline* (left) and *Study* (right) *Scenarios*.

3.5. Impacts Relative to a Traditional Business-As-Usual Scenario

8 We use the same assumptions for storage resource potential, costs, and performance as in NREL (2012).

In the above sections, we describe the electric sector impacts of all new wind deployment estimated in the *Study Scenarios* relative to *Baseline Scenarios* where U.S. wind capacity is fixed at 2013 levels (61 GW) for all years. This approach allowed us to quantify impacts for all future wind deployment (post-2013). In this section, we present a more traditional BAU scenario where future wind deployment is based on economics and existing energy policies only and without the application of predetermined penetration levels or artificial limits on future wind installations. For this *BAU Scenario*, we use central assumptions (see Section 2.3) for wind technology costs, fossil fuel costs, and other inputs. Accordingly, the *BAU Scenario* provides a potential outlook for the future U.S. electricity system under current and plausible future conditions.

Wind deployment and economic impacts (e.g., electricity rates, net present value of system costs) for the *BAU scenario* are also compared to the respective *Central Study Scenario* to provide an indicator of the magnitude of intervention potentially required to realize the *Study Scenario* wind deployment levels and their associated impacts.

Under the *BAU Scenario*, growth in wind energy in the near term is estimated to be significantly less than in recent history and under the *Study Scenario*. Annual new wind capacity additions from 2015 to 2030 are estimated at 3 GW/yr, resulting in 116 GW installed by 2030 compared with 224 GW under the *Central Study Scenario*. Wind penetration in 2030 reaches 10% of end-use demand, which is equivalent to the 2020 penetration level envisioned under the *Study Scenarios* and half of the 2030 level. After 2030, wind deployment grows at a significant rate (8 GW/yr between 2031 and 2050) similar to the *Study Scenario*. By 2050, wind capacity and penetration reach 280 GW and 25%, respectively, under the *BAU Scenario*. While these estimated 2050 deployment and penetration levels are lower than those under the *Study Scenario*, they are significantly greater than 2013 levels and point to the economic viability of wind in the long term. However, the lower levels of wind deployment found through 2030 indicate that challenges to near term wind deployment exist.

Other indications of challenges to wind development are reflected through differences in electricity prices and system costs of the *BAU* and *Study Scenarios*. For example, relative to the *BAU Sce*nario, we find incremental electricity prices in the *Central Study Scenario* to be positive for all years with 2030 and 2050 prices being 1.3% and 3% higher, respectively. Comparatively, prices were nearly equivalent in 2030 and 2% lower in the central *Study Scenario* relative to the "no-new-wind" *Baseline Scenario*. Similarly, we find incremental net present value of system costs (2013-2050, 3% real discount rate) to be $59 billion higher for the *Study Scenario* relative to the BAU Scenario compared to $149 billion lower relative to the *Baseline Scenario*.

Qualitatively, these cost results are not surprising given that the *BAU Scenario* reflects a future that aligns more closely to an unconstrained economic optimum without predetermined wind levels. The results indicate that growth in new wind capacity needed to reach levels envisioned in the *Study Scenarios*—and to realize some of the associated benefits and impacts estimated in Wiser et al. (forthcoming)—would require policy support, further reductions in wind energy costs, or other market shifts particularly through the next decade. Quantitatively, the results suggest that the amount of policy support or other advancements needed may not be substantial.

4. Conclusions

We model scenarios of the U.S. electric sector with increased and sustained growth in wind power such that wind generation reaches 10% of end-use electricity demand in 2020, 20% in 2030, and 35% in 2050. To achieve these levels, we estimate that over 400 GW of installed wind power capacity, distributed across all states, would be needed. The expansion of the U.S. wind industry in capacity and electricity generated is estimated to have widespread implications for the rest of the U.S. electricity sector. Compared with a baseline without any new wind deployment post-2013, achieving the envisioned wind penetration levels will reduce fossil fuel-fired, particularly natural gas-fired, generation. Other long-term implications of a more wind-reliant electricity future are the need for transmission expansion and additional challenges related to grid integration. However, we find that even at the higher wind penetration levels modeled, these transmission and integration needs are similar in scale to what current and historical trends suggest. Finally, we evaluate the cost of achieving 35% wind by 2050 and estimate that—under central assumptions—electricity consumers will bear an incremental (<1%) cost in the near term (through 2030), compared with the no-new-wind baseline, but that longer-term savings are possible. On a net present value basis, and also under central assumptions, we find *savings* of $150 billion for the 2013–2050 study period.

We also model a set of sensitivity scenarios to assess uncertainties associated with future wind technology costs, fossil fuel costs, and their combined impacts. In particular, we find from these sensitivities that on a net present value basis the potential incremental electricity sector expenditures range from savings of $388 billion to a cost increase of $254 billion. These results point to the value that advancing wind technologies could have as well as the importance of fossil fuel costs to the future evolution of the U.S. electricity system.

The present paper focuses on the direct electricity system impacts of achieving a 35% wind by 2050 future in the United States. Wiser et al. (forthcoming), evaluates the social, environmental, and other benefits and impacts associated with the same high wind scenarios. In particular, the impacts assessment in Wiser et al. (forthcoming) includes those associated with avoided GHG emissions, other avoided air pollution emissions, water use, risk and diversity, land use, and economic development. Together, the two complementary assessments are intended to inform valuation of future wind deployment for the purposes of policy development and design. Our results suggest that a future U.S. electricity system where wind plays a major role is plausible; could result in enduring benefits globally, nationally, and locally; and could result in consumer and system benefits in the long run, if nearer-term (pre-2030) cost barriers are overcome. At the same time, these opportunities are not anticipated materialize in their full form under “business-as-usual” conditions.

Two practical applications result from the advanced methodology used in our research and the quantitative findings of costs, benefits, and impacts of future wind energy in the United States. First, the estimated positive near-term incremental costs suggest that policy interventions may be needed for wind deployment trajectories along the lines needed to achieve the high-penetration wind futures. Various policies, including federal tax credit policies, renewable portfolio standards, and carbon regulations, have been or are employed in the United States to bridge these cost barriers. In the longer term, our analysis finds that wind can offer cost savings to consumers and to power system expenditures. The related research of the same high-wind scenarios, as reported in Wiser et al. (forthcoming), finds sizeable long-term environmental and societal benefits and impacts. However these cost savings and positive impacts might be in jeopardy if the near-term barriers are not overcome. In addition, we find that even under “business-as-usual” conditions, wind penetration does not reach the 35% penetration levels and therefore the potential positive attributes of wind are likely to not fully materialize absent further interventions. Furthermore, our findings point to the need for greater

transmission expansion and improved wind integration practices—two areas where further interventions might be needed to successfully integrate high shares of wind.

Second, the state-of-the-art modeling and methods applied in the assessment might be adopted for other contexts and regions. For example, analysts supporting regional entities in the United States or from other countries might apply similar methods to consider the costs, benefits, and impacts of greater wind deployment in their system or to evaluate other generation options. We note that our analysis seeks to inform policy, but does not suggest or recommend a specific policy. Nonetheless, the methods applied herein can also be applied to evaluate policies under consideration.

Acknowledgements

We thank the many contributors to the analysis described in this paper: Chad Augustine (NREL), Stuart Cohen (NREL), Ed Demeo (Consultant), Ed Eugeni (SRA International), David Feldman (NREL), Maureen Hand (NREL), Donna Heimiller (NREL), Brendan Kirby (Consultant), Jessica Lin-Powers (NREL), Michael Milligan (NREL), David Mulcahy (formerly NREL), Patrick O'Connor (ORNL), Aaron Smith (NREL), Rich Tusing (New West Technologies), and Jose Zayas (U.S. DOE). We also thank Jeff Logan, Paul Schwabe, and Scott Gossett of NREL and Mary Lukkonen for their reviews and edits. This work was supported by the Office of Energy Efficiency and Renewable Energy (Wind and Water Power Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC36-08GO28308 with the National Renewable Energy Laboratory. The opinions represented in this article are the authors' own and do not reflect the view of the U.S. DOE or the U.S. government. Any and all errors are the responsibility of the authors.

Appendix

This appendix includes an abbreviated documentation of the NREL Regional Energy Deployment System (ReEDS) model used to generate the scenarios described in the present research. It is intended to give a basic understanding of the model and the key factors that influence model decisions. The full model documentation (Short et al. 2011), chapter 3 of the Wind Vision report (DOE 2015), and Appendices G and H of the Wind Vision (DOE 2015) are sources for further details on model equations and data assumptions. In addition, other recent publications using ReEDS include the *SunShot Vision* study (DOE 2012), the *Renewable Electricity Futures* study (NREL 2012), and other papers (Mai et al. 2014a; Mai et al. 2014b; Clemmer et al. 2014; Mignone et al. 2013; Lantz et al. 2014; Logan et al. 2013).

A.1. Least-cost Optimization

ReEDS is an electric sector capacity expansion model where the primary inputs include parameters representing the existing infrastructure, cost and performance parameters for future infrastructure, and assumptions for demand growth, retirements, and policies. It models the continental U.S. electricity system starting from 2010 and marching forward, in 2-year "solve" periods, to 2050. All major generator types, including multiple fossil fuel (coal, gas, oil) technologies, nuclear, and renewable technologies (biopower, geothermal, hydropower, concentrating solar power (CSP), solar photovoltaic (PV), land-based wind, and offshore wind), are modeled in ReEDS. In addition to investment of new generation capacity, ReEDS also simultaneously simulates the expansion of storage and transmission. The investment decisions in ReEDS are co-optimized with dispatch decisions within a linear programming framework that finds the least-cost solution subject to many constraints. We qualitatively describe the core equations of the optimization model below. Sections A.2-A.4 describe the unique features of ReEDS

that are designed to better represent wind (and other variable renewable) energy and its impact on future power system operations and investments.

For each 2-year solve period between 2010 and 2020, ReEDS finds the optimal least cost solution based on 20-year net present value costs for all new capital investments, fixed and variable O&M costs, and fuel costs for the model system. Capital infrastructure considered by the model includes new renewable and non-renewable generator, storage, and transmission capacity. All of these costs are reflected in the cost metrics (electricity prices and electric system expenditures) reported in this paper. Financing assumptions, include an 8.9% (nominal) discount rate used to estimate all 20-year NPV costs, are further described in Appendix G of the Wind Vision (DOE 2015). The objective function that is minimized by the linear program in ReEDS is as follows:

Objective function = capital cost * new generation capacity
+ fixed O&M cost * (existing generation capacity + new generation capacity)
+ (variable O&M + fuel costs) * (generation from existing capacity + generation from new capacity)
+ capital cost * new transmission capacity
+ capital cost * new storage capacity
+ fixed O&M cost * (existing storage capacity + new storage capacity)
+ (variable O&M + fuel costs) * (generation from existing storage capacity + generation from new storage capacity)

ReEDS minimizes the objective function value by finding the optimal amount and location of new capacity and the generation from new and existing capacity. This least-cost minimization is subject to many constraints, including the following primary constraints:

Energy Balance [applied to each model balancing area for each time-slice]
generation + imports * (1 – transmission losses) + RE curtailment = end-use consumption * (1 + distribution losses) + exports

Operating Reserves [applied to each model balancing area for each time-slice]
capacity – generation + operating reserve contract imports – operating reserve contract exports > (contingency + frequency regulation reserves) * end-use consumption + forecast error reserves * RE capacity

Planning Reserves [applied to each model balancing area]
capacity * capacity value + firm capacity imports – firm capacity exports > peak demand * (1 + reserve margin)

Resource Limits [applied to each resource region or balancing area and for each technology]
existing capacity + new capacity < resource potential

State Renewable Portfolio Standards (RPS) [applied to each state]
qualifying renewable generation > RPS fraction * annual consumption

Details for the above constraints along with descriptions of many other constraints can be found in the model documentation and other reports described previously. For the Study Scenarios with predetermined wind penetration levels (e.g., 10% by 2020, 20% by 2030, and 35% by 2050), we apply the following additional constraints:

Total Wind Penetration Requirement [applied nationally]

land-based wind generation + offshore wind generation = wind penetration fraction * end-use consumption

Offshore Penetration Requirement [applied to each of five offshore regions]

offshore wind generation = offshore wind penetration fraction * end-use consumption

A.2. Spatial Resolution and Transmission Representation

ReEDS is designed with high spatial resolution in order to better represent geographically varying resource quality and potential for wind and other electricity options. High spatial resolution also enables the model to better capture potential mismatches between load and generation, and associated transmission needs and expansion opportunities. More specifically, ReEDS segments the continental United States into 356 wind/CSP resource regions where wind resources are represented (see Section A.4 on specific representations for wind technologies) and 134 model balancing areas (BA) where most other technologies and load are modeled. Figure A1 shows the model BAs and resource regions used in ReEDS. The BAs and wind/CSP regions follow state boundaries to facilitate modeling state policies (e.g., state renewable portfolio standards). High spatial resolution is also used to facilitate other sub-national regional assessments and representations, including the three separate synchronous interconnections, electric reliability regions, water basins, and others. The high spatial resolution of the model also enables consideration of regionally varying capital and fuel costs.

Interregional transmission and dispatch modeling in ReEDS is also based on the 134 BAs. For example, the energy balance equation from Section A.1 is applied for each model BA with transmission imports into or exports out of each BA considered. Figure A1 shows the reduced form transmission network used in ReEDS, where each line represents an interface limit between connected BAs. These approximately 300 interface limits are used to constrain imports and exports, but long-distance transmission expansion is also considered in the model. Transmission modeling relies on a linearized DC power flow representation.

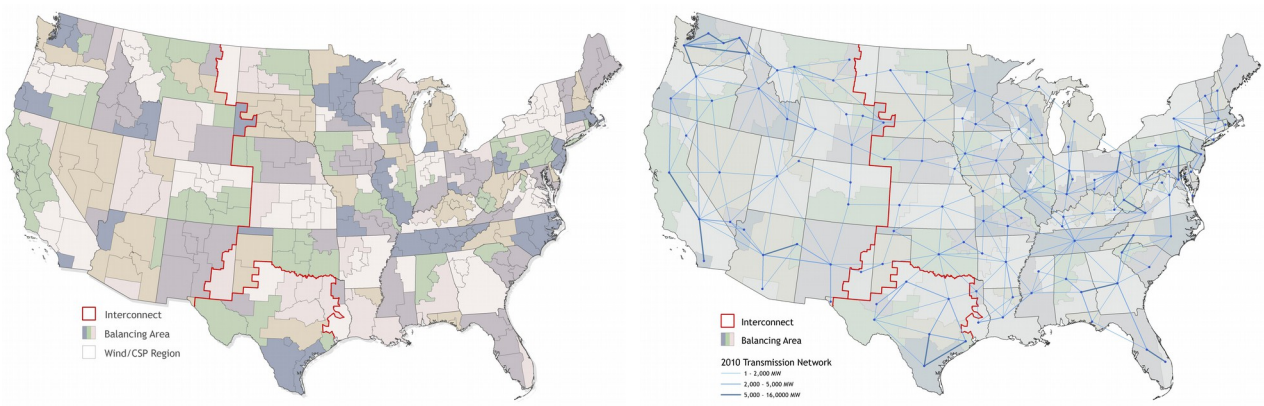


Figure A1. Model regions (left) and 2010 interregional transmission network (right)

A.3. Temporal Resolution and Treatment of Variability and Uncertainty

ReEDS' dispatch modeling uses 17 time-slices during each solve period to capture seasonal and diurnal patterns in electricity consumption and renewable output profiles. More particularly, the time-slices

include four diurnal periods (morning, afternoon, evening, and night) for each of four seasons (Winter, Spring, Summer, and Fall) and a super-peak period representing the top 40 load hours during the summer afternoon period. Economic dispatch in ReEDS includes energy balance and adequate reserve requirements based on the average consumption and renewable and non-renewable plant availability during each time-slice.

Since variability in load, wind output, and solar output profiles occurs over higher frequency timescales (e.g., hourly or subhourly) than the model time-slices, we further constrain and parameterize ReEDS' dispatch and investment equations using statistical treatment of three primary quantities: capacity value, forecast error reserve requirements, and curtailments. Capacity value reflects the fraction of wind or solar nameplate capacity that can reliably contribute to planning reserve requirements. We estimate additional operating reserves that might be needed to accommodate forecast errors for wind and solar. Finally, we estimate wind and solar curtailments when available variable renewable generation is unused, which occurs during hours with abundant solar and wind relative to electricity demand and/or due to a combination of transmission limits or power plant flexibility limits. All three types of parameters are calculated based on hourly data, which are used to generate statistical distributions in every region. The distributions are used to calculate average and marginal values for capacity value, forecast error reserve requirements, and curtailments. Ultimately, these metrics are used to inform the optimization algorithm of the impact of geospatial diversity and the value of storage, transmission, and investment of different generator mixes. The parameters are used to help ensure that the future portfolio mix result in a reliable electric system. This approach has been tested by evaluating ReEDS scenarios using hourly and subhourly production cost simulations (NREL 2012, Brinkman 2015).

A.4. Wind Modeling

ReEDS models five separate techno-resource groups (TRG) to represent land-based wind and 10 TRGs for offshore wind for each wind/CSP resource region. In addition to the long-distance transmission lines modeled, ReEDS also considers shorter *intra*-regional spur lines for wind. This relies on a GIS analysis (see Appendix H of the Wind Vision report) that compares wind resource potential and quality at each 20km grid cell and nearby transmission interconnection features. For each of 356 regions and five TRGs, ReEDS uses a supply curve that reflects the cost of developing wind capacity including spur lines versus the resource potential. Figure A2 shows the aggregate wind supply curve for the continental United States represented for 2014.

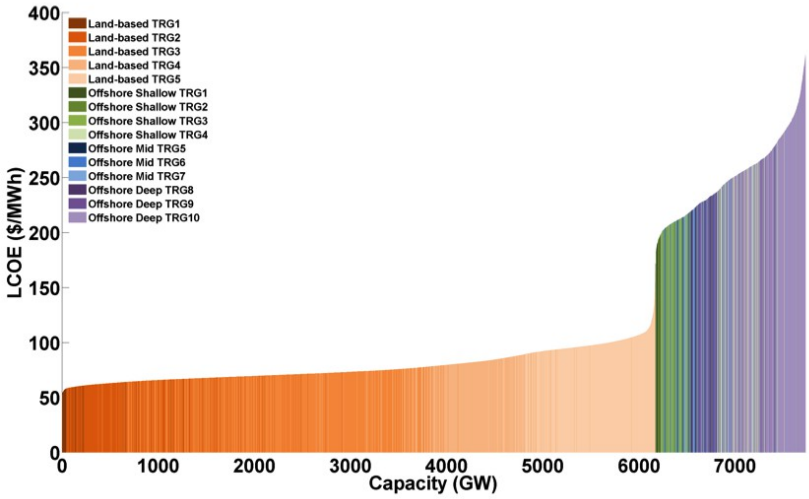


Figure A2. Base-year wind plant levelized cost of energy (LCOE) for the continental United States

In addition to current costs, ReEDS relies on future technology cost and performance assumptions. For the present study, we use three separate future wind technology advancement trajectories (Figure A3). Other details on wind energy assumptions or model representations can be found in the model documentation (Short et al. 2011), Wind Vision report (DOE 2015), and other cited source papers.

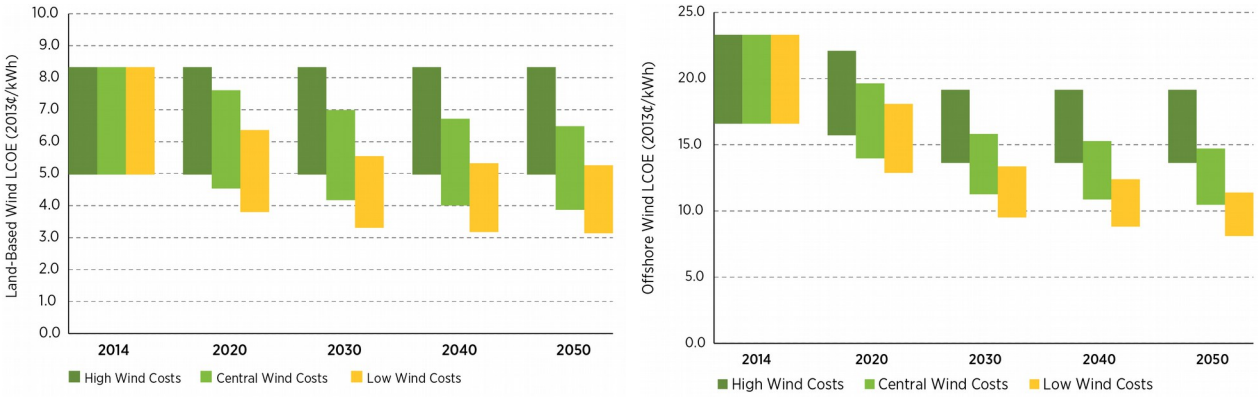


Figure A3. Land-based (left) and offshore (right) wind LCOE projections

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