Chapter 3

Wind Vision:

A New Era for Wind Power in the United States

U.S. DEPARTMENT OF ENERGY

3 Impacts of the *Wind Vision*

Summary

Chapter 3 of the *Wind Vision* identifies and quantifies an array of impacts associated with continued deployment of wind energy. This chapter provides a detailed accounting of the methods applied and results from this work. Costs, benefits, and other impacts are assessed for a future scenario that is consistent with economic modeling outcomes detailed in Chapter 1 of the *Wind Vision*, as well as existing industry construction and manufacturing capacity, and past research. Impacts reported here are intended to facilitate informed discussions of the broad-based value of wind energy as part of the nation's electricity future.

The primary tool used to evaluate impacts is the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) model. ReEDS is a capacity expansion model that simulates the construction and operation of generation and transmission capacity to meet electricity demand. In addition to the ReEDS model, other methods are applied to analyze and quantify additional impacts.

Modeling analysis is focused on the *Wind Vision Study Scenario* (referred to as the *Study Scenario)* and the *Baseline Scenario*. The *Study Scenario* is defined as wind penetration, as a share of annual end-use electricity demand, of 10% by 2020, 20% by 2030, and 35% by 2050. In contrast, the *Baseline Scenario* holds the installed capacity of wind constant at levels observed through year-end 2013. In doing so,

the *Baseline Scenario* provides the requisite point of comparison from which the incremental impact of all future wind deployment and generation can be assessed. Sensitivity analyses around the *Study Scenario*—varying wind technology cost and performance and fossil fuel costs while holding the wind penetration trajectory at the 10%, 20%, 35% levels—are used to assess the robustness of key results and highlight the impacts of changes in these variables. Sensitivities include single variable *Low/High Wind Cost* or *Low/High Fossil Fuel Cost Scenarios,* as well as combined *Unfavorable* (High Wind Cost and Low Fossil Fuel Cost) and *Favorable* (Low Wind Cost and High Fossil Fuel Cost) *Scenarios.*

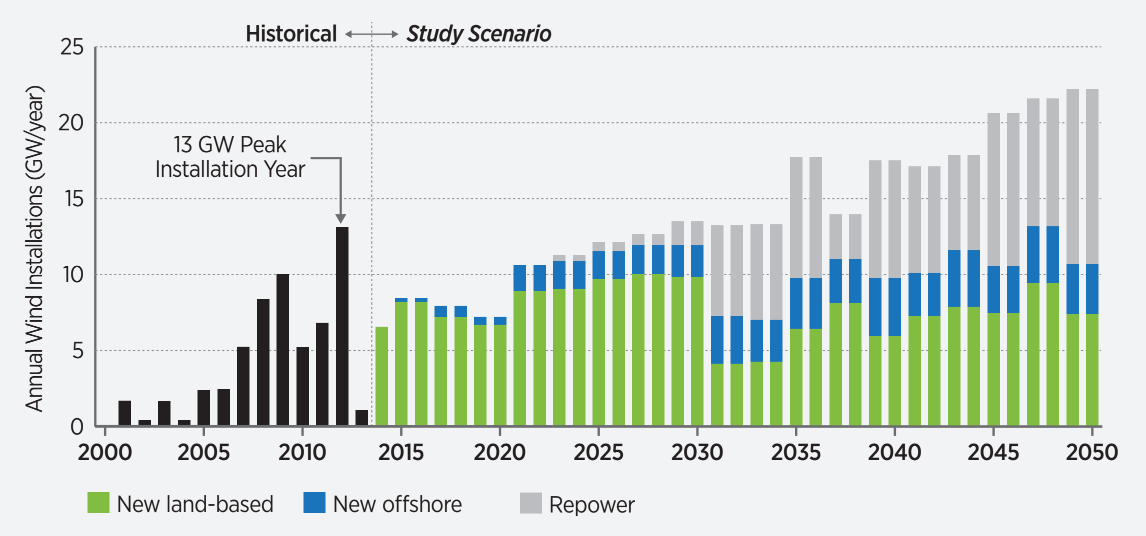
Many of the results presented in this chapter emphasize outcomes across the full range of sensitivities. In some instances, however, results are presented only for a single central case. This central case, referred to as the *Central Study Scenario,* applies common modeling inputs with the *Business-as-Usual (BAU) Scenario* but also includes the prescribed wind trajectory of 10% by 2020, 20% by 2030, 35% by 2050. Where the *Central Study Scenario* is the point of focus (e.g., greenhouse gas reductions, air pollution reductions), uncertainty is typically reflected by a range in the value of a given impact. For several additional impacts analyzed, results are discussed qualitatively (e.g., wildlife, offshore and distributed wind) or reported in absolute terms for the *Study Scenario* rather than relative to the *Baseline Scenario* (e.g., cumulative installed wind capacity, land area impacts, and gross jobs supported by wind investments).

Within the *Wind Vision* analysis, existing policies are represented and analyzed as of January 1, 2014 (e.g., the wind production tax credit [PTC] is expired). No new policies beyond these existing policies, including new or proposed environmental regulations, are explicitly modeled.

Impacts, costs, and benefits of the scenarios presented here are contingent on the analysis approach of prescribed wind penetration levels in the electric sector. Because the resulting impacts, costs, and benefits depend, in part, on underlying policy and market conditions as well as economy-wide interactions, alternative approaches to reaching the wind penetration levels outlined here would yield different results.

Wind Industry and Electric Sector Impacts in the Study Scenario

In the *Central Study Scenario*, total installed wind capacity increases from the 61 gigawatts (GW) installed by 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 and includes all wind applications: land-based, distributed, and offshore wind. 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 capacity needed to meet the deployment levels considered in the *Study Scenario* will depend on future wind technology development. For example, with improvements in wind technology yielding higher capacity factors, only 382 GW of wind capacity are needed to reach the 35% penetration level in 2050. Conversely, 459 GW would be required using 2013 technologies without further advancements. Across the full range of technology assumptions, the *Study Scenario* utilizes only a fraction of the more than 10,000 GW of gross wind resource potential.



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. Levels of wind capacity to achieve the penetration trajectory in the *Study Scenario* will be affected by future advancements in wind turbine technology, the quality of the wind resource where projects are located, and market conditions, among other factors.

Figure 3-1. Historical and forward-looking wind power capacity in the *Central Study Scenario*

The *Study Scenario* supports new capacity additions at levels comparable to the past, but drives increased demand for new wind turbine equipment as a function of repowering needs. Demand for wind turbines averages approximately 8 GW/year from 2014 to 2020, 12 GW/year from 2021 to 2030, and increases to 18 GW/year from 2031 to 2050. While aggregate demand trends upward (Figure 3-1), it is primarily concentrated in new land-based wind in the near term. Deployment of offshore plants and repowering (the replacement of turbine equipment at the end of its useful life with new state-of-the-art turbine equipment) become more substantive factors in the 2031–2050 timeframe.

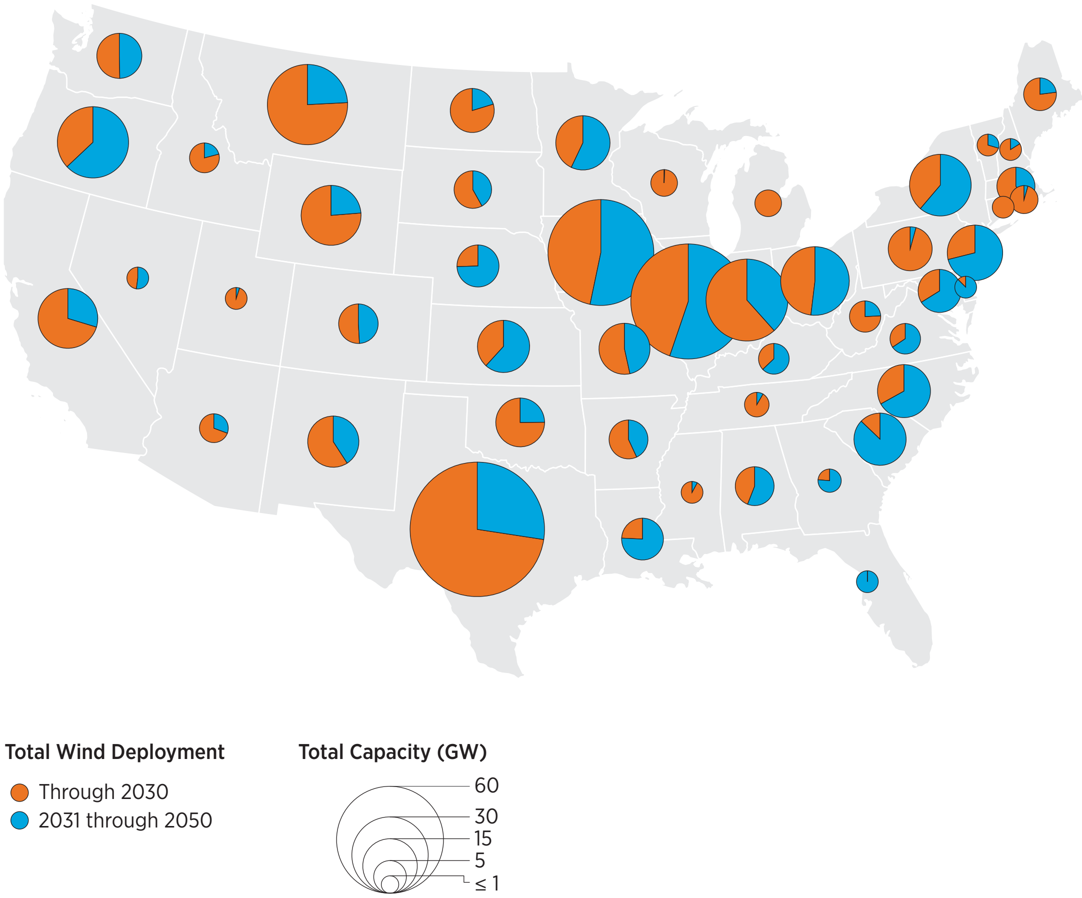
In the *Study Scenario,* wind industry expenditures (new capital and development expenditures, annual operating expenditures, and repowered capital expenditures) grow to more than $30 billion/year (in constant 2013 dollars) from 2020 to 2030, and are estimated at approximately $70 billion/year by 2050.[1] By 2050, annual expenditures exceed $23 billion/year for operations, $22 billion/year for repowering, and $25 billion/year for new greenfield development.

The *Study Scenario* suggests continued geographical diversity in wind power deployment. Figure 3-2 illustrates the state-level distribution of 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, with 37 states having more than 1 GW of capacity. By 2050, wind capacity exists in all 50 states, with 40 states having more than 1 GW of installed wind capacity.[2]

Variations in wind resource quality, relative distances to load centers, and existing infrastructure drive regional differences in modeled wind penetration levels. Based on model outcomes from the *Study Scenario*, most of the western and central parts of the United States have penetration levels that exceed the 10% nationwide level by 2020, with some regions approaching or exceeding 30% penetration. By 2050, wind penetration levels exceed 40% across much of the West and upper Midwest, with levels of 10%–40% in California, the mid-Atlantic, and New England. In the Southeast, wind penetration

1. Unless otherwise specified, all financial results reported in this chapter are in 2013$.

2. As of 2013, wind installations of 62 MW and 206 MW exist in Alaska and Hawaii respectively. 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 in 2030 or 2050 because the modeling analysis was restricted to the 48 contiguous United 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 scope.

Figure 3-2. *Study Scenario* distribution of wind capacity by state in 2030 and 2050

levels by 2050 are lower than in other regions and range from less than 1% (Florida) to more than 20% (coastal Carolinas).

The levels of wind penetration examined in the *Study Scenario* increase variability and uncertainty in electric power system planning and operations (Figure 3-3). From the perspective of planning reserves, the aggregated capacity value of wind power in the *Study Scenario* is about 10–15% in 2050 (with lower marginal capacity value). This reduces the ability of wind compared to other electricity generation to contribute to increases in peak planning reserve requirements. In addition, the uncertainty introduced by wind in the *Study Scenario* increases the level of operating reserves that must be maintained by the system. Operational constraints result in average curtailment of 2–3% of wind generation starting around 2030, modestly increasing the threshold for economic wind deployment. These costs are embedded in the system costs and retail rate impacts noted. Such challenges can be mitigated by various means, including increased system flexibility, greater electric system coordination, faster dispatch schedules, improved forecasting, demand response, greater power plant cycling, and—in some cases—storage options. Specific circumstances dictate the best solution. Continued research is expected to provide more specific and localized assessments of impacts, as further discussed in Chapter 4.

Industry Investment	Deployment	Integration[b]	Transmission[c]	Offshore Wind
• 8-11 GW/year average net capacity additions throughout the 2013–2050 period • 18 GW/year annual turbine demand as more wind plants are repowered from 2031 to 2050 • $70 billion/year[a] by 2050 annual wind industry investment from new capacity additions, repowered capacity, and operations and maintenance	• 404 GW of cumulative capacity by 2050 for 35% wind energy • All 50 states with wind deployment by 2050 • 37 states by 2030 and 40 by 2050 with more than 1 GW of wind power (within the contiguous United States)	• Increased system flexibility is required, but can be acquired from many sources • 2–3% average curtailment of annual wind generation; estimated wind capacity value of 10–15% by 2050 • Integration solutions required, but will vary by region	• 2.7x incremental transmission needs by 2030; 4.2x by 2050 • 10 million MW-miles incremental transmission capacity required by 2030 Cumulatively 29 million incremental MW-miles required by 2050 • Through 2020: incremental 350 circuit miles/year needed 2021–2030: incremental 890 circuit miles/year, and 2031–2050: incremental 1,050 circuit miles/year	• Established U.S. offshore wind market and supply chain by 2020 • 22 GW installed by 2030 and 86 GW installed by 2050 • By 2050, offshore wind in multiple regions, including the East Coast, West Coast, Great Lakes, and Gulf of Mexico

a. Expenditures in 2013$

b. Increased costs associated with greater demand for system flexibility and wind curtailments are embedded in the system costs and retail rate impacts reported in Chapter 3.

c. All transmission estimates reported are the incremental difference between the *Study Scenario* and *Baseline Scenario*. Estimated circuit miles assume a single-circuit 345-kilovolt transmission line with a nominal carrying capacity of 900 MW. ReEDS transmission capacity additions exclude those added for reliability purposes only and conductor replacement on existing infrastructure. Estimates shown here represent point to point transfers, for which explicit corridors have not been identified.

Figure 3-3. Summary of wind industry and other electric sector impacts in the *Central Study Scenario*

Transmission expansion is another key variable with respect to future wind deployment. New transmission capacity to support the *Study Scenario* is 2.7 times greater in 2030 than the respective *Baseline Scenario,* and about 4.2 times greater in 2050 (Table 3-1). Although transmission expansion needs are greater in the *Study Scenario,* transmission expenditures are less than 2% of total electric sector costs. Incremental cumulative (beginning in 2013) transmission needs of the *Central Study Scenario* relative to the *Baseline Scenario* amount to 10 million megawatt (MW)-miles by 2030 and 29 million MW-miles by 2050. Assuming single-circuit 345-kilovolt (kV) 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 circuit miles/year between 2031 and 2050 (Table 3-1). This compares with the recent (as of 2013) average of 870 circuit miles added each year since 1991.[3]

In the *Study Scenario*, wind primarily displaces fossil fuel-fired generation, especially natural gas, with the amount of displaced gas growing over time (Figure 3-4). In the long-term (after 2030), wind in the *Study Scenario* also affects the growth of other renewable generation and, potentially, future growth

3. Transmission estimates for the *Study Scenario* exclude maintenance for the existing grid, reliability-driven transmission, and other factors that would be similar between the *Baseline Scenario* and *Study Scenario.*

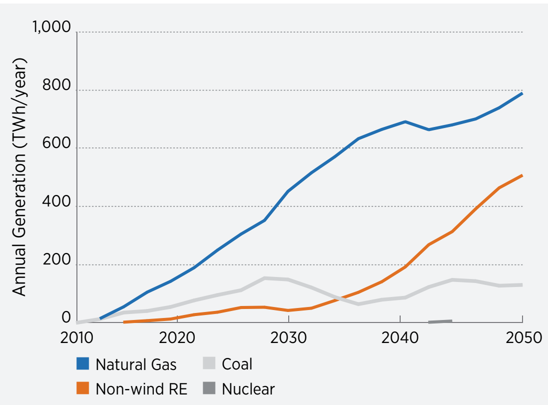
Table 3-1. Transmission Impacts in the *Central Study Scenario*

	Historical Average	2014–2020	2021–2030	2031–2050	Cumulative 2014–2050
Study Scenario MW-miles (change from *Baseline Scenario*)		311,000/year	801,000/year	949,000/year	29,000,000
Study Scenario circuit miles (change from *Baseline Scenario*)[a]	870/year	350/year	890/year	1,050/year	33,000
		By 2020	**By 2030**	**By 2050**	
Ratio of *Study Scenario* to *Baseline Scenario*		1.5x	2.7x	4.2x	

Note: ReEDS transmission capacity additions exclude those added for reliability purposes only and conductor replacement on existing infrastructure. Estimates shown here represent point to point transfers, for which explicit corridors have not been identified.

a. Assuming a representative transmission line with a carrying capacity of 900 MW, typical for single-circuit 345-kV lines

of nuclear generation. The avoided generation mix will ultimately depend on uncertain future market conditions, including fossil fuel prices and technology costs. Displaced fossil fuel consumption leads to avoided emissions and other social impacts. With wind penetration increasing to the levels envisioned under the *Study Scenario*, the role of the fossil fleet in providing 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.

Figure 3-4. Change in annual generation between the *Central Baseline Scenario* and the *Central Study Scenario* by technology type

Costs of the *Wind Vision Study Scenario*

National average retail electricity prices for both the *Baseline Scenario* and the *Study Scenario* are estimated to grow (in real terms) between 2013 and 2050. Through 2030, incremental retail electricity prices of the *Central Study Scenario* are less than 1% higher than those of the *Baseline Scenario*. In the long-term (2050), retail electricity prices are expected to be lower by 2% in the *Central Study Scenario* relative to the *Baseline Scenario*.

A wider range of future costs and savings are possible as estimated by the sensitivity scenarios. Sensitivities analyzed include specific scenarios in which wind costs or fossil fuel costs are expected to be higher and lower than those estimated in the *Central Study Scenario*. Sensitivities analyzed also include scenarios where both wind costs and fossil fuel costs are altered such that low wind costs are coupled with high fossil fuel prices and high wind costs are coupled with low fossil fuel prices.

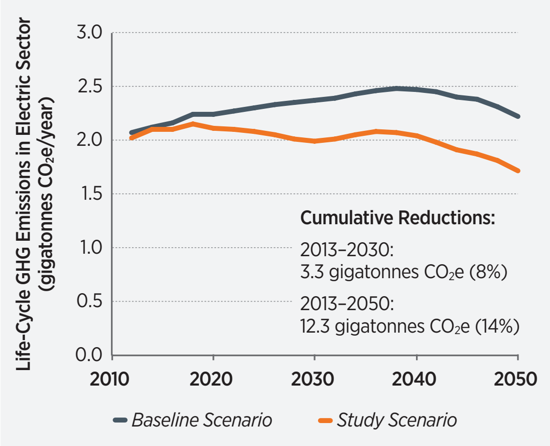
In 2020, the range of estimated incremental retail electricity rate ranges from a nearly zero cost difference vs. the *Baseline Scenario* up to a 1% cost increase. In 2030, incremental costs are estimated to be as high as a 3% increase vs. the *Baseline Scenario* under the most unfavorable conditions for wind (low fuel cost combined with high wind technology costs). Under the most favorable conditions modeled (high fuel cost combined with low wind costs), the *Study Scenario* results in a 2% reduction in retail electricity prices relative to the *Baseline Scenario*. By 2050, incremental electricity prices of all cases of the *Study Scenario* are estimated to range from a 5% increase to a 5% savings over the corresponding *Baseline Scenario*.

On an *annual* basis for the *Central Study Scenario*, consumers of electricity incur an increase in costs of \$2.3 billion (0.06¢ per kilowatt-hour [kWh]) in 2020 and \$1.5 billion (0.03¢ per kWh) in 2030, but realize a savings of \$14 billion (0.28¢/kWh) in 2050, as compared to the *Baseline Scenario*. Across the range of sensitivities, annual impacts to consumers range from the potential for costs as well as savings. In the near-term (2020), cost increases of \$0.8–\$3.6 billion are observed. In the mid-term (2030), consumer electricity cost effects range from savings of up to \$12 billion to costs of up to \$15 billion. In the long-term (2050), consumer electricity cost effects range from savings of up to \$31 billion or costs of up to \$27 billion. Electricity costs and savings from future wind deployment will depend strongly on future technology and fossil fuel cost conditions, with low technology costs or high fossil fuel costs supporting savings and stagnant technology or relatively lower fossil fuel costs driving consumer costs.

In present value terms, cumulative electric sector expenditures (fuel, capital, operating, and transmission) are lower for the *Study Scenario* than for the *Baseline Scenario* across most sensitivities evaluated. From 2013 to 2050, the *Central Study Scenario* results in cumulative present value (using a 3% real discount rate) savings of approximately \$149 billion (-3%). Potential electricity sector expenditures range from savings of \$388 billion (-7%) to a cost increase of \$254 billion (+6%), depending on future wind technology cost trends and fossil fuel costs.

Societal Benefits of the *Wind Vision Study Scenario*

The *Central Study Scenario* reduces electric sector life-cycle greenhouse gas (GHG) emissions by 6% in 2020 (0.13 gigatonnes of carbon dioxide equivalents, or CO_2e), 16% in 2030 (0.38 gigatonnes CO_2e), and 23% in 2050 (0.51 gigatonnes CO_2e), compared to the *Baseline Scenario*. Cumulative GHG emissions are



Note: Life-cycle GHG emissions include upstream emissions, ongoing combustion and non-combustion emissions, and downstream emissions. Upstream and downstream emissions include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, on-site construction, project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site material.

Figure 3-5. Life-cycle GHG emissions in the *Central Study Scenario* and *Baseline Scenario*

Table 3-2. Example Economic and Health Benefits from Reduced Air Pollution in the *Central Study Scenario* Relative to the *Baseline Scenario*

Type of Benefit	Amounts
Cumulative monetized benefits (2013\$)	\$108 billion
Avoided premature deaths	21,700
Avoided emergency room visits for asthma due to $PM_{2.5}$ effects	10,100
Avoided school loss days due to ozone effects	2,459,600

Note: Central estimate results are presented, which follow the 'EPA Low' methodology for calculating benefits, further detailed in Section 3.8. Monetized benefits are discounted at 3%, but mortality and morbidity values are simply accumulated over the 2013–2050 time period. Health impacts presented here are a subset of those analyzed and detailed in Section 3.8.

reduced by 12.3 gigatonnes CO_2e from 2013 to 2050 (14%) (Figure 3-5). Based on the U.S. Interagency Working Group's (IWG's) Social Cost of Carbon (SCC) estimates, these reductions yield global avoided climate change damages of an estimated $85–$1,230 billion, with a central estimate of $400 billion (2013–2050 discounted present value). This is equivalent to a levelized benefit of wind energy ranging from 0.7¢ per kWh of wind to 10¢ per kWh of wind, with a central levelized benefit estimate of 3.2¢ per kWh of wind.

The *Central Study Scenario*, as compared with the *Baseline Scenario*, results in reductions in other air pollutants including fine particulate matter, sulfur dioxide, and nitrogen oxides ($PM_{2.5}$, SO_2, and NO_X). These reductions yield societal health and environmental benefits that range from $52–$272 billion (2013–2050, discounted present values) depending on the methods of quantification. The single largest driver of these benefits is reduced premature mortality resulting from reductions in SO_2 emissions in the eastern United States. In total, the air pollution impacts of the *Study Scenario* are equivalent to a levelized benefit of wind energy that ranges from 0.4¢ per kWh of wind to 2.2¢ per kWh of wind. A selection of health outcomes is listed in Table 3-2.

The *Central Study Scenario* results in reductions in national electric-sector water withdrawals (1% reduction in 2020, 4% in 2030, and 15% in 2050) and water consumption (4% reduction in 2020, 11% in 2030, and 23% in 2050), compared to the *Baseline Scenario.*[4] Anticipated reductions, relative to the *Baseline Scenario*, exist in many parts of the United States, including the water-stressed arid states in the Southwest (Figure 3-6). Water use reductions driven by the *Study Scenario* offer environmental and economic benefits as well as reduced competition for scarce water resources.

The total value of reduced GHG and air pollution emissions in the *Central Study Scenario* relative to the *Baseline Scenario* exceeds the estimated increase in electricity rates observed in the 2020 and 2030 time periods by three and 20 times, respectively. By 2050, the *Central Study Scenario* results in savings across all three categories—electricity rates ($14 billion), GHG emissions ($42 billion), and air pollution emissions ($10 billion) (Figure 3-7). On a cumulative basis, savings across these metrics are also experienced for the *Central Study Scenario* relative to the *Baseline Scenario* (Figure 3-8). These quantitative outcomes hold across many of the sensitivities analyzed.

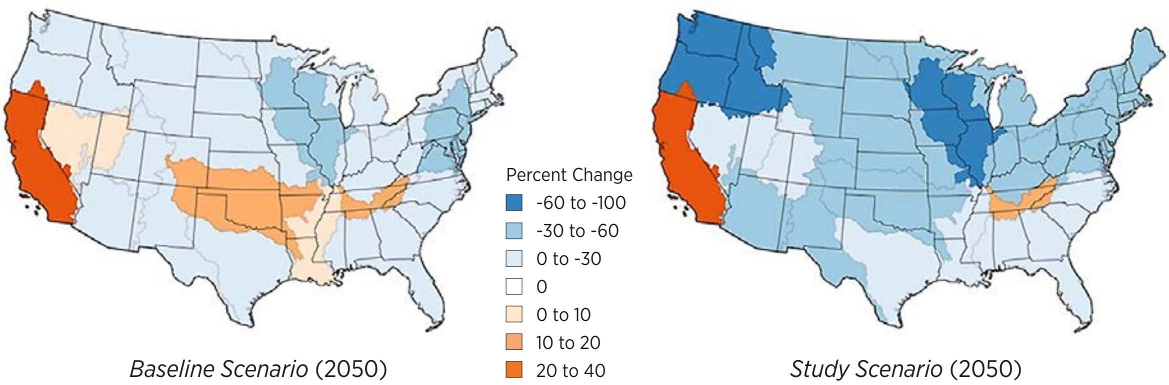
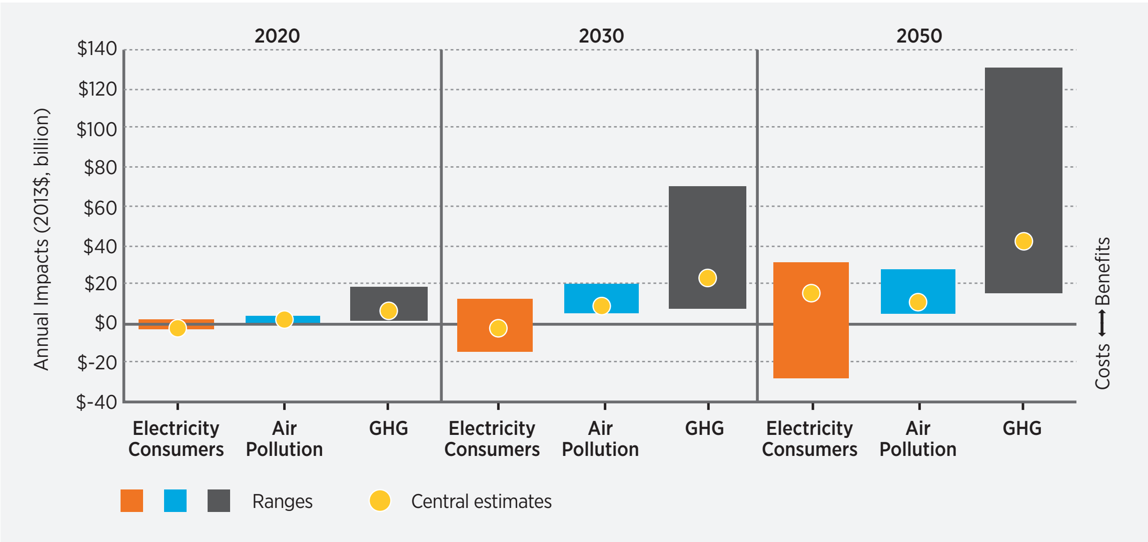


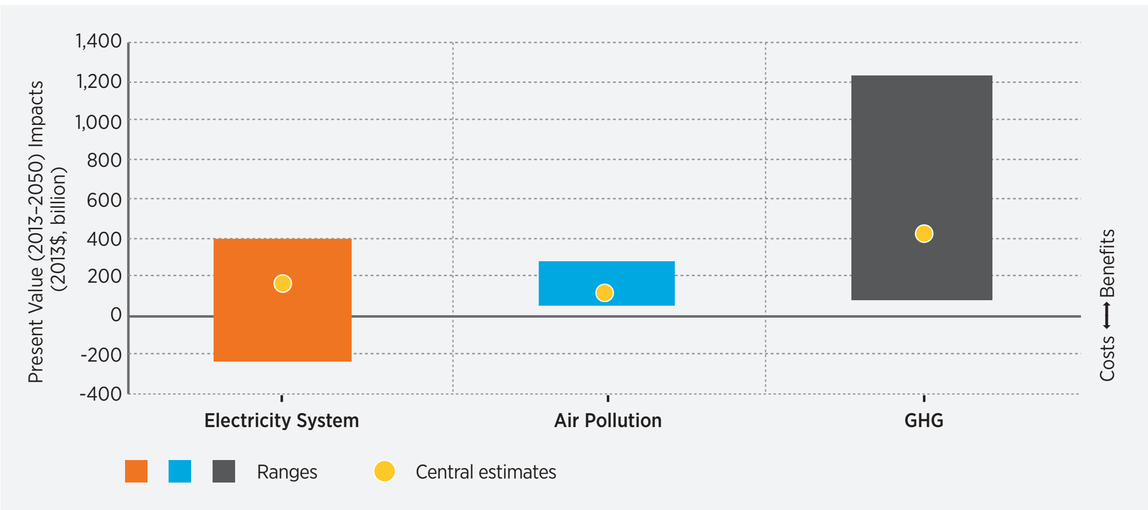
Figure 3-6. Change in water consumption used in electricity generation from 2013 to 2050 for the *Baseline Scenario* and *Central Study Scenario*

4. Water withdrawal is defined as water removed from the ground or diverted from a water source for use, but then returned to the source, often at a higher temperature. Water consumption is defined as water that is evaporated, transpired, incorporated into products or crops, or otherwise removed from the immediate water environment.



Note: Results represent the annual incremental costs or benefits (impacts) of the *Study Scenario* relative to the *Baseline Scenario.* Central estimates are based on *Central Study Scenario* modeling assumptions. The electricity consumers costs range reflects incremental expenditures (including capital, fuel, and operations and maintenance for transmission and generation of all technologies modeled) across a series of sensitivity scenarios. Air pollution and GHG estimates are based on the *Central Study Scenario* only, with ranges derived from the methods applied and detailed in the full report.

Figure 3-7. Monetized impacts of the *Study Scenario* relative to the *Baseline Scenario* in 2020, 2030, and 2050



Note: Results represent the present value of incremental costs or benefits (impacts) of the *Study Scenario* relative to the *Baseline Scenario.* Central estimates are based on *Central Study Scenario* modeling assumptions. The electricity system cost range reflects incremental expenditures (including capital, fuel, and operations and maintenance for transmission and generation of all technologies modeled) across a series of sensitivity scenarios. Air pollution and GHG estimates are based on the *Central Study Scenario* only, with ranges derived from the methods applied and detailed in the full report.

Figure 3-8. Cumulative (2013–2050) present value of monetized impacts of the *Study Scenario* relative to the *Baseline Scenario*

Additional Impacts Associated with the Study Scenario

The *Study Scenario* contributes to reductions in both long-term natural gas price risk and natural gas prices, compared to the *Baseline Scenario.*[5] The *Central Study Scenario* results in total electric system costs that are 20% less sensitive to long-term fluctuations in coal and natural gas prices. Additionally, the *Study Scenario* leads to a potential $280 billion in consumer savings due to reduced natural gas prices outside the electric sector, equivalent to a levelized consumer benefit from wind energy of 2.3¢ per kWh of wind.

The *Study Scenario* supports a robust domestic wind industry, with wind-related gross jobs from investments in new and operating wind power plants ranging from 201,000 to 265,000 in 2030, and increasing to between 526,000 and 670,000 in 2050. Actual future wind-related jobs (on-site, supply chain, and induced) will depend on the future strength of the domestic supply chain and additional training and educational programs as necessary.

Wind project development examined in the *Wind Vision* affects local communities through land lease payments and local property taxes. Under the *Central Study Scenario*, wind power capacity additions lead to land-based lease payments that increase from $350 million in 2020 to $650 million in 2030, and then to $1,020 million in 2050. Offshore wind lease payments increase from $15 million in 2020 to $110 million in 2030, and then to $440 million in 2050. Property tax payments associated with wind projects are estimated to be $900 million in 2020; $1,770 million in 2030; and $3,200 million in 2050.

Under the *Study Scenario,* the land area occupied by turbines, roads, and other infrastructure for wind development equates to 0.03% of the land area in the contiguous United States in 2030 and 0.04% in 2050. For comparison, this area equates to less than one-third of land area occupied by U.S. golf courses in 2013. Land area occupied by wind power plants (accounting for requisite turbine spacing and typical densities) equates to less than 1.5% of the land area in the contiguous United States by 2050. Land surrounding wind power plants is typically able to support other land uses, such as ranching and farming.

Continued wind deployment will need to be executed with sensitivity to the potential impacts on avian, bat, and other wildlife populations; the local environment; the landscape; and communities and individuals living in proximity to wind projects. Experience, continued research, and technological solutions (e.g., strategic operational strategies and wildlife deterrents) are expected to make siting and mitigation more effective and efficient.

5. Wind power can be sold at fixed prices for long periods (e.g., 20 years), and, as a result, provides a hedge against volatility in commodity fuels such as natural gas. When wind power is a more significant part of the electricity generation portfolio, as is the case in the *Study Scenario*, electricity system costs are less sensitive to market fluctuations in fossil fuel prices. In addition, deployment and operation of wind power plants reduces demand for fossil fuels, including natural gas, leading to lower fuel prices within and outside of the electric sector and supporting cost savings for consumers.

System Costs[a]	Benefits[a,b,c]		
$	GHG	Air Pollution	H_2O
$149 billion (3%) lower cumulative electric sector expenditures	14% reduction in cumulative GHG emissions (12.3 gigatonnes CO_2-equivalents), saving $400 billion in avoided global damages	$108 billion savings in avoided mortality, morbidity, and economic damages from cumulative reductions in emissions of SO_2, NO_x, and PM 21,700 premature deaths from air pollution avoided	23% less water consumption and 15% less water withdrawals for the electric power sector

Additional Impacts

Energy Diversity	Jobs	Local Revenues	Land Use	Public Acceptance and Wildlife
Increased wind power adds fuel diversity, making the overall electric sector 20% less sensitive to changes in fossil fuel costs. The predictable, long-term costs of wind power create downward price pressure on fossil fuels that can cumulatively save consumers $280 billion from lower natural gas prices outside the electric sector.	Approximately 600,000 wind-related gross jobs spread across the nation.	$1 billion in annual land lease payments $440 million annual lease payments for offshore wind plants More than $3 billion in annual property tax payments	Less than 1.5% (106,000 km^2) of contiguous U.S. land area occupied by wind power plants Less than 0.04% (3,300 km^2) of contiguous U.S. land area impacted by turbine pads, roads, and other associated infrastructure	Careful siting, continued research, thoughtful public engagement, and an emphasis on optimizing coexistence can support continued responsible deployment that minimizes or eliminates negative impacts to wildlife and local communities.

Note: Cumulative costs and benefits are reported on a Net Present Value basis for the period of 2013 through 2050 and reflect the difference in impacts between the *Central Study Scenario* and the *Baseline Scenario*. Results reported here reflect central estimates within a range.

a. Electric sector expenditures include capital, fuel, and operations and maintenance for transmission and generation of all technologies modeled, but excludes consideration of estimated benefits (e.g., GHG emissions).

b. Morbidity is the incidence of disease or rate of sickness in a population.

c. Water consumption refers to water that is used and not returned to the source. Water withdrawals are eventually returned to the water source.

Figure 3-9. Summary of costs, benefits, and other outcomes associated with the *Central Study Scenario* relative to the *Baseline Scenario* by 2050

Benefits Specific to Offshore and Distributed Wind

Contributions from offshore wind under the *Study Scenario* are characterized by an industrial base that evolves from its nascent state in 2013 to one that can supply more than 20 GW of offshore capacity by 2030 and more than 80 GW by 2050. This deployment represents just 5.5% of the resource potential for offshore areas adjacent to the 28 coastal and Great Lakes states. Under this scenario, the offshore wind industry would complement and bolster a strong land-based industry through the use of common supply chain components and the development of workforce synergies.

The cost of offshore wind needs to be reduced. Through innovation and increasing scale, however, this market segment could bring notable potential benefits. In particular, offshore wind offers the ability to reduce wholesale market power clearing prices and consumer costs in transmission-congested coastal areas, supports local jobs and port development opportunities, and offers geographic proximity to densely populated coastal regions with limited renewable power alternatives.

Distributed wind applications, including customer-sited wind and wind turbines embedded in distribution networks, offer a number of unique attributes relevant to the *Wind Vision*. On-site distributed wind turbines allow farmers, schools, and other energy users to benefit from reduced utility bills, predictable costs, and a hedge against the possibility of rising retail electricity rates. At the same time, decentralized generation such as distributed wind can benefit the electrical grid. Distributed wind also supports a domestic market; U.S. suppliers dominate the domestic small wind turbine market, with 93% of 2013 sales on a unit basis and 88% on a capacity basis. These suppliers maintain domestic content levels of 80–85% for turbine and tower hardware and are well positioned to capitalize on export opportunities, including growing global demand for decentralized electricity.

Conclusion

Wind power has the potential to provide a substantial share of the nation's electricity at modest near- and mid-term costs and with long-term savings. Overcoming these costs and achieving the *Study Scenario* would require an array of actions (detailed in Chapter 4), but analysis also suggests that robust deployment of wind offers the opportunity to realize a range of additional benefits. Based on current estimates, these benefits exceed the expected near- and mid-term investments and other costs that might result from continued growth of wind energy, across nearly all analyzed scenarios.

3.0 Introduction

Wind industry proponents often point to societal attributes such as lower GHG emissions and rural economic development opportunities as a basis for deployment of wind power. Critics argue that the costs associated with deployment and operation of wind power offset the potential benefits. This chapter informs both perspectives by providing a detailed accounting of various impacts associated with wind deployment under the *Wind Vision Study Scenario*. While Chapter 2 is a retrospective analysis, Chapter 3 provides an assessment of potential future impacts.

Reported impacts are assessed across a number of societal variables. Where possible, impacts are quantified and reported as costs and benefits. Changes in electricity rates, annual electricity consumer costs or savings, and cumulative system expenditures are quantified and reported based on a range of future fossil fuel prices and cost trajectories for wind technology. Impacts on GHG emissions, human health and the environment, water consumption and withdrawals, energy diversity and risk reduction, wind workforce and economic development, transmission and other infrastructure needs, and land use are also analyzed and reported quantitatively. Issues related to electric system reliability, operations and markets, and public acceptance and local impacts are also considered and discussed.

The *Wind Vision* impacts assessment relies on scenarios of future wind deployment to estimate incremental impacts. As discussed in Chapter 1, the *Study Scenario* uses prescribed wind energy penetration levels of 10% by 2020, 20% by 2030, and 35% by 2050, a portion of which is assumed to be offshore wind.[6,7] These penetration levels are grounded in a broad analysis of wind deployment under various market and technology conditions, recent industry trends, and wind energy penetration levels studied in prior work [1, 2]. Impacts from the *Study Scenario* are compared with the *Baseline Scenario*, which holds wind capacity constant at year-end 2013 levels. This approach allows for the quantification of impacts from all future wind deployment. More comprehensive discussion of the development of the *Study Scenario* and the *Baseline Scenario* is in Chapter 1.

In addition to detailing the impacts assessment and general quantification of costs and benefits, this chapter discusses the electric sector modeling methods and relevant modeling inputs. These aspects are covered in Sections 3.1 and 3.2, respectively. Using these tools, Section 3.3 translates the *Study Scenario* into more concrete implications for the wind industry in terms of annual capacity additions and investment. Section 3.4 details the expected impacts on electricity rates and system costs. Sections 3.5 and 3.6 highlight the expected changes in the national generation mix under the *Study Scenario* and the relevant impacts to the electric system. Each of these sections is based on a comparison of the *Study Scenario* with the *Baseline Scenario*. Given uncertainties about future wind energy costs as well as the cost of fossil generation, sensitivities are also considered in order to provide further insight.

Sections 3.7–3.12 describe various additional benefits and impacts of the *Study Scenario*:

- Greenhouse Gas Emissions Reductions (Section 3.7)
- Air Pollution Impacts (Section 3.8)
- Water Usage Reduction (Section 3.9)
- Energy Diversity and Risk Reduction (Section 3.10)
- Workforce and Economic and Development Impacts (Section 3.11)
- Local Impacts, including land area (Section 3.12)

In these sections, the core electric sector modeling results are supplemented with additional analysis tools and assumptions to quantify impacts. The focus is principally on a comparison of the *Study Scenario* under central conditions (i.e., the *Central Study Scenario*) with the respective *Baseline Scenario*

6. Percentage wind energy penetration is calculated as the share of total wind generation relative to total end-use energy demand.

7. Distributed wind turbines connected to the transmission grid are represented within the larger land-based designation. Turbines sited to serve onsite customer needs (connected to the distribution grid) are not captured in the *Wind Vision* report or its quantitative analysis due to limited modeling capabilities. These modeling capabilities are under development and a vision report specific to distributed wind is planned for 2015. Unique benefits of distributed wind are discussed in greater detail in Section 3.13.2.

(i.e., the reference scenario with the corresponding central fuel price assumption). A range of results is often presented and is based on other considerations (apart from the fossil fuel prices and wind cost assumptions that are the basis of the sensitivities in Sections 3.3–3.6).

Finally, Section 3.13 discusses unique benefits associated with offshore and distributed wind that are not otherwise covered in depth in other sections of the chapter. Various appendices provide further details on the methods applied in this chapter and are noted where applicable.

3.1 Impacts Assessment Methods and Scenarios

The economic, environmental, and social impacts of wind deployment depend on the evolution of wind technology and the context under which the deployment occurs. For example, the relative economics of wind will depend on wind technology improvements as well as technology improvements of other power generation technologies and the associated fuel costs. The environmental or social benefits of wind power are also dependent upon the quantity and type of generation displaced. While the market conditions for wind deployment will evolve and there is increasing uncertainty further into the future, impacts assessment over the near- (2020), mid- (2030), and long- (2050) term facilitates understanding of the potential range of costs and benefits of greater wind deployment.

Estimating these future impacts requires analysis techniques that capture the potential evolution of wind technologies as well as potential changes within the power sector given current trends and expectations. The following section describes the computational tools used for this analysis and introduces the scenarios designed to estimate the future impact of the *Study Scenario*.

3.1.1 Regional Energy Deployment System (ReEDS) Model

The primary analytic tool used for the *Wind Vision* impacts assessment is NREL's ReEDS electric sector capacity expansion model [3]. ReEDS simulates the construction and operation of generation and transmission capacity to meet electricity demand. The model relies on system-wide least cost optimization to estimate the type and location of fossil, nuclear, renewable, and storage resource development; the transmission infrastructure expansion requirements of those installations; and the generator dispatch and fuel needed to satisfy regional demand requirements and maintain grid system adequacy. The model also considers technology, resource, and policy constraints, including state renewable portfolio standards. ReEDS models scenarios of the continental U.S. electricity system in two-year solve periods out to 2050.[8] Within the context of the *Wind Vision*, ReEDS is used to generate a set of future scenarios of the U.S. electricity sector from which the impacts of a high penetration wind future are assessed. Although ReEDS scenarios are not forecasts or projections, they provide a common framework for understanding the incremental effects associated with specific power sector changes such as those prescribed in the *Study Scenario*.

ReEDS is specifically designed to represent the unique characteristics of wind generation—variability, uncertainty, and geographic resource constraints—and its impacts on the broader electric system. The model's high spatial resolution[9] and statistical treatment of the impact of variable wind and solar resources enable representation of the relative value of geographically and temporally constrained renewable power resources. In particular, ReEDS explicitly and dynamically estimates and considers the need for new transmission, increases in operating reserve requirements,

8. Alaska, Hawaii, and Puerto Rico are not included in ReEDS analysis. The analysis assumes net energy transfers from Canada to the United States (see Appendix G), but ignores the limited interactions with Mexico. The start year for ReEDS is 2010, but *Wind Vision* results are primarily presented from 2013.

9. ReEDS represents the continental United States using 356 wind resource regions in which wind quality and resource availability are characterized, and 134 model balancing areas. Most other technologies, generator dispatch, load balancing, and other system operation factors are considered within the 134 model balancing areas. In addition, transmission modeling, including power transfers and transmission capacity expansion, occurs between the 134 balancing areas. Transmission expansion within a balancing area is estimated, in this report, for new wind interconnections only. Balancing area boundaries in ReEDS do not correspond identically with actual balancing authority area boundaries.

and changing contributions to planning reserves that may be driven by increases in renewable generation, including wind. ReEDS dispatches all generation using multiple time-slices to capture seasonal and diurnal demand and renewable generation profiles.[10]

In addition to modeling wind technologies (land-based and offshore), ReEDS features a full suite of major generation and storage technologies. This includes coal, natural gas, oil and gas steam, nuclear, biopower, geothermal, hydropower, utility-scale solar, pumped hydropower storage, compressed air energy storage, and batteries.[11] ReEDS applies standardized financing assumptions for investments of all technologies represented in the model. Financing rates assume a weighted average cost of capital of 8.9% (nominal).[12] With this model representation of fossil, nuclear, renewable, and storage technologies, and the treatment of variable generation, ReEDS is able to provide estimates of the impact of greater wind penetration to the system over time.

The ReEDS documentation [3] provides a more detailed description of the model structure and key equations. Recent publications using ReEDS include the U.S. Department of Energy's (DOE's) *SunShot Vision Study* [5], the *Renewable Electricity Futures* study [2], lab reports [6, 7, 8, 9] and journal articles [10, 11, 12, 13].[13] The ReEDS model was also used to develop scenarios for the *20% Wind Energy by 2030* report [1].[14] The model documentation and subsequent publications, however, describe a large number of model developments subsequent to that study.

While ReEDS represents many aspects of the U.S. electric system, it has certain limitations:

- ReEDS is a system-wide optimization model and, therefore, does not consider revenue impacts for individual project developers, utilities, or other industry participants.
- ReEDS does not explicitly model constraints associated with the manufacturing sector. All technologies are assumed to be available up to their technical resource potential.[15]
- Technology cost reductions from manufacturing economies of scale and "learning by doing" are not endogenously modeled for this analysis. Rather, current and future cost reduction trajectories are defined as inputs to the model (see Appendices G and H).
- With the exception of future fossil fuel costs, foresight is not explicitly considered in ReEDS (i.e., the model makes investment decisions based on current conditions, without consideration for how those conditions may evolve in the future).
- ReEDS is deterministic and has limited considerations for risk and uncertainty.
- The optimization algorithm in ReEDS does not fully represent the prospecting, permitting, and siting hurdles that are faced by project developers for either electricity generation capacity or transmission infrastructure.[16]
- ReEDS does not include fuel infrastructure or land competition challenges associated with fossil fuel extraction and delivery.

10. Each solve year includes 17 time-slices: four diurnal time-slices (morning, afternoon, evening, night) for each of the four seasons (winter, spring, summer, fall) and a summer peaking time-slice.
11. Coal and natural gas with and without carbon capture and storage are included. ReEDS models natural gas combined cycle and combustion turbine technologies independently. Utility-scale solar includes photovoltaic and concentrating solar power with and without thermal energy storage; rooftop solar deployment is not modeled but applied as an exogenous input into the system. Short et al. [3] describes the array of the technologies modeled in ReEDS in greater detail.
12. An additional risk adder is applied to new coal power plant capacity that does not include carbon capture and sequestration to reflect long-term risk associated with potential new carbon or other environmental policies. This approach is consistent with assumptions made in the Energy Information Administration's Annual Energy Outlook 2014 [4].
13. See *www.nrel.gov/analysis/reeds* for a list of publications and further description about ReEDS.
14. The version of the model used in the *20% Wind Energy by 2030* report was referred to as the Wind Deployment System (WinDS) model; ReEDS reflects the current name of the model.
15. ReEDS includes a growth penalty in which the rapid deployment of a technology is penalized with additional capital costs. For wind technologies, this is represented by having capital costs extend beyond the defined amounts if annual capacity additions exceed 1.44 times the additions in the previous solve year.
16. Standard exclusions are applied that limit wind resources below the gross resource potential (see Appendix H). As a linear optimization model, ReEDS also likely underestimates transmission needs due to the lumpiness of real transmission investments and the non-direct paths in real transmission lines compared to the point-to-point model paths. Transmission dispatch modeling in ReEDS, however, includes a linearized DC power flow representation that accounts for non-direct paths of electricity flows.

- ReEDS models the power system of the continental United States and does not represent the broader United States or the global energy economy. For example, competing uses of resources across sectors (e.g., natural gas) are not dynamically represented in ReEDS and end-use electricity demand is exogenously input to ReEDS for the *Wind Vision*.

One consequence of these model limitations is that system expenditures estimated in ReEDS 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. Because wind technologies are expected to require new transmission infrastructure development and to benefit from broad-based system coordination, this effect may be amplified when considering high wind penetration scenarios. At the same time, spatial resolution in ReEDS provides sophisticated evaluation of the relative economics among generation resources. It also offers significant incremental insight into key issues surrounding future wind deployment, including locations for future deployment, transmission expansion needs, impacts on planning and operating reserves, and wind curtailments.

ReEDS analysis uses the Solar Deployment System, or SolarDS, model [14] to generate a projection of rooftop solar photovoltaic (PV) deployment. Rooftop PV deployment is then input to ReEDS. All ReEDS scenarios rely on the same single rooftop PV capacity projection.[17] The input parameters for SolarDS used in this analysis are similar to those used in the *SunShot Vision Study* [5], with some exceptions presented in Appendix G. No other distributed generation technologies are modeled explicitly in the *Wind Vision* scenarios, although the unique attributes associated with distributed wind generation are discussed in Section 3.13.[18]

3.1.2 Model Outputs to Assess the Impacts of the *Wind Vision*

Primary *Wind Vision* outputs from the ReEDS model include the location, capacity, and generation of technologies deployed and operated over the period of study (2013–2050). Fixed and operating costs, fuel usage and costs, and other associated costs are also reported, as are transmission infrastructure expansion and related costs. These scenario data are reported in this chapter and are used to inform and support the various impacts assessments, including GHG emissions, other environmental and health benefits, water use, energy diversity and risk, workforce and economic development impacts, and land use. Specific scenario data uses and methods for each impact category are provided in subsequent sections.

ReEDS is also used to estimate electric sector cost implications. Two cost metrics are provided by ReEDS: (1) a nationwide average retail electricity rate, and (2) a net present value system cost. ReEDS estimates electricity prices with a cost-of-service model[19] and accounts for all capital and operating expenses [3] . While this metric is not indicative of actual retail prices in all regions (e.g., price impacts for restructured markets are not evaluated with ReEDS), it provides an indication of the price impacts over time. In addition, annual electricity consumer cost, which is the product of annual rates and end-use consumption, is estimated. The present value system cost metric accounts for capital and operating expenditures incurred over the entire study horizon for all technology types considered, including wind and non-wind generation, transmission, and storage. The cost metrics provided directly from ReEDS do not include any environmental or health externalities (e.g., social cost of carbon emissions).

17. The only differences across scenarios associated with rooftop PV relate to rooftop PV curtailment estimates within ReEDS, which have only minor effects. Rooftop PV capital and operations and maintenance costs are excluded from ReEDS system expenditures. In the case of the *Wind Vision*, however, there is no effect on reported electricity rates or system costs from this exclusion, since results focus on the change in outcomes between two scenarios that do not include these costs in their estimates.

18. A distributed wind deployment model comparable to SolarDS is being developed but was not applied in the *Wind Vision* (see Section 1.2.2).

19. The cost-of-service model assumes a single rate base for the continental United States that includes all capital expenditures amortized over 30 years. Impacts of wind generation on wholesale prices are not estimated for the modeled scenarios and are not described in this section. Text Box 3-6 qualitatively discusses the impacts of wind deployment on wholesale electricity prices. The methodology to estimate electricity prices in ReEDS uses a calibration step to match historical (2010) retail rates to consider distribution costs and/or the markup between wholesale and retail rates for regions with restructured markets. This additional cost is assumed to be uniform across all years and scenarios.

3.1.3 Scenario Framework

The *Wind Vision* modeling analysis is focused on the *Study Scenario* and the *Baseline Scenario*. The *Study Scenario* provides insight into possible high penetration wind futures and allows for description and quantification of effects on the broader electric power sector associated with deployment and operation of a high penetration wind electric system. The *Baseline Scenario* fixes installed wind capacity at year-end 2013 levels and provides the requisite reference from which the incremental impact of all future wind deployment and generation can be assessed. The choice of *Baseline Scenario* as the reference is critical because it allows analysis and quantification of the impacts from all incremental wind energy. None of the scenarios within either of these categories represents a forecast or prediction. Instead, they provide the framework for understanding the impacts in a future that includes high levels of wind power.

Under the *Study Scenario*, annual wind power electricity generation is prescribed to reach pre-determined levels for each ReEDS solve year for the period of 2013 to 2050. Explicit wind electricity generation levels in the *Study Scenario* are 10% of annual end-use electricity demand by 2020, 20% by 2030, and 35% by 2050 (Figure 3-10 illustrates this scenario; Chapter 1 includes a discussion of how this trajectory was developed). While the scenario results are focused on these specific end-point years, wind generation levels are also prescribed for intermediate years by linear interpolation.[20] These values represent the overall national prescriptions and include combined generation from both land-based and offshore wind technologies.

Included within the total wind recommendations under the *Study Scenario*, 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

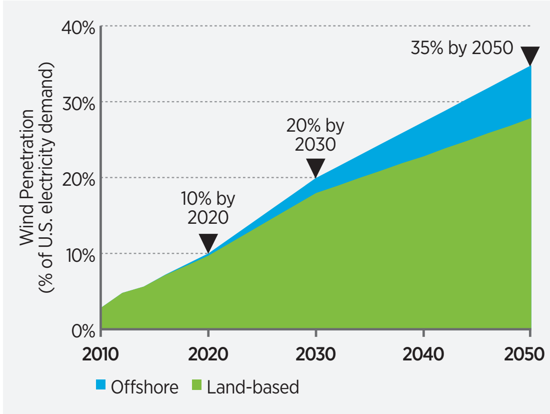


Figure 3-10. Wind penetration levels for the *Study Scenario*

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.[21]

No predetermined capacity requirements from wind power are modeled in the *Study Scenario.* Total capacity required to reach the wind penetration levels is determined by the assumed future performance (capacity factor) 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.

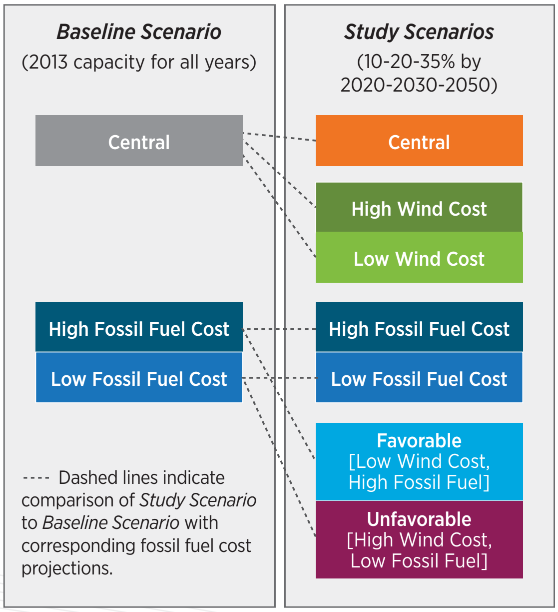
As noted above, the *Baseline Scenario* constitutes the reference scenario that is used to compare the impacts of wind deployment in the *Study Scenario* and to assess the cost, benefits, and trade-offs of deploying wind relative to other options. In the

20. The prescribed wind penetration levels for 2016 and 2018 are set to 7.2% and 8.6%, respectively; all other years assume linear increases in wind penetration up to the specific levels established for the three end-point years of 10% in 2020, 20% in 2030, and 35% in 2050.

21. The North Atlantic region includes Atlantic offshore areas from Maryland to Maine. The South Atlantic region includes Atlantic offshore areas from Virginia to Florida, inclusive of only the Atlantic coast of Florida. The Gulf region includes the Gulf coast of Florida and coastal states westward through Texas. The Pacific includes California, Oregon, and Washington. The Great Lakes includes all states touching one of the lakes, but only the westernmost portions of New York. The remainder of New York is considered part of the Atlantic Region. The regional distribution of offshore wind generation is also prescribed for all years. For 2020, the distribution is 80% in the North Atlantic and 20% in the Gulf; for 2030, the distribution is 50% in the North Atlantic, 15% in all other offshore regions except the Pacific, and 5% in the Pacific; and for 2050, the distribution is 33% in the North Atlantic, 22% in the South Atlantic, 20% in the Pacific, 15% in the Great Lakes, and 10% in the Gulf.

Baseline Scenario, future wind capacity in the continental United States is restricted to be the total installed capacity as of year-end 2013.[22] As noted, this artificial limit on new wind capacity reflects the fact that the *Baseline Scenario* is constructed exclusively to provide a point of reference relative to the *Study Scenario* and allows an evaluation of the impacts of all *incremental* wind deployment in the *Study Scenario.*

Given uncertainties associated with future market conditions, multiple sensitivities are modeled for both the *Study Scenario* and *Baseline Scenario*. Figure 3-11 shows the scenario framework with ten modeled sensitivities (seven *Study Scenarios* and three *Baseline Scenarios*). Future market variables are limited to wind cost and performance and fossil fuel costs. All other input data assumptions are identical across sensitivities and are described in Section 3.4 and Appendices G and H. These scenario sensitivities allow for increased insight into the robustness of the modeled outcomes, the magnitude of change that may result given uncertainty in specific variables, and the conditions under which a potential change in direction of impact may occur.



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

Figure 3-11. *Study Scenario* and *Baseline Scenario* framework with associated sensitivities

Three trajectories of future wind cost—*Central, High,* and *Low Wind Cost*—and three trajectories of future fossil fuel costs—*Central, High,* and *Low Fuel Cost*—are considered. The wind cost trajectories are developed based on ranges provided by multiple independent published projections. The *High Wind Cost* trajectory represents no technology improvement from 2014 for land-based wind and only moderate improvements for offshore wind technology through the mid-2020s, with no further improvements thereafter. The *Low Wind Cost* trajectory represents the low end of cost reductions found from these literature sources. The *Central Wind Cost* trajectory represents the median value. Greater detail on the wind costs are provided in Section 3.4.1 and Appendix H.[23]

Similar to the wind costs, the fossil fuel cost trajectories provide a range of future fossil fuel costs and are based on the Energy Information Administration's (EIA's) Annual Energy Outlook (AEO) 2014 scenarios [4]. In particular, the *Central Fuel Cost* trajectory uses the AEO 2014 Reference Case prices for coal and natural gas; the *High Fuel Cost* trajectory uses the AEO 2014 High Coal Cost and Low Oil/Gas Resource scenarios for coal and natural gas prices, respectively; and the *Low Fuel Cost* trajectory uses the AEO 2014 Low Coal Cost and High Oil/Gas Resource scenarios.

22. The Ventyx Velocity Suite (*http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite*) is the basis of all existing installed capacity data for ReEDS for 2010 to year-end 2012. Wind capacity installations in 2013 are based on data from the American Wind Energy Association [15]. The year-end 2013 installed wind capacity represented in ReEDS and included in the *Baseline Scenario* for all post-2013 years totals 60 GW. This differs slightly from the U.S. total of 61 GW estimated by the American Wind Energy Association [15]. Differences are a function of minor discrepancies in the underlying datasets and the exclusion in ReEDS of capacity in Alaska, Hawaii, and Puerto Rico, which is reported in the American Wind Energy Association's total. ReEDS models the continental United States only. These differences have negligible effect on the overall results presented in this analysis. For the *Baseline Scenario,* year-end 2013 installed capacity remains for all future years in that the capacity is automatically repowered upon its assumed lifetime. This differs from the *Study Scenario*, where repowering is a decision made within ReEDS. Repowering garners higher assumed capacity factors, including in the *Baseline Scenario.*

23. Wind technology improvements are characterized through a combination of capital cost reductions, operations expenditure cost reductions, and capacity factor improvements. See Appendix H for additional detail.

Reliance on central assumptions across all model inputs allows the *Central Study Scenario* to be the primary estimate.[24] Figure 3-11 shows the other single-variable sensitivities with assumptions for wind costs (*High Wind Cost*, *Low Wind Cost*) and fossil fuel costs (*High Fuel Cost*, *Low Fuel Cost*) considered independently. Figure 3-11 also shows the multiple variable or combined sensitivities analyzed including the *Favorable* (*Low Wind Costs coupled with High Fuel Cost*) and *Unfavorable* (*High Wind Costs coupled with Low Fuel Cost*) conditions, respectively. When considered together, these multivariable sensitivities are referred to as the *Combined* sensitivities.

The seven *Study Scenario* sensitivities are compared with three *Baseline Scenario* sensitivities. The *Central Baseline Scenario* provides a reference for the three *Study Scenario* sensitivities that rely on the central fossil fuel cost case, and the *Baseline Scenario* sensitivities under *High* and *Low Fuel Cost* assumptions provide references for the *Study Scenario* sensitivities 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.

Many of the results presented in this chapter focus on the full range of analysis sensitivities. Reported impacts including wind capacity additions, economic impacts, electric system impacts, and transmission and grid integration impacts rely on data from the full set of scenario sensitivities modeled. In some instances, impacts are assessed for the *Central Study Scenario* only. For example, GHG benefits, air pollution impacts, water use reduction, workforce and economic development impacts, and energy diversity and risk reduction are calculated solely for the *Central Study Scenario*. Even in those instances in which impacts are calculated based on the *Central Study Scenario,* a range of results is presented to reflect the uncertainties associated with these impacts. Impacts calculated from the full set of scenarios are clearly distinguished from those calculated from the *Central Study Scenario* alone. This distinction is important, but does introduce challenges for direct comparisons across the reported impact metrics.

These scenarios and their respective sensitivities provide a means to quantify the impacts of higher wind deployment. In particular, the scenario framework is designed to provide general bounding assessments specific to wind technology and fossil fuel market variables. Ultimately, however, this framework primarily demonstrates the changes in the results as a function of those variables alone. Other market factors, including electricity demand growth and non-wind technology costs, can also impact results and introduce uncertainty; however, modeling the sensitivity of results to these factors is outside the scope of this particular scenario analysis. In addition, other than the prescribed wind penetration levels in the *Study Scenario*, 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. The assumption of no new policies, beyond the prescribed wind penetration levels, does not represent policy forecasts or recommendations. Section 3.2 provides the key input assumptions of the analysis.

It is important to note that—while the *Wind Vision* analysis is policy-agnostic and focused entirely on the electric sector—the impacts, costs, and benefits of the *Study Scenario* and respective sensitivities will be dependent on the policy and market factors used to yield wind deployment levels consistent with the *Wind Vision*, and on larger economy interactions. The impacts, costs, and benefits presented here are driven by the approach to implementing the *Study Scenario* in ReEDS: prescribed wind generation levels in the electric sector. Alternative approaches to reaching the same deployment levels, through policy drivers and/or market dynamics, would be expected to yield different results. Research has generally found that energy 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. These effects are discussed in Section 3.7, but are not modeled in the *Wind Vision* analysis.

24. Although the *Central Study Scenario* reflects a central estimate, it has not been assigned a higher probability (in fact, no probabilities are explicitly assigned to any single scenario) and should not be construed as a most likely outcome. It is simply the central estimate given the range of potential input variables that exist as of 2013.

3.2 Summary of ReEDS Inputs

The ReEDS model requires a diverse set of inputs. Inputs of particular importance for the *Wind Vision* analysis include generation capacity cost and performance from 2014 to 2050 for wind technologies, other renewable technologies, and non-renewable technologies (e.g., coal, gas, nuclear). Key market variables that also serve as important modeling inputs through 2050 include anticipated generation plant retirements, future load growth, and fossil fuel prices. This section summarizes the values applied for the inputs and, where applicable, describes the methods by which these inputs were developed. Data reflect costs to build and operate new plants only and apply to the *Study Scenario* and the *Baseline Scenario*. For supplemental detail on these inputs, as well as operating costs associated with the existing plants, transmission costs, and storage costs, see Appendices G and H.

3.2.1 Wind Power Technologies

Wind technology inputs applied in this study are grounded in historical trends and published projections of future wind technology cost and performance. They assume continued technology development, optimization, and maturation. Although ReEDS uses explicit capital cost, capacity factor, and operations and financing inputs, this summary of ReEDS inputs reports costs strictly in terms of levelized cost of electricity (LCOE).[25]

3.2.1.1 Land-Based Wind

Land-based wind inputs were developed by the *Wind Vision* project team and are grounded in reported costs, e.g., [16] and modeled performance of currently available technology e.g., [17]. Primary cost inputs were developed from Interior region data as defined by Wiser and Bolinger [16] to control for non-technology regional cost differences (e.g., variability in labor rates and other non-turbine input costs).[26,27] Capital cost, estimated operating expenditures, and modeled performance data were coupled with high-resolution (200-meter [m]) hourly wind resource data to estimate LCOEs for all potential (non-excluded)[28] resource sites in the continental United States. Estimates of LCOE across a full array of potential project sites are required as a result of the multi-decadal time period covered by the analysis.

The *Wind Vision* project team also developed land-based wind LCOE projections through 2050. Projections were derived from a review and analysis of independent literature projections. More than 20 projection scenarios from more than 15 independent studies were considered (see also [18, 19]). Individual LCOE projections were estimated, extracted, and normalized to a common starting point using a process similar to, e.g., Lantz et al. 2012 [18]. This process resulted in an overall range of projected land-based LCOE reductions of 0–40% through 2050. From these results, three explicit projections were selected for modeling:

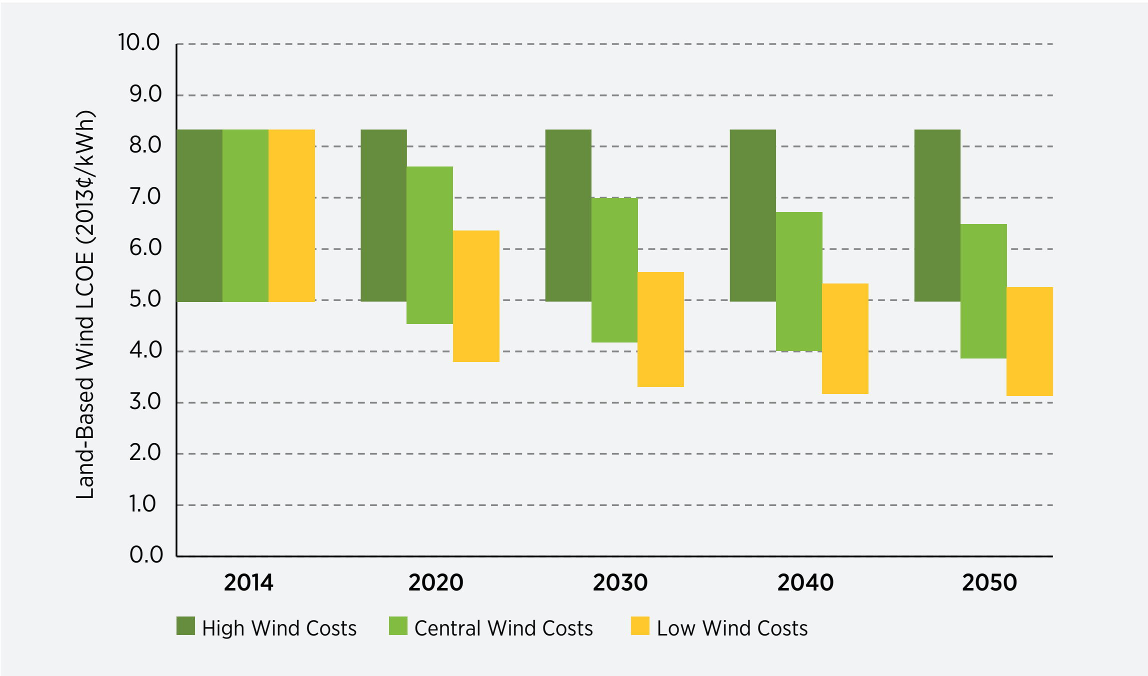
- *High Wind Costs*: Constant wind LCOEs from 2014 to 2050
- *Central Wind Costs*: Median annual cost reduction identified in the literature
- *Low Wind Costs*: Maximum annual cost reduction identified in the literature

25. Although there are various metrics that can be used to report generation costs, LCOE represents the present value of total costs divided by the present value of energy production over a defined duration (20 years in the referenced analysis). Actual disaggregated inputs are contained in Appendices G and H. LCOE values shown reflect permanent elements of the tax code (e.g., Modified Accelerated Cost Recovery System, or MACRS) but exclude policy support requiring periodic re-authorizations, such as the wind Production Tax Credit, as well as specific state policy support mechanisms (e.g., Renewable Energy Credits, property tax abatements, sales tax abatements). LCOE values should not be construed as representative of all system or societal costs. ReEDS modeling and subsequent impacts. assessment detailed in Sections 3.4–3.13 represent a more complete accounting of electric system and societal impacts.

26. The Interior region selected here is consistent with the Interior region as defined by Wiser and Bolinger for industry reporting in the 2012 Wind Technologies Market Report [16]. This region comprises states from the Rocky Mountains east to the Mississippi River, excepting Arkansas and Louisiana, which are grouped as part of the Southeast.

27. While ReEDS inputs are derived from empirical Interior region cost data, the ReEDS model adjusts for regional differentials in cost as well as the cost to move energy from a wind resource site to load either as a function of local spur lines or long-distance interstate transmission (see also Appendix G).

28. Excluded land areas include urban areas, national parks, highly sloped land areas, and others. For a full list of resource exclusions, see Appendix H.



Note: Ranges result from consideration of a broad array of wind speed conditions. For areas outside the Interior region, capital cost multipliers are applied, resulting in a broader range of estimated costs for the country as a whole than reflected here. Data shown represent the plant-level LCOE, excluding potential intraregional transmission needed to move the power to the grid and interregional transmission to move the power to load.

Figure 3-12. Land-based wind changes in LCOE by sensitivity (2014–2050, Interior region)

Figure 3-12 illustrates the range of land-based wind LCOEs represented in the *Wind Vision* scenario framework for the Interior region and related changes from 2014 to 2050.[29] Data shown represent plant-level LCOE, excluding potential intraregional transmission needed to move the power to the grid and interregional transmission to move the power to load. Ranges reflect the variability in resource quality captured within the ReEDS model. Changes from 2014 LCOEs are 0% by 2050 under *High Wind Costs*; 9% by 2020, 16% by 2030, and 22% by 2050 under *Central Wind Costs*; and 24% by 2020, 33% by 2030, and 37% by 2050 under *Low Wind Costs*. Additional detail regarding the development of land-based wind costs as well as explicit ReEDS capital costs, capacity factors, and operations costs are detailed in Appendix H. For insights into the comparability of these inputs with current market data, see Text Box 3-1.

3.2.1.2 Offshore Wind

Offshore wind inputs were developed in a similar manner as their land-based counterparts. A greater diversity of technology (e.g., shallow water versus deepwater), limited data, a less mature industry, and fewer long-term projections necessitated some key differences. Data limitations are particularly significant for mid-depth (30–60 m) and deepwater (60–700 m) sites.

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 [23, 19]. These data were coupled with engineering assessments and distance-based cost functions (specific to the offshore export cable and incremental construction cost associated with moving farther from shore) to determine expected site-specific costs for technology across a broad range of water depths and distances

29. All dollars are in real 2013$ unless otherwise noted.

Text Box 3-1.

Benchmarking *Wind Vision* Inputs with Expected Costs for Current Projects

Estimated wind technology ReEDS LCOEs developed from the methods described in Section 3.2.1.1 were compared with 2012 historical market power purchase agreement (PPA) data and PPA data for projects scheduled to come online in 2014-2016. Although this benchmarking exercise is limited by the standardized financing terms applied in ReEDS (Appendix H) and the resulting simplified representation of the value of the PTC in the ReEDS LCOE values, it offers the opportunity for basic validation of the *Wind Vision* analysis inputs. Benchmarking results are reported only for resource areas best represented by the locations where active development is concentrated today and assumes Interior region costs.

Assuming qualification for the PTC, estimated ReEDS LCOEs for projects in the Interior region likely to have been commissioned in 2012 range from approximately $27/megawatt-hour (MWh) to $38/MWh. The interior region generation weighted average market PPA price for projects signing contracts in 2012 was approximately $31/MWh with a range of approximately $20/MWh to $40/MWh [20]. Estimated ReEDS LCOEs for projects likely to be commissioned in 2014–2016 (and qualifying for the PTC) range from $24/MWh to $35/MWh in the *Central Wind Cost* case and $18/MWh to $29/MWh in the *Low Wind Cost* case. Recent Interior region PPA price data (contracts signed in 2013–2014) for projects to be delivered in 2014–2016 indicate a generation weighted average of approximately $23/MWh with an approximate range extending from below $20/MWh to about $30/MWh [20]. These simple comparisons suggest that ReEDS LCOE alignment with 2012 market PPA data is strong; ReEDS LCOEs also appear to be relatively consistent with 2014–2016 market data, particularly when considering the range offered by the *Low Wind Cost* case.

Notwithstanding the general alignment illustrated above, the standardized ReEDS financing assumptions reflect long-term electric generation financing cost estimates. This long-term perspective results in slightly greater financing costs (~100 basis points) than are observed in the market today. In contrast, the ReEDS financing assumptions also reflect the full nominal value of the PTC. Based on the work of Bolinger [21] and Bloomberg New Energy Finance [22], the cost of tax equity and lower project debt levels required to monetize the tax credits may erode as much as 30% of the full nominal value of the PTC. Accordingly, without the PTC, the costs represented in ReEDS may be modestly conservative when compared to market expectations for projects in the latter half of this decade.

Given somewhat variable historical pricing trends as well as a tendency for wind and other generation prices to be influenced by market factors (e.g., the cost of generation from natural gas–fired plants), some degree of conservatism is merited within the context of the current scenario analysis. There are other modeling elements that could be weighed against any perceived conservatism in terms of individual project cost representation. These factors include environmental and wildlife exclusions that do not fully represent the near-term challenges associated with building on federal public land or in other environmentally sensitive regions, as well as the ability for the ReEDS model to select among a vast array of project sites with no transaction costs or associated sunk costs.

from shore.[30] Modeled performance data for state-of-the-art technology available as of 2013 were also compiled. As was done for land-based wind, estimated capital costs, operations expenditures, and performance data were applied to high-resolution hourly wind resource data to estimate LCOEs for all potential (non-excluded) offshore wind resource sites. Applying the standardized financing assumptions, ReEDS LCOEs range from approximately $170/MWh to $230/MWh for shallow-water sites as of 2013.[31] If current market-based financing assumptions (e.g., a weighted average cost of capital of approximately 10%–11% nominal) were applied, this LCOE range would increase by approximately $20/MWh to $30/MWh. These estimates can be compared with contracted sales prices for offshore wind as reflected in PPAs. Pricing ranged from $180/MWh to $245/MWh (2013$) for projects in the United States under development as of 2013 (see also Chapter 2).

Offshore wind LCOE projections through 2050 were developed using a combination of methods. Review and analysis of independent literature-based projections were used to inform estimates of cost reduction through the mid-2020s [24, 25, 26].[32] Beyond the mid-2020s, offshore wind projections rely on three independent learning rate estimates to project costs from the mid-2020s to 2050.[33] Common learning rates were applied independent of site-specific impacts on technology (e.g., water depth, geotechnical considerations, distance from staging area). For the *High Wind Cost* inputs, a 0% learning rate is assumed; in effect, no further improvements are considered.[34] For the *Central Wind Cost* inputs, a 5% learning rate is assumed. This 5% rate is generally consistent with rates projected by van der Zwaan et al. [27]. For the *Low Wind Cost* inputs, a 10% learning rate is assumed, consistent with estimates for the global wind industry by Wiser et al. [28] and Musial and Butterfield [29]. Learning rates are applied to estimated global capacity assuming a compound average annual growth rate of approximately 10% from 2013 to 2050.[35]

Figure 3-13 illustrates the range, as a function of wind resource quality and water depth, of offshore wind LCOEs in the *Wind Vision* scenario framework, and how these LCOEs change from 2014 to 2050. Data represent the plant-level LCOE, excluding the marine export cable, potential intraregional transmission needed to move the power to the grid, and interregional transmission to move the power to load. Changes from 2014 LCOEs are 5% by 2020, 18% by 2030, and 18% by 2050 under *High Wind Costs*; 16% by 2020, 32% by 2030, and 37% by 2050 under *Central Wind Costs*; and 22% by 2020, 43% by 2030, and 51% by 2050 under *Low Wind Costs*. Additional detail regarding the development of offshore wind costs as well as explicit ReEDS capital costs, capacity factors, and operations costs are available in Appendix H.

Given the data limitations and relative immaturity of offshore wind technology, a number of caveats should be considered for these estimated cost data. First, cost reductions presented here are based on the methods described. Apart from what is reflected in the literature for expectations through the mid-2020s, the approach has not considered explicit innovation opportunities. This is particularly notable for deepwater technology (60–700 m)—and, to a lesser degree,

30. Site-specific estimates did not consider regional cost multipliers or land-based grid infrastructure costs. The purpose of the base cost characterization and data binning was to rank sites based on their cost of energy delivered to shore, neutral of non-technical market cost drivers (e.g., variable labor costs by region). Both non-technical market cost drivers and land-based grid infrastructure costs are separately captured in the ReEDS model (see Appendix G).

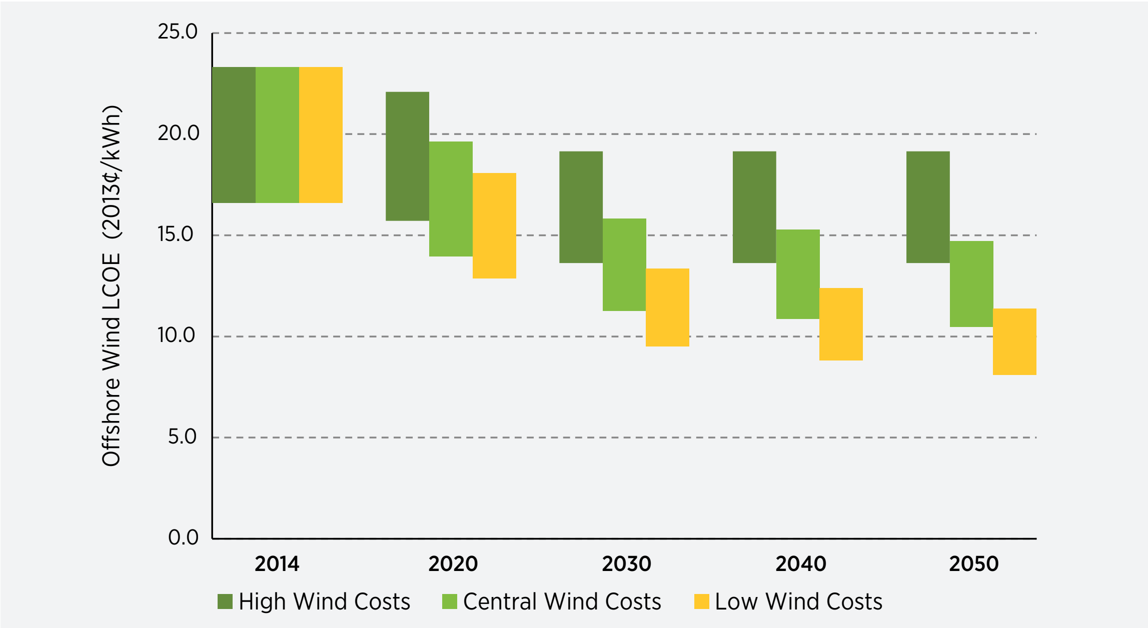
31. ReEDS standardized financing costs were applied to calculate LCOEs. As such, actual LCOEs are likely underestimated for projects under development in U.S. waters as of 2014. Nonetheless, implicit in the standardized ReEDS financing costs is the assumption that industry and technology maturation will bring parity in all energy infrastructure financing costs.

32. Literature projections were not applied to the long term because only a small sample of projections extend beyond the mid-2020s and representation of recent industry trends in those studies is poor.

33. Learning rates rely on historical trends to project future technological improvement. The learning rate is defined as the percent change in cost for every doubling in cumulative production or units installed. Wiser et al. [17] provide a detailed review of learning rates as such rates apply to wind energy.

34. Given the current maturity of offshore wind technology, this learning rate assumes very limited or no industry growth outside of the United States and, in many respects, an inability for the industry to achieve adequate scale and volume required to reduce costs.

35. Actual compound average annual growth rate is expected to decline with time, achieving potentially 30% in the near term but declining to 5% sometime after 2030. Near-term growth is generally expected to develop in Europe and China, with the United States, Japan, and other countries potentially supporting growth in 2020 and beyond.



Note: Consistent with land-based wind cost estimates, ranges result from consideration of a broad array of wind speed conditions. In addition, regional multipliers are applied to offshore wind capital costs. As a result, actual generation costs represented in ReEDS vary from those shown in this figure, at levels consistent with regional variability in labor rates and other non-turbine input costs. Data shown represent the plant-level LCOE, excluding the marine export cable, potential intraregional transmission needed to move the power to the grid, and interregional transmission to move the power to load.

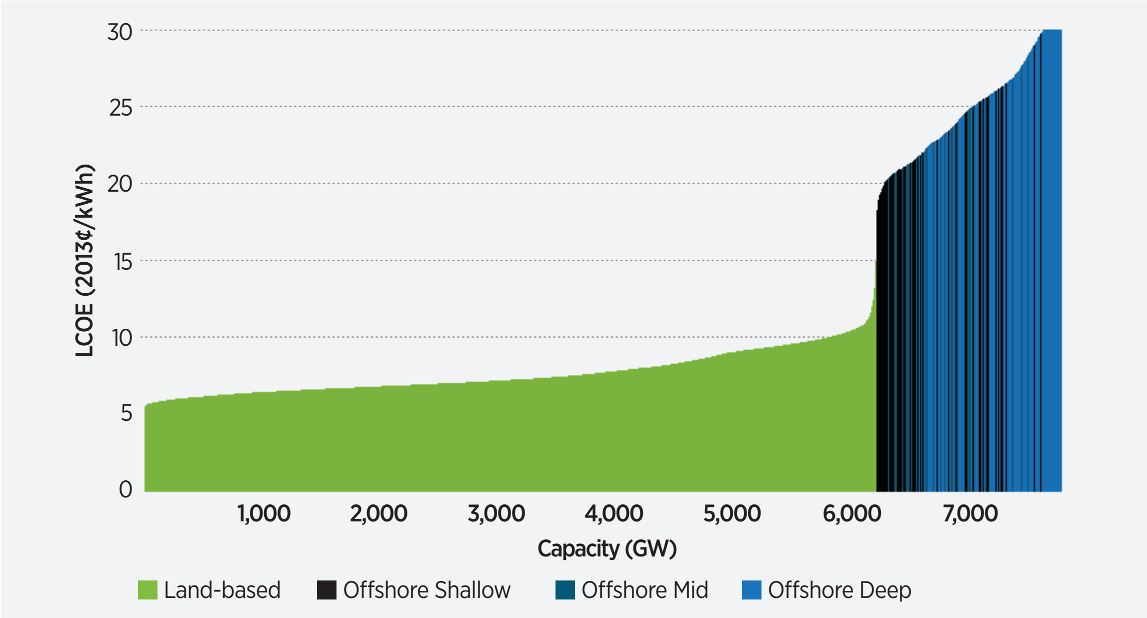
Figure 3-13. Offshore wind changes in LCOE by sensitivity (2014–2050)

mid-depth technology (30–60 m)—as the literature is principally focused on fixed-bottom shallow-water technology and may understate the overall long-term cost reduction potential for other, deeper-water offshore technologies. Second, the use of learning curves to derive the long-term projections requires estimates of global installed capacity. Such estimates are highly uncertain, since future deployment will depend on the cost of competing alternatives as well as on potential GHG or other environmental commitments which may spur additional deployment of renewable energy. Finally, the learning rates chosen reflect a range of estimates derived from literature [27, 30] and the experience of land-based technology [29, 28]. While empirical learning rates for offshore wind have not yet been developed given the nascent status of the industry, it is likely that actual offshore learning rates will differ from those applied here.

Despite these limitations, the cost trajectories associated with wind technology sensitivities provide a broad range of cost reduction potential for offshore wind. While it is possible that cost reductions greater than those examined here may be realized, the results demonstrate the substantial and continued need for innovation and maturation in the offshore wind industry.

Figure 3-14 combines existing cost estimates for land-based and offshore wind with high-resolution wind resource data to develop a supply curve or illustration of the total resource potential for wind at various LCOE levels. The supply curve considers the array of wind resource quality groups represented in ReEDS, as well as various environmental or other exclusion areas (described in Appendix H). Resource quality groups are denoted here as Techno-Resource Groups, as they consider both wind resource and applicable technology design considerations.[36] To place these numbers in context, the U.S. electric system currently includes approximately 941 GW of installed electric capacity across all technologies.

36. See Appendix H for an expanded description of Techno-Resource Groups, as well as regional capital costs and performance characteristics, interconnection costs, and other regional factors.



Note: LCOE estimates exclude the PTC or investment tax credit.

Figure 3-14. Combined land-based and offshore wind resource supply curve, based on estimated costs in 2012

3.2.2 Other Renewable Power

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. Some methodological deviations were required given data limitations, resource constraints, and intrinsic differences in technology and resource requirements. A single cost and performance trajectory was developed for each renewable technology and applied across the full set of modeled scenarios.

Solar power capital costs were benchmarked to cost data reported by Bolinger and Weaver [31] and GTM Research/Solar Energy Industries Association [32]. Capital cost projections from 2013 to 2020 are aligned with the 62.5% reduction scenario (from 2010 levels) documented by DOE [5]. This cost trajectory was subsequently grounded against a sample of cost projections from the EIA [33], International Energy Agency [26], Bloomberg New Energy Finance [34], Greenpeace/European Photovoltaic Industry Association [35], GTM Research/Solar Energy Industries Association [36, 32]. From 2020 to 2040, costs decline to $1.20/AC watts ($W_{AC}$) for utility-scale PV, to $1.90/$W_{AC}$ for distributed residential rooftop PV, and to $3.60/$W_{AC}$ for concentrating solar power.[37] Although there are fewer literature estimates that emphasize this time period, this cost trajectory was also generally consistent with an average literature estimate [26, 34, 33]. Costs were assumed to be unchanged (in real terms) from 2040 to 2050.[38] Performance for all solar technologies varies regionally and is based on solar irradiance data from the National Solar Radiation Database.[39]

Hydropower is represented in the current analysis by the most recent national-scale resource potential estimates for non-powered dams [37] and undeveloped sites [38]. Resource estimates exclude upgrades and expansions at existing facilities and new sites less than 1 MW.[40] Costs are derived from methods developed by

37. Costs reported here in AC watts are consistent with targets under DOE's SunShot Initiative, e.g., $1.00/DC watt for utility-scale PV (*http://energy.gov/eere/sunshot/sunshot-initiative*).

38. Potential justifications for flat cost over this time period include increasing uncertainty with time and diminishing returns from research and development investment.

39. The National Solar Radiation Database is available at *http://rredc.nrel.gov/solar/old_data/nsrdb*.

40. Marine hydrokinetic technologies are also excluded from the analysis.

the Idaho National Laboratory and are consistent with cost representations applied in the EIA's AEO [4] as well as past ReEDS analysis, including the *Renewable Electricity Futures* study [2].[41]

Geothermal resources represented in ReEDS include identified hydrothermal resources and near-hydrothermal field enhanced geothermal systems consistent with the EIA AEO 2014 Reference Case and Augustine et al. [39]. All other potential geothermal resource areas are excluded. Current costs and total available potential are detailed by Augustine et al. [39]. Given substantial uncertainty in future cost trends, costs are constant for the period of analysis.[42]

Biomass power represented in ReEDS includes both co-fired and dedicated biomass units. Cost and performance estimates are derived from the EIA AEO 2014 Reference Case. Supplemental detail is provided in Appendix G.

3.2.3 Non-Renewable Power Technologies

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 EIA AEO 2014 Reference Case. Cost and performance estimates for natural gas combined cycle with carbon capture and storage, and for coal with carbon capture and storage, are consistent with those from the EIA AEO 2014 Reference Case. Full detail on these inputs is in Appendix G.

3.2.4 Market Variables

Other power sector variables also play a role in determining the associated impacts of the *Study Scenario*. Of particular significance are expected retirements, changes in demand for electricity generation, and future fossil fuel prices.

3.2.4.1 Retirements

Retirements in ReEDS are primarily a function of plant age and assumed lifetimes. Fossil fuel-fired plant ages are derived from data reported using Ventyx.[43] 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.[44] No refurbishment costs or increased operations and maintenance (O&M) costs are applied to extend the nuclear or fossil plant life. Figure 3-15 details the resulting age-based retirements across existing coal, oil and gas steam turbines, nuclear, and gas-fired capacity (natural gas combined cycle and natural gas combustion turbine), as well as the share of existing 2012 capacity retired throughout the period of analysis. These assumptions result in retirement by 2050 of nearly all of the existing oil and gas steam turbine and nuclear fleets, and about half of the existing coal fleet.

Plant lifetimes are also estimated for newer 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. While all generator types retire at the end of their defined equipment lifetimes, the site-specific technologies that have resource accessibility supply curves (wind, solar, geothermal) require some special consideration. When a parcel of capacity retires (for instance, some wind capacity retiring upon reaching its assumed 24-year life), the freed resource potential in that site is available for new builds. This new build is assumed to have no accessibility cost, since the spur line and other site infrastructure developed for the original plant can be re-used for any new builds on these sites.

41. Ongoing DOE work is expected to provide insight into the long-term potential for hydropower electricity capacity and generation at a level that is not reflected in the present study or modeling treatment (*http://energy.gov/eere/water/new-vision-united-states-hydropower*).

42. While an endogenous treatment of technology learning from the National Energy Modeling System model is used for the AEO reports, it is not included in the present ReEDS analysis. As such, the geothermal technology costs used here differ slightly from the costs reported in the AEO.

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

44. A single service life extension period was selected as a central assumption given significant uncertainty in current nuclear plant lifetimes. High uncertainty persists due to the potential for new investments that might be required to keep existing plants in operation (e.g., San Onofre) as well as marginal operations costs that may not be supported by current wholesale power prices. At the same time, the possibility for a single or perhaps even double service life extension remains, given perceived GHG risks [4] .

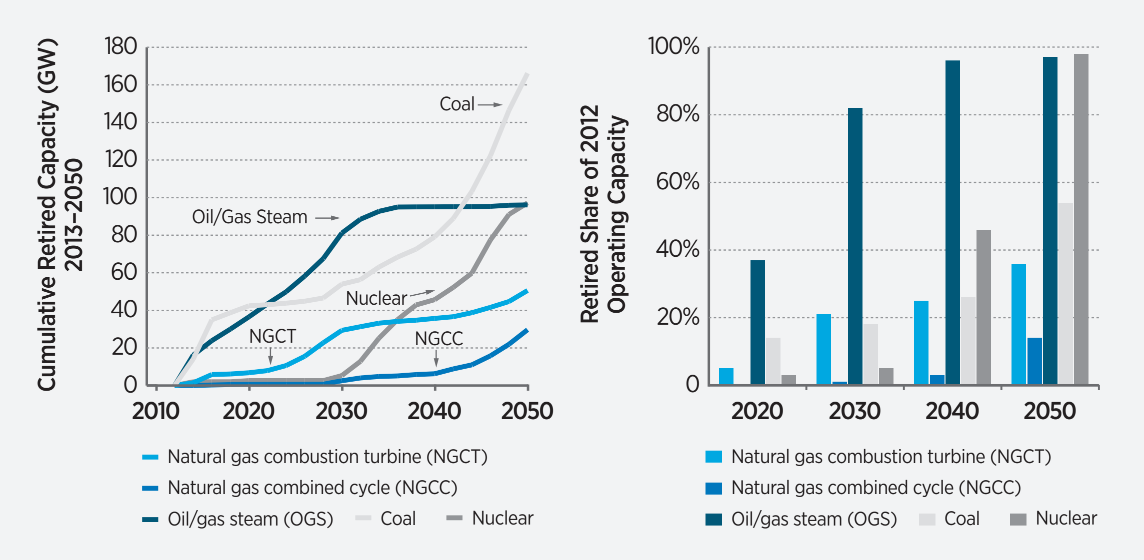


Figure 3-15. Estimated age-based and announced cumulative retirements and retirements by share of the operating fleet

In addition to age-based retirements, other near-term coal retirements are reflected in the modeled scenarios by incorporating announced retirements [40],[45] and long-term retirements are incorporated by considering plant utilization. As illustrated in Figure 3-15, assumed age-based and announced coal retirements total 42 GW of coal capacity retirements from 2013 to 2020, 54 GW by 2030, and 166 GW by 2050.[46] Modeled utilization-based coal retirements represent a proxy for economic-based considerations and accelerate coal retirements. For example, 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.[47]

Degradation of the efficiency of solar PV capacities over time is also modeled at 0.5% per year [44]—i.e., the capacity of PV that generates energy is reduced by 0.5% every year. In the *Wind Vision* analysis, however, the total PV capacity reported does not reflect this degradation and remains at initial capacity. Instead, the generation reported from this capacity is reduced, reflecting the efficiency degradation of that capacity over time.

3.2.4.2 Load Growth

The *Wind Vision* analysis applies a single load growth trajectory. Load growth in the *Wind Vision* is assessed by the change in end-use electricity demand and is based on the EIA's AEO 2014 Reference Case. Load growth is extracted from the AEO 2014 Reference Case for the time period of 2013 to 2040, and is extrapolated through 2050.[48] Regional differences reflected by the AEO are also represented in ReEDS. The overall change in electricity demand associated with this scenario is approximately 34% from 2013 (3,700 terawatt-hours [TWh]) to 2050 (4,900 TWh) and averages 0.8% per year. Growth is generally linear from 2013 to 2050.

45. Due to ReEDS geospatial requirements, these data reflect announced retirements only (e.g., [40]). Other estimated retirements (e.g., [41, 42, 43]) lack sufficient geospatial and temporal resolution to be incorporated into ReEDS, but are addressed to a degree by overlaps with Saha [40], and by the age-based and plant utilization-based retirements.

46. Age-based and announced coal retirements from 2010 (the ReEDS model start year) to 2020 total 57 GW. A direct comparison of this assumption with other literature (e.g., [41, 42, 43]) is difficult, as the starting year is not consistent across references.

47. Under the *Baseline Scenario,* coal capacity experiences greater utilization. Thus, fewer retirements are observed to occur across *Baseline Scenario* sensitivities compared with the *Study Scenario.*

48. The method and data sources used to both calibrate the 2010 ReEDS start year load profiles and extrapolate to future years (see Appendix G) lead to slight differences to the end-use demand trajectory in ReEDS compared to the AEO 2014 Reference Case projection. These differences have negligible effect on the scenario results.

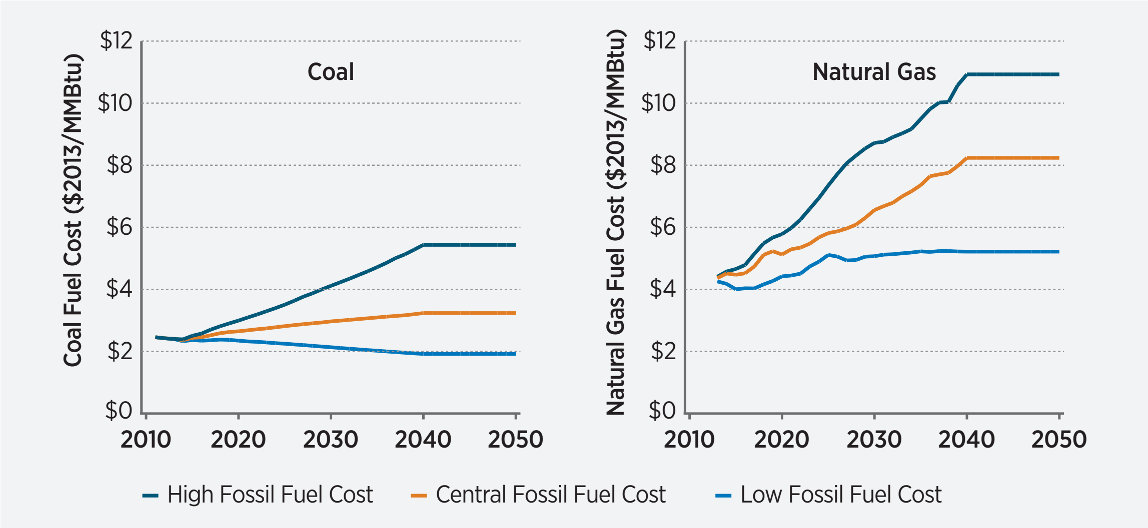


Figure 3-16. Base coal and natural gas fuel cost trajectories applied in the *Wind Vision*

3.2.4.3 Fossil Fuel Costs

A range of fossil fuel costs (coal and natural gas) are applied in the *Wind Vision* analysis. Three explicit trajectories are considered: *Low Fuel Costs*, *Central Fuel Costs*, and *High Fuel Costs*. This approach is intended, in part, to reflect the substantial uncertainty in future fuel cost projections and the sensitivity of future modeling outcomes to changes in the projected fossil fuel prices. Fuel cost scenarios are grounded in the work of the EIA and published in AEO 2014 [4].

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. *High Fuel Costs* are extracted from the Low Oil and Gas Resource and High Coal Cost scenarios in the AEO. Because the AEO data extend only through 2040, fossil fuel costs for each specific trajectory (i.e., *Low, Central, High*) are assumed to be constant in real dollar terms from 2040 to 2050.[49] Constant cost treatment during this time period is justified based on the high uncertainty associated with 2040 prices and the overall price levels also projected in 2040. Figure 3-16 illustrates these cost trends for the full period of the analysis. Values shown in Figure 3-16 represent the national ReEDS model inputs. In the *Wind Vision* analysis, however, more highly resolved regional data are applied. Natural gas cost adjustments are also incorporated in ReEDS to account for the sensitivity of fuel costs (prices) to changes in regional electric sector fuel usage (see also [11] and Appendix G).

3.2.5 Policy Assumptions

Existing policies are represented as enacted as of January 1, 2014. All state renewable portfolio standards (RPSs) are modeled, federal tax incentives are included as they exist on January 1, 2014, and accelerated depreciation rules that exist as a permanent part of the tax code are reflected in the cost of new technologies. The wind PTC and investment tax credit (ITC) are assumed to be expired without further extensions. The Modified Accelerated Cost Recovery System depreciation schedules remain in place through 2050. The solar ITC is assumed to be 30% until after 2016, after which it is assumed to remain at 10% through 2050. The geothermal ITC is assumed to be 10% for all years. California's Assembly Bill 32, or AB32, is modeled.[50,51]

49. Prices are assumed to increase with the rate of inflation over this time period.

50. California Assembly Bill 32 is modeled in ReEDS as a carbon cap for the electricity sector. The cap limits are derived from California emissions in the AEO 2013 Reference scenario [33] and consider in-state generation as well as imports from outside of California. Other regional, state, or local carbon cap-and-trade systems, including the Regional Greenhouse Gas Initiative, are not represented.

51. In the *Baseline Scenario,* the model treatments of existing state policies (RPSs and California AB32) are modified to reduce cost distortions that these state policies would have when wind is not available to meet these standards.

No new policies, including new or proposed environmental regulations, are explicitly modeled; however, wind penetration levels are enforced in the model. U.S. Environmental Protection Agency (EPA) regulation is partially represented in the announced retirements captured by the model (Section 3.2.4.1).[52] The EPA's proposed Clean Power Plan is not modeled directly in ReEDS.

Modeling and associated cost and price impacts presented here do not consider future limits to criteria pollutants or carbon dioxide (CO_2).[53] However, environmental impacts from reduced air pollution and GHG as a function of the *Study Scenario* are quantified and monetized in Sections 3.7 and 3.8.

This approach allows for a consistent estimation of the costs, benefits, and impacts of the *Wind Vision* scenarios. However, it does not reflect a policy recommendation, expectation, or preference. Moreover, the impacts, costs, and benefits of the *Wind Vision* will be somewhat dependent on the policy and market variables used to achieve wind deployment, as discussed in Section 3.3. Text Box 3-3 provides added context on current and past government incentives for energy supply.

3.2.6 Summary of Inputs

The ReEDS inputs discussed in previous sections of 3.2 are summarized in Text Box 3-2 for reference in future sections.

As introduced in Section 3.1.3, a number of sensitivities were analyzed to understand the range of potential impacts of the *Study Scenario*. The upcoming sections—3.3 Wind Capacity Additions, 3.4 Economic Impacts, 3.5 Electricity Sector Impacts, and 3.6 Transmission and Integration Impacts—present results for the *Central Study Scenario* as well as some of the sensitivities summarized.

52. A sulfur dioxide cap is also included in ReEDS (see Section 3.8).

53. A risk factor applied to new investments in coal-fired capacity without carbon capture and storage is included to capture the potential for new carbon policy (see Appendix G).

Text Box 3-2.

Impacts Analysis Scenario Framework and Inputs Summary

The *Wind Vision* uses scenarios to explore the range of potential impacts that could result from increased deployment of wind power as defined in the *Study Scenario*. *Study Scenario* impacts are generally assessed relative to the *Baseline Scenario*, with limited exceptions for specific metrics (e.g., land use is assessed for the total installed wind capacity in the *Study Scenario*). To assess the robustness of the results, additional scenario sensitivities were conducted, focusing on changes in wind costs and fossil fuel costs independently and in combination. These sensitivities are designed to inform the range of outcomes. Table 1 defines the key modeling constants across scenarios. Table 2 summarizes the scenarios considered and highlights their differences.

Table 1. Constants Across Modeled Scenarios

Input Type	Input Description
Electricity demand	AEO 2014 Reference Case (average annual electric demand growth rate of 0.8%)[a]
Fossil technology and nuclear power	AEO 2014 Reference Case
Non-wind renewable power costs	Literature-based central 2013 estimate and future cost characterization
Policy	As legislated and effective on January 1, 2014
Transmission expansion	Pre-2020 expansion limited to planned lines; post-2020, economic expansion, based on transmission line costs from Eastern Interconnection Planning Collaborative

a. Modeling work described in Chapter 1 to inform the development of the *Study Scenario* included sensitivities in which electricity demand was varied. See Chapter 1 for additional details.

Continues next page

Text Box 3-2. *(continued)*

Impacts Analysis Scenario Framework and Inputs Summary

Table 2. Scenario Definition and Variables

Scenario Label	Description	Inputs
Central Study Scenario	This scenario applies the *Study Scenario* wind trajectory of 10% wind by 2020, 20% by 2030, 35% by 2050 and *Central* modeling inputs. It is the primary analysis scenario for which impacts are assessed and reported.	All constants noted in Table 1 Fossil fuel costs: AEO 2014 Reference Case Wind power costs: Median 2013, with cost reductions derived from literature review
Central Baseline Scenario	This scenario applies the *Baseline Scenario* constraint of no new wind capacity. This scenario also relies on central inputs and is the primary reference case from which impacts are assessed and reported.	All constants noted in Table 1 Fossil fuel costs: AEO 2014 Reference Case Wind power costs: Median 2013, with cost reductions derived from literature review
High/Low Fossil Fuel Cost Study Scenario	These scenarios examine the sensitivity of changes in fossil fuel costs to the results of the *Study Scenario*. Modeling outcomes are compared with the *Baseline Scenario* that includes the respective fossil fuel cost assumptions.	All constants noted in Table 1 Fossil fuel costs: AEO 2014 Low/High Oil and Gas Resource Case and AEO High/Low Coal Cost Case Wind power costs: Median 2013, with cost reductions derived from literature review
High/Low Fossil Fuel Cost Baseline Scenario	These scenarios examine the sensitivity of changes in fossil fuel costs to the results of the *Baseline Scenario*. Modeling outcomes are compared those derived from the *Study Scenario* with the respective fuel cost assumptions.	All constants noted in Table 1 Fossil fuel costs: AEO 2014 Low/High Oil and Gas Resource Case and AEO High/Low Coal Cost Case Wind power costs: Median 2013, with cost reductions derived from literature review
High/Low Wind Cost Scenario	These scenarios examine the sensitivity of the *Study Scenario* results to changes in wind power cost reductions from 2014–2050. Results are compared to the *Central Baseline Scenario*, which holds wind capacity constant at current levels and is therefore unaffected by changes in wind costs.	All constants noted in Table 1 Fossil fuel costs: AEO 2014 Reference Case Wind power costs: No change in costs from 2014–2050; Max. literature-based change in costs from 2014–2050
Favorable Scenario Study Scenario	By combining low wind costs with high fossil fuel costs, this sensitivity represents the conditions most conducive to wind deployment considered in the analysis and forms a low cost bookend for the *Study Scenario*. Results are compared to the *High Fossil Fuel Cost Baseline Scenario.*	All constants noted in Table 1 Fossil fuel costs: AEO 2014 Low Oil and Gas Resource Case and AEO High Coal Cost Case Wind power costs: Max literature-based change in cost from 2014–2050
Unfavorable Study Scenario	By combining high wind costs with low fossil fuel costs, this sensitivity represents the conditions least conducive to wind deployment considered in the analysis and forms a high cost bookend for the *Study Scenario*. Results are compared to the *High Fossil Fuel Cost Baseline Scenario.*	All constants noted in Table 1 Fossil fuel costs: AEO 2014 High Oil and Gas Resource Case and AEO Low Coal Cost Case Wind power costs: No change in cost from 2014–2050

Text Box 3-3.

Government Incentives for Energy Supply

The United States has a long history of offering incentives at both the federal and state levels for energy development, technologies, and use. In the early days of oil and gas development, Congress adopted policies allowing favorable tax accounting practices; coal similarly received support through favorable tax policy (e.g., [45]). Nuclear energy was initially indirectly supported through military efforts, later leading to commercial reactors for electricity generation. Favorable tax policy applies to nuclear energy, and the Price-Anderson Act was established to partially indemnify the nuclear industry against liability claims arising from nuclear incidents (e.g., [46]).

Federal energy research and development (R&D) has also existed for many decades. A 2012 Congressional Research Service report reviewed available data on R&D funding and found that, "[f]or the 65-year period from 1948 through 2012, nearly 12% went to renewables, compared with 10% for efficiency, 25% for fossil, and 49% for nuclear" [47]. The overall proportion of R&D funding for renewable energy has, however, increased in years leading up to 2014 [47]. Renewable energy has also benefited from favorable federal tax policy and a variety of state-level incentives.

Some widely cited goals of government incentives include: (1) addressing the environmental effects of energy technologies, (2) reducing barriers to the development and adoption of innovative technologies, (3) creating opportunities for local economic development benefits, and (4) increasing energy security and diversity. The relative importance of these goals—and the extent to and efficiency with which various incentives achieve them—is the subject of continual debate. Research has generally found it to be more cost-effective to address market failures (e.g., unpriced environmental effects) directly through policies (e.g., environmental taxes) specifically intended to internalize these "external" costs, rather than solely through technology- or sector-specific incentives (e.g., [48,49, 50, 51]).

One question that often arises is the relative size of incentives for different energy technologies. Studies conducted as of 2013 have led to widely varying estimates as a result of three types of complications. First, the definition of what is considered an energy incentive varies widely. Some incentives—such as federal direct spending via grants, favorable taxation, and R&D—are almost always included, whereas others, such as the failure to price environmental effects, are rarely addressed. Second, estimates are greatly impacted by the analysis methods used, the scope applied (e.g., timescale, whether state incentives are included), and how different technologies are categorized. Third, estimates are often reported differently, because timescales and units of interest vary. While each of the metrics noted in the table below can be useful depending on the goals of the analysis, the variety of approaches makes it difficult to compare different studies.

Variations in the Types of Incentives Included in Studies	Variations in Methods and Scope	Variations in Metrics Reported
• Direct spending (e.g., grants) • Tax reduction (e.g., tax credits, accelerated depreciation) • Support for R&D • Market access (e.g., access to public land, use mandates) • Risk reduction (e.g., loan guarantees, insurance) • Failure to price environmental effects (rarely included)	• Methods used to assess complicated programs • Scope: generation-only or full life cycle; timescale; treatment of state/local • Whether subsides are allocated to electricity production, and form of categorization into sectors	• Dollar value in recent year ($/year) • Cumulative dollar value since beginning of incentives ($) • Dollar value in first 10–30 years of technology development ($) • Total dollar value in recent year, divided by production (¢/kWh) • Projected future incentives under current policy ($/year)

Text Box 3-3. *(continued)*

Government Incentives for Energy Supply

Complications in Comparing Estimates of Relative Government Incentives

Given these differences, it is difficult to generalize about the relative size of incentives offered to various energy technologies. Depending on the factors included, different studies have reported estimates of total subsidies that vary by more than an order of magnitude (e.g., [52]). In broad terms, however, and focusing principally on federal government incentives since most available studies do not consider state incentives, the literature suggests:

- If "recent incentives per year" is used as the metric, incentives for renewable energy are comparable to—and, in the most recent years (as of 2013), potentially greater than—those provided to nuclear or fossil energy sources; examples from some recent studies are in the table below.
- If "cumulative incentives" or "total incentives over an initial deployment period (10–30 years)" is used as the metric, renewable energy has received fewer incentives relative to nuclear or some fossil energy sources. A 2011 study by DBL Investors, for example, found that, "federal incentives for early fossil fuel production and the nascent nuclear industry were much more robust than the support provided to renewables today" [53]. Studies by the Congressional Research Service [47], Management Information Services [54], the Congressional Budget Office [51], and Badcock and Lenzen [55] present similar results for historical incentive patterns.
- If "recent incentives per unit of electricity" is used as the metric, renewable electricity is more heavily supported than other technologies, in part because renewable energy is still a relatively small share of the overall electricity mix (e.g., [56, 57, 58]).
- If "projected future incentives under current policy" is used, renewable energy sources are sometimes expected to receive relatively lower levels of incentives than other energy sources (e.g., [59]). This is because many of the available federal incentives for renewable energy have expired or are set to expire. In contrast, a number of the currently available incentives for other energy sources do not have an established expiration date.

Virtually none of the studies reviewed consider the failure to fully price environmental impacts as an "incentive." As suggested elsewhere in Chapter 3, however, and as assessed by Kitson et al. [57], the economic consequences of such "externalities" are substantial. If such factors were considered as implicit incentives, a number of the general conclusions herein could change.

Vast differences in approach and findings in the literature make it challenging to draw firm conclusions. It is certain, however, that billions of dollars of incentives are designated for fossil, nuclear, and renewable energy each year and that these diverse incentives have been partly responsible for the development of each sector. The incentives are of many different types, vary significantly from year to year, and are intended to accomplish many different—and sometimes contradictory—purposes. No single, simple answer exists regarding the relative size of these incentives.

Estimates of Recent U.S. Incentives for Various Energy Sources ($2013 billion/year)

Source	GAO 2007	EIA 2008	ELI 2009	EIA 2011	CBO 2012	CRS 2013
Study Period	**2002–2007**	**2007**	**2002–2008**	**2010**	**2011**	**2013**
Nuclear electricity	1.1	1.5	NA	2.7	0.9	NA
Oil and gas	NA	2.4	10.0	3.0	NA	2.7
Coal	NA	3.7	0.5	1.5	NA	0.6
Fossil total[a]	**3.1**	**6.0**	**11.3**	**4.5**	**2.5**	**3.3**
Biofuels	NA	3.6	2.6	7.1	7.0	2.2
Renewables (ex. biofuels)	NA	1.9	1.8	8.5	6.1	11.8
Renewable total[a]	**0.8**	**5.5**	**4.4**	**15.7**	**13.1**	**14.0**

Sources: GAO 2007 [60], EIA 2008 [56], ELI (Adeyeye et al.) 2009 [61], EIA 2011 [58], CBO 2012 [51], CRS 2013 [62].

Note: Table reports average annual incentives in billion dollars per year; values were adjusted from study estimates to 2013$ by multiplying by the annual average Consumer Price Index ratio. NA values are not reported due to different studies using different categorization methods. Caution should be used when comparing these values, as study scope and methods vary substantially, and there were many changes to energy policy in the time period reviewed. Acronyms used in this table: General Accounting Office (GAO); Energy Information Administration (EIA); Environmental Law Institute (ELI); Congressional Budget Office (CBO); Congressional Research Service (CRS)

a. Individual categories do not always sum to total because not all direct spending was reported by fuel.

Continues next page

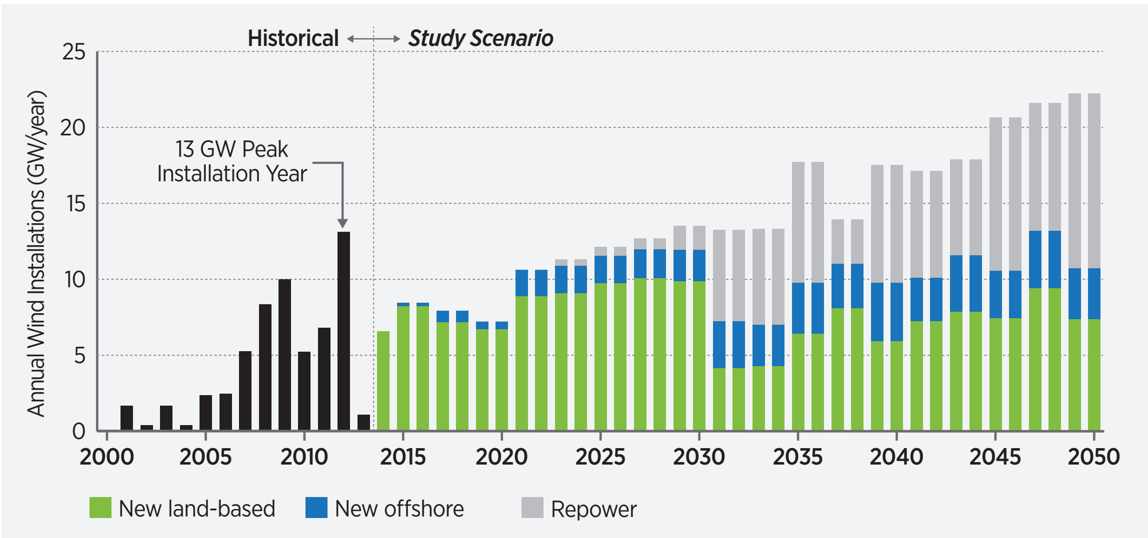
3.3 Wind Capacity Additions and Investment

Moving wind power penetration from approximately 4.5% of end-use demand in 2013 to the *Wind Vision* levels of 10% by 2020, 20% by 2030, and 35% by 2050 is expected to result in changes within the wind energy industry. Among the more notable changes is the anticipated growth in the U.S. wind power fleet. Under the *Wind Vision,* total installed capacity increases from the 61 GW installed at year-end 2013 to ranges of 111–115 GW by 2020, 213–235 GW by 2030, and 382–459 GW by 2050. Results for the *Central Study Scenario* are in the middle of that range, at 113 GW, 224 GW, and 404 GW by 2020, 2030, and 2050, respectively; of this, 3 GW, 22 GW, and 86 GW are from offshore installations in 2020, 2030, and 2050 respectively. This growth requires nearly three doublings of installed capacity. Although capacity and investment levels will vary as a function of technology performance improvements and costs, results presented in this section are primarily based on the *Central Study Scenario*.

3.3.1 Capacity Additions

The *Wind Vision* analysis assumes a linear increase in wind power penetration to the noted levels in 2020, 2030, and 2050. This drives consistent growth in annual capacity additions throughout the period of analysis. Despite continued growth, capacity added in new land-based sites actually declines as technology becomes more productive, deployment of offshore plants increases, and repowering—with its associated performance improvements from installing new equipment—becomes a more substantive share of the annual capacity installations (Figure 3-17).

In the near term, *Central Wind Cost* assumptions result in wind capacity additions of 7.7 GW/year from 2014 to 2020.[54] During this time period, approximately 430 MW/year are offshore and only 1 MW/year is repowered land-based wind facilities. More rapid technological improvements (*Low Wind Costs*) would



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. Levels of wind capacity to achieve the penetration trajectory in the *Study Scenario* will be affected by future advancements in wind turbine technology, the quality of the wind resource where projects are located, and market conditions, among other factors.

Figure 3-17. Historical and forward-looking wind power capacity in the *Central Study Scenario*

54. The most recent five-year average of wind capacity additions from 2009 to 2013 is 7.25 GW/year.

Table 3-3. Estimated Average Annual Wind Deployment across Wind Cost Sensitivities

Annual Capacity Additions (GW/year)		2014–2020			2021–2030			2031–2050		
Central Study Scenario	**Total**	**7.7**			**12.1**			**17.5**		
	New Land-Based/New Offshore/Repowered	7.2	0.4	0.0	9.5	1.9	0.7	6.8	3.3	7.4
Low Wind Cost Study Scenario	**Total**	**7.4**			**11.1**			**16.7**		
	New Land-Based/New Offshore/Repowered	6.9	0.4	0.0	8.6	1.8	0.7	6.3	3.2	7.1
High Wind Cost Study Scenario	**Total**	**7.9**			**13.0**			**20.0**		
	New Land-Based/New Offshore/Repowered	7.5	0.4	0.0	10.4	1.9	0.7	9.1	3.4	7.6

Note: Totals may not sum because of rounding.

reduce the average annual new installations for this period to approximately 7.4 GW/year by capturing more energy per unit of installed capacity. Assuming no further technology performance improvements (*High Wind Costs*) increases the annual installed capacity average to 7.9 GW/year but would simultaneously result in increased electric sector costs (see Section 3.6).[55] From 2021 to 2030, growth in the form of annual wind capacity additions increases to 12.1 GW/year in aggregate, with a range of 11.1–13 GW/year again as a function of *Low* and *High Wind Cost* assumptions; approximately 1.9 GW per year are offshore and 0.7 GW/year are repowered land-based wind facilities. From 2031 to 2050, aggregate annual wind capacity additions increase even further to approximately 17.5 GW year (range of 16.7–20 GW/year), with repowering and new offshore installations constituting about 40% and 20% of aggregate annual wind installations, respectively. Table 3-3 summarizes the annual wind deployment results from the *Central Study Scenario, Low Wind Cost,* and *High Wind Cost* sensitivities. Workforce implications associated with these changes in annual capacity additions are detailed in Section 3.11.

3.3.2 Distribution of Capacity

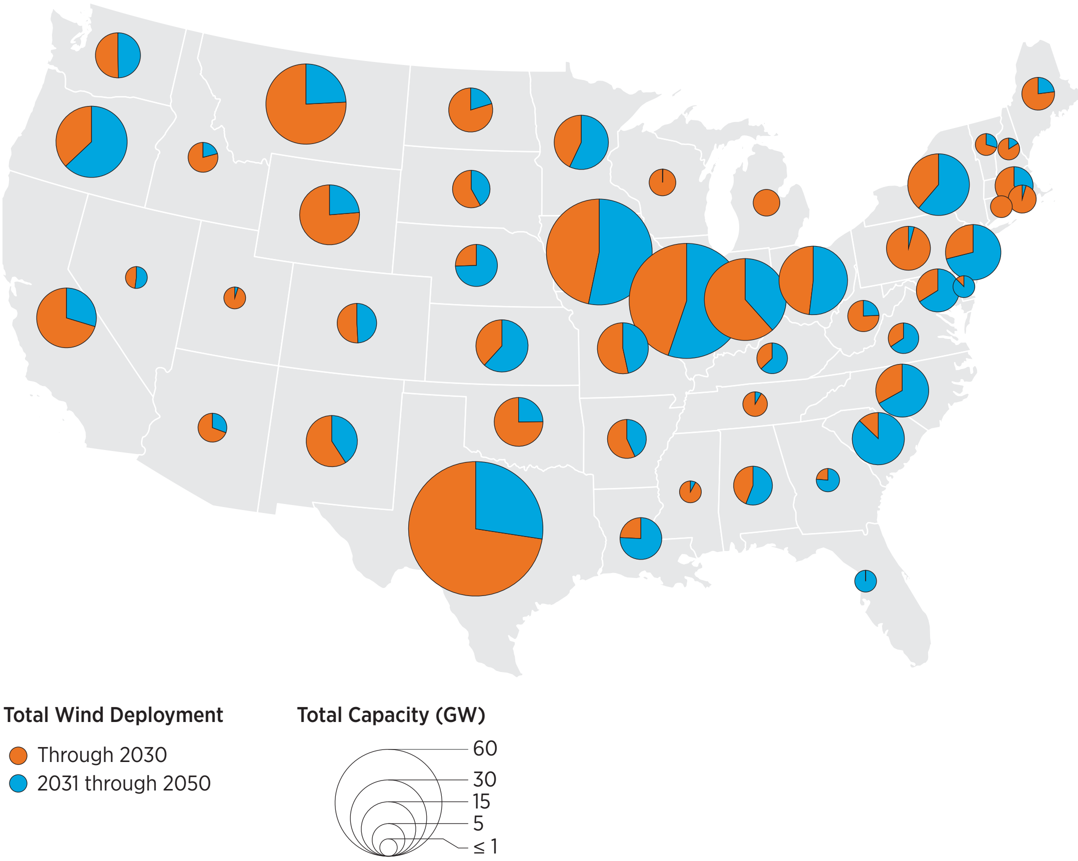
Through year-end 2013, land-based wind power was installed in 39 states; 16 states have more than 1 GW of installed capacity. The *Study Scenario* continues this trend of geographical diversity in wind power. Figure 3-18 illustrates the state-level distribution of wind capacity in 2030 and 2050, as associated with the *Central Study Scenario*.

By 2030, installed wind capacity exists in 49 states, and 37 states have met or surpassed the 1 GW threshold. By 2050, wind deployment is observed in all states and 40 states have more than 1 GW of installed wind capacity.[56]

Although the *Study Scenario* relies on expansion of long-haul transmission lines to move power eastward from the upper Midwest, Great Plains, and Texas, and from the western Interior to the Pacific Coast, the geographic diversity noted earlier is indicative of the fact that technology improvements continue to open previously marginal sites to wind development. Access to lower-quality sites in the Southeast, Northeast, and elsewhere are enabled in part by continued

55. Since the wind electricity penetration levels are prescribed across all *Study Scenarios,* the amount of capacity needed is largely dependent on the assumed capacity factors. As such, the *High Wind Cost Study Scenario* with its associated lower wind capacity factors yields higher installed capacity than the other scenarios.

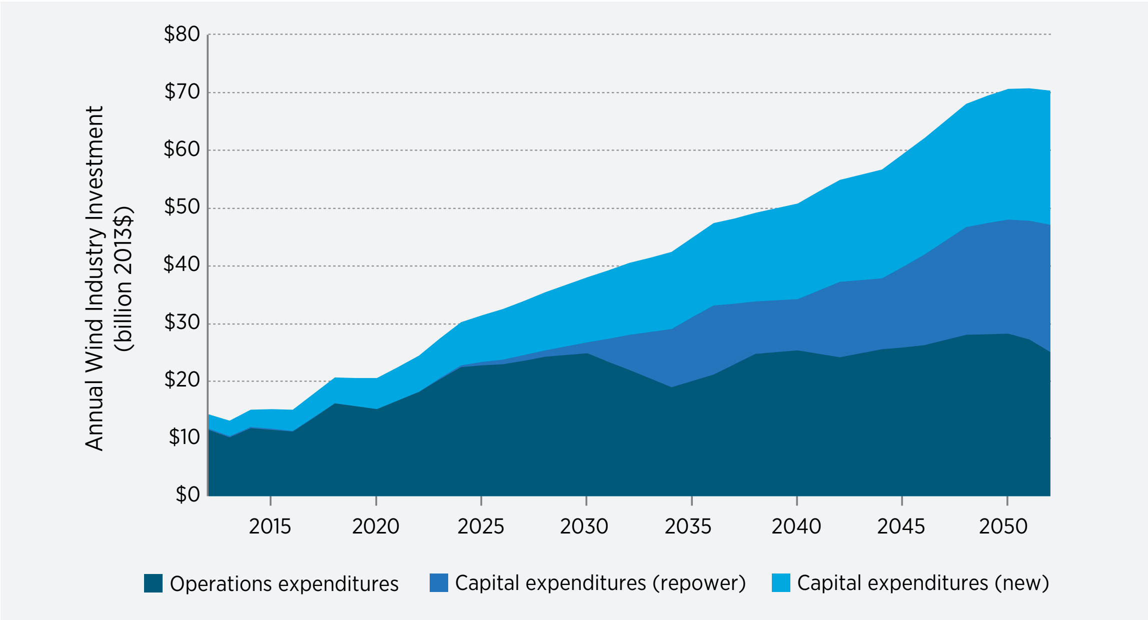
56. As of 2013, wind installations of 62 MW and 206 MW exist in Alaska and Hawaii respectively. While future wind deployment in these states is expected and could potentially grow beyond 1 GW, these states are not counted among the states with more than 1 GW in 2030 or 2050 because the modeling analysis 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 3-18. *Study Scenario* distribution of wind capacity by state in 2030 and 2050

increases in hub heights and rotor diameters that allow these sites to become economically viable as wind technology costs fall, fuel costs increase, and retirements result in more demand for new capacity. In addition, offshore resources offer wind deployment opportunity in regions where land-based resources may be more limited. Land and offshore area impacts associated with the deployment and distribution of wind capacity are discussed in Section 3.12. Transmission expansion impacts of the *Study Scenario* are discussed in Section 3.6.



Note: The value shown for any given year represents a four-year (previous year, year noted, and two future years) rolling average. The capital investments (historical and future) are not amortized.

Figure 3-19. Wind industry investments by market segment in the *Central Study Scenario*

3.3.3 Wind Capital and Operating Expenditures

Annual investment in new wind power plants averaged $15 billion/year from 2009 to 2013. In the *Central Study Scenario,* investments in new plants and ongoing operations average $20 billion/year through 2020 and more than $30 billion/year from 2021 to 2030. Between 2031 and 2050, investment in new plants and operations averages more than $55 billion/year and ultimately grows to more than $70 billion/year by 2050 (constant 2013 dollars).[57] Figure 3-19 illustrates market size by industry segment over time. Consistent with annual capacity additions, growth trends upward throughout the period of analysis despite reduced investments in new sites after 2030. In the long term, repowering and O&M expenditures become significant portions of annual industry expenditures at $22 billion/year and $23 billion/year by 2050, respectively. In fact, repowering and O&M together eventually comprise greater expenditures than new capital investments. Total offshore wind investment (new capacity, repowered capacity, and operations) under the *Central Study Scenario* averages $2.5 billion/year through 2020 before settling at an average of $20 billion/year from 2030 to 2050.

By the mid-2030s, repowering and operations of the fleet provide steady industry demand that is at least partially decoupled from demand for new electric power capacity. This represents a shift from the existing state of the industry, which is largely dependent on new capacity additions to generate capital flow into the industry.

57. The historical capital investment values include the cost of construction financing and some interconnection costs. In contrast, capital expenditures shown for future years simply represent overnight capital investments incurred for each year. These figures exclude construction financing costs, other financing costs, and any interconnection costs.

3.4 Economic Impacts

Impacts to the wind industry are important for direct industry participants. A more holistic view, however, is offered through analysis of the broad-based economic impacts of the *Study Scenario,* along with other costs and benefits provided by wind power. This section describes the estimated economic cost of the *Study Scenario* and associated sensitivities relative to the respective *Baseline Scenario*. Subsequent sections describe the potential benefits and non-economic costs of the *Study Scenario*, which provide context to evaluate the economic impacts presented.

The economic impact of the *Study Scenario* is estimated using two metrics from the ReEDS model—national average electricity price and present value of total system cost—described in Section 3.1.2 and in Short et al. [3]. Both metrics consider all capital and operating expenditures in the U.S. power sector to assess the relative costs of different scenarios.[58] In terms of the limitations of this portion of the analysis, Section 3.1 describes how the system-wide cost optimization perspective of ReEDS might affect the overall cost results of the analysis provided below. None of the economic metrics considered reflects a comprehensive macroeconomic analysis; economic impacts presented in this section are restricted solely to the electricity sector and do not explicitly consider cross-sector interactions, economy-wide impacts, or potential externalities.[59] The economic impact is assessed for the continental United States as a whole and distributional effects are not presented. Regional economic impacts will depend on future markets and regulations that are beyond the scope of the present analysis.

Notwithstanding these limitations, the electricity price and system cost impacts provide insights into the magnitude and direction of economic impacts associated with the *Study Scenario*.

3.4.1 National Average Retail Electricity Price Impacts

The *Wind Vision* analysis shows that, for the near-term (2020) and mid-term (2030), electricity price differences between the *Central Study Scenario* and the *Baseline Scenario* have a (positive) incremental cost of less than 1% (Figure 3-20 and Table 3-4). In the long-term (2050), electricity price *savings* exist for the *Central Study Scenario,* driven primarily by reduced wind costs and increased fossil fuel costs. Higher near-term incremental costs and reduced long-term savings are possible if fossil fuel costs are lower and/or wind technologies realize less improvement than estimated in the *Central* assumptions. Conversely, incremental costs can be reduced or eliminated through some combination of higher fossil fuel costs or greater wind cost improvements.

Estimated electricity prices presented in this section represent national average retail prices to serve the average consumer across regions and sectors—industrial, residential, and commercial. Figure 3-20 shows estimated price trajectories for the full array of *Study Scenario* and *Baseline Scenario* sensitivities. Before 2030, for the *Central Study Scenario* (and respective *Baseline Scenario*) estimated average electricity prices remain similar to recent historical prices for both scenarios; prices increase about 0.3¢/kWh from 2013 to 2030.[60] The relatively flat electricity price trajectories during this time period reflect, in part, the limited need for new capacity in the near term (Section 3.2.4.2). Beyond 2030, electricity prices in both the *Study Scenario* and the *Baseline Scenario* increase more rapidly due to rising fossil fuel costs and the increase in demand for new capacity driven by load growth and retirements. Retail electricity prices in

58. The ReEDS model represents the expansion and dispatch of the bulk transmission-level electric system, but does not model the distribution system. As such, expenditures for the distribution network are not captured in the cost estimates. In addition, while the cost of transmission expansion is considered, the cost to maintain the existing transmission network is not. Finally, while retirements are based on assumed plant lifetimes that exceed many decades (see Section 3.2.4.1 for technology-specific retirement assumptions), refurbishment costs beyond standard O&M are not included. As the economic impact of the *Study Scenario* is assessed relative to the reference *Baseline Scenario,* many of these limitations have little effect on the incremental cost impacts. Future expenditures for the distribution system, transmission maintenance, and plant refurbishment would exist at similar levels across the *Study Scenario* and *Baseline Scenario,* and their omission therefore has limited impact on the estimated incremental costs.

59. Section 3.10 describes the impacts of the *Study Scenario* on fuel diversity and price suppression effects that extend beyond the power sector. Section 3.11 describes national impacts on workforce and economic development, and Section 3.12 discusses local impacts.

60. All costs are presented in real 2013$ throughout this section and chapter unless otherwise noted. As such, any estimated price increases reflect increases above inflation.

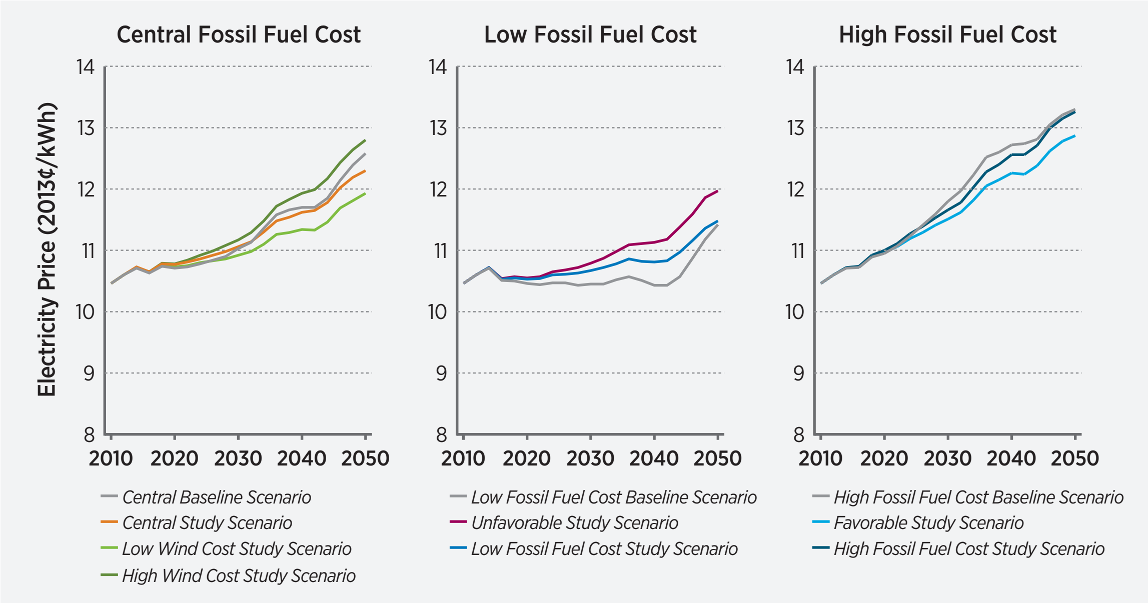


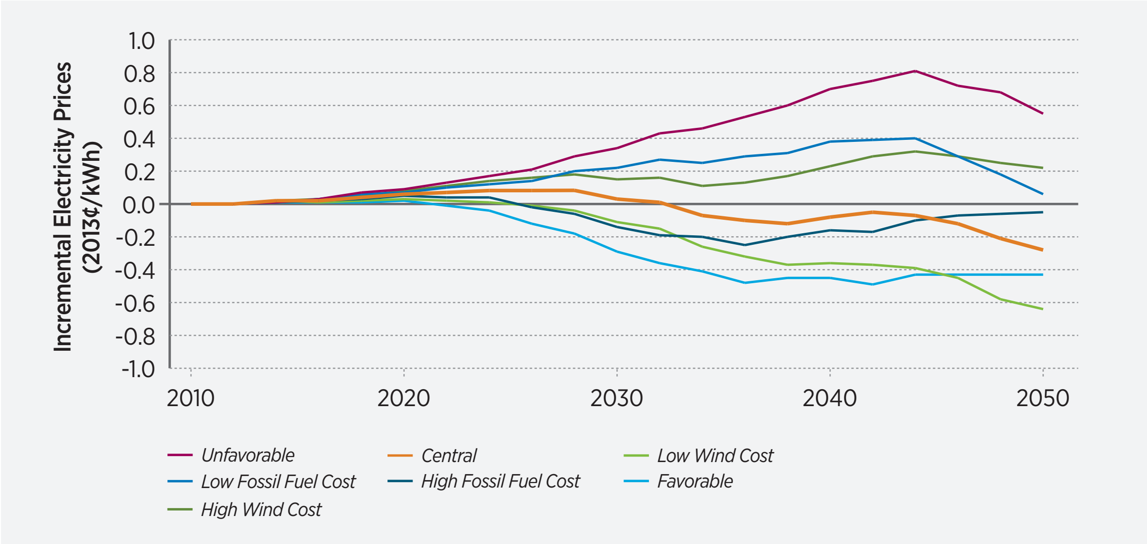
Figure 3-20. National average retail electricity price trajectories for the *Study Scenario* and *Baseline Scenario* (across sensitivities)

2050 are estimated to be 12.6¢/kWh and 12.3¢/kWh for the *Central Baseline Scenario* and *Study Scenario*, respectively. Uncertainties exist for all estimates and increase with time.

Study Scenarios with higher and lower wind technology cost projections, but still under *Central Fuel Cost* assumptions, yield 2050 electricity prices of 12.8¢/kWh and 11.9¢/kWh, respectively. Under *Low Fuel Cost* assumptions, electricity prices are generally flat through 2040 for the *Study Scenario* and experience a slight decline for the *Baseline Scenario* over the same period of time. From 2040 to 2050, electricity prices in both the *Baseline Scenario* and *Study Scenario* experience a sharper increase, however, 2050 prices remain lower (at 11.4-11.5¢ /kWh) than all scenarios under *Central Fuel Cost* assumptions. The *Unfavorable* (combined *Low Fuel Cost* and *High Wind Cost*) *Study Scenario* results in electricity prices that are higher than the other *Low Fuel Cost* scenarios. Under *High Fuel Cost* assumptions, electricity prices rise more rapidly and result in 2050 prices of about 13.3¢/kWh for both the *Baseline Scenario* and *Study Scenario*. *Favorable* (combined *High Fuel Cost* and *Low Wind Cost*) conditions yield lower prices for the *Study Scenario*, but the 2050 price in this scenario remains higher than prices under all scenarios under *Central* or *Low Fuel Cost* conditions. These results point to the influence of future fuel prices on electricity rates.

While future fuel prices will impact the magnitude of electricity prices across any scenario, they—along with future wind technology development—also impact the incremental price of achieving the *Study Scenario* relative to the *Baseline Scenario*. Figure 3-21 shows the incremental electricity price across all modeled *Study Scenario* sensitivities, where the incremental price is defined as the difference in electricity price between the *Study Scenario* and the corresponding base fuel price *Baseline Scenario* sensitivity.[61] In 2020, the incremental electricity price is 0.06¢/kWh (+0.6%) for the *Central Study Scenario*. The range of electricity price impacts reflect 2020 incremental *costs* of up to about 0.09¢/kWh (+0.9%) under the least favorable conditions considered—*High Wind Cost* and *Low Wind Cost*. Under favorable conditions, incremental costs are only 0.02¢/MWh (+0.2%). While the near-term incremental electricity prices of the *Study Scenario* sensitivities depends on future wind technology cost and future fuel prices, the magnitude of the 2020 electricity price impacts is relatively small across all sensitivities considered.

61. The *Central, High Wind,* and *Low Wind Study Scenario* sensitivities are compared with the *Central Baseline Scenario;* the *High Fuel Cost* and *Favorable Study Scenario* sensitivities are compared with the *High Fuel Cost Baseline Scenario;* and the *Low Fuel Cost* and *Unfavorable Study Scenario* sensitivities are compared with the *Low Fuel Cost Baseline Scenario.*



Note: Incremental prices are shown relative to the associated fuel cost *Baseline Scenarios* in which installed wind capacity is fixed at 2013 levels.

Figure 3-21. Incremental average electricity prices in *Study Scenario* sensitivities relative to the *Baseline Scenario*

The incremental electricity price of the *Central Study Scenario* is positive between 2020 and 2030 (representing a *cost* relative to the *Baseline Scenario*), peaking at 0.08¢/kWh (+0.8%) in the mid-2020s. By 2030, this incremental price drops to 0.03¢/kWh (+0.3%). The range of estimated incremental prices across all sensitivities modeled is larger in 2030 than in 2020, with an incremental *cost* of up to 0.34¢/kWh (+3.3%) and *savings* of up to 0.29¢/kWh (–2.4%). Future fossil fuel costs and advances in wind technology are found to have measurable effects on 2030 incremental prices with the directionality following the expected manner: Low wind costs, high fuel costs, or their combination lead to incremental savings; while high wind costs, low fuel costs, or their combination lead to incremental costs.

For the *Central Study Scenario*, the 2050 electricity price is estimated to be 0.28¢/kWh (–2.2%) lower than the *Baseline Scenario*. In fact, incremental savings in electricity prices are found across a majority of *Study Scenario* sensitivities. Wind technology improvement provides the greatest long-term savings; the largest 2050 price savings are about 0.64¢/kWh (-5.1%) in the *Low Wind Cost* sensitivity, while the *Favorable* sensitivity achieves savings of 0.43¢/kWh (–3.2%).[62] Greatest 2050 incremental costs of 0.55 cents/kWh (+4.8%) are found in the *Unfavorable* sensitivity.[63] While uncertainty exists for cost estimates during this time period, the analysis indicates that, in the long term, deployment of wind power to reach levels in the *Study Scenario* is cost effective under a range of possible future conditions, including under *Central* assumptions.

The estimated average retail rate impacts can be translated to annual electricity consumer impacts by evaluating the product of the incremental prices above with projected end-use electricity demand. Incremental annual electricity consumer *costs* for the *Central Study Scenario* total $2.3 billion and $1.5 billion in 2020 and 2030, respectively. In 2050, electricity consumers are estimated to *save* $14 billion in the *Central Study Scenario* relative to the *Baseline Scenario*. The range of incremental annual electricity consumer 2020 *costs*—across all sensitivities—is $0.8–$3.6 billion. By 2030, annual incremental *costs* grow to up to $15 billion under the least favorable conditions, but *savings* of $12 billion are estimated to be possible under favorable ones. Consumer impacts in 2050 range from possible *savings* up to $31 billion to *costs* of up to $27 billion.

62. The *Low Wind Cost Study Scenario* sensitivity counterintuitively achieved slightly greater 2050 savings than the *Favorable* sensitivity. Two separate *Baseline Scenarios* are used as references, however, to estimate incremental prices for these *Study Scenario* sensitivities. As such, the greater savings found under the *Low Wind Cost* sensitivity is possible. The difference in 2050 incremental prices between these scenarios is small.

63. Under the *Unfavorable* sensitivity, peak incremental prices occur in the mid-2040s, at about 0.81¢/kWh (+7.6%).

Table 3-4. Changes in Electricity Prices for the *Study Scenario* Relative to the *Baseline Scenario* (Across Sensitivities)

	2020	2030	2050
Central Study Scenario electricity price (change from *Baseline Scenario*)	0.06 ¢/kWh cost (+0.6%)	0.03 ¢/kWh cost (+0.3%)	0.28 ¢/kWh savings (-2.2%)
Central Study Scenario annual electricity consumer costs (change from *Baseline Scenario*)	$2.3 billion costs	$1.5 billion costs	$13.7 billion savings
Study Scenario sensitivity range (% change from *Baseline Scenario*)	+0.2% to +0.9%	-2.4% to +3.2%	-5.1% to +4.8%
Study Scenario annual electricity consumer costs range (change from *Baseline Scenario*)	$0.8 to $3.6 billion costs	$12.3 billion savings to $14.6 billion costs	$31.5 billion savings to $26.9 billion costs

Note: Expenditures in 2013$

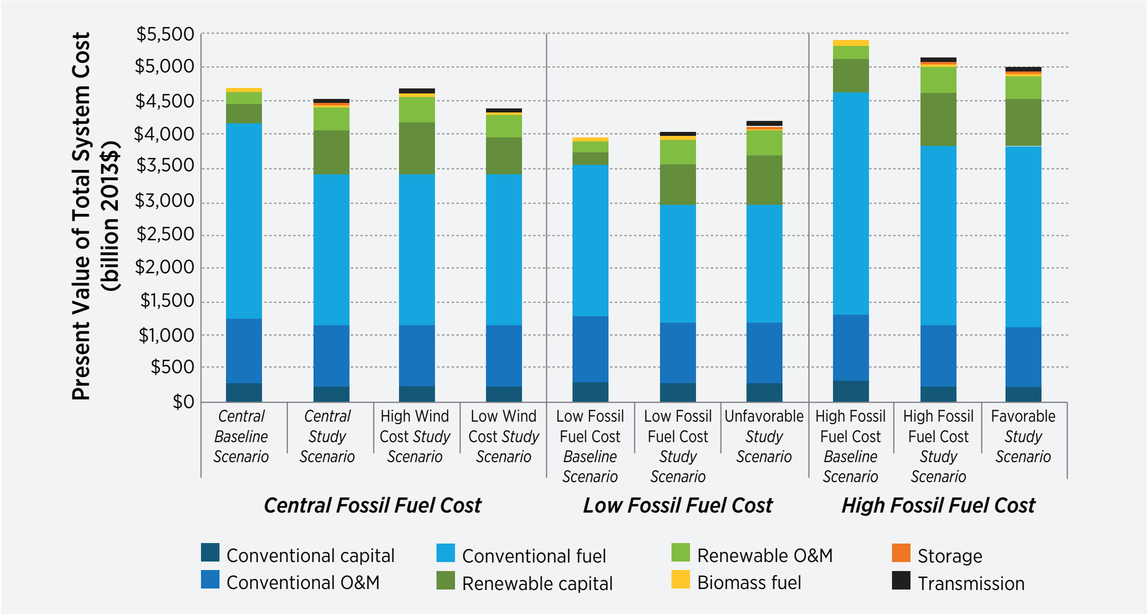
3.4.2 Present Value of Total System Cost

The present value of total system cost measures cumulative expenditures over the entire study period (2013-2050). Figure 3-22 shows the present value of total system costs for all *Baseline* and *Study Scenario* sensitivities modeled with a 3% real discount rate.[64] Multiple cost components are shown separately in Figure 3-22, including capital, O&M, and fuel costs for conventional and renewable technologies.[65] Under the *Central Baseline Scenario*, system costs total approximately $4,690 billion. A large fraction (62%) of this cost is for conventional fuel—coal, natural gas, uranium—expenditures. With conventional fuel expenditures greatly outweighing any other cost category under the *Baseline Scenario* conditions, future fuel price assumptions have a dramatic effect on total system costs. For example, under the *High Fuel Cost Baseline Scenario*, the present value of total system cost equals $5,390 billion, 15% higher than the *Central Baseline Scenario*. Conversely, under the *Low Fuel Cost Baseline Scenario*, present value of total system cost totals $3,940 billion, 16% lower than the *Central Baseline Scenario*.

The *Central Study Scenario* is found to have a present value of total system cost of nearly $4,540 billion, 3% lower (–$149 billion) than that of the *Baseline Scenario*. These results and the electricity price results presented earlier indicate that the long-term *savings* of the *Central Study Scenario* outweigh the near-term incremental *costs* relative to the *Baseline Scenario* in which no wind capacity is deployed after 2013, even after accounting for the greater discount factor in the long term. The majority of the savings are associated with decreased conventional fuel expenditures (–$670 billion) at the expense of increased renewable capital (+$380 billion) and renewable O&M (+$170 billion) expenditures. The *Study Scenario* results with higher and lower wind technology cost have respective higher and lower total system cost than the *Central Study Scenario*. Different assumed fuel price trajectories have a similar effect on the total system cost of *Study Scenario* sensitivities as on the *Baseline Scenario* sensitivities. The range of system costs driven by fossil fuel assumptions, however, is narrower under *Study Scenario* sensitivities versus the *Baseline Scenario* sensitivities. This narrowing is a function of

64. The discount rate used in ReEDS (8.9% nominal or 6.2% real) is not to be confused with the discount rate used to describe the present value of overall system cost (5.6% nominal or 3% real). The discount rate used in ReEDS is selected to represent private-sector investment decisions for electric system infrastructure and approximates the expected market rate of return of investors. The lower "social" discount rate is only used to present the cost implications of the *Wind Vision Study Scenario* results and is generally consistent with the discount rate used by the DOE, EIA, International Energy Agency, and Intergovernmental Panel on Climate Change when evaluating energy technologies or alternative energy futures. A 3% discount rate is also consistent with The White House Office of Management and Budget guidance when conducting "cost-effectiveness" analysis that spans a time horizon of 30 years or more.

65. Conventional technologies include fossil (coal, natural gas, oil) and nuclear generators. Renewable technologies include wind (land-based and offshore), biomass (dedicated and co-fired with coal), geothermal, hydropower, and solar (utility-scale PV and concentrating solar power). Expenditures associated with distributed rooftop PV are not considered in the total system costs. This omission has no effect on incremental costs, as the same rooftop PV capacity projections are used across all *Baseline* and *Study Scenario* sensitivities.



Note: Present value of total system costs for 2013-2050 calculated using a 3% discount rate

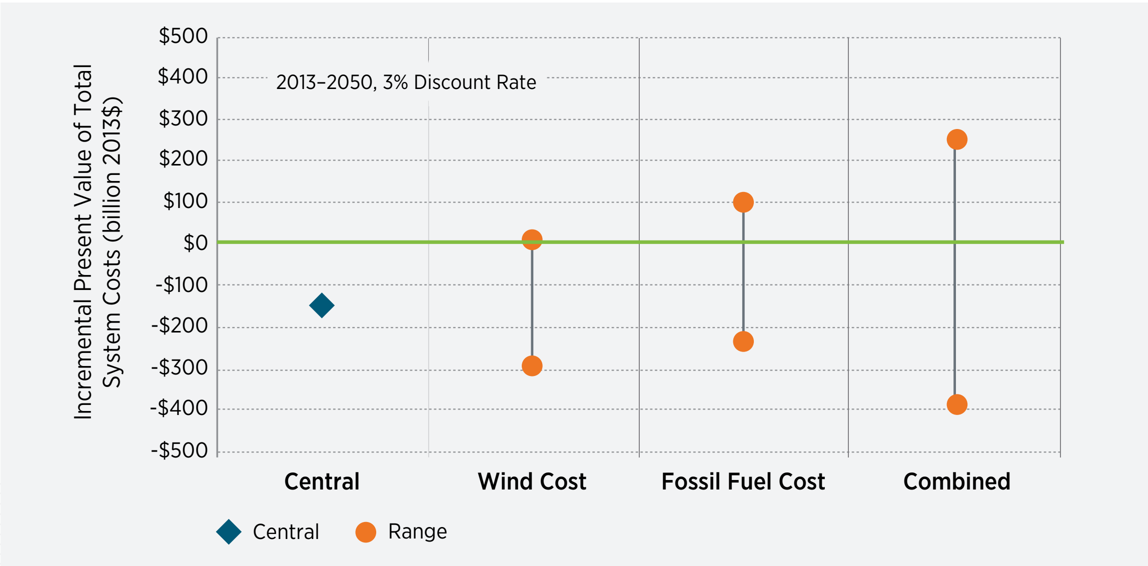
Figure 3-22. Present value of total system cost for the *Baseline Scenario* and *Study Scenario* (across sensitivities)

the reduced prominence of fossil fuel in the cumulative portfolio and is discussed in greater detail in Sections 3.5 and 3.10.

Figure 3-23 shows the incremental total system cost for the *Study Scenario* sensitivities relative to the corresponding *Baseline Scenario* sensitivities. The *Central Study Scenario* is estimated to have a system cost that is $149 billion lower (–3%) than that of the *Central Baseline Scenario*. Greatest savings are observed under the *Favorable Scenario* (combined low wind technology and high fossil fuel costs), in which the total system cost is $388 billion lower (–7%) than that of the *High Fuel Cost Baseline Scenario*. In contrast, the greatest incremental present value of total system cost is observed under the *Unfavorable Scenario* (combined high wind technology costs and low fossil fuel costs), in which an incremental cost of $254 billion (+6%) relative to that of the *Low Fuel Cost Baseline Scenario* is estimated.[66]

In summary, the incremental economic impacts of the *Study Scenario* sensitivities ranges from a *savings* of up to 7% to a *cost* of up to 6%, in present value terms (2013–2050, 3% discount rate). The results indicate that—while fossil fuel prices are important drivers for these incremental costs—wind technology improvements can help reduce the cost to achieve the *Wind Vision* penetration levels or even enable savings compared with a future in which no new wind capacity is placed in service. *Central* assumptions of wind costs and fuel prices result in savings of $149 billion (–3%). This demonstrates the economic competitiveness of wind despite low fossil fuel prices in years leading up to 2013, particularly when economic impacts are evaluated over multiple decades.

66. Using a higher discount rate would lead to lower overall system costs for both *Baseline Scenario* and *Study Scenario* sensitivities, and changes in incremental costs. For example, with a 6% (real) discount rate, present value of system cost for the *Central Baseline Scenario* and *Study Scenario* is estimated to be nearly identical. On a percentage basis, the upper range of incremental costs would increase to about 8% (+$212 billion), while the possible magnitude of percent savings would decline to about 5% (–$173 billion). These changes related to a higher discount rate reflect the changing competitiveness of wind relative to other technology options over time, under the assumptions used.



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 3-23. Incremental system costs of *Study Scenario* sensitivities relative to the *Baseline Scenario*

3.5 Electricity Sector Impacts

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%.[67] Nuclear and hydropower power plants contributed 19% and 6.6%, respectively. Generation from wind power plants totaled 4.1% of 2013 generation.[68] Other renewable technologies, including solar, geothermal, and biomass, contributed 2.1%.[69] Among seven broad technology categories—coal, natural gas, nuclear, hydropower, wind, solar, and other renewable energy—wind was the fifth largest contributor to the U.S. electricity system on a net electricity generation basis. Wind electricity was generated from approximately 61 GW of installed wind capacity by year-end 2013. There are approximately 941 GW in total installed capacity in the 2013 U.S. electricity generation fleet.

This section describes the evolution of the U.S. electric system from the 2013 starting point envisioned under the *Study Scenario* and *Baseline Scenario*. This discussion includes description and illustration of the generation and capacity mixes under the scenarios.

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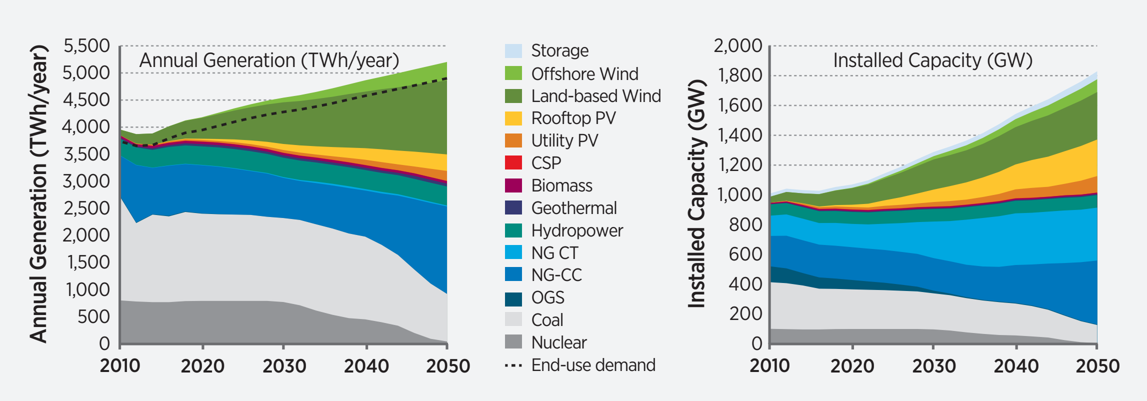
67. The total market share from fossil fuel-fired generation has not changed significantly in the decade leading up to 2014. Significant fuel switching from coal to natural gas has been observed since 2010, however, primarily driven by historically low natural gas prices from 2010 to 2013.

68. The wind generation share (4.1%) presented here differs from the percentage of end-use demand (4.5%) indicated elsewhere in the report, but both reflect the same amount of electricity produced from wind power plants.

69. 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 section 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.



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 3-24. Annual generation and installed capacity by technology type and year under the *Central Study Scenario*

The position of wind power within this broader electric sector is provided here for context, while Section 3.3 more fully describes the impacts to the wind industry specifically.

Significant uncertainty exists for all time periods, and an even greater degree of uncertainty exists in the long term. Uncertain factors that can and will drive future investment and dispatch decisions in the electric system include environmental regulations, electricity demand growth and plant retirements (particularly coal and nuclear retirements), and future technology and fuel costs. While results from scenario variations of two key drivers—wind technology costs and fossil fuel costs—are described to provide an indication of the range of possible outcomes, these and other uncertainties need to be recognized in interpreting scenario results. Also, none of the scenarios represent forecasts or projections.

3.5.1 Evolution of the Electricity Sector under the *Study Scenario*

In the wind penetration levels of the *Study Scenario*, total wind power generation moves from its 2013 position as the fifth largest source of annual electricity generation to the second largest source of electricity by 2030, and to the single largest source of electricity generation by 2050 in the *Central Study Scenario*.

Growth in electricity demand through 2030 is met primarily by the expansion of wind under the *Study Scenario*. Figure 3-24 shows the generation and capacity mixes under the *Central Study Scenario*. As shown, the growth in wind generation exceeds the growth in electricity demand for most years, reducing 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 Scenario*. Outside of wind, solar generation exhibits the greatest growth, at 1% in 2020 to 4% in 2030, although from a smaller starting base. Nuclear generation remains generally constant (18%–20%) through 2030, as the current nuclear fleet continues to operate through its assumed first service life extension period. Other technologies experience changes in annual generation on the order of tens of TWh or less.[70] For example, hydropower generation remains at 8–9% of end-use demand through 2030, including imports from Canada.

70. Percentage totals for the *Central Study Scenario* or any other single scenario exceed 100% because the percentages reflect the fraction of end-use demand and not total generation. Transmission and distribution losses total 6–7% of total generation.

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 Scenario* continues to exceed growth in electricity demand. By 2050, natural gas-fired generation in the *Central Study Scenario* equals 33% of end-use demand, representing higher absolute natural gas-fired generation than historical totals. 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*.[71] 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.

Under the *Central Study Scenario*, the *capacity* expansion trajectory (Figure 3-24, right) largely follows the same trends as the *generation* trajectory (Figure 3-24, left) 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 U.S. power sector that is not observed in the annual generation values presented earlier. 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. Wind and solar PV have a lower capacity factor compared with many other energy sources (e.g., nuclear and coal) that are being replaced in the long term. 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. Capacity growth is limited for other renewable technologies.[72]

In summary, under the *Study Scenario,* the U.S. electricity sector experiences a significant transformation. In the near term, the growth of wind power satisfies new electricity demand and replaces declining fossil generation. In the long term, significant declines in coal and nuclear are observed and replaced by the continued growth of wind, solar, and natural gas generation.

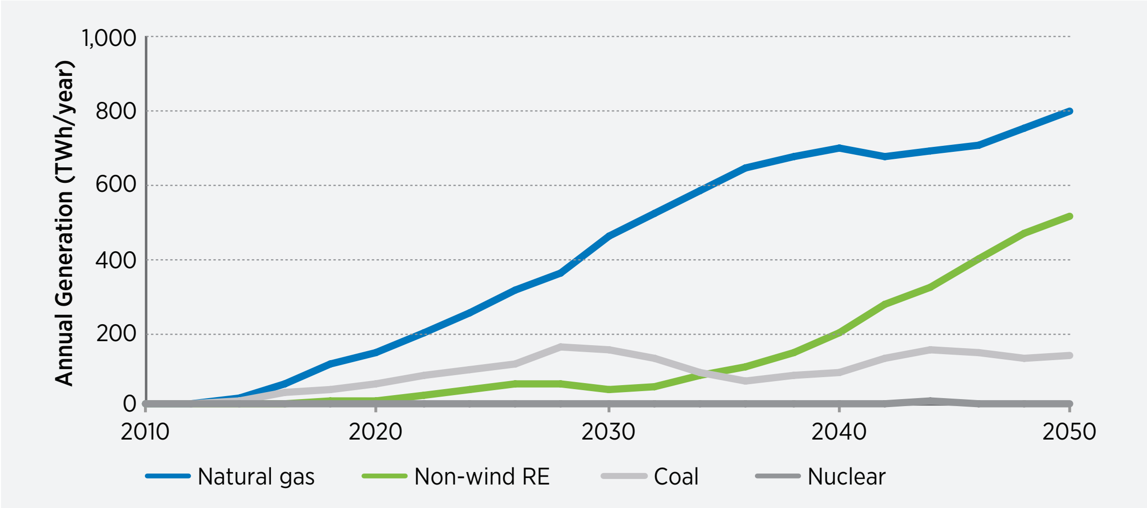
3.5.2 Comparing the Electric Sector under the *Study Scenario* and *Baseline Scenario*

The *Baseline Scenario* sensitivities provide the requisite reference scenario needed to evaluate the costs and benefits of the *Study Scenario* sensitivities. The change in generation between these two scenarios under central assumptions drives many of the environmental and other impacts reported in Sections 3.7-3.12.

Figure 3-25 shows the difference in non-wind generation between the *Central Baseline Scenario* and *Study Scenario* for four categories: natural gas, coal, nuclear, and non-wind renewable generation. The difference in non-wind generation reflects the type of generation "displaced" by wind between these two scenarios. In the near- and mid-term, wind generation primarily displaces fossil generation. In particular, 2020 wind generation under the *Central Study Scenario* primarily takes the place of fossil generation found in the *Baseline Scenario*, including 142 TWh of natural gas-fired generation and 54 TWh of coal-fired generation. Wind continues to displace fossil generation in 2030, including 452 and 149 TWh of natural gas-fired and coal-fired generation, respectively. Differences in generation shares in the other broad technology

71. In the modeled scenarios, nuclear and coal generation is largely driven by assumptions around the available installed capacity of these plants, due to the low operating costs of nuclear and many coal-fired plants. Nuclear units are assumed to be retired after one service life extension period, resulting in a 60-year lifetime for nuclear units. With a second service life extension and the associated total 80-year lifetime, nuclear would achieve greater generation in the latter years than the findings suggestion. Other plant retirement assumptions are described in Section 3.2.4.1 and Appendix G.

72. Section 3.2.2 describes the underlying assumptions used for this analysis. While technology sensitivities beyond wind technology costs were not conducted as part of this study, they would yield different results. For example, the inclusion of other geothermal technologies with greater resource potential—including undiscovered hydrothermal and greenfield-enhanced geothermal systems—could lead to greater market share from geothermal generation. Different assumptions about hydropower, such as inclusion of upgrades at existing facilities or new sites with <1 MW capacity, biomass costs and resources, or nuclear technology costs, could also yield larger shares from these energy sources.



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.

Figure 3-25. Difference in annual generation between the *Central Study Scenario* and *Baseline Scenario* by technology type

categories are more modest through 2030. For example, in aggregate, 42 TWh of all non-wind renewable technologies are displaced by wind in 2030.

Wind deployment under the *Central Study Scenario* continues to displace fossil generation in the long term, including 789 TWh of displaced natural gas-fired generation and 130 TWh of displaced coal displacement in 2050. The growth in the displacement of natural gas and more constant amount of coal displacement reflects the underlying fossil fuel switching observed in both the *Study Scenario* and *Baseline Scenario*. With an electric sector transitioning over time to be more heavily dependent on natural gas compared to coal, the *Central Study Scenario* results in greater amounts of avoided natural gas in the long term. By 2050, wind not only displaces fossil generation, but also has a significant impact on solar generation; the *Central Study Scenario* includes 489 TWh less solar generation in 2050 than the *Baseline Scenario*. Differences in 2050 hydropower and other renewable energy generation are smaller, at 18 TWh in total. Under *Central* assumptions, differences in nuclear generation between the *Baseline Scenario* and *Study Scenario* results are negligible in all years.

The amount of capacity displaced is not as drastic as the amount of electricity production displacement, particularly for the near- and mid-terms. The *Central Study Scenario* results in minor reductions of natural gas-fired combustion turbine capacity (5 GW) in 2020 compared with the *Baseline Scenario*. In 2030, these differences grow to 22 GW of natural gas combustion turbine and also include 5–6 GW each of natural gas-fired combined cycle and coal capacity. Even by 2050, differences in installed fossil capacity between these two scenarios remain relatively small at 51 GW and 14 GW, respectively, of natural gas and coal, compared with a fleet of about 1,800 GW.[73] The much smaller displacement of fossil capacity compared to fossil generation by the *Study Scenario* reflects some of the system-wide contributions the fossil fleet provides beyond energy provision, as described in Sections 2.7 and 3.6.

73. The *Central Study Scenario* includes greater natural gas-fired combustion turbines capacity (+43 GW) compared with the *Central Baseline Scenario,* but less natural gas-fired combined cycle capacity (-94 GW), resulting in a net difference of only 51 GW of 2050 natural gas capacity. This trade-off reflects wind's greater role in providing energy compared with capacity reserves.

3.5.3 The Evolution of the Electricity Sector is Dependent on Future Fuel Prices

Assumptions around fossil fuel prices can have a sizable effect on the evolution of the electricity system, particularly on the generation differences found across the full set of *Baseline* and *Study Scenario* sensitivities. While three variants of wind technology cost scenarios are modeled, future wind technology development is found to have little effect on the remaining generation mix under the prescribed scenario framework.[74] For all years up to 2030, different fuel price assumptions largely affect the relative displacement of natural gas and coal-based generation, indicating the fuel switching possibility between coal and natural gas in the U.S. electricity system.[75] By 2050, the direct trade-off between coal and natural gas is reduced relative to earlier years, but the contributions from natural gas remain strongly tied to assumed long-term fuel prices. For example, in 2050, natural gas generation reaches 62% of 2050 end-use demand (from more than 3,000 TWh) under the *Low Fuel Cost Baseline Scenario* compared with 32% under the *High Fuel Cost Baseline Scenario.* During this long-term period, the trade-off is made between natural gas and other technologies, primarily nuclear and non-wind renewables.[76]

Under the scenario construction of this study, wind generation levels over time are prescribed. As a consequence, other generation sources will achieve less generation in the *Study Scenario* compared to the corresponding *Baseline Scenario*. The starkest differences are found in 2050, when the 35% wind penetration displaces fossil generation and leaves less room for nuclear and renewable generation. The mix of displaced generation enables a consistent estimate of the impacts, costs, and benefits of future wind deployment. Ultimately, however, the generation mix will depend on economic, policy, and other conditions—including those that can accommodate growth of multiple technology types.

3.6 Transmission and Integration Impacts

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 in the electric power system at all timescales—from multiple decades to microseconds. Variability and uncertainty are inherent in the system as a result of changing electricity demand and generator availability, as well as the potential for power plant and transmission line outages. Although sources of variability and uncertainty exist throughout the power system, including from all generator types, greater reliance on variable output generation such as wind further add to the challenges of system operation. Increasing penetration[77] of wind energy may result in increased ramping needs, increased operating reserves, and transmission expansion. Section 2.7 provides a description of the renewable integration challenges and solutions experienced recent to 2013. This section (3.6) presents the ReEDS scenario results associated with transmission expansion and grid integration and does so within the context of broader transmission and grid integration issues with increased renewable penetration.

74. Wind technology costs have a more sizable effect on the cost implications of the *Study Scenario*, as described in Section 3.4.

75. The *Low Fuel* and *High Fuel Cost* scenarios assume both coal and natural gas fuel prices to be adjusted in the same direction relative to the *Central* assumption; however, the scenario assumptions change the relative competitiveness of these two energy sources.

76. Installed 2050 nuclear capacity totals about 83 GW under the *High Fuel Cost Baseline Scenario* compared with about 6–16 GW in all other scenarios modeled. This is mostly the result of the assumed single service life extension for existing nuclear units and the limited growth in nuclear capacity under the assumptions used.

77. In this section, penetration refers to the annual percentage of energy sourced from wind power plants. The prescribed wind penetration levels associated with the *Study Scenario* of 10% by 2020, 20% by 2030, and 35% by 2050 for the continental United States reflect the annual electricity generated by wind power plants divided by annual end-use electricity demand. When regional wind penetration levels are displayed in this section, the denominator is instead represented by the total annual electricity generated in that region.

The modeled scenarios are developed using the ReEDS long-term nationwide capacity expansion model described in Section 3.1.1, which is designed to consider the major grid integration issues surrounding future electricity infrastructure development. The present analysis is not intended to be a full integration study that relies on hourly or sub-hourly modeling; instead, it provides a high-level and semi-quantitative assessment of the grid integration challenges at high wind penetration. The scenario analysis complements and is supported by the conclusions found in integration studies, including those that evaluate 30–50% wind and solar penetration levels [2, 63, 64, 65, 66, and others]. Further work could provide additional high-resolution insights specific to the transmission and integration impacts of the *Study Scenario.*

Notwithstanding the limitations of the *Wind Vision* analysis discussed here, the ReEDS scenarios provide a general assessment of the impacts of greater wind deployment, including issues around system operations and transmission expansion. In addition, while the analysis focuses on wind integration, many of the practices and technologies described to support greater wind deployment can have system-wide benefits even without wind.

3.6.1 Integrating Variable and Uncertain Wind Energy

The *Study Scenario* includes wind penetration levels that are significantly higher than the 4.5% penetration level experienced in 2013 [4] . In this section, the impacts of this increased wind penetration level to system operations are considered in terms of wind capacity value or contributions to system planning reserves, impacts to operating reserves, and wind curtailments. Regional implications are also explored.

At the planning timescale, ReEDS estimates that the capacity value[78] of wind (i.e., the contribution of wind in providing firm capacity planning reserves to meet peak or net peak[79] demand hours) declines with increasing wind penetration. For example, for the *Study Scenario*, ReEDS estimates the *average* capacity value of the entire wind fleet providing 35% of 2050 demand to be about 10–15%, and the *marginal* capacity value to be near zero in most regions.[80] Accordingly, wind's aggregate contribution to planning reserves is relatively modest compared to its nameplate capacity, and new plants installed late in the period of analysis have zero contribution to planning reserves. This result does not imply that new wind deployment causes a need for more capacity, nor does it create new peak planning reserve *requirements*. It does, however, reflect that wind may not reduce the need for new capacity as much as alternative resources with higher capacity value. In other words, a consequence of low marginal wind capacity value is that non-wind options, including new thermal generation, demand-side resources, or other options may be needed to ensure sufficient planning reserves due to peak electricity demand growth.

At operational timescales, ReEDS ensures that capacity reserves are held to adequately meet operating requirements, including contingency, regulation, and forecast error reserve requirements.[81] Changes in the requisite operating reserve capacity resulting from increased wind deployment are modeled in ReEDS through increased forecast error reserve requirements. For example, wind forecast error reserves of approximately 10–15% of wind capacity are estimated for the *Study Scenario*. As a result, the *Study Scenario* requires that a greater amount of capacity is available to providing operating reserves compared to the *Baseline Scenario*. This result does not necessarily

78. Capacity value is a statistical metric used to identify the amount of a power plant's (or technology group's) total nameplate capacity that can be reliably used during peak hours [68, 69]. Effective load-carrying capacity calculations are widely accepted reliability-based methods used to estimate wind capacity value. ReEDS uses simplified effective load carrying capacity calculations to estimate wind and solar capacity value dynamically for all regions, penetration levels, and system configurations [70].

79. Net peak hours occur when electricity demand minus variable generation is highest.

80. Marginal values reflect the capacity value for the next increment of wind capacity, while average values reflect the capacity value for the entire amount of wind capacity in a region in existence as of that year.

81 Contingency reserves are used to address unexpected generator or transmission outages. The amount of contingency requirement is typically assessed based on the largest generating unit or transmission line in a region. Regulation refers to the very short (less than 5-minute) timescale deviations between generation and load. ReEDS allows regions to trade reserve capacity (operating and planning) between model regions, but constrains the amount of trading by the available transmission capacity. ReEDS assumes contingency and regulation reserves to be 6% and 1.5% of demand, respectively, in every model balancing area. ReEDS treatment of operating reserves is described in Short et al. 2011 [3] and Mai et al. 2014 [10].

imply that new capacity is needed to provide these reserves, but that greater existing (or new) capacity is online or can be made readily available at the operating timescale (hourly or shorter). Increased wind penetration could free up other generators to provide operating reserves instead of energy [63, 67]. Increased operating reserve requirements could impose higher costs or prices for ancillary services [67]. Such potential cost increases may be offset by lower wholesale energy prices that result from increased wind penetration at least in the short run (see Text Box 3-6). The net cost implications of increased operating reserves and other grid integration issues are included in the ReEDS scenario cost estimates described in Section 3.4.

The ReEDS analysis does not consider a number of other short timescale grid services needed to ensure system reliability, including voltage stability, inertia, and frequency response. Other studies (e.g., [71]) have evaluated the effects of wind penetration on these services, and further research is needed to examine them for the *Study Scenario*. Wind power plants with active power control can provide a range of ancillary services, including synthetic inertia, regulation, reactive power, voltage support, and contingency reserves.[82]

Increased wind penetration also creates the potential for greater wind curtailment. ReEDS estimates the amount of wind curtailment (the amount of wind energy available but not used due to transmission constraints and/or system inflexibility) across all scenarios. Wind curtailment amounts of approximately 20 TWh (2% of annual wind generation) in 2030 and 50 TWh (3%) in 2050 are estimated for the *Central Study Scenario*.[83] On a percentage basis, these curtailment values are similar to wind curtailments experienced leading up to 2013 across many regions of the United States [72]; however, the *Study Scenario* includes much higher levels of wind deployment than existed in 2013. Many factors affect curtailment, including the efficiency of resource sharing across balancing areas, which is assumed to be highly efficient within the system-wide optimization construct in ReEDS. Generator flexibility, including the ability to operate at a low generation point, ramp rapidly, and start/stop, can also have substantial effects on curtailment. While the curtailment values for the *Study Scenario* are low, marginal curtailment values can be higher and potentially impose challenges to investment decisions for new wind capacity.[84]

The ReEDS analysis finds that wind curtailment occurs most prominently during times of low demand and high wind generation, which coincide with spring nights for many regions in the United States. Under high wind penetration regimes, grid integration challenges are found to be generally most acute during these same time periods. This includes increased ramping and cycling of thermal power plants in addition to curtailments [2, 65]. More detailed hourly or sub-hourly modeling would be needed to better estimate and understand wind curtailment and operational changes under the *Wind Vision Study Scenario*.

While the prescribed wind penetration levels apply to the continental United States as a whole, the variations in wind quality and relative distances to load centers and the existing infrastructure drive regional differences in wind penetration levels. Figure 3-26 shows these differences for 2030 and 2050 in the *Central Study Scenario*. In 2030, many regions in the western, central, and northeastern parts of the United States have penetration levels that exceed the 20% nationwide level, with some regions exceeding 30% penetration. Resource limitations for land-based wind diminish wind growth in some regions (e.g., California and the southeastern United States). Under the *Central Study Scenario*, however, wind capacity is found across nearly all states by 2030. By 2050, regional wind penetration levels exceed the 35% nationwide *Study Scenario* level in many regions, especially in the western and central parts of the United States. Only two regions in the Southeast have wind penetration levels below 20% by 2050 and, in fact, are well below 10%. Figure 3-26 demonstrates that grid integration challenges will vary in magnitude and timing between regions.

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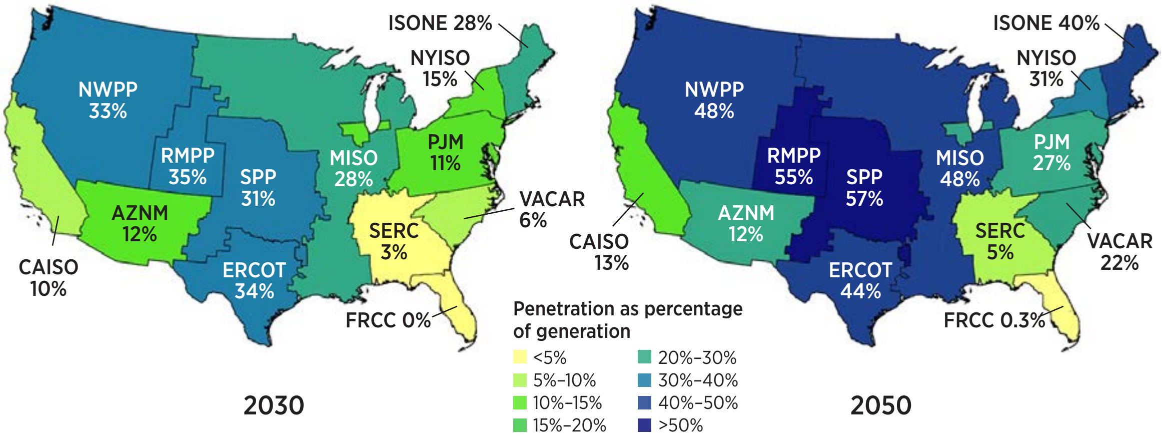
82. Wind's low energy cost typically makes wind a higher-cost option for ancillary service supply than thermal generation, due to the higher opportunity cost incurred when wind curtails energy production in order to make capacity available for reserves. If wind is curtailed for other reasons (minimum load limits on thermal generation, for example), it can be a cost-effective ancillary service provider.

83. Curtailment values can vary significantly between regions.

84. The LCOE of wind is inversely proportional to the amount of energy wind provides; therefore, increased curtailment would increase this cost.



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 3-26. Regional annual wind penetration for 2030 and 2050 under the *Central Study Scenario*

These findings demonstrate some of the grid integration challenges associated with greater wind deployment. In combination with a large body of renewable grid integration studies (e.g., [2, 63, 64, 65, 73]), they also indicate that these challenges can be mitigated through a portfolio of supply-side, demand-side, and market solutions to increase system flexibility. This includes coordination over wider areas, increased transmission, improved wind forecasting, faster dispatch and commitment schedules, demand response, electric vehicles, wind curtailment, and storage.[85] Similar to the regional variations of the grid integration challenges posed in the *Study Scenario*, as indicated by Figure 3-26, the deployment of mitigation options will also vary by region. The cost impacts presented in Section 3.4 include the costs to deploy the mitigation options as assumed in ReEDS. ReEDS does not represent all flexibility options, nor does it comprehensively assess their costs and value. It does, however, give an indication of the potential deployment of a subset of options. For example, the *Central Study Scenario* results in about 28 GW of total installed storage capacity by 2030 and 54 GW by 2050. In contrast, there are approximately 22 GW of operating storage capacity in the U.S. electric system, and 24 GW installed by 2050 in the *Baseline Scenario*. These results are reflective of the assumptions used for storage and other flexibility options and the associated representation in ReEDS. Greater understanding of the costs and benefits of storage and other mitigation options to support higher wind penetrations would be needed to more accurately estimate future adoption of flexibility technologies and practices.

Text Box 3-4 summarizes the grid integration challenges associated with the *Study Scenario* (across sensitivities). It also summarizes the estimated transmission needs of the *Central Study Scenario* as discussed in greater detail in the following section.

85. Synergies between nightly electric vehicle charging and excess wind energy exist [74, 75, 76], as advanced controls on vehicle charging can enable demand response to provide additional reserves required to accommodate wind integration.

Text Box 3-4.

Transmission and Grid Integration Challenges of the *Wind Vision*

The variable, uncertain, and location-dependent nature of wind energy introduces grid integration challenges associated with the *Wind Vision.*

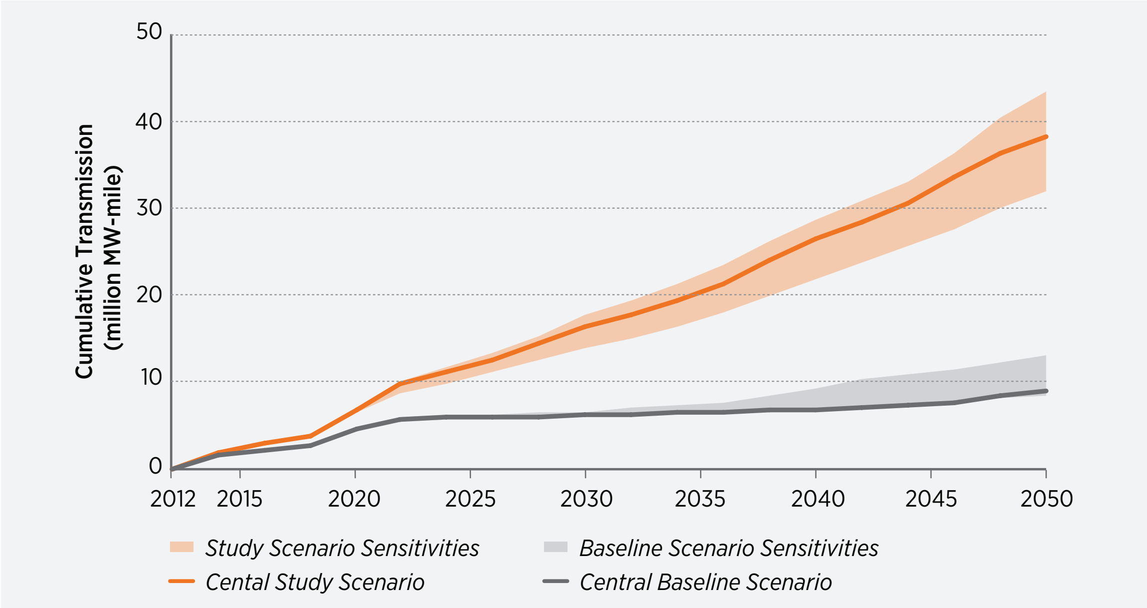
Planning Reserves: The contribution of wind as a firm capacity resource to meet long-term planning reserves typically declines with increasing wind penetration [68, 69]. ReEDS estimates that the aggregate capacity value of the wind fleet is about 10–15% in 2050, when wind penetration reaches 35%. Marginal capacity value can be even lower, and near zero for many regions. While adding wind does not increase planning reserve requirements, wind's low capacity value implies that other sources may be needed to meet any potentially growing peak system adequacy requirements.

Operating Reserves: Wind energy cannot be perfectly predicted and can introduce increased ramping needs. The typical means of managing these needs is to increase operating reserve requirements and hold greater amounts of reserve capacity online. ReEDS estimates increased operating reserve requirements of 10–15% of wind capacity in 2050. Increased reserves can incur greater costs and prices for ancillary services [67]. These costs are captured in the cost results presented in Section 3.6, with much of the need being serviced by existing generators.

Wind Curtailments: The inherent variability of wind energy, in combination with system inflexibility such as transmission constraints and physical generator limits, can lead to wind curtailment [72]. ReEDS estimates that 2–3% of potential wind energy is curtailed in 2050. Curtailment influences the economic position of wind, but can be a source of valuable system flexibility that can reduce the cost of managing the electric system's supply and demand balance [71].

Mitigation Options: Diverse options are available to help manage the variability and uncertainty of wind. These include market and institutional solutions (e.g., wider area coordination, faster commitment and dispatch schedules), operational practices (e.g., improved forecasting, increased dispatch flexibility, curtailments), technology solutions (e.g., storage, demand-side options), and transmission expansion. ReEDS estimates an incremental 29 GW of storage capacity in the *Central Study Scenario* by 2050, relative to the *Baseline Scenario.* The costs to deploy storage are captured in the cost results presented in Section 3.6 but further work is needed to understand the cost and benefits of different mitigation solutions. These solutions increase overall flexibility and could garner benefits to the system even absent wind.

Transmission Expansion: Transmission infrastructure expansion is needed to access and deliver remote wind resources to load centers. It also helps facilitate resource sharing between regions. ReEDS estimates a cumulative incremental transmission need of 29 million MW-miles (or 32,000 circuit-miles, assuming 900-MW single-circuit 345-kV lines are used to meet this increment) by 2050 for the *Study Scenario,* relative to the *Baseline Scenario.* Challenges with transmission expansion include siting and cost allocation, but advanced transmission options such as high-voltage direct-current and transmission switching [77] can further support system flexibility.



Note: Figure depicts cumulative transmission measured from 2013 up to the x-axis year.

Figure 3-27. Cumulative transmission expansion under the *Baseline Scenario* and *Study Scenario*

3.6.2 Transmission Expansion Needed to Support the *Wind Vision*

The ReEDS analysis estimates increased transmission expansion in the *Study Scenario* compared with the *Baseline Scenario*. Figure 3-27 shows the cumulative transmission expansion needs estimated for the *Central Study Scenario* and *Baseline Scenario* as well as the range of results across the sensitivity scenarios. Between 2013 and 2020, as shown by the differences in transmission expansion between the two *Central* scenarios in Figure 3-27, estimated incremental transmission needs to support the *Central Study Scenario* total 2.3 million MW-miles.[86] By 2030 and 2050, these *incremental* transmission demands increase to 10 and 29 million MW-miles, respectively.[87] For comparison, the existing transmission system in the United States totals approximately 200 million MW-miles [78].[88] In other words, while the new transmission requirement in the *Central Study Scenario* is 2.7 times greater than in the *Baseline Scenario* by 2030 and 4.2 times greater by 2050, the total transmission needs of the *Central Study Scenario* would expand the *existing* transmission network by less than 10% by 2030 and by less than 20% by 2050.

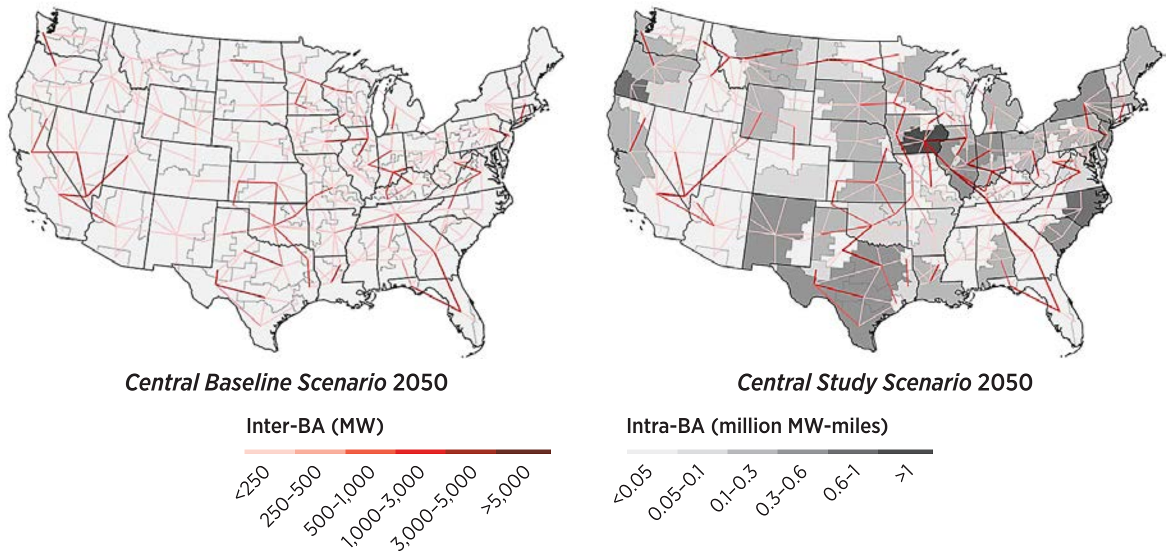
The incremental transmission needs of the *Central Study Scenario* relative to the *Baseline Scenario* can be expressed in units of circuit miles by assuming that the representative transmission line used has a carrying capacity of 900 MW, which is typical for single-circuit 345-kV lines.[89] Under this assumption, cumulative

86. Modeled transmission infrastructure is presented using the unit MW-mile, which represents a transmission line rated with a carrying capacity of 1 MW of power and a 1-mile extent. The amount of new transmission includes long-distance interregional transmission lines as well as spur lines used for grid interconnection of new wind capacity. Planned and under-construction transmission projects are included in ReEDS and reported in Appendix G.

87. The range of incremental cumulative (from 2013) transmission expansion estimated across all *Study Scenario* sensitivities is 7–12 million MW-miles by 2030 and 18–34 million MW-miles by 2050.

88. For another comparison, all interregional lines in the existing transmission network are represented in ReEDS as 88 million MW-miles; however, this metric excludes all lines that do not cross model region boundaries. The scenario-specific transmission expansion results include both inter-regional and intra-regional lines. For the *Study Scenario* sensitivities, estimates are that approximately one-third of the total transmission needs are for intra-regional lines.

89. The selection of single-circuit 345 kV as the representative transmission line is only used to provide a simple estimate of circuit miles. Future transmission expansion will rely on different voltages and technologies, and will result in different distance estimates for the incremental transmission needs of the *Study Scenario*.



Note: Red lines represent long-distance interregional transmission, and gray shades represent intraregional lines, primarily to interconnect new wind capacity. Transmission model regions in ReEDS are referred to as balancing areas (BAs) in the figure. While boundaries of real balancing authority areas help inform the design of the model BAs, the ReEDS BAs do not necessarily correspond with real balancing authority areas. Real balancing authority areas boundaries have evolved and are constantly evolving. Thus, model alignment under this dynamic condition has not been attempted.

Figure 3-28. New (2013–2050) transmission expansion under the *Central Baseline Scenario* and *Study Scenario*

incremental transmission needs of the *Central Study Scenario* total about 11,000 and 33,000 circuit miles of new transmission by 2030 and 2050, respectively. These values correspond to an average of 350 circuit miles/year between 2014 and 2020, 890 miles/year between 2013 and 2030, and 1,050 miles/year between 2031 and 2050. For comparison, North American Electric Reliability Corporation (NERC) [79] reports that, since 1991, an average of 870 miles/year of new transmission have been added and 21,800 circuit miles are planned with in-service dates before 2023.[90]

On a present value basis, total transmission-related expenditures comprise less than 2% of total system costs[91] for the *Study Scenario* sensitivities (see Section 3.4.2). Such costs include all fuel, O&M, and capital expenditures. The present value of incremental transmission-related expenditures of the *Central Study Scenario* compared to the *Baseline Scenario* totals $60 billion. As a linear optimization model, however, ReEDS likely underestimates the amount of transmission needed due to the lumpy nature of transmission investments, non-direct paths in real transmission lines compared to the point-to-point model paths, and siting and permitting challenges for these infrastructure investments. ReEDS also does not estimate the cost to maintain the existing transmission grid, which would have a similar effect to the *Baseline Scenario* and *Study Scenario*. In addition, construction of new transmission lines can serve reliability and other purposes that are beyond the scope of the ReEDS model. For this reason, the total amount of transmission expansion and associated costs estimated for both the *Baseline* and *Study Scenarios* are likely understated. Including transmission maintenance costs or other modifications to the economic representation of transmission deployment in ReEDS would likely only have minor effects on the amount of total system cost for transmission-related expenditures.

Figure 3-28 shows the location of new transmission paths estimated by ReEDS for the *Central Baseline Scenario* (left) and *Central Study Scenario* (right).

90. The regions assessed by NERC also include Canadian provinces and a portion of northern Baja Mexico.

91. The present value (2013-2050, 3% discount rate) of transmission-related costs are estimated to be about $70 billion for the *Central Study Scenario* and range from $62 billion to $79 billion across all *Study Scenario* sensitivities. On an undiscounted basis, average annual transmission expenditures totals about $4 billion per year for the *Central Study Scenario* between 2013 and 2050.

In addition to the increased magnitude of new transmission infrastructure estimated for the *Study Scenario* relative to the *Baseline Scenario*, the geographic distribution also differs between these two scenarios. In particular, though new transmission is generally uniformly distributed across the continental United States under the *Baseline Scenario*, somewhat higher concentrations of transmission projects are found in certain regions including the Midwest, the south central states, the West, and the northern Atlantic region under the *Study Scenario*. These new transmission locations reflect the geographic location of high quality land-based wind regions relative to the load centers.

The ReEDS model co-optimizes transmission and generation expansion, but it is not designed to formulate a coordinated transmission plan. Others have explored transmission network options to help support expansion of wind and other renewable technologies and to support improved reliability (e.g., [80]). In particular, numerous high-voltage direct-current (HVDC) projects are in various development stages. These projects can enhance coordination over long distances and help system operators and regional reliability organizations manage increased variability due to higher wind deployment. Further research would be needed to evaluate transmission plans and technologies to enable cost-effective access of high-quality wind. Further research would also be needed on the additional benefits that advanced technologies like HVDC can provide in terms of stability, contingency reserves, and greater operating flexibility, with or without additional wind.

3.7 Greenhouse Gas Emissions Reductions

The majority of scientists agree that significant changes will occur to the Earth's climate on both a multi-decadal and multi-century scale as a result of past and future GHG emissions. These changes may include rising average temperatures, increased frequency and intensity of some types of extreme weather, rising sea levels due to both thermal expansion and ice melt, and ocean acidification [81, 82, 83, 84, 85, 86]. In part as a result, there is growing agreement among scientists and economists on the desirability of near-term rather than delayed actions to reduce GHGs [87, 85, 88, 89].

Wind power is one of a family of clean energy technologies[92] that could be deployed to reduce GHG emissions, in turn decreasing the likelihood and severity of future climate-related damages [84, 85]. Additionally, near-term action to limit GHGs may lessen the longer-term cost to society of meeting future policies intended to reduce GHGs [90]. Some states (e.g., California) and regions (e.g., a number of northeastern states) have already enacted carbon policies [90], and the U.S. Congress has also considered such policies [90]. The U.S. EPA has implemented GHG reduction programs for the transport sector [91] and has proposed carbon dioxide emission limits for new and existing power plants [92]. In part as a result, utilities regularly consider GHG regulatory risk in resource planning [93, 94].

This section first estimates the potential GHG reductions associated with the *Study Scenario* compared to the *Baseline Scenario*, on both a direct-combustion and life-cycle basis.[93] It then quantifies the economic benefits of these GHG reductions based on the range of social cost of carbon estimates developed by the U.S. IWG and used by the U.S. government [95, 96]. The methods applied here are consistent not only with those used by U.S. regulatory agencies [97], but also with those used in the academic literature [98, 99, 100, 101, 102]. Text Box 3-5 also briefly summarizes the literature on the net energy requirements of different electricity generation technologies. Net energy is another metric often used to compare energy technologies on a life-cycle basis, and one in which wind energy performs relatively well in comparison to other electricity generation sources.

92. Including other forms of renewable energy, nuclear, fossil-based carbon capture and sequestration, and energy efficiency.

93. This section evaluates the impacts of the *Study* and *Baseline Scenarios,* under *Central* assumptions only. The ranges presented in this section are driven by the range of parameters evaluated and not by the range of scenario results.

3.7.1 Wind Energy Reduces GHG Emissions

Achieving the wind deployment levels of the *Study Scenario* will reduce fossil energy use (see Section 3.5), leading to reduced fossil fuel-based carbon emissions in the electric sector. Figure 3-29 shows the decline in annual combustion-related carbon emissions (left panel) and annual life-cycle emissions (right panel) for the *Study Scenario* relative to the *Baseline Scenario*.

Based on output from ReEDS, the left panel of the figure shows that, by 2050, direct combustion CO_2 emissions are estimated to decline by 23% in the *Study Scenario* relative to the *Baseline Scenario*.[94] Cumulative emissions from 2013-2050 are 13% lower in the *Study Scenario* than in the *Baseline Scenario*.

The estimates of combustion-related emissions in the left panel of Figure 3-29, however, do not consider several potentially important effects. First, only CO_2 emissions are considered while other potent GHGs are ignored, an omission that may be particularly important for methane released in coal mining, oil production, and natural gas production and transport. Second, and related, only emissions from the combustion of fossil energy are counted, while emissions from upstream fuel extraction and processing are disregarded. Finally, a focus on combustion-only emissions means that the GHG emissions from equipment manufacturing and construction, O&M activities, and plant decommissioning are not considered for wind or any other electric power plants.

A more comprehensive evaluation requires that GHG emissions across the full life cycle of each technology be evaluated with life-cycle assessment (LCA) procedures, and the results of this assessment are presented in right panel of Figure 3-29.[95] In particular, an extensive review and analysis of previously published LCAs on electricity generation technologies

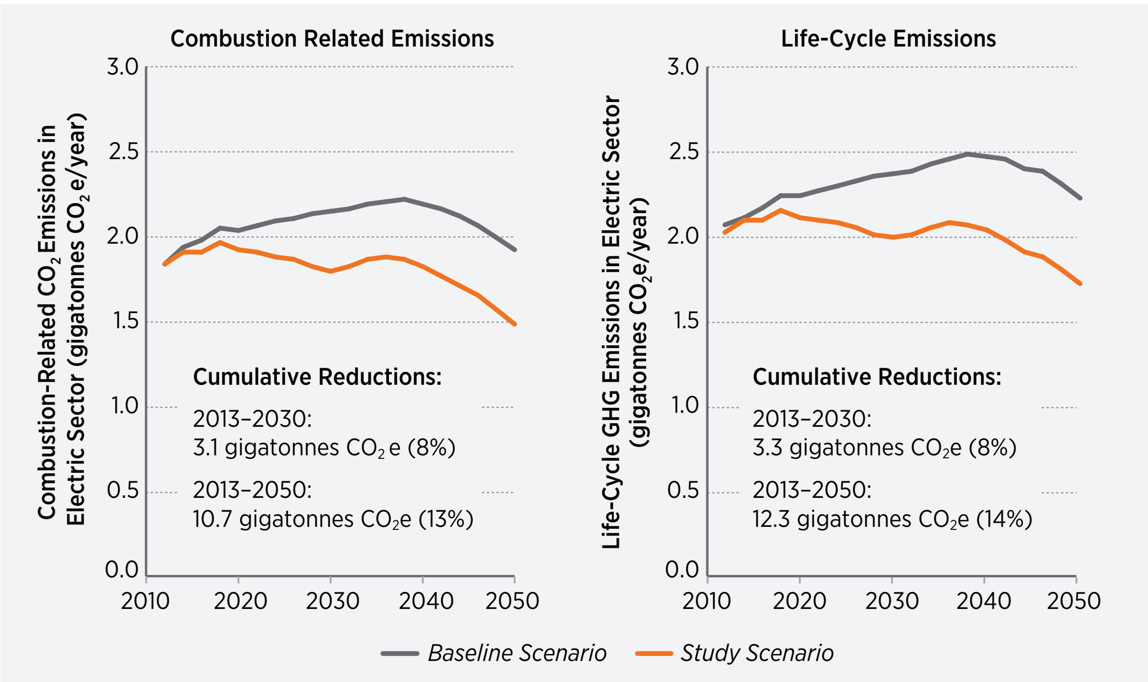
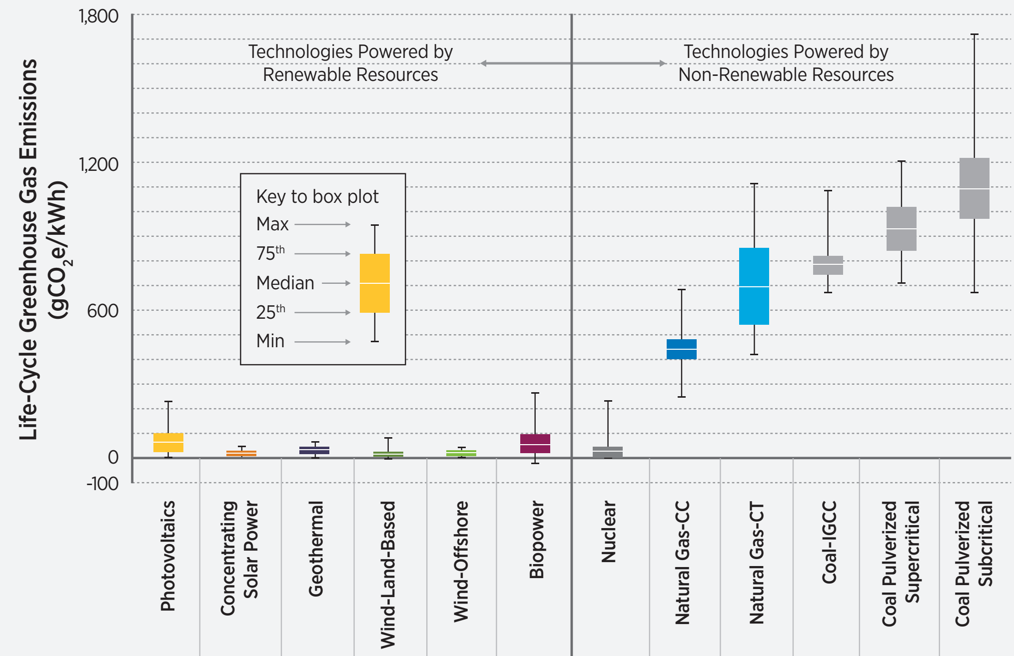


Figure 3-29. Greenhouse gas emissions in the *Central Study Scenario* and *Baseline Scenario*

94. Unless otherwise noted, all reported values related to carbon dioxide or GHG emissions are in units of metric ton (i.e., tonne) of CO_2 or CO_2 equivalent (CO_2eq).

95. A full LCA considers upstream emissions, ongoing combustion and non-combustion emissions, and downstream emissions. Upstream and downstream emissions include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, on-site construction, project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site material.



	Photovoltaics	Concentrating Solar Power	Geothermal	Wind-Land-Based	Wind-Offshore	Biopower	Nuclear	Natural Gas-CC	Natural Gas-CT	Coal-IGCC	Coal Pulverized Supercritical	Coal Pulverized Subcritical
Estimates (count)	124	20	8	154	32	102	99	55	22	21	17	120
References (count)	26	7	6	62	18	26	27	34	11	16	7	41

Note: Acronyms used in this figure: Natural Gas-CC = Natural gas combined cycle; Natural Gas-CT = Natural gas combustion turbine; Coal - IGCC = Coal integrated gasification combined cycle

Figure 3-30. Summary of systematic review of estimates of life-cycle GHG emissions from electricity generation technologies

was conducted through the LCA Harmonization project.[96] For the *Wind Vision* analysis, this foundation was augmented by the assessment of additional LCA literature for wind technologies, published through August 2013. Figure 3-30 summarizes the results of this extensive literature review for a wide range of renewable and non-renewable electricity generation technologies, including the full range of estimates of life-cycle emissions factors for each technology. (See Appendix J for further details for wind, including a listing of the large number of publications reviewed. For all other technologies, see Appendix C, Volume 1 of *Renewable Electricity Futures* [2]).[97] Based on this comprehensive literature assessment, the median life-cycle, non-combustion GHG emission values for each generation technology were used to estimate GHG emissions that are in addition to the ReEDS-calculated combustion-only CO_2 emissions shown in the left panel of Figure 3-29.

96. *http://www.nrel.gov/harmonization*

97. The life-cycle GHG emissions for natural gas-fired combustion technologies has recently become a topic of intense interest and debate. Two meta-analyses of available LCAs were published in 2014: O'Donoughue et al. [103] harmonized estimates for electricity generated using conventionally produced natural gas; Heath et al. [104] harmonized evidence for unconventional natural gas. Both support the prevailing view that, on average, life-cycle GHG emissions from natural gas-fired generators are half that of coal, though there could be cases with emissions much higher. Measurements in some natural gas production basins, e.g., [105, 106] suggest higher methane leakage rates than have typically been included in the harmonized LCAs. These have, however, only measured a few, small basins, and not enough evidence is available to develop a national average based on measurements. A 2014 synthesis of measurement evidence of methane leakage from natural gas systems [107] concludes that natural gas retains climate benefits over coal, even considering the available evidence from measurements. The *Wind Vision* report uses the available LCA literature to assign GHG emission estimates to each life-cycle stage. These assignments could be updated as new evidence becomes available.

The extensive literature demonstrates that, on a life-cycle basis, wind has among the lowest levels of GHG emissions of different energy technologies (Figure 3-30). As a result, when considering the full life-cycle, Figure 3-30 (right panel) shows that the *Study Scenario* is estimated to significantly reduce GHG emissions in the electric sector relative to the *Baseline Scenario*: 6% in 2020 (0.13 gigatonnes CO_2e), 16% in 2030 (0.38 gigatonnes CO_2e), and 23% in 2050 (0.51 gigatonnes CO_2e). Cumulative life-cycle GHG emissions are reduced by 12.3 gigatonnes CO_2e from 2013 to 2050 (14%). Life-cycle GHG reductions are larger in absolute terms than combustion-only CO_2 reductions.

These estimates suggest significant potential for wind energy in reducing GHG emissions, consistent with previous literature [1, 28].The foregoing analysis, however, does not consider two factors that may degrade to a degree the actual emissions savings from increased wind deployment. First, the GHG benefits of variable renewable generation may be eroded to a degree by the increased cycling, ramping, and partial loading required of conventional generators. Partial loading of fossil generators, for example, means operating those plants at less-efficient output levels. This creates a penalty for fuel efficiency and GHG emissions relative to optimally loaded plants. Though the analysis discussed here does not capture these effects, the difference implied by this omission is, in this case, expected to be modest. The reduction in GHG benefits can be significant when considering small, isolated systems with little geographic diversity of wind and few plants to offer balancing services, but the effects are much smaller in large systems—such as those analyzed here—with many conventional generators and considerable smoothing from geographic diversity [108, 109]. Recent studies have found that the GHG emissions benefits of wind energy are diminished by, at most, less than 10% [110, 111, 112,113]. In the largest and most sophisticated of these studies, Lew et al. [65] find that the emissions impact is negligible (less than 1%).

Second, economy-wide rebound and spillover effects can impact emissions reductions, especially when those rebound and spillover effects are affected by policy mechanisms.[98] The model used for the *Wind Vision* analysis focuses on the electric sector, and the analysis is intentionally policy-agnostic. This voids the opportunity for an assessment of economy-wide spillover or rebound effects. Other literature, however, has shown that spillover and rebound effects can impact GHG savings, as can the specific policy mechanisms used to support renewable energy deployment. In particular, there is general agreement that GHG savings will be greater and/or achieved at lower cost when met, at least in part, through economy-wide carbon pricing, and lower when met solely through sector-specific financial incentives for low-carbon technologies [48, 49, 50, 85, 114, 115, 116, 117, 118, 119]. Depending on the policies employed and related rebound and spillover effects, the GHG reductions estimated here may therefore over- or under-state actual emissions reductions associated with the wind deployment levels envisioned in the *Study Scenario*.

3.7.2 Economic Benefits of Wind Energy in Limiting Climate Change Damages

The economic benefits of wind energy due to limiting damages from climate change can be estimated through the use of a metric known as the social cost of carbon, or SCC. The SCC reflects, among other things, monetary damages resulting from the future impacts of climate change on agricultural productivity, human health, property damages, and ecosystem services [95, 96].The methodology for estimating the benefits from reduced GHG emissions involves multiplying the emissions reduction (on a life-cycle, CO_2eq basis) in the *Study Scenario* (relative to *Baseline Scenario*) in any given year by the SCC for that year, and then discounting those yearly benefits to the present.[99]

Estimating the magnitude and timing of climate change impacts, damages, and associated costs is challenging, especially given the many uncertainties involved [81, 84, 85, 86, 95, 96, 120, 121]. Models of climate response to GHG emissions and damage functions associated with that response are imperfect. Even when looking to events over the several decades leading up to 2013, such as the upward trend in damage costs associated with extreme environmental events [122], caution is necessary to separate causation from correlation [123]. In addition, because the majority of effects will be felt many decades and even centuries

98. As one example, if policies used to support wind development tend to decrease retail electricity prices, then customer incentives for energy efficiency will be muted, potentially reducing GHG savings. The opposite would be anticipated if retail electricity prices increase.

99. The discount rate varies for any individual calculation to be consistent with that assumed in the SCC estimate.

in the future, the choice of discount rate becomes a key concern when estimating the present value of future damages. This can, in turn, greatly influence the relative benefits and timing of alternative strategies to reduce carbon emissions [124, 125].

In part as a result, a number of widely ranging estimates of the SCC are available [85, 120, 126]. Key uncertainties about the SCC result from: (1) difficulties in estimating future damages associated with different climate-related causes, as well as uncertainties about the likelihood, timing, and potential impact of (nonlinear) tipping points; (2) the high sensitivity of the SCC to assumptions about growth in world population, gross domestic product, and CO_2 emissions; and (3) large differences in the present value of estimated damages depending upon choice of discount rate [120, 127, 128].

Though these uncertainties have led some to suggest possible improvements to SCC estimates [125, 129, 130, 131] or even to question the use of these estimates [128], U.S. government regulatory bodies now regularly use SCC estimates when formulating policy [97, 130]. Under Executive Order 12866,[100] U.S. agencies are required, to the extent permitted by law, to assess costs and benefits—even though these are considered difficult to quantify—during regulatory proceedings. To that effect, in 2010, the U.S. IWG on the SCC[101] used three integrated assessment models to estimate the SCC under four scenarios [95]. The IWG SCC reflects *global* damages from GHGs, and IWG recommends use of global damages. That approach is followed in the *Wind Vision*, recognizing that lower values are obtained if only damages within the United States are considered.[102] In 2013, IWG updated its estimates based on improvements in the integrated assessment models, which lead to an increase in SCC values [96]. IWG SCC estimates have been widely used in regulatory impact analyses in the United States, including in numerous proposed or final rules from the EPA, DOE, and others [97].

To reflect the inherent uncertainties, the IWG [96] has published four SCC trajectories (see Figure 3-31 for these four trajectories from 2010 to 2050). Three of the four trajectories are based on the expected value of the SCC (estimated by averaging the results of the three IWG models), assuming discount rates of 2.5%, 3%, and 5%.[103] A fourth trajectory represents a 95th percentile of the SCC estimates across all three models at the central 3% social discount rate. This 95th percentile case is intended to reflect a much less likely outcome, but one with a much higher than expected impact, e.g., due to more extreme temperature changes.[104]

Using the four IWG SCC estimates, Figure 3-32 shows the present value of the estimated global benefits of life-cycle GHG reductions from 2013 to 2050 from the *Study Scenario* (compared to the *Baseline Scenario*, and assuming no rebound or spillover effects). For the IWG central value case, discounted present-value benefits are estimated to be $400 billion. Across the three expected-value cases, benefits range from $85 billion (for the 5% discount rate case) to $640 billion (for the 2.5% discount rate case). The fourth case that accounts for the small possibility of more extreme effects results in a benefit estimate of $1,230 billion.[105,106]

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100. *http://www.archives.gov/federal-register/executive-orders/pdf/12866.pdf*
101. U.S. agencies actively involved in the process included the EPA and the Departments of Agriculture, Commerce, Energy, Transportation, and Treasury. The process was convened by the Council of Economic Advisors and the Office of Management and Budget, with active participation from the Council of Environmental Quality, National Economic Council, Office of Energy and Climate Change, and Office of Science and Technology Policy.
102. The IWG notes that a range of values from 7–23% should be used to adjust the global SCC to calculate domestic effects, but also cautions that these values are approximate, provisional, and highly speculative [95].
103. The use of this range of discount rates reflects uncertainty among experts about the appropriate social discount rate [95, 129].
104. Each of the integrated assessment models estimates the SCC in any given year by modelling the impact of CO_2 emissions in that year on climate damages over a multi-century horizon (discounted back to that year). The SCC increases over time because, as IWG explains, "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change" [96].
105. As suggested by the IWG, domestic benefits might be 7–23% of these global estimates [95].
106. Annual benefits reflecting the discounted future benefits of yearly avoided emissions are as follows: (1) low: $1.8 billion (2020), $7.0 billion (2030), $15.5 billion (2050); (2) central: $6.3 billion (2020), $22.8 billion (2030), $42.3 billion (2050); (3) high: $9.4 billion (2020), $32.9 billion (2030), $57.8 billion (2050); (4) higher-than-expected: $18.9 billion (2020), $69.7 billion (2030), $131.0 billion (2050) [2013$].

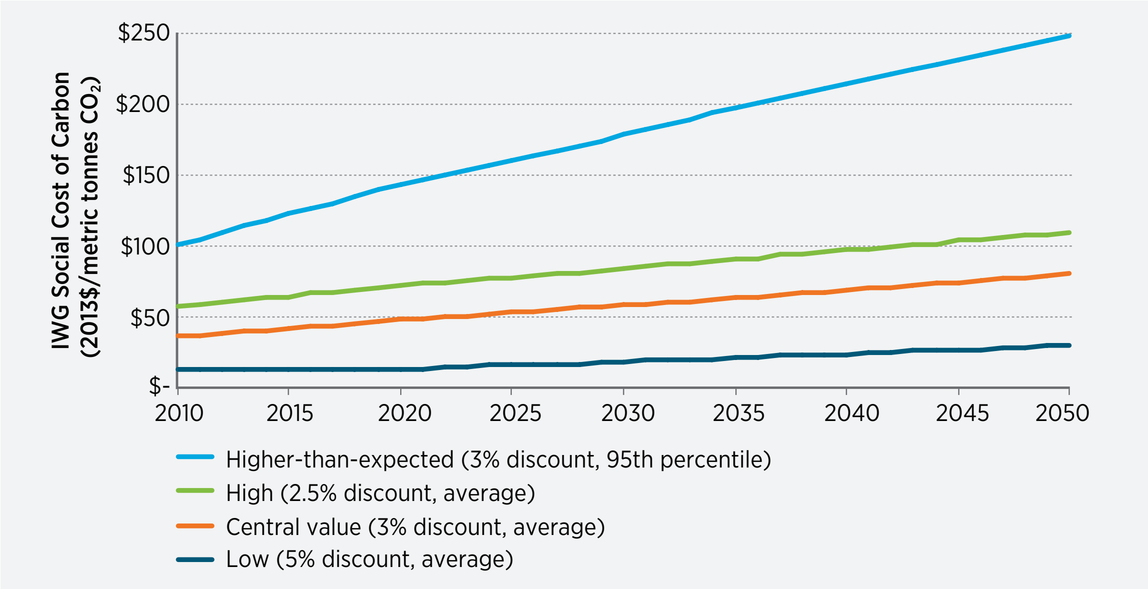


Figure 3-31. IWG social cost of carbon estimates

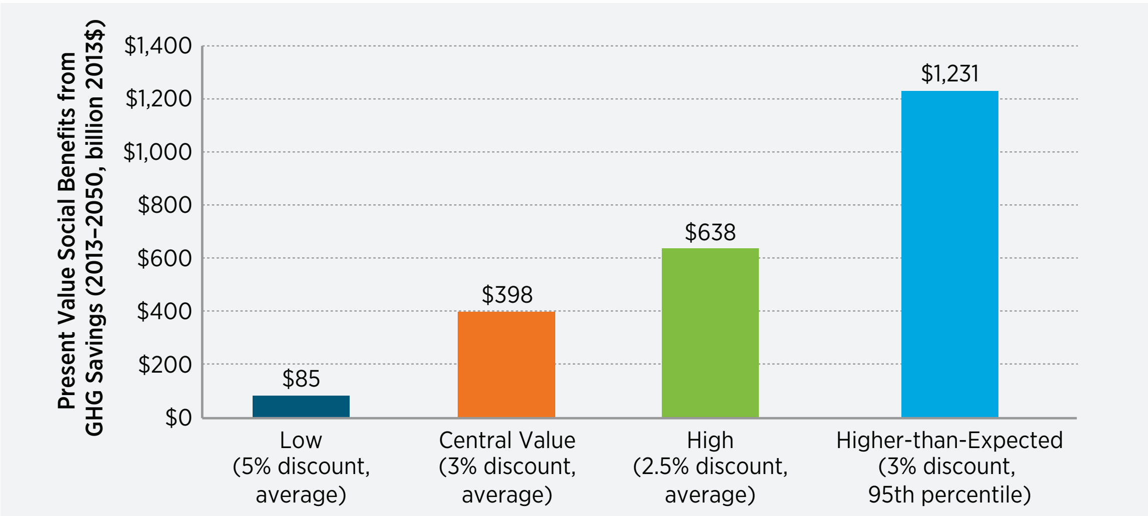


Figure 3-32. Estimated benefits of the *Study Scenario* due to avoided climate change damages

To put these figures in another context, the central value estimate represents a levelized global benefit of wind energy of 3.2¢/kWh of wind. Across the remaining three scenarios, the estimated GHG savings benefit ranges from 0.7¢/kWh of wind (low) to 5.2¢/kWh of wind (high) to 10¢/kWh of wind (higher than expected).[107]

107. These **levelized** impacts are calculated by dividing the discounted benefits by the discounted difference in total wind generation in the *Study Scenario* relative to the *Baseline Scenario.* When instead presented on a **discounted,** average basis (dividing discounted benefits by the non-discounted difference in total wind generation in the *Study Scenario* relative to the *Baseline Scenario*), the central value estimate is 1.5¢/kWh of wind; across the remaining three scenarios, the estimated benefit ranges from 0.3¢/kWh of wind (low) to 2.5¢/kWh of wind (high) to 4.7 ¢/kWh of wind.

Text Box 3-5.

Net Energy Requirements for Different Electric Generating Technologies.

Similar in concept to the assessment of life-cycle GHG emissions is the aim of a large body of literature to estimate on a life-cycle basis the amount of energy required to manufacture and operate energy conversion technologies or fuels (i.e., "input" energy). This concept helps inform decision makers on the degree to which various energy technologies provide a "net" increase in energy supply, and is often expressed in the form of either:

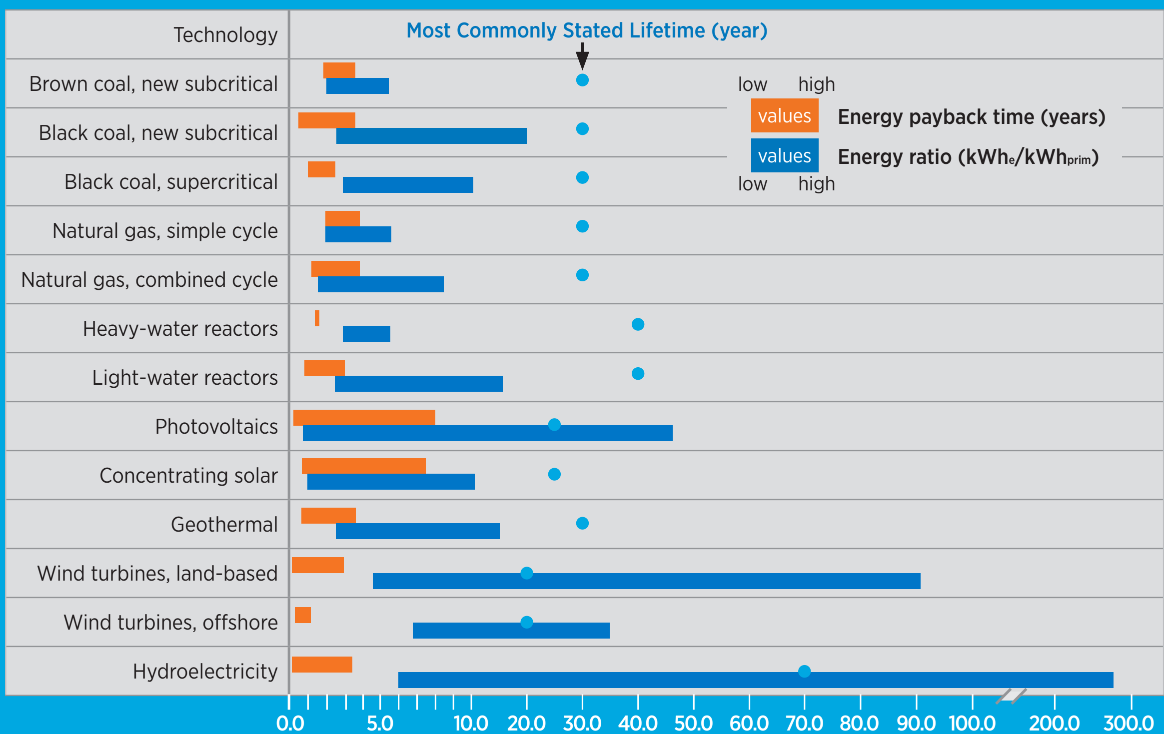
- **Energy ratio:** a ratio of the amount of energy produced by a technology over its lifetime to its input energy; or
- **Energy payback time:** the amount of time required to pay back the input energy given the amount of yearly energy produced.

This text box summarizes published estimates of these two metrics for wind technologies, in comparison to estimates for other electric generation technologies as presented in a recent report from the Intergovernmental Panel on Climate Change [132]. With regard to wind energy, 55 references reporting more than 130 net energy estimates were reviewed, using the same literature screening approach as for the review of life-cycle GHG emissions (see Appendix J).

Figure A presents a summary of the review. To be clear, these results are reported from studies that exhibit considerable methodological variability. Although previous work has identified several key issues that can influence results (e.g., [133, 134, 135]), the literature remains diverse and unconsolidated. Variability in the results for wind, for example, may in part be due to difference in the treatment of end-of-life modeling (e.g., recycling); assumed system lifetime and capacity factor; technology evaluated (turbine size, height); and whether turbine replacement is considered.

Notwithstanding these caveats, the results suggest that both land-based and offshore wind power have similar, if not somewhat lower, energy payback times as other technologies, with higher (especially at the high end) energy ratios. That is, wind energy performs relatively well in comparison to other electric generation technologies on these metrics, requiring roughly the same or even lower amounts of input energy relative to energy produced.

Figure A. Review of energy payback and energy ratios of electricity generating technologies



Note: Energy ratio is the ratio of energy produced by a technology over its lifetime to the input energy required to build the power generating technology. Energy payback time is the amount of time required to pay back the technology's input energy requirements given the amount of yearly energy produced

Source: Non-wind estimates from [132]; wind estimates based on literature review detailed in Appendix J.

3.8 Air Pollution Impacts

Using wind energy to offset the use of fossil generation brings potential public health and environmental benefits. The health, environmental, and ecosystem impacts of electricity supply are far reaching, with every energy source having some impact in terms of air pollutants, water pollutants, land use and degradation, and waste generation and disposal. A thorough review of all types of impacts is beyond the scope of the *Wind Vision*, but reviews can be found elsewhere [132, 136, 137, 138]. The *Wind Vision* analysis focuses on air pollutant emissions. This is because the costs to society of air pollutant emissions are significant, and are often much higher than some other environmental impacts of energy supply [132].

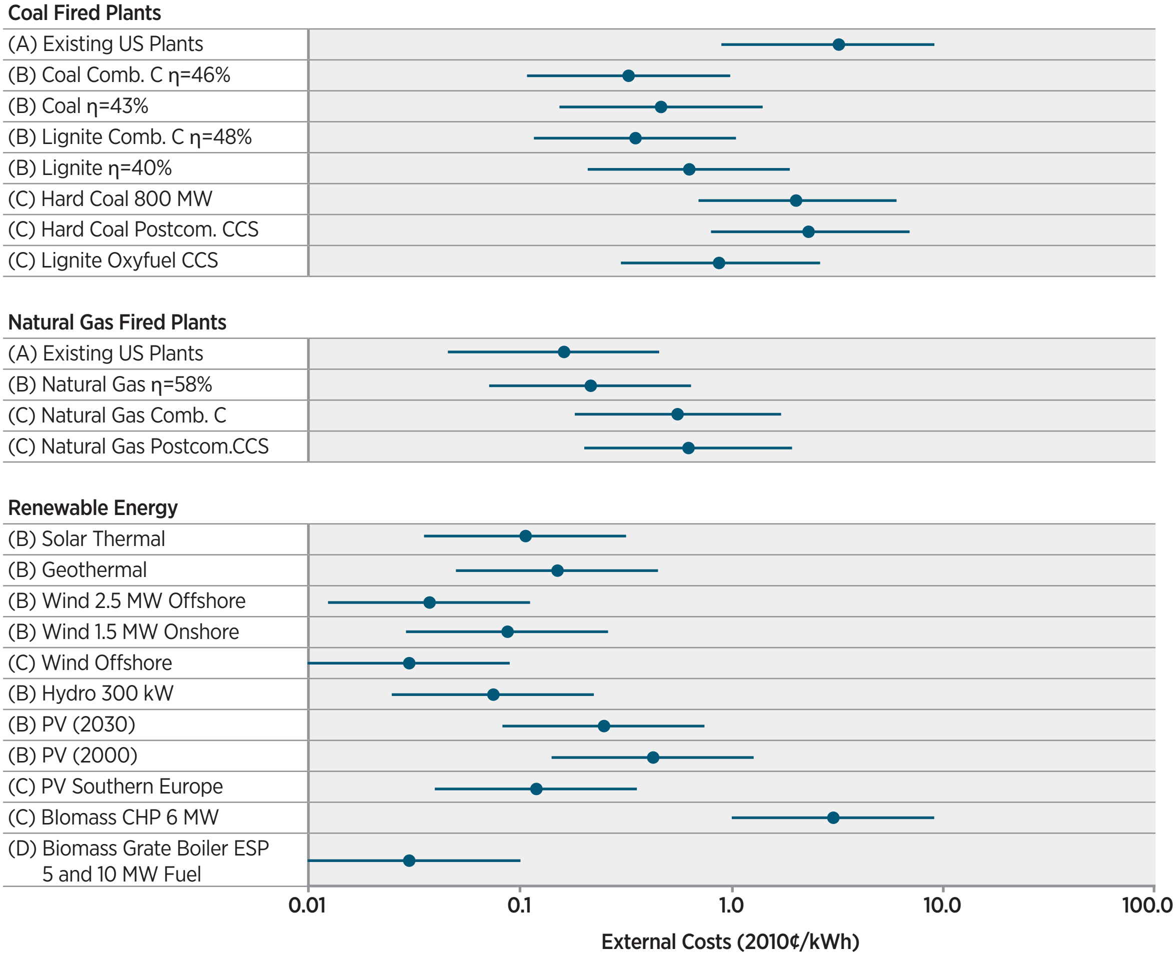
Turconi et al. [139] and Edenhofer et al. [132] reviewed published estimates of air pollutant emissions from electricity generation technologies. Emissions were considered across the life-cycle of each technology—from those associated with extraction and processing of fuels, to manufacture and construction of generation facilities, to operation of those facilities and their end-of-life decommissioning. In short, these meta-studies find consistent evidence that, on a life-cycle basis, wind has very low air pollutant emissions as compared to fossil fuels.

Estimating the impact of different energy technologies on the health of ecosystems and humans, and then quantifying those impacts in monetary terms, is challenging. Nonetheless, several major studies have been conducted in the European context to estimate these so-called "externalities" [146, 147, 148], and one prominent study for the United States was completed by the National Research Council (NRC) in 2010 [138]. Figure 3-33 displays the range of results from some of these studies, focusing on damages from air pollutants. It indicates a similar outcome as that for physical emissions: Health-related externalities are much lower for wind than almost any other electric generation technology.

The NRC study's [138] quantitative damage estimates were restricted to a limited set of air pollutants: particulate matter (PM) [both coarse particles (PM_{10}) and fine particles ($PM_{2.5}$)], SO_2, and NO_X. The monetized adverse effects from these emissions were primarily due to human health outcomes (premature mortality and morbidity), but also included consequences from decreased timber and agriculture yields, reduced visibility, accelerated degradation of materials, and reductions in recreation services. Damages were evaluated from the operation of combustion technologies; for renewable energy technologies, externalities were only discussed qualitatively. The NRC acknowledged significant uncertainty in its assessment, but concluded that the estimated damages should be considered underestimates of true damages given that not all impact pathways were considered.[108] Notwithstanding these caveats, NRC estimated that, in 2005, the emissions from 406 U.S. coal-fired power plants caused aggregate damages of $62 billion (or 3.2¢/kWh) in 2007$, primarily from exposure to PM created from SO_2 emissions [138]. Pollution damages from gas-fueled plants tend to be substantially lower than those from coal plants; the NRC's sample of 498 gas facilities produced damages in 2005 estimated at $740 million, or 0.16¢/kWh.

More recent research suggests that the NRC study may have substantially understated the health and environmental damages of air pollution emissions. Since the publication of the NRC study in 2010, updated damage estimates have been released [140] that were on average 2–3 times higher than the original values in NRC. Researchers at the EPA have also estimated far greater damages from electricity generation. Fann et al. [141] estimate damages from power plant SO_2 emissions alone to be equivalent to $280 billion in 2005 and $133 billion in 2016 (2010$) in the United States. Machol and Rizk [142], following a similar methodology as developed by Fann et al. [143], estimate total damages from fossil fuel electricity in the United States to equal $361.7–$886.5 billion (2010$) annually. Similarly, Thompson et al. [144] apply EPA-based methods to estimate sizable heath co-benefits from carbon mitigation (see also [145]). The EPA, meanwhile, has applied the methodology presented in Fann et al. [141, 143] on a number of occasions to estimate the benefits of emission reductions from power generation. As a result, the EPA's Clean

108. Non-quantified impacts included heavy metal releases; radiological releases; waste products, land use, and water quality impacts associated with power and upstream fuel production; noise; aesthetics; and others.



Notes: Figure utilizes a logarithmic scale and is derived from Edenhofer et al. [116]. More specifically, the figure summarizes the results of four prominent externalities studies conducted worldwide ((A) NRC 2010 [138]; (B) Krewitt and Schlomann 2006 [146]; (C) Preiss 2009 [147]; Ricci 2010 [148]; (D) Sippula et al. 2009 [149]). Uncertainty is assumed to be a factor of three. Costs are in 2010 ¢/kWh. Abbreviations: CCS = carbon capture and storage; Comb.C = combined cycle; Postcom = post-combustion; η = efficiency factor; PV = photovoltaic; CHP = combined head and power; ESP = electrostatic precipitators.

Figure 3-33. Range of health-related costs from air pollutant emissions from electricity generation technologies

Power Plan [92] and other regulatory actions now include larger estimates of the benefits from emissions reductions than those in the NRC study.

This section summarizes the analysis methods used to quantify the air pollution benefits of achieving the *Wind Vision Study Scenario* (see Appendix L for further details on these methods and underlying assumptions). It then presents estimates for the potential air pollutant emissions reductions from the *Study Scenario*, relative to the *Baseline Scenario*, and assesses the health and environmental benefits associated with those potential emissions reductions.[109] Two methods are used to quantify the reduced health and environmental damages of the *Study Scenario* in monetary terms, resulting in three different monetary estimates (EPA includes a "low" and a "high" case). In all cases, only a subset of the potential air pollution benefits of wind energy are evaluated, focused specifically on impacts from SO_2, NO_X, and $PM_{2.5}$ emissions. A brief discussion of an alternate approach to quantifying the air pollution benefits of the *Study Scenario*

109. This section evaluates the impacts of the *Central Study Scenario* and *Baseline Scenario* only. See Section 3.1.3 for detailed explanation of the scenarios. The ranges presented in this section are driven by the range of parameters evaluated and not by the range of scenario results.

is also provided, one in which the benefits derive not from reduced health and environmental damages but instead from reducing the cost of meeting more stringent air pollution regulations.[110]

3.8.1 Methods

This section summarizes the basic methodology used to estimate potential air pollution benefits for the *Study Scenario*. Appendix L more fully describes the assumptions, data sources, and calculations used.

Health benefits are realized when exposure to pollutants is reduced. The estimates used in the *Wind Vision* to calculate these benefits depend on three critical steps: (1) estimation of pollutant emissions from power plants; (2) modeling the atmospheric dispersion and secondary reaction of those pollutants; and (3) estimation of population exposure to primary and secondary pollutants, the exposure-response relationship for specific outcomes (i.e., morbidity or premature mortality), and the monetary quantification of those outcomes.

For step (1), pollutant emission estimates are developed for both the *Study Scenario* and the *Baseline Scenario*, and are a function of the product of ReEDS generation outputs (MWh, by generation type and vintage) for both scenarios with assumed emission rates (grams/MWh, by generation type and vintage). The stringency of future air pollution regulations impacts emissions rates (and generation investment and dispatch decisions), and, therefore, also affects estimates of the air pollution benefits of wind energy. For the purpose of this analysis, initial year-one emission rates were estimated based on reported historical plant-level emission rates for SO_2, NO_X, and $PM_{2.5}$, and aggregated to each type of power plant in ReEDS and to each of the 134 ReEDS regions across the contiguous United States. Emission rates were updated over time as plants retire, under the assumption that the Mercury and Air Toxics Standards (MATS) are implemented in 2016, and as limited by the Cross-States Air Pollution Rule (CSAPR) starting in 2014. The MATS requirements, in particular, significantly limit SO_2 emission rates.

As discussed in Section 3.7, increased reliance on variable wind generation will require fossil plants to operate in a more flexible manner, potentially increasing the air pollution emissions from those plants on a per-MWh basis (e.g., [150]). This may create an emissions penalty relative to a fully loaded plant [102]. Though the *Wind Vision* analysis does not capture these effects, research results suggest that emissions are reduced by wind energy, even after accounting for any emissions penalties [73, 109, 151]. In a 2013 analysis of this issue, Lew et al. [65] find that accounting for emissions impacts related to increased coal plant cycling slightly improves (by 1–2%) the avoided NO_X emissions of wind and solar relative to the avoided emissions, based on an assumption of a fully loaded plant. This result is driven by average emissions rates of coal plants decreasing during times when the plants are part-loaded. Conversely, that study finds that accounting for cycling impacts on SO_2 emissions reduces the avoided SO_2 emissions of wind and solar by 3–6% relative to avoided emissions based on an assumption of a fully loaded plant. A similarly detailed analysis of avoided NO_X and SO_2 emissions with wind and solar in the mid-Atlantic region reports more substantial emissions penalties, in part due to frequent cycling of supercritical coal plants [73]. In both cases, however, the impacts are not large enough to dramatically alter the basic results reported here. Further research is warranted to quantify emissions penalties related to cycling and to identify strategies for mitigating those emissions.

For steps (2) and (3), this analysis depends on previous estimates of pollutant dispersion and reaction, exposure and response, and monetary damage assessment. Two different approaches are used, resulting in three estimates. The first method is as applied by the EPA, most recently in its 2014 Regulatory Impact Analysis for the Clean Power Plan [92]. EPA applied two different sets of estimates for the average benefit per ton of reduced SO_2, NO_X, and $PM_{2.5}$ emissions from power plants across three broad regions on the United States, resulting in an "EPA-low" and an "EPA-high" estimate of the benefits of the *Study Scenario*. As an alternative to the EPA estimates, we use benefit-per-ton estimates from the Air Pollution Emission Experiments and Policy analysis model version 2 (originally APEEP, now abbreviated AP2), also for SO_2, NO_X, and $PM_{2.5}$. The AP2 model was used in the 2010 NRC study [138] discussed previously,

110. Basic economics demonstrate it is more cost-effective to address unpriced environmental effects directly through, e.g., environmental taxes or cap-and-trade, rather than through technology- or sector-specific incentives [117]. Also, conceptually, additional welfare benefits from pollution reduction can only occur if these direct environmental regulations have not already been established at the optimal welfare maximizing level [50, 101, 102].

as well as by Siler-Evans et al. [99] to estimate the benefits of wind and solar energy in reducing the health and environmental damages from existing power plants from 2009 to 2011.[111]

Both EPA (low and high) and AP2 develop benefit-per-ton estimates by combining air quality modeling with exposure modeling, exposure-response relationships, and monetary damage estimates. There are, however, significant differences in air quality modeling methodology between EPA and AP2; in the assumed relationship between exposure and impact between EPA-low, EPA-high, and AP2; and in the specific health and environmental impacts assessed. The result is three distinct monetary estimates of the reduced air pollution damages associated with the *Study Scenario* relative to the *Baseline Scenario*.

In addition to estimating the air pollution benefits of the *Study Scenario*, this analysis also presents an alternate approach to quantifying air pollution benefits. This alternative approach assumes the presence of binding cap-and-trade programs limiting air pollution, and focuses on the ability of wind to potentially offset the cost of meeting those air pollution regulations. Details are provided in the next section.

Overall, the basic approaches described above have been commonly used to quantify the benefits of renewable energy. Siler-Evans et al. [99], for example, used AP2 to estimate the health and environmental benefits of wind and solar energy. Additionally, to account for the possibility of binding cap-and-trade programs, Siler-Evans et al. [99] developed a benefit estimate in which wind generation does not decrease air pollutant emissions for capped pollutants in locations where the cap-and-trade governs, but rather principally avoids costs associated with the implementation of other pollution control strategies. Several studies [98, 100, 101] also quantify the benefits of renewable energy due to reduced air pollution damages. Heeter et al. [153] find that state-level studies of the benefits and costs of RPS policies sometimes use either damage-based or compliance cost-based approaches to quantify air pollution impacts. Finally, Bolinger and Wiser [154] report that electric utilities sometimes consider future air pollution regulations and associated compliance costs when selecting among alternative energy resource portfolios.

3.8.2 Air Pollution Benefits of Wind Energy

Achieving the *Study Scenario* will provide air pollution benefits, relative to the *Baseline Scenario* in which no additional growth in wind capacity is assumed to occur. Considerable uncertainty exists about the magnitude of these benefits, however, including uncertainties driven by the representation of future air pollution regulations, air pollutant transport assumptions that connect emissions to concentrations, assumptions about the future such as population and income growth, and the translation of emission concentrations to impacts and monetary quantification.

Figure 3-34 illustrates potential electric-sector air emissions for the *Study Scenario* and *Baseline Scenario*. On a national basis, emissions of SO_2, NO_X, and $PM_{2.5}$ are shown to be lower in the *Study Scenario*. Specifically, on a cumulative basis, the *Study Scenario* has estimated emissions reductions from 2013 to 2050 (relative to the *Baseline Scenario*) of 2.6 million metric tons of SO_2, 4.7 million metric tons of NO_X, and 0.5 million metric tons of $PM_{2.5}$.

An important feature of the data in Figure 3-34 is the precipitous drop of SO_2 emissions from 2010 through 2016 in both scenarios. This decline is due to the assumed implementation of MATS, which requires that all (new and existing) coal plants meet acid gas (such as SO_2 or hydrogen chloride), PM and other pollutant emission-rate limits. Note that MATS is modeled outside of ReEDS, as a post-processing step; see Appendix L for further details. Aside from this dramatic change to SO_2 emissions, emissions of all three pollutants are relatively stable until 2040, when they are projected to decline by half over the course of a decade as a result of a drop in coal generation. This is due in part to additional coal plant retirements.

111. One important value used to generate the monetary benefit estimates is the value of a statistical life assumed for mortality damages. The AP2 analysis assumes that the cost of premature deaths is $6 million (in 2000$), regardless of age, which is consistent with the value used by the NRC [138] and Siler-Evans et al. [99]. This cost is also near the mid-point of available literature estimates, and is in line with value of statistical life assumptions used by the EPA in regulatory impact analyses (e.g., [152]). The EPA-based analysis assumes that the cost of premature deaths is $6.3 billion (in 2000$, adjusted for currency inflation and income growth). Note that the EPA provides benefit estimates that increase in the future with population and income growth. For the *Wind Vision*, damages from AP2 are scaled over time based on U.S. Census Bureau population projections and are based on per capita income growth projections used by EIA [4], using an elasticity of the value of statistical life to income growth consistent with NRC [138].

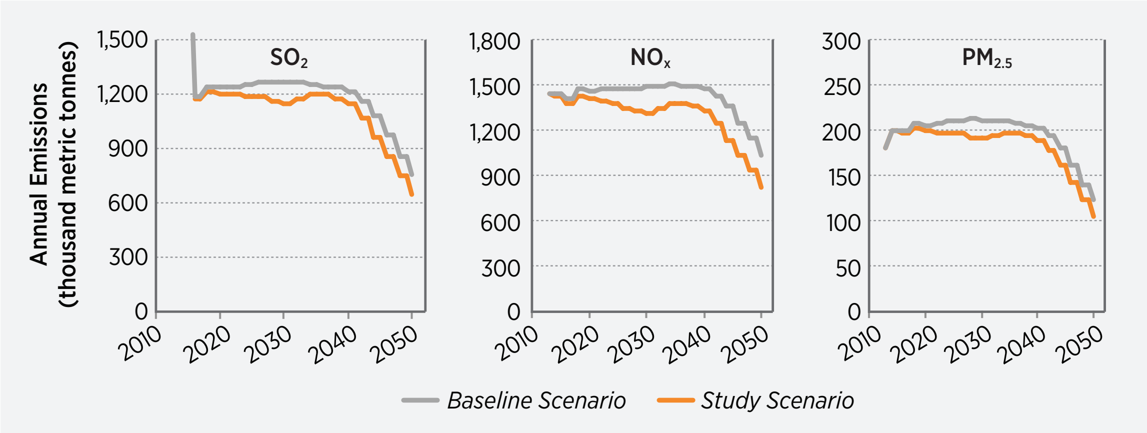


Figure 3-34. Electric sector SO_2, NO_X, and $PM_{2.5}$ emissions in *Study* and *Baseline Scenarios*

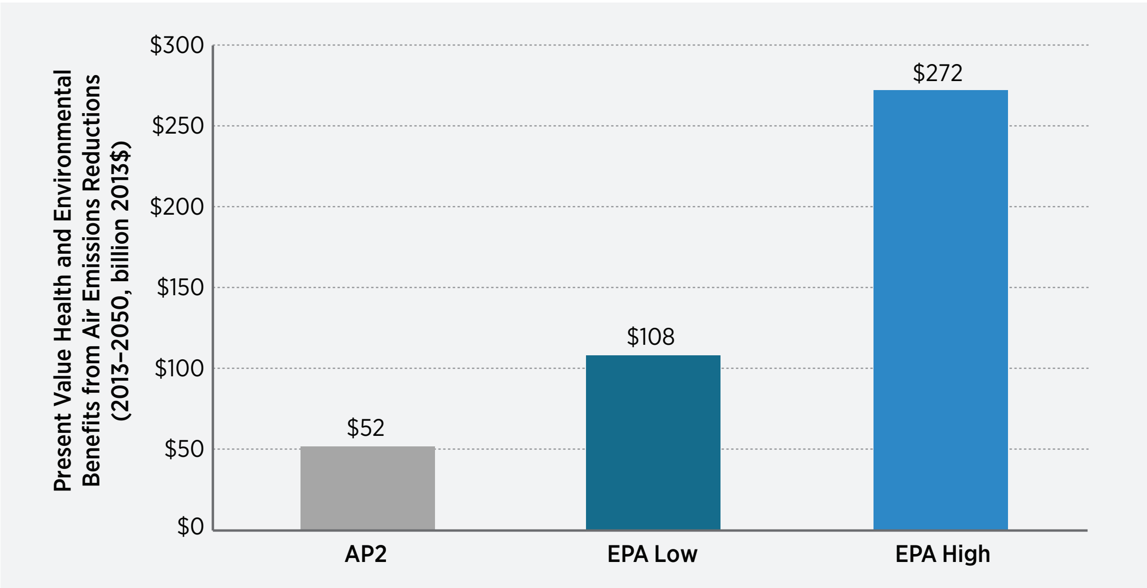


Figure 3-35. Estimated benefits of the *Study Scenario* due to reduced SO_2, NO_X, and $PM_{2.5}$ emissions

Based on these SO_2, NO_X, and $PM_{2.5}$ emissions reductions, Figure 3-35 summarizes the estimated present value of the air pollution benefits of the *Study Scenario* (relative to the *Baseline Scenario*), applying the methods described previously and detailed in Appendix L. Discounted, present value air pollution benefits are estimated at $52 billion, $108 billion, and $272 billion under AP2, EPA-low, and EPA-high respectively (3% discount rate, 2013–2050).[112,113] To put these figures in another context, they are equivalent to an average levelized benefit of 0.4¢/kWh of wind, 0.9¢/kWh of wind, and 2.2¢/kWh of wind.[114]

The range of benefit estimates that exists between EPA-low ($108 billion) and EPA-high ($272 billion) is due to uncertainty in the epidemiology that connects pollution exposure to health consequences. EPA-low is based on research summarized in Krewski et al. [155] and Bell et al. [156], whereas EPA-high is based on research presented in Lepeule et al. [157] and Levy et al. [158]. Both sets of epidemiology research have different strengths and weakness and EPA does not favor one result over the other; see Appendix L for more information.

The lower AP2 estimate ($52 billion) relies on epidemiology assumptions consistent with EPA-low, but applies different air quality and meteorological modeling techniques. This drives the differences between AP2 and EPA-low. Both sets of air quality modeling techniques have advantages and disadvantages vs. one another; a description of these differences is provided in Appendix L. One difference between EPA and AP2 relates to the specific health and environmental impacts considered. In this instance, however, the differences would—all else being equal—deflate the EPA estimates relative to AP2. In particular, both AP2 and EPA consider many of the health (mortality and morbidity) consequences of SO_2, NO_X, and $PM_{2.5}$ emissions, but the specific impact pathways differ somewhat. As one example, AP2 includes primary pollutant exposure as well as secondary exposure to ozone during the ozone season and to secondary $PM_{2.5}$ that derives from directly emitted SO_2 and NO_X. EPA, on the other hand, does not include primary exposure to SO_2 and NO_X, focusing instead entirely on secondary particulate matter and ozone exposure. Unlike EPA, AP2 also includes consequences from decreased timber and agriculture yields, reduced visibility, accelerated degradation of materials, and reductions in recreation services. These differences in quantified impact pathways imply that the AP2 results are somewhat more inclusive. The majority of the damages derive from mortality and morbidity from primary and secondary $PM_{2.5}$ and ozone exposure [140, 159], however, and the differences between AP2 and EPA on this score are minor. Further discussion of the differences between AP2 (and, previously, APEEP) and EPA are highlighted in Fann et al [141], Machol and Rizk [142], and Brown et al. [160].

Table 3-5 provides additional detail on these monetary estimates over the entire 2013–2050 analysis period and, for the EPA-derived figures, also lists in some detail the estimated health (mortality and morbidity) benefits from the *Study Scenario*. Overall, the majority of the monetary benefits derive from reduced levels of premature mortality associated with the *Study Scenario*. Focusing on the EPA-low estimate, because it is in the middle of the range of estimates presented, the *Study Scenario* is found to result in nearly 22,000 fewer premature mortalities than the *Baseline Scenario* over the 2013–2050 timeframe. Though the monetary benefit is smaller, a large number of additional morbidity benefits are

112. Though the emission rate estimates developed outside of the ReEDS model and applied in this section include a representation of MATS, the ReEDS generation estimates do not include MATS. They instead include a representation of a SO_2 cap-and-trade system; the core ReEDS results were not updated to include MATS because MATS was under legal challenge at the time the scenario approach was finalized. Preliminary analysis suggests that the *Wind Vision* air quality benefit estimates presented here would increase by at least 20–30% if ReEDS were updated to account for the new regulatory environment, with potentially even-greater benefits depending on how the new environment is represented. The benefit increase would be seen as the SO_2 cap-and-trade system would become non-binding in most years due to the emission controls required by MATS. On the other hand, representation of another recent proposed change to the regulatory environment, the EPA's Clean Power Plan, would likely reduce future estimates of air quality benefits. At the time of this publication, the status of MATS remains in legal review pending a decision by the U.S. Supreme Court. See Appendix L for more details.

113. Annual benefits reflecting yearly avoided emissions are as follows: (1) **AP2:** $0.9 billion (2020), $4.3 billion (2030), $4.8 billion (2050); (2) **EPA-low:** $2.4 billion (2020), $8.3 billion (2030), $10.1 billion (2050); (3) **EPA-high:** $5.6 billion (2020), $20.3 billion (2030), $27.4 billion (2050) [2013$].

114. These **levelized** impacts are calculated by dividing the discounted benefits by the discounted difference in total wind generation in the *Study Scenario* relative to the *Baseline Scenario.* When instead presented on a **discounted,** average basis (dividing discounted benefits by the non-discounted difference in total wind generation in the *Study Scenario* relative to the *Baseline Scenario*), the values are 0.2¢/kWh of wind, 0.4¢/kWh of wind, and 1.0¢/kWh of wind.

Table 3-5. Accumulated Emissions, Monetized Benefits, and Mortality and Morbidity Benefits over 2013–2050 for the *Study Scenario* Relative to the *Baseline Scenario*

Impacts	SO_2	NO_X	$PM_{2.5}$	Total
Emissions Reductions				
Central Study Scenario air pollution reduction (million metric tonnes)	2.6	4.7	0.5	—
Total Monetized Benefits (Present Value)				
EPA-low benefits (billion 2013$)	71	28	9	108
EPA-high benefits (billion 2013$)	174	78	21	272
AP2 benefits (billion 2013$)[a]	24	19	8	52
EPA Total Mortality Reductions				
EPA-low mortality reductions (count)	14,400	5,500	1,900	21,700
EPA-high mortality reductions (count)	29,100	15,200	4,300	48,700
EPA Morbidity Reductions from Primary and Secondary $PM_{2.5}$ Impacts				
Emergency department visits for asthma (all ages)	7,000	2,200	900	10,100
Acute bronchitis (age 8–12)	18,800	5,500	2,500	26,800
Lower respiratory symptoms (age 7–14)	242,200	69,900	31,900	344,000
Upper respiratory symptoms (asthmatics age 9–11)	383,000	111,600	45,600	540,200
Minor restricted-activity days (age 18–65)	9,118,000	2,685,800	1,243,000	13,046,600
Lost work days (age 18–65)	1,525,800	462,900	2,040,008	2,192,700
Asthma exacerbation (age 6–18)	858,800	104,300	47,700	1,010,800
Hospital admissions, respiratory (all ages)	5,000	1,400	600	7,000
Hospital admissions, cardiovascular (age > 18)	5,400	1,800	700	7,900
Non-fatal heart attacks (Peters et al. 2001)	17,700	5,400	2,300	25,300
Non-fatal heart attacks (pooled estimates—4 studies)	2,000	600	200	2,800
Morbidity Reductions from NO_X → Ozone Impacts				
Hospital admissions, respiratory (ages > 65)	—	9,200	—	9,200
Hospital admissions, respiratory (ages < 2)	—	2,800	—	2,800
Emergency room visits, respiratory (all ages)	—	3,800	—	3,800
Acute respiratory symptoms (ages 18–65)	—	5,882,000	—	5,882,000
School loss days	—	2,459,600	—	2,459,600

Note: Monetized benefits are discounted at 3%, but mortality and morbidity values are simply accumulated over the 2013–2050 time period. EPA benefits derive from mortality and morbidity estimates based on population exposure to direct emissions of $PM_{2.5}$ and secondary $PM_{2.5}$ (from SO_2 and NO_X emissions), as well as ozone exposure from NO_X emissions during the ozone season (May–September). Primary and secondary $PM_{2.5}$ effects account for approximately 90% of the mortalities and monetized benefits in both the high and low cases.

a. AP2 benefits are derived from mortality and morbidity estimates based on population exposure to direct emissions of $PM_{2.5}$, SO_2 and NO_X, and secondary $PM_{2.5}$ (from SO_2 and NO_X emissions), as well as ozone exposure from NO_X emissions during the ozone season (May–September). AP2 benefits also include consequences from decreased timber and agriculture yields, reduced visibility, accelerated degradation of materials, and reductions in recreation services.

also associated with the *Study Scenario*, as detailed in Table 3-5. For example, the *Study Scenario* is estimated to lead to ~41,000 fewer visits to the emergency department or hospital due to cardiovascular, respiratory, or asthma symptoms. The improved air quality in the *Study Scenario* is also estimated to result in ~2.2 million fewer lost work days.

Under the EPA-low case, 66% of estimated monetary benefits are derived from reductions in SO_2 emissions. Reductions in NO_X emissions account for 26% of the monetary benefits in the EPA-low case. Reductions in direct $PM_{2.5}$ emissions account for 8% of the benefits.

Consistent with the results from Siler-Evans et al. [99] and NRC [138], a large majority (>95%) of these health benefits are found to be concentrated in the eastern half of the United States, especially in areas where air pollution from coal plants predominates. Benefits in the western United States are limited due, in part, to lower overall emissions in those areas and to lower population densities.

As noted earlier, there is an alternate approach to valuing emission reductions in the case that binding cap-and-trade regulations exist. This approach reflects the fact that the design of air pollution regulations can impact not only the size but also the nature of the benefit derived from wind energy. In particular, when cap-and-trade programs are used to limit air pollution (as under the Clean Air Interstate Rule and CSAPR for SO_2, NO_X, and in some regions of the United States), and if those caps are strictly binding over time, increased wind energy may not reduce capped pollution emissions because the potential avoided emissions from wind may be offset by increases in emissions elsewhere as allowed under the cap [99, 101]. In this case, the benefits of increased wind energy derive not from reduced health and environmental damages, but instead from reducing the cost of complying with the air pollution regulations, as determined by pollution allowance prices.[115]

Though cap-and-trade programs currently exist in various regions of the United States for both SO_2 and NO_X, those programs have not been fully binding [162, 163]. Assessment of the *Study Scenario* and *Baseline Scenario* suggests that the CSAPR caps are unlikely to be strongly binding in the presence of MATS. The benefits of the *Study Scenario,* therefore, are not estimated from the perspective of reducing pollution regulation compliance costs. This alternative valuation approach is provided, however, because it is possible that future national or regional cap-and-trade regulations could impact the size and nature of the benefits from the *Study Scenario*. Whether any such resulting benefits are lower or higher than those health and environmental benefits presented here would depend on the stringency of the presumed cap and the resulting projected cost of pollution allowances. Due to a lack of ability to forecast the presence of future regulations and their stringency, this valuation approach is not applied here. With MATS, it is less likely that a binding cap-and-trade program for SO_2 emissions would be established in future years. For comparison purposes, however, note that EPA-estimated SO_2 allowance prices under the CSAPR (before MATS was proposed) [164] were roughly $1/40^{th}$ the monetized health benefits value estimated in EPA [92], and that historical SO_2 and NO_X allowance prices have similarly been well below health-based estimates. As such, it is possible under binding cap-and-trade policies that the air emissions benefits of wind energy would be lower than otherwise presented earlier in this section.

Overall, the air pollution benefits of the *Study Scenario*, relative to the *Baseline Scenario* in which no new wind is added, are estimated to be sizable but uncertain. The range presented here of \$52–\$272 billion reflects some, but not all, of that uncertainty, as discussed in more depth in EPA [92]. At the same time, the health and environmental impact pathways analyzed here include only a subset of the impacts associated with SO_2, NO_X, and $PM_{2.5}$, and exclude any benefits associated with reductions in heavy metal releases, radiological releases, waste products, water quality impacts, and many others. If these additional impact pathways were able to be quantified, benefits estimates would increase.[116]

115. Pollution allowance prices represent the marginal cost of complying with a cap-and-trade program. These prices embed the cost of reducing air emissions, whether through the installation of pollution control technologies, fuel switching, or altered generation dispatch. Under a binding pollution cap, wind energy effectively reduces these costs by offsetting fossil generation and helping to meet the emissions cap. Thus, pollution allowance prices may be used to estimate the savings of not needing to pay for compliance.

116. The subset of benefits analyzed here likely represents the majority of the value, because reductions in premature mortality have a high valuation relative to other potential benefits and are strongly associated to reductions to ambient $PM_{2.5}$ concentrations (i.e., linked to reductions in SO_2, NO_X, and $PM_{2.5}$ emissions).

3.9 Water Usage Reduction

Water usage is evaluated based on two key metrics: withdrawal and consumption. Water withdrawal is the amount of water removed from the ground or diverted from a water source for use, but then returned to the source, often at a higher temperature; water consumption is the amount of water that is evaporated, transpired, incorporated into products or crops, or otherwise removed from the immediate water environment [165]. The U.S. electric sector is the largest *withdrawer* of freshwater in the nation; it accounted for 41% of all withdrawals in 2005 [165]. Freshwater *consumption* from the electric sector represents a much smaller fraction of the national total (3%), but can be regionally important [166, 167].

The primary water demand for the electric sector, both withdrawal and consumption, is for plant cooling. Approximately 80% of the electricity generated in the United States uses a thermodynamic cycle that requires water for cooling [168]. Consequently, the electricity sector both impacts and is highly dependent on water resources [169, 170, 171, 172, 173]. Power plants have sometimes been forced to curtail generation or shut down due to water-related restrictions, in some cases creating electric reliability challenges [174, 175].

The future development of the electric sector will be influenced by water availability, which can affect what types of power plants and cooling systems are built and where those plants are sited. Some proposed power plants have been canceled or had to change locations or cooling systems as a result of water-related restrictions [174]. Water-related operational and siting vulnerabilities could be exacerbated by future changes in the climate, which could alter the spatial and temporal distribution of freshwater resources, water temperatures, and power plant efficiencies [86, 175].

Operational water use requirements can vary greatly depending on fuel type, power plant type, and cooling system, with wind power requiring the lowest amount of water [176]. Figure 3-36 highlights water withdrawal and consumption rates for a variety of power plant types and cooling systems. As shown, thermal power plants using once-through cooling withdraw more water per MWh of electricity than do plants using recirculating cooling systems. Once-through cooling has lower water consumption demands, however, than recirculating systems. Dry cooling can be used to reduce both water withdrawal and consumption for thermal plants, but at a cost and

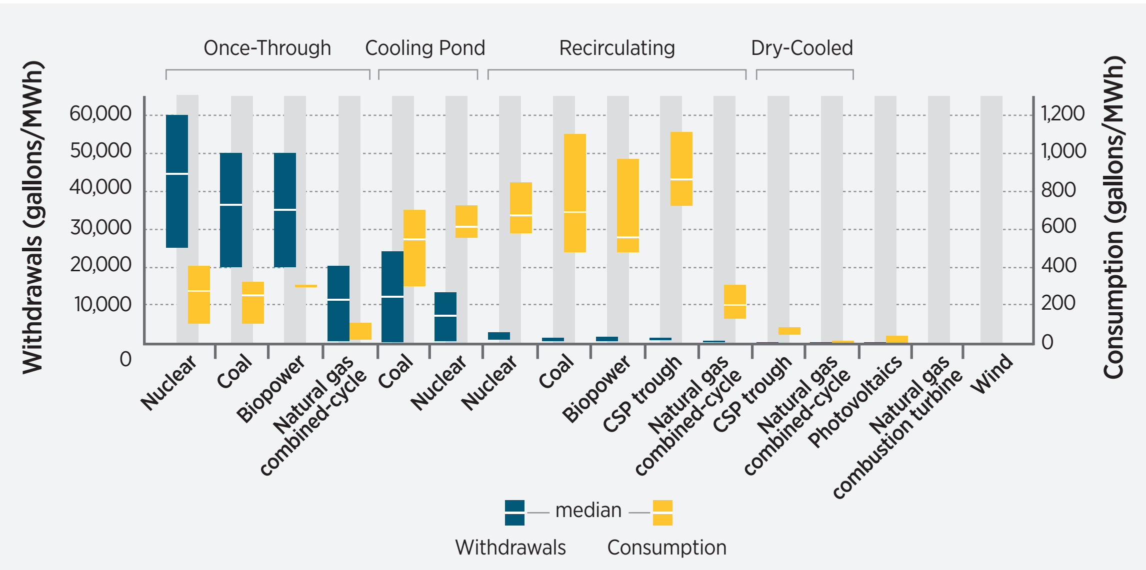


Figure 3-36. Water use rates for various types of power plants

efficiency penalty [177]. Non-thermal renewable energy technologies, such as wind and PV, do not require water for cooling and thus have very low water use intensities. Wind power plants require effectively no water for operations, while PV can use a relatively small amount, primarily for washing panels.

In addition to water required for plant cooling and other operations, water may also be needed in the fuel cycle, in equipment manufacturing, and in construction [178, 179]. On a life-cycle basis, thermo-electric water withdrawals and consumption during plant operations are orders of magnitude greater than these other demands [179]; as such, this section focuses on operational water requirements. However, as discussed in Averyt et al. [174], these additional fuel-cycle water demands can have important water quality implications due to, for example, water used in mining, coal washing, and hydraulic fracturing.

Given its low water use intensity, wind energy has the potential to reduce water impacts and water-related vulnerabilities in the U.S. electric sector, potentially providing economic and environmental benefits. Some states (e.g., California, New York) have already proposed measures to reduce the water intensity of the electricity produced in their states (California State Lands Commission 2006; New York State Department of Environmental Conservation 2010). The EPA has also invoked the Clean Water Act to propose various measures to limit the impacts of thermal power plant cooling on aquatic habitats [180]. To the extent that wind deployment can reduce electric sector water demands, it might also reduce the cost of meeting future policies intended to manage water usage.

This section evaluates the potential operational water withdrawal and consumption reductions associated with the *Study Scenario* compared to the *Baseline Scenario*.[117] National water impacts were evaluated, including by fuel and cooling system type. Because water resources are managed locally and regional trends can differ substantially from national trends, regional water impacts are also presented. Finally, the potential economic and environmental benefits of water use reductions are explored.

3.9.1 Wind Energy Reduces National Water Usage[118]

Meeting the wind deployment levels of the *Study Scenario* is estimated to reduce national electric sector water use, both in comparison to recent use and in comparison with the *Baseline Scenario* in which no additional growth in wind capacity is assumed to occur.

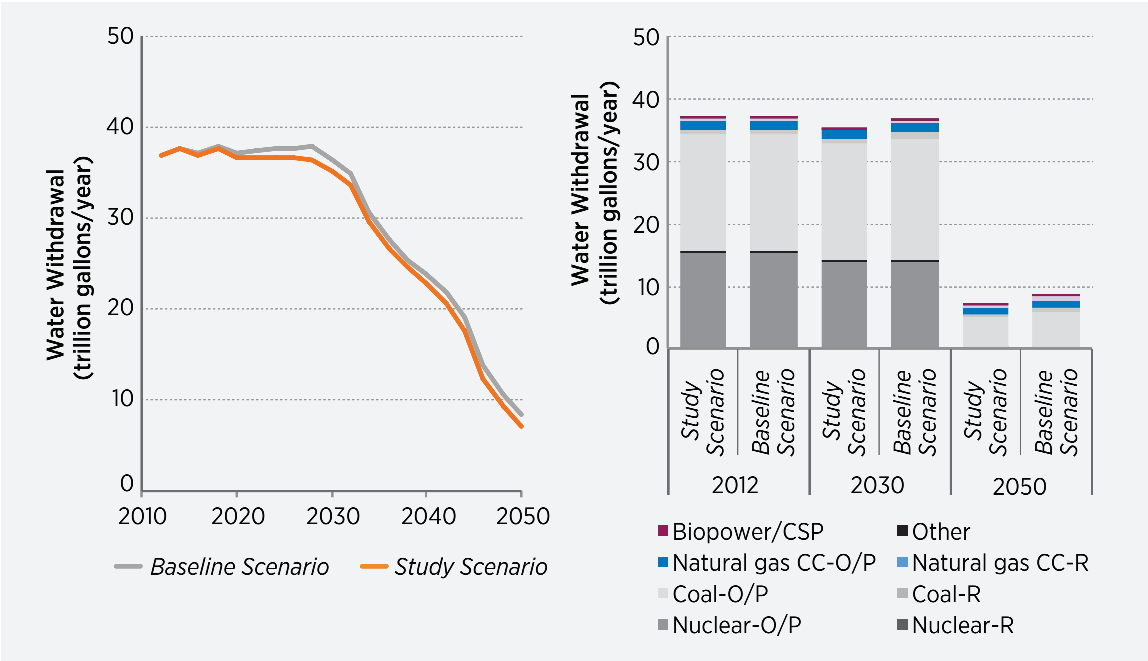
Figure 3-37 shows the decline in annual electric sector water withdrawals for the *Study Scenario* and *Baseline Scenario*, based on ReEDS output, as well as by fuel and cooling system type. On a national level, withdrawals are estimated to decline substantially over time under both the *Study Scenario* and the *Baseline Scenario*. This is largely due to the retirement and reduced operations of once-through cooled facilities and the assumed replacement of those plants with newer, less water-intensive generation and cooling technologies.[119] In the *Baseline Scenario*, once-through cooled plants are largely replaced by new thermal plants utilizing recirculating cooling. In the *Study Scenario*, water-intensive plants are replaced by new, less water-intensive thermal power plants as well as by wind energy, driving somewhat greater reductions in water withdrawals. As a result, national electric sector water withdrawals decline by 1% in 2020 (0.4 trillion gallons), 4% in 2030 (1.3 trillion gallons), and 15% in 2050 (1.3 trillion gallons) in the *Study Scenario* relative to the *Baseline Scenario*.

Figure 3-38 shows the change in annual electric sector water consumption for the *Study Scenario* and *Baseline Scenario*, based on ReEDS output, as well by fuel and cooling system type for 2012, 2030, and 2050. Unlike withdrawals, national electric sector water consumption remains higher than 2012 values until after 2040 under the *Baseline Scenario.* It declines after this point, but to a lesser extent than water withdrawals. Consumption decreases sooner and more significantly in the *Study Scenario*. The delayed decrease in water consumption in the *Baseline Scenario* is caused by the assumed replacement of once-through cooled plants with those using recirculating cooling systems (recirculating cooling has higher water consumption). Such cooling system

117. This section evaluates the impacts of the *Study* and *Baseline Scenarios,* under *Central* assumptions only. See Section 3.1.3 for detailed explanation of the scenarios. The ranges presented in this section are driven by the range of parameters evaluated and not by the range of scenario results.

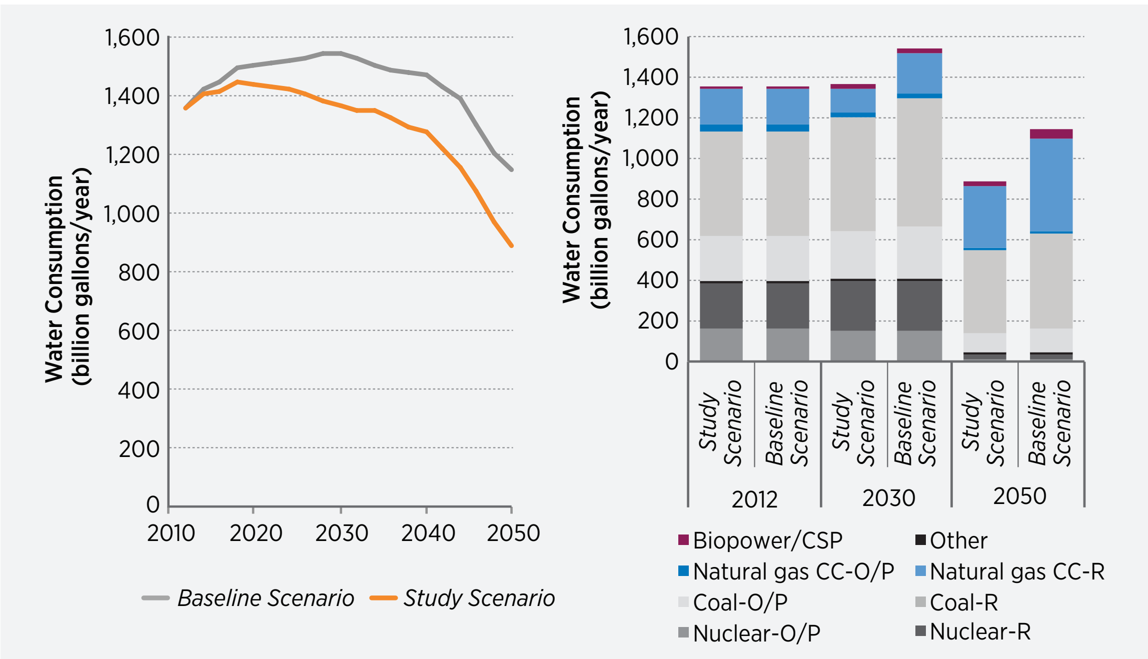
118. Some of the data underlying the figures presented in this section can be found in Appendix K.

119. Consistent with prior studies and proposed EPA regulations, new power plants in ReEDS are not allowed to employ once-through cooling technologies [170, 172].



Note: Acronyms used: CSP = concentrating solar power; CC = combined cycle; O/P = once-through or pond cooling system; R = recirculating cooling system.

Figure 3-37. Electric sector water withdrawals for the *Central Study Scenario* and *Baseline Scenarios* (2012–2050), and by fuel type and cooling system



Note: Acronyms used: CSP = concentrating solar power.; CC = combined cycle; O/P = once-through or pond cooling system; R = recirculating cooling system.

Figure 3-38. Electric sector water consumption for the *Study* and *Baseline Scenarios* from 2012 to 2050, and by fuel type and cooling system changes also occur in the *Study Scenario*, but the greater penetration of wind energy reduces water consumption for the sector as a whole. Overall, national electric sector water consumption declines by 4% in 2020 (62 billion gallons), 11% in 2030 (173 billion gallons), and 23% in 2050 (260 billion gallons) in the *Study Scenario* relative to the *Baseline Scenario*. These percentage reductions are greater than for water withdrawals because wind energy is found to generally offset generation that has higher water consumption but lower water withdrawals, e.g., recirculating natural gas combined cycle plants. In comparison to 2012 values, *Study Scenario* consumption is 35% lower in 2050.

These estimates suggest significant potential for wind energy in reducing water use. Water use, however, will be impacted by a variety of changes in the electric sector, such as coal plant retirements, new natural gas combined cycle construction, and, potentially, increased use of dry cooling. These changes may be driven in part by future state and federal water policies, and could affect the estimated water savings of the *Study Scenario*.

3.9.2 Regional Water Usage Trends[120]

Because water resources are managed locally and water is not easily transferred across basins, regional impact analyses can provide critical insight into the sustainability of water use. Because water resource boundaries do not follow state boundaries, analyzing water resource impacts at the watershed level is also useful to water managers. The analysis presented here therefore focuses on 18 defined watershed regions in the contiguous United States.[121]

Figure 3-39 highlights regional percentage changes in water withdrawal in 2050 compared with 2012 for the *Study Scenario* (right) and the *Baseline Scenario* (left). Due to the large estimated reductions in national electric sector water withdrawals over time, all but one of the 18 major watershed regions in the United States experiences reductions in withdrawals in the *Baseline Scenario* from 2012 to 2050, and all regions experience reductions in the *Study Scenario* (there are additional regional increases by 2030; see Appendix K). The degree of estimated water withdrawal reductions varies geographically, with the *Study Scenario* driving somewhat deeper declines by 2050.

More substantial differences between the *Study Scenario* and *Baseline Scenario* are apparent when looking at water consumption. Water consumption declines by 2050 in all but two of the defined watershed regions under the *Study Scenario*; in 11 of 18 regions, consumption reductions are greater than 30% (Figure 3-40). Regional increases under the *Study Scenario* occur in portions of the Southeast and in California. In the Southeast, high withdrawal and low consumption cooling technologies for thermal power plants are assumed to be replaced by low withdrawal and high consumption cooling

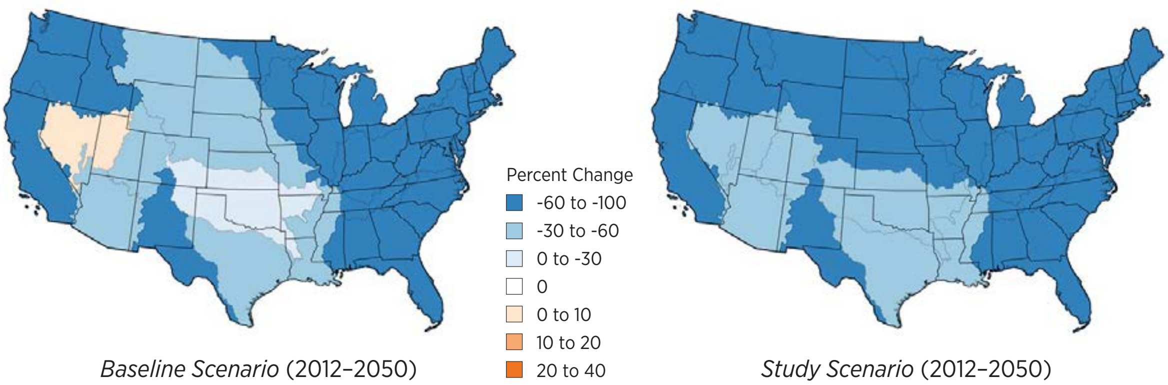


Figure 3-39. Percentage change in water withdrawals in 2050 compared with 2012 for the *Baseline* and *Study Scenarios*

120. Some of the data underlying the figures presented in this section can be found in Appendix K.

121. In particular, water impacts were aggregated from the 134 ReEDS model regions to the two-digit U.S. Geological Survey Hydrologic Unit Code watershed regions, of which there are 18 in the contiguous United States [181]. Data aggregation techniques follow those described in Macknick et al. and Sattler et al. [170, 182].

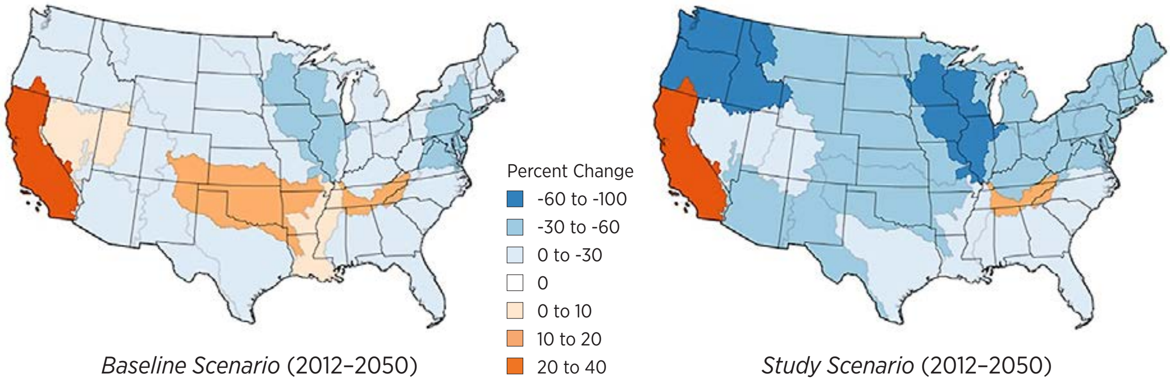


Figure 3-40. Percentage change in water consumption in 2050 compared with 2012 for the *Baseline Scenario* and the *Study Scenario*

technologies, and wind penetration is lower than other regions. In California, increases in consumption are a result of additional recirculating natural gas combined cycle plants and geothermal generation.[122] In the *Baseline Scenario*, five regions experience an increase in consumption by 2050. Specifically, consumption increases in watershed regions covering parts of water-stressed states such as Texas, Oklahoma, New Mexico, Nevada, Utah, and Colorado. The electric sector is not a major contributor to water *consumption* nationally. However, the large potential percentage increases in electric sector water consumption under the *Baseline Scenario* in arid states and regions that, in many cases, already experience water availability issues, could increase regional competition for water resources.[123] Additional maps of water consumption and withdrawal impacts through 2030 are shown in Appendix K.

3.9.3 Economic and Environmental Considerations of Water Use Reduction

The ability of wind energy to reduce water withdrawals and consumption may offer economic and environmental benefits, especially where water is scarce. By reducing electric sector water use, wind energy reduces the vulnerability of electricity supply to the availability or temperature of water, potentially avoiding electric sector reliability events and/or the effects of reduced thermal plant efficiencies. These are concerns that might otherwise grow as the climate changes [175]. Additionally, increased wind deployment might help make available water that could then be used for other productive purposes (e.g., agricultural, industrial, or municipal use), or to strengthen local ecosystems (e.g., benefiting wildlife due to greater water availability). The lower life-cycle water requirements of wind energy can help to alleviate other energy sector impacts to water resource quality and quantity that could occur during fuel production for other technologies, e.g., water used in mining, coal washing, and hydraulic fracturing [174]. Finally, wind deployment might help reduce the cost of future national or state policies intended to limit electric sector water use.

The ReEDS model includes the cost and performance characteristics of different cooling technologies as well as the availability and cost of water supply in its optimization; these costs and considerations are embedded in the results presented earlier. Quantifying in monetary terms any separable, additional benefits from the water use reductions estimated

122. In California, freshwater consumption increases by nearly 50%, largely due to the replacement of once-through cooled facilities along the ocean with power plants utilizing freshwater in recirculating cooling systems. This is consistent with the recommendation of no once-through cooling by the California State Lands Commission (2006).

123. Results in this section were developed using a version of ReEDS that incorporates water availability as a constraint for future development, and model results find that there is sufficient freshwater available in these regions to sustain the model results. However, assumed available water resources include water currently being used for agriculture, which may in practice be difficult to access. In addition, the water availability information used in ReEDS does not take into account all other potential sources of increased water demand, which could further increase competition for scarce resources.

under the *Study Scenario* is difficult, as no standardized methodology exists in the literature to do so. One way to assess the potential economic benefit of water savings is to consider wind deployment as avoiding the *possible* need to otherwise employ thermal power plants with lower water use, or to site power plants where water is available and less costly. To an extent, these costs are already embedded in the ReEDS results, as discussed above. However, water could become scarcer in the future and/or water policy could become stricter, both of which would necessitate additional investments. In such an instance, a possible upper limit of the incremental cost of water associated with conventional thermal generation can be estimated by comparing the cost of traditional wet cooling with the cost of dry cooling. Dry cooling adds capital expense to thermal plants and reduces plant efficiencies. The total cost increase of dry cooling for coal thermal generation has been estimated to be 0.32–0.64¢/kWh [183]. For natural gas combined cycle plants, Maulbetsch and DiFilippo [184] estimate an "effective cost" of saved water at $3.8–$6.8 per 1,000 gallons, corresponding to approximately 0.06–0.17¢/kWh.[124]

These estimated incremental costs for dry cooling are relatively small, and likely set an upper limit on the water-related benefits of wind energy or any other power technology intended, in part, to reduce water usage. The actual benefits would be lower than these figures for a few reasons. First, many regions of the country are not facing water scarcity, so the economic benefits of reduced water use are limited. Second, to the extent that wind offsets more electricity supply (kWh) than electricity capacity (kW), it may not be able to offset the full capital and operating cost of less water-intensive cooling technologies. Third, few plants as of 2013 have been required or chosen to implement dry cooling; alternative, lower-cost means of obtaining and/or reducing water have predominated, including simply locating plants where water is available. Alternative water resources, such as municipal wastewater or shallow brackish groundwater, could also be more cost-effective than dry cooling in some regions [172]. These lower-cost methods of reducing water use are likely to dominate for the foreseeable future. Because of these complicating factors, a separable monetary benefit of the *Study Scenario* in terms of reduced water usage is not estimated.

3.10 Energy Diversity and Risk Reduction[125]

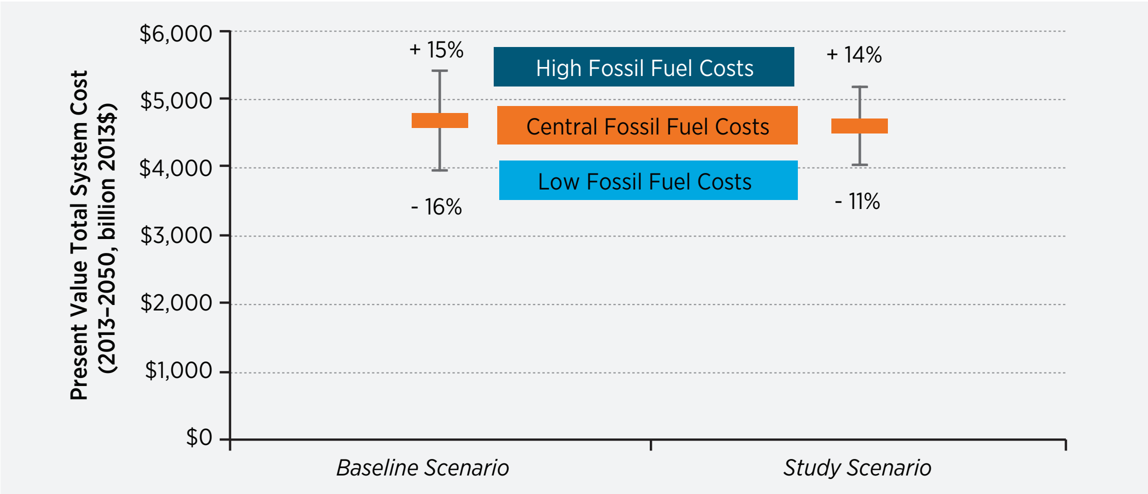
Traditional energy planning focuses on finding least-cost sources of supply. In balancing different electricity supply options, however, the unique risk profiles of each generating source and varying portfolios of multiple generation sources are also considered.

Though wind energy is not free of risk (e.g., due to its variable output and capital-intensive nature), it nevertheless relies on a "fuel" stream that is domestic and is not subject to significant resource exhaustion or price uncertainty. In contrast, fossil generation, and especially natural gas, relies on fuels that have experienced substantial price volatility and for which historical price forecasts have been decidedly poor. As a result, utility-scale wind energy is most often sold through long-term, fixed-price contracts, while fossil generation—and particularly gas-fired generation—is most often sold through short-term contracts and/or at prices that vary with the underlying cost of fuel. In evaluating new generation resources across seven different categories of risk (construction cost, fuel and operating cost, new regulation, carbon price, water constraint, capital shock, and planning risk), Binz et al [185] identified land-based wind as not only one of the lowest cost sources of new generation, but also as one of the lowest risk resources overall.

A variety of methods have been used to assess and sometimes quantify the benefits of fixed-price renewable energy contracts relative to variable-price fossil generation contracts, as well as the benefits of electricity supply diversity more generally. These methods have included the use of risk-adjusted discount rates [186]; Monte Carlo and decision analysis [187]; mean variance-based portfolio theory [188, 189]; market-based assessments of the cost of conventional fuel price hedges [190]; various diversity indices [191, 192]; comparing empirical wind PPA prices to gas price forecasts

124. 2006$ adjusted to 2013$.

125. This section draws heavily on Mai et al. [2].



Note: Central Fossil Fuel Costs reflect the *Central Baseline Scenario* and *Central Study Scenario* modeling inputs; High Fossil Fuel Costs and Low Fossil Fuel Costs reflect *High* and *Low Fossil Fuel Cost Study* and *Baseline Scenarios,* respectively.

Figure 3-41. Electric system cost variability under a range of fuel price scenarios

[193]; and estimating a generation portfolio's sensitivity to high and low fuel prices under high renewable penetration scenarios [194]. Many of these methods have proven to be incomplete or even controversial, and, as a result, a single, standard approach to benefit quantification has not emerged.

Though a full suite of standardized tools for quantifying the myriad risks associated with different electricity resource portfolios is not available, there is broad recognition that the deployment of wind energy can reduce certain risks. In particular, even though natural gas prices and price expectations have declined in recent years, an increase in wind generation mitigates long-term fossil fuel price risks in two ways that *can* be quantified using recognized and—with appropriate caveats—accepted methods. First, by providing electricity purchasers with a long-term fixed-price source of supply (at least when sold under a traditional power sales contract), wind can directly offset the use of fuel streams with variable and uncertain prices, thereby potentially reducing uncertainty in electric system costs. Second, by reducing demand for exhaustible fossil fuels, wind can place downward pressure on fossil fuel prices, with benefits to energy consumers both within and outside of the electricity sector. Though it is acknowledged that these are not the only pertinent areas of risk associated with higher levels of wind generation, the following subsections quantify these two possible impacts, while some of the additional risk mitigation aspects of offshore and distributed wind applications are noted in Section 3.13.[126] Finally, a brief discussion of the competitive and complementary relationship between wind and natural gas is included at the end of this section.

3.10.1 Reducing Uncertainty in Electric System Costs

Figure 3-41 illustrates the sensitivity of total electricity sector costs (on a present value basis) to low and high fuel prices under two scenarios: the *Baseline Scenario* and the *Study Scenario*. In the *Baseline Scenario*, total system costs under *High Fuel Cost* and *Low Fuel Cost* assumptions range from +15% to -16% around the *Central* fuel cost assumptions.[127] Under the *Study Scenario*, the overall range narrows to +14% to -11%.[128]

126. This section primarily evaluates the impacts of the *Study* and *Baseline Scenarios,* under *Central* assumptions. See Section 3.1.3 for detailed explanation of the scenarios.

127. See Section 3.2.4.3 for a summary of the specific fuel price assumptions used in the *Central, Low Fuel Cost,* and *High Fuel Cost* cases.

128. ReEDS implicitly assumes a cost-plus environment for capacity planning similar to the regulated markets that are common in many, but not all, parts of the United States. This modeling approach is reasonable for this study, as it provides a consistent comparison of the relative economics of different technologies. Some of the nuances involved with competitive wholesale markets, however, are not captured in ReEDS (see Text Box 3-6).

Thus, by replacing gas- and coal-fired generation with wind generation, the *Study Scenario* results in a total portfolio that may be 20% less sensitive to long-term fluctuations in fossil fuel prices.[129] It therefore provides some insurance value against rising costs to consumers due to higher-than-expected fossil fuel prices. Translating this reduced risk into monetary units is not straightforward, however, and would require knowledge about the risk preferences of electricity sellers and purchasers, as well as about the availability, cost, and effectiveness of alternative risk mitigation mechanisms such as forward gas contracts and physical gas supply contracts [190, 194].[130]

The displacement of coal- and gas-fired generation under the *Study Scenario* (relative to the *Baseline Scenario*) also reduces overall demand for coal and natural gas, which in turn can suppress coal and gas prices. This effect results from a shift of the demand curve for fossil fuels along an upward-sloping supply curve,[131] and, while there remains some uncertainty as to the magnitude of the price response, the effect has been both empirically estimated and modeled extensively (e.g., [195]).

Figure 3-42 provides an estimate of this effect using modeling results, showing in particular an increasing reduction over time in natural gas demand and prices under the *Study Scenario*.[132] These gas price reductions are already captured within the ReEDS modeling results presented earlier, but only within the electricity sector, which is just one of the gas-consuming sectors of the overall U.S. economy. If these gas price reductions are applied to AEO Reference Case projections of natural gas consumption *outside* of the electricity sector [4], they yield a present value (from 2013 to 2050 and discounted at a 3% real discount rate) of approximately $280 billion in consumer savings that is not captured within the ReEDS modeling results.

Importantly, these potential price reductions and consumer savings are likely to be primarily or even exclusively *transfer payments* from gas producers and those that benefit from gas production, such as owners of mineral rights (through rents) and governments and taxpayers (through taxes), to gas consumers. As such, the potential for $280 billion in consumer savings outside of the electricity sector, as well as the additional savings captured by ReEDS within the electricity sector, do *not* necessarily reflect a true net increase in aggregate economic wealth. Lower prices for natural gas benefit consumers, at the expense of producers. These significant consumer benefits may, nevertheless, be interesting from a public policy perspective, given that public policy is often formulated with consumers in mind.

It is important to recognize that the gas price reductions shown in Figure 3-42, as well as the $280 billion consumer savings estimate, do not take into account the possibility of a rebound in demand for natural gas outside of the electric sector, spurred by the lower gas prices that result from increasing wind power penetration within the electric sector. ReEDS is an electric sector model, covering only one sector in the broader

129. Moving from a range of +15% to -16% to a range of +14% to -11% is a 20% reduction in sensitivity.

130. Though considered a benefit by many—e.g., recent purchasers of wind power have touted wind's long-term hedge value as an important driver [15, 193]—this reduction in long-term fuel price risk may not be valued as highly (or even at all) by less risk-averse consumers. Furthermore, wind generation is not unique in its ability to reduce fossil fuel price risk, which can also be mitigated through fixed-price fuel contracts or low-cost financial hedges. Physical and financial fuel price hedges, however, are not typically available over long terms, in part due to counterparty risk [193], which is why gas-fired generation in particular is most often contracted only over short terms and/or at prices that vary with fuel costs. This stands in contrast to wind power, which is most often sold over long terms and at prices that are fixed in advance. Finally, the risk reduction shown in Figure 3-41 is measured over the long term. As noted in Text Box 3-6, however, over shorter time durations increased wind penetration may be expected to increase wholesale price volatility due to the variability in wind generation.

131. These supply and demand curves should be thought of as long-term curves reflecting long-term elasticities. Over the short term, price reductions could be even larger, as it will take time for suppliers to restrict supply in response to a reduction in demand (i.e., short-term supply and demand curves are generally thought to be steeper than corresponding long-term curves). Over the long term, supply will have ample time to respond to lower demand, leading to less of a price shift along a flatter supply curve—though not completely flat, since fossil fuels are exhaustible. It is these more enduring long-term price impacts that are of primary interest to this analysis, and that are captured within the ReEDS model. Note that, although ReEDS focuses solely on the electricity sector, it also approximates the long-term supply elasticities that are embedded within the EIA's cross-sector, economy-wide National Energy Modeling System [11].

132. Demand for coal within the electricity sector also declines relative to the *Baseline Scenario,* but the ReEDS model does not project the corresponding impact on coal prices. Because the long-term inverse price elasticity of supply is generally thought to be lower for coal than for natural gas [195], coal price reductions are likely to be muted relative to the gas price reductions shown in Figure 3-42. Further, unlike natural gas, coal is not widely used in the United States outside of the electricity sector, which limits the broader, economy-wide consumer benefit of any coal price reductions.

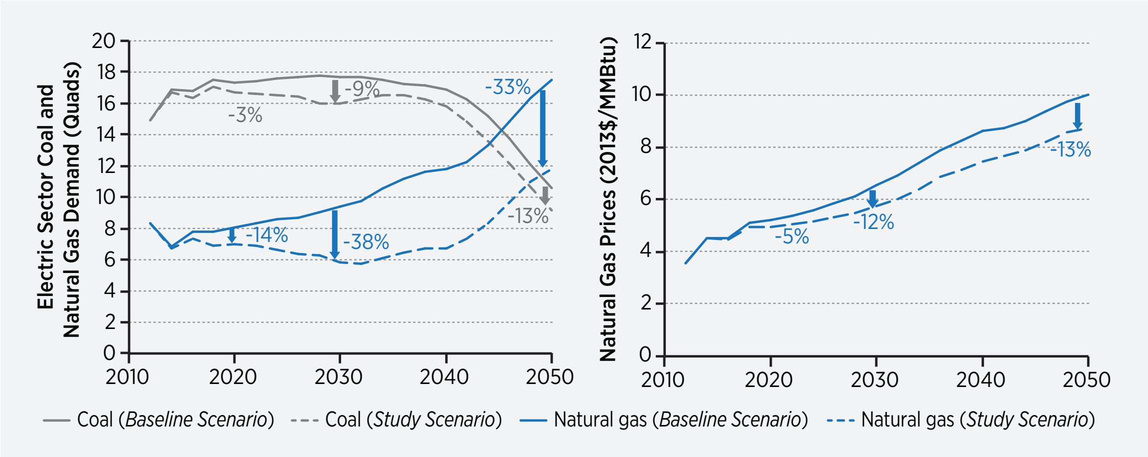


Figure 3-42. Reduction in demand for, and price of, fossil fuels under the *Study Scenario*

economy, and not able to fully account for such macro-economic impacts. This rebound effect, which might also include an increase in natural gas exports, would presumably lead to smaller market-wide price reductions than are shown in Figure 3-42. The impact on overall consumer savings is less clear, as the smaller price reductions would benefit a larger amount of consumption due to the rebound, leaving the aggregate dollar impact uncertain.

Notwithstanding these caveats, the $280 billion is equivalent to a levelized *consumer* benefit from wind energy of 2.3¢/kWh of wind.[133] Considering a household with a typical level of natural gas consumption, the estimated natural gas bill reduction benefit equates to an average of $0.40/month from 2013 to 2020 and $1.50/month from 2021 to 2030, increasing to $2.60/month from both 2031 to 2040 and 2041 to 2050.

Finally, some stakeholders point to the potential impact of increased wind power deployment on reducing wholesale electricity prices in organized competitive markets. Though not quantified here, the nature of this impact and relevant literature analyzing it are discussed in Text Box 3-6.

3.10.2 Wind and Natural Gas: Competitors and Partners in the Electric Sector

The significant displacement of gas-fired generation shown in Figure 3-25 under the *Study Scenario* (relative to the *Baseline*) suggests that utility-scale wind and gas compete in the electric sector. A closer analysis, however, reveals that gas-fired and wind generation are important partners in the *Study Scenario*, and that their combined presence may yield diversity-related benefits. In particular, despite being partially displaced by wind, natural gas continues to play a major role in the electricity sector under the *Study Scenario*, with demand eventually rising above today's levels (Figure 3-24). In addition, gas-fired *capacity* is not displaced as much as gas-fired generation under the *Study Scenario* (see Section 3.5.1), since a high-wind future requires a significant amount of flexible capacity to help integrate wind power, meet peak loads, and maintain system reliability. Ensuring that gas plants are adequately compensated for providing these services may be a precondition to achieving the *Study Scenario*.

133. This **levelized** impact is calculated by dividing the discounted benefit by the discounted difference in total wind generation in the *Study Scenario* relative to the *Baseline Scenario.* When instead presented on a **discounted,** average basis (dividing the discounted benefit by the non-discounted difference in total wind generation in the *Study Scenario* relative to the *Baseline Scenario*), the value is 1.1¢/kWh of wind.

Text Box 3-6.

Impact of Wind Power on Wholesale Electricity Prices

One potential impact of wind energy not explicitly analyzed in the *Wind Vision* is its potential to lower wholesale electricity prices in the short run (i.e., within the time it takes new generation to be built or to retire). In particular, in organized, competitive wholesale markets such as those in many parts of the United States, the wholesale price is largely based on the variable cost of the most expensive generator required to meet demand. The addition of wind lowers demand for power from other generators, resulting in lower-cost generators setting wholesale prices. This short-run reduction in wholesale prices is often referred to as the "merit-order effect." This effect is not present, or is present to a lesser extent, in still-regulated markets that operate in a cost-plus environment (rather than an environment in which the marginal generator sets the price for all generation) and in markets where wholesale purchases are a subset of supply costs.

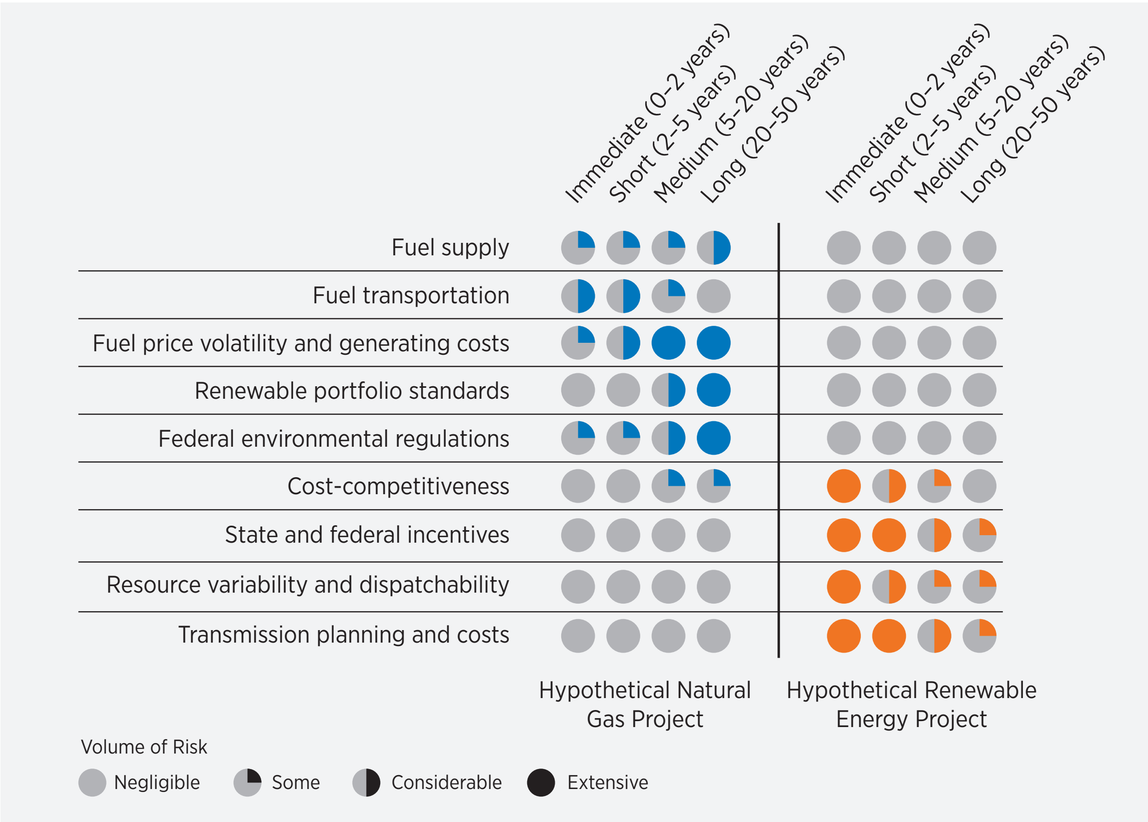
The magnitude of this effect has been estimated through simulations [66, 196, 197] and empirical analysis [198, 199]. In a review of many studies, Würzburg et al. [200] find a roughly 0.1¢/kWh (within a range of 0.003¢/kWh to 0.55¢/kWh) reduction in wholesale prices per percentage penetration of wind energy. The price effect is expected to be larger when plants with different fuels and efficiencies are used (i.e., when the generation supply curve is steep), whereas a smaller effect is expected if similar plant types are consistently on the margin [113]. Likewise, a relatively small effect of wind on wholesale prices was found in the hydro-dominated region of the Pacific Northwest [201]. Section 3.13.1.3 discusses this effect as it relates to offshore wind applications.

As with the impact of wind on natural gas prices (see Section 3.10.1), the change in wholesale electricity prices with the addition of wind affects electricity customers and generators differently. Assuming demand is inelastic (meaning demand does not increase substantially as the wholesale power price is reduced), customer costs are reduced by the difference in wholesale price times the amount of power purchased from the market. This reduction in costs for customers, however, is equal to the reduction in revenues earned by generators selling power in this market. Hence, just as with the impact of wind on natural gas prices, the merit-order effect results in a transfer of wealth from generators to consumers, and does not reflect a net increase of societal welfare [202].

There are two other reasons wholesale price effects are not separately quantified in the *Wind Vision* report. First, the modeling tool used here (ReEDS) estimates the total costs of producing electricity—it is not capable of estimating hourly wholesale market prices, and does not separately identify impacts to consumers versus impacts to generators. Second, as described below, the merit-order effect may be temporary. This is unlike the impact of wind on natural gas prices, which are presumed to have a long-term price response to altered demand conditions because the underlying gas resource is exhaustible.

The reason a persistent, long-term merit-order effect is less likely is that a reduction in revenue to generators reduces the incentive for new generators to enter a market or for existing generators to stay in a market [203, 204]. Sustained reductions in wholesale prices may therefore change the amount and type of generation capacity. In the long run, a number of studies suggest that, with high wind penetration, the generation mix will shift away from generators with higher up-front cost but lower variable costs (i.e., coal and perhaps combined cycle gas turbines) to generation with lower up-front cost but higher variable cost (i.e., natural gas plants, and perhaps especially combustion turbines) [170, 205, 206]. As a result of the increased investment in plants with higher variable costs, wholesale prices may not decrease in the long run to the same degree as observed in the short run.

Two characteristics of the impact of wind on wholesale prices that are expected to endure in the long run are an altered temporal pattern of short-term prices and an increase in short-term price volatility. Prices will be low during periods with high wind generation but can still be high in periods with low wind and high load [207]. The impact and importance of these altered prices—both due to short-term merit-order effects and long-term changes in price volatility—on electricity markets, resource adequacy, system flexibility, and revenue sufficiency are topics of current concern, as discussed briefly in Section 2.4.6.



Source: Lee et al. (2012) [208]

Figure 3-43. Qualitative framework for evaluating investment in new natural gas or wind projects by risk source, magnitude, and time scale

Utility-scale wind and gas-fired generation can complement each other in a number of ways within an overall electric system portfolio, given the diverse and often opposing characteristics and risks associated with these two resource types [208, 209]. For example, as suggested in Figure 3-43 and as described in Lee et al. [208], a portfolio that includes both wind and gas can help to partially protect consumers against natural gas price and delivery risk, while also providing insurance against the unknown costs of potential environmental regulations. Continuing to invest in and deploy a more diverse portfolio that includes renewable energy reduces the risks associated with locking in to a narrow range of technologies,[134] and may also enhance long-term energy security by preserving the nation's finite natural gas resource. At the same time, the inclusion of natural gas in this same diverse portfolio can mitigate the consumer price impact of any potential loss of federal tax incentives for wind, help manage wind output variability, and help minimize the need for and cost of new transmission.[135]

134. In addition, including offshore wind in the portfolio would help to prevent the possible premature lockout of a promising technology whose costs may decline significantly in the future as a result of deployment-related learning.

135. Gas-fired generators can often be sited closer to load than can wind generators, thereby minimizing the need for new transmission. In addition, pairing wind with flexible gas-fired capacity may allow for greater utilization of transmission assets than if used for wind generation alone.

3.11 Workforce and Economic Development Impacts

Workers are needed to develop, construct, operate, and maintain wind projects. In addition, supply chain workers manufacture and assemble turbine components, and businesses provide financial, legal, and other services. These workers, in turn, support additional jobs in their communities through purchases at restaurants, daycare centers, retail outlets, and more. Jobs create opportunities for local economic development, as do other local impacts associated with wind-related manufacturing and deployment, such as property taxes and land lease payments. An extensive body of literature has analyzed these impacts within the context of the U.S. wind sector [1, 210, 211, 212, 213, 214, 215].

The potential *national* wind sector labor force required to achieve the *Study Scenario* is analyzed here. Because these impacts are uncertain, depending in part on the future competitiveness of U.S. wind manufacturing, a range of potential labor force needs is quantified. Section 3.12.1 elaborates on these results, focusing on *local and state-specific* impacts. Section 3.13 provides additional context on the economic development aspects of offshore and distributed wind applications, respectively.

This section focuses on the potential "gross" wind-related labor force and economic development impacts of the *Study Scenario*[136]; it does not include an assessment of gross wind-related jobs in the *Baseline Scenario*, or of "net" economy-wide impacts. Increased wind generation will directly displace demand for natural gas, coal, and other sources of electric generation, impacting job totals and economic development associated with those sectors of the economy. Additionally, to the extent that increased wind deployment impacts the cost of energy, or has other macro-economic effects, this too may affect employment in the broader economy. Though not covered here, studies that have evaluated the economy-wide net effects of renewable energy deployment have shown differing results in terms of the net impact of renewable energy deployment [216, 217, 218, 219, 220, 221, 222, 223, 224, 225, 226, 227, 228].[137] In general, however, there is little reason to believe that net impacts are likely to be sizable in either the positive or negative direction (e.g., [227]). Brietschopf et al. [229] provide guidelines for the estimation of both the gross and net effects of renewable energy on employment, noting that input-output models can be useful for gross effects, but that a complete net-effects analysis requires the use of macroeconomic, economy-wide models.

3.11.1 Methods and Assumptions

To assess the potential gross wind-related employment and economic development impacts of the *Study Scenario*, this analysis uses the land-based and offshore wind Jobs and Economic Development Impacts (JEDI) models. JEDI is an input-output model designed to estimate the jobs, earnings, and gross output (economic activity) associated with energy projects. JEDI has been used extensively in both national and local assessments of land-based and offshore wind.[138] For more information about JEDI and its limitations, as well as further explanation of the metrics it reports, see Appendix I.

Three key sets of parameters are used to calculate labor needs in JEDI: deployed capacity, expenditures, and domestic content. Land-based and offshore wind power deployment in the United States and underlying expenditures come from the *Study Scenario*, described in Section 3.1.3. No export of U.S. wind-related goods and services is assumed. In reality, an export market for domestically manufactured wind equipment already exists—both for utility-scale wind [20, 232] and for distributed wind (primarily those 100 kW and under in size; see [233] and Chapter 2). The continuation or expansion of these existing exports would increase domestic wind-related jobs. Additionally, jobs associated with the increased interconnection and transmission infrastructure required under the *Study Scenario* are excluded, as are jobs

136. This section evaluates the impacts of the *Central Study Scenario* only. See Section 3.1.3 for detailed explanation of the scenarios. The ranges presented in this section are driven by the range of domestic content parameters evaluated, and not by the range of ReEDS scenario results.

137. Questions also remain as to whether any such effects serve as economic justification for government policy (e.g., [50, 117, 230, 231].

138. For examples of JEDI use in national studies, see, e.g., [1, 241, 242]. For examples of JEDI use in local studies, see, e.g., [213, 243, 244, 245, 246].

associated with behind-the-meter wind applications. Incorporation of these impacts would further increase the jobs estimates reported in this section.

Domestic content is defined as the portion of specific expenditures associated with wind deployment in the United States that is procured—and produced, in the case of manufactured goods—domestically. The extent to which wind developers, turbine manufacturers, and operators source components and services domestically depends on a number of factors (Figure 3-44; see also [20, 234, 235, 236, 237, 238, 239, 240]). Transportation costs and logistical complexity increase with larger, heavier components such as towers, blades, and offshore foundations, which tends to increase domestic sourcing.[139] International manufacturers, however, can often produce components at a lower cost than their U.S. counterparts. This is especially true for components that require significant amounts of labor and can be produced in countries with lower prevailing wages, or for components requiring materials that are less expensive in some countries, e.g., steel.

As discussed in Chapter 2, the domestic wind supply chain has strengthened since the early 2000s, albeit with some pullback since 2012. The steady, sustained deployment envisioned in the *Study Scenario*—a scenario that reduces the risk of fluctuations in demand for wind-related businesses—would, all else being equal, continue to strengthen the domestic manufacturing market. This trend would also be supported by the expected continued growth in turbine size, which will create greater transportation costs and complexities that can be mitigated through more localized manufacturing and assembly. Another development that may increase domestic content is increasing production automation and the associated decrease in labor needed to manufacture and assemble wind components, which will make the United States more globally competitive with countries that have comparatively lower labor costs. Additionally, manufacturers are developing new technologies such as hybrid towers[140] that could be manufactured completely or partially on-site, potentially further supporting domestic content. Finally, lower natural gas prices will reduce the materials cost for wind-related domestic supply (e.g., steel, plastics, and adhesives), which utilize natural gas in their manufacture.

There are, however, other trends that could lead to decreases, or limit increases, in domestic content (Figure 3-44). The most significant could be the

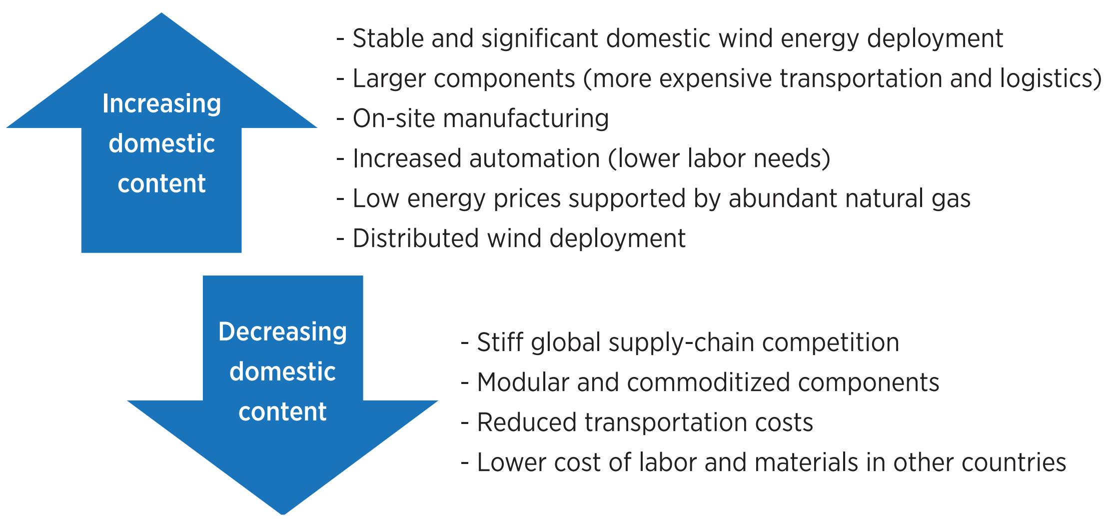


Figure 3-44. Factors that could increase or decrease domestic content of wind equipment installed in the United States

139. In the case of operational wind projects, operators may choose domestically produced components to minimize downtime created while waiting for replacement components to arrive from an international source or shipping components overseas for repair.

140 Hybrid towers are made out of steel along with concrete that is typically poured at the construction site.

development of modular, commoditized components—for example, blades and nacelle components. These technologies ease transportation constraints, thus making imports more cost competitive. Additionally, stiff competition among turbine manufacturers has led to supply chain consolidation, with manufacturers seeking only the lowest-cost components within their increasingly global supply chains. Assuming this trend continues, there may be an increasing concentration of component manufacturing and assembly in locations and facilities that offer the absolute lowest-cost delivered prices, with larger manufacturing facilities potentially offering economies of scale.

To account for uncertainty about these various trends, a range of component- and activity-specific domestic content assumptions are used for the *Study Scenario* workforce analysis (Appendix I). These ranges accommodate some potential shifts in global and industrial trends and allow for other unknowns, including changes in exchange rates, import tariffs, natural resource prices, and manufacturing and transportation technology. Under both the lower and higher ranges of domestic content, achieving the *Study Scenario* is assumed to support a robust domestic supply chain given the steady, significant growth in wind deployment envisioned. The lower case, however, assumes a greater tendency toward international supply, whereas the higher case presumes that the trends toward domestic supply predominate. Specifically, the lower case is intended to reflect, loosely, the level of domestic content achieved for 2012 installations in the United States (see, e.g., [20]). It is assumed that the wind deployment under the *Study Scenario* (which is both significant in magnitude and far more stable on a year-to-year basis than historical deployment levels) is likely to be sufficient to support that historical level of domestic manufacturing. Given the potential for even greater localization of manufacturing with the steady, significant growth in the *Study Scenario*, the higher case assumes much higher levels of domestic content.

Table 3-6. Domestic Content Assumptions for Land-Based and Offshore Wind

	Average Domestic Content (2013–2050)	
Component	**Lower**	**Higher**
Towers	60%	90%
Blades	60%	90%
Nacelle components	20%	50%
Balance of plant materials	80%	95%
Labor (construction and O&M)	100%	100%
Replacement parts	30%	60%

Note: Offshore substructure and foundation costs are placed in the "Towers" category, above. Replacement parts include all parts replaced during scheduled and unscheduled maintenance.

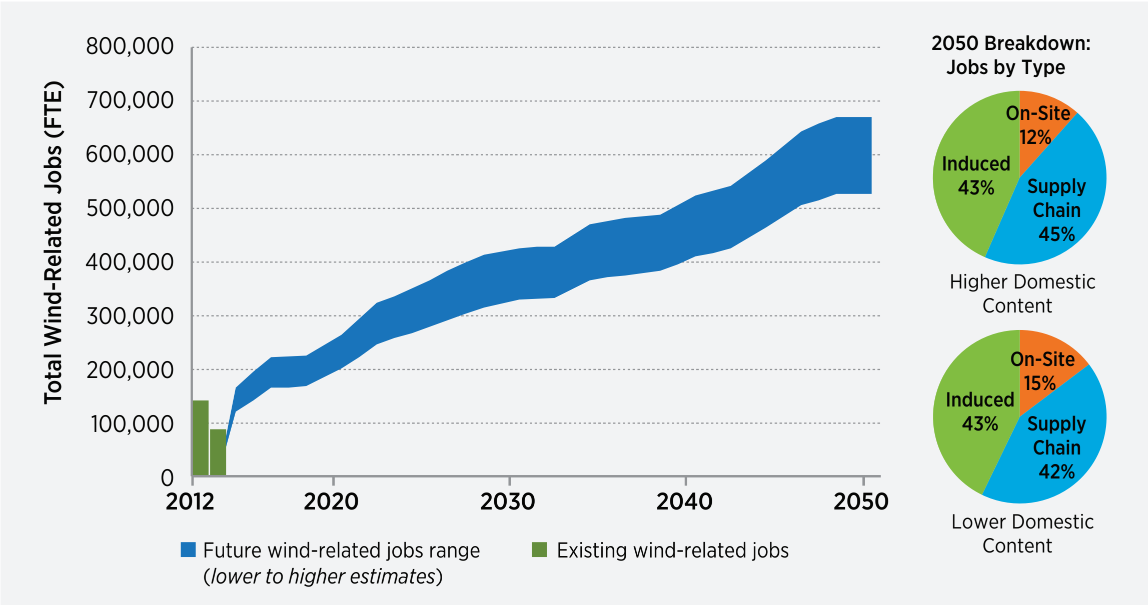
3.11.2 Gross Employment and Economic Development Impacts

Increasing wind deployment will support jobs directly or indirectly related to the U.S. wind industry in manufacturing, construction, and O&M. Figures 3-45 and 3-46 show the estimated total number of gross full-time equivalent (FTE) jobs[141] under the *Study Scenario* from 2020 to 2050, based on the range of domestic content assumptions.[142] These figures encompass jobs associated with both the construction and operation phases of wind project development, and include induced jobs. Three different types of jobs are identified (for more information, see Appendix I):

- **Onsite jobs** come directly from labor expenditures and include O&M technicians and construction workers, as well as labor associated with project development.
- **Turbine and supply chain jobs** relate to the supply of equipment, materials, and services to project operators and developers. These include manufacturing/production, as well as business-to-business services such as accounting, legal services, finance, and banking.
- **Induced jobs** are supported by on-site and supply chain workers who spend money in the United States. These include retail, food service, education, and entertainment jobs.

141. An FTE job is the equivalent of one person working full-time (40 hours per week) for one year or two people working half-time (20 hours per week) for one year.

142. Note that all jobs estimates presented here are reported as four-year rolling averages, rather than as yearly point estimates from JEDI, in order to reflect the planning and development times for land-based and offshore wind.



Note: Existing job estimates for 2012 and 2013 utilized American Wind Energy Association data for on-site and supply chain jobs and then the JEDI model to estimate the additional induced jobs.

Figure 3-45. Wind-related gross employment estimates, including on-site, supply chain, and induced jobs: 2012–2050

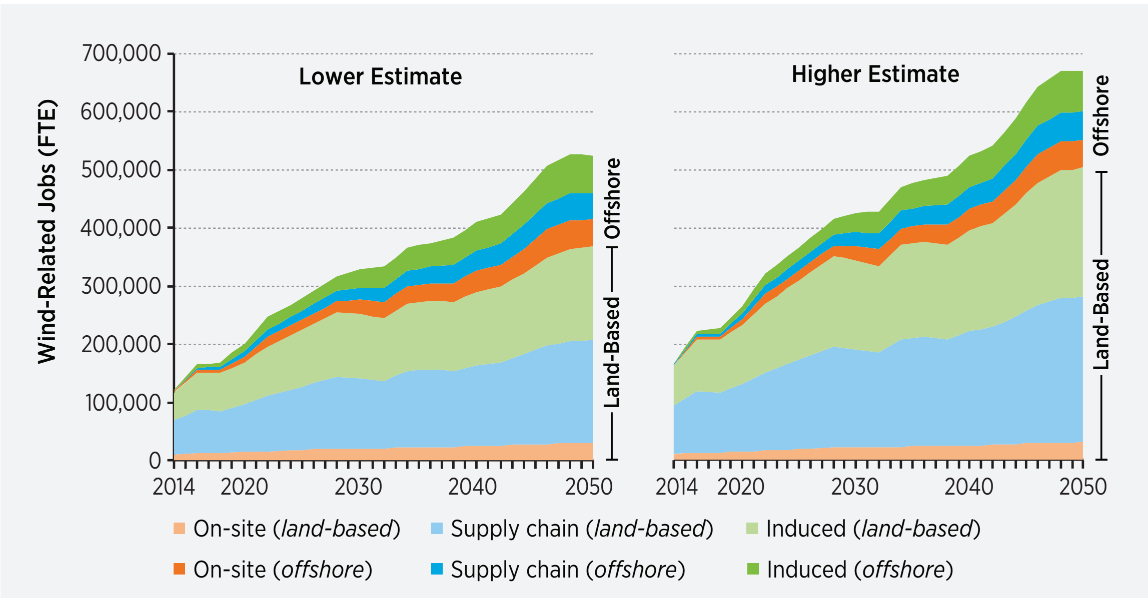


Figure 3-46. Wind-related employment estimates for land-based and offshore wind

Table 3-7. Construction-Phase Estimated FTE Jobs

Type of Job	2020	2030	2050	2020	2030	2050
	Low Estimate (FTE)			High Estimate (FTE)		
On-site and project development	17,000	32,000	58,000	17,000	32,000	58,000
Turbine and supply chain	58,000	85,000	139,000	81,000	118,000	189,000
Induced	48,000	75,000	127,000	65,000	100,000	165,000
Total	**123,000**	**193,000**	**323,000**	**163,000**	**250,000**	**412,000**

Note: Totals may not sum because of rounding. Induced jobs are supported by on-site and supply chain workers who spend money in the United States on retail, food service, education, and entertainment.

Table 3-8. Operation-phase Estimated FTE Jobs

Type of Job	2020	2030	2050	2020	2030	2050
	Low Estimate (FTE)			High Estimate (FTE)		
On-site labor	7,000	12,000	19,000	7,000	12,000	19,000
Local revenue and supply chain	32,000	57,000	85,000	44,000	76,000	112,000
Induced	39,000	67,000	98,000	51,000	88,000	127,000
Total	**78,000**	**136,000**	**202,000**	**102,000**	**176,000**	**258,000**

Note: Totals may not sum because of rounding. Induced jobs are supported by on-site and supply chain workers who spend money in the United States on retail, food service, education, and entertainment.

As shown in Figure 3-45, total estimated wind-related (including induced) jobs range from 201,000 to 265,000 in 2020; 329,000 to 426,000 in 2030; and 526,000 to 670,000 in 2050. In 2050, 12–15% of these jobs are projected to be on-site, 42–45% are turbine and supply chain jobs, and 43% are induced. These totals compare to the American Wind Energy Association's estimates of 80,700 wind-related on-site and supply chain jobs in the United States at the end of 2012, and 50,500 jobs at the end of 2013 [15], which corresponds to approximately 140,000 and 90,000 jobs when also considering induced impacts.

Figure 3-46 provides additional detail, by general job type and by land-based and offshore wind. As shown, the proportion of offshore-related jobs increased with time: by 2050, 23–28% of the total wind-related jobs are driven by offshore wind development. A further regional segmentation of the on-site jobs is provided in Section 3.12.

Under the lower domestic content scenario, total *construction-phase* impacts are estimated to be 123,000 FTE jobs in 2020; 193,000 in 2030; and 323,000 in 2050 (Table 3-7). Under the higher domestic content scenario, there are 163,000 jobs in 2020; 250,000 in 2030; and 412,000 in 2050. The majority of these positions are turbine and supply chain jobs—approximately 46% under the higher scenario and 43% under the lower scenario.

Total *operation-phase* jobs are estimated to be 78,000 in 2020; 136,000 in 2030; and 202,000 in 2050 under the lower scenario (Table 3-8). Under the higher scenario, there are 102,000 jobs in 2020; 176,000 in 2030; and 258,000 in 2050.

In addition to employment implications, wind project development can also impact local communities through, for example, land lease payments and local property taxes. Under the *Study Scenario*, wind power capacity additions are estimated to lead to land-based lease payments that increase from $350 million in 2020 to $650 million in 2030, and then to $1,020 million in 2050. Offshore wind lease payments increase from $15 million in 2020 to $110 million in 2030, and then to $440 million in 2050. Property tax payments associated with wind projects are estimated at $900 million in 2020; $1,770 million in 2030; and $3,200 million in 2050.[143]

3.11.3 Occupational Needs

These results provide estimates of the future workforce associated with the *Study Scenario*, but do not characterize who might fill these positions or what skills they may need. Workers who fill positions supported by the *Study Scenario* may be previously unemployed, may move from other industries, or may come from educational or vocational training programs. Many of the workers needed under the *Study Scenario*, at least in the near future, may already be employed in the wind industry.

Notwithstanding the potential availability of some already qualified workers, additional training and educational programs are likely to be necessary. In particular, according to a 2013 report, the United States may need to offer increased wind-related education and training in several areas in order to reach 20% wind penetration by 2030 [247]. This includes post-secondary professional certificate programs (90 additional programs needed), bachelor's degree programs (30 additional programs needed), and master's, Ph.D., and law degree programs (10 additional programs needed).

3.12 Local Impacts

It is important to examine the potential positive and negative local impacts of wind development. Local impacts covered in this section include: economic development, land and offshore use, wildlife, aviation and radar, aesthetics and public acceptance, and health and safety. Where it is feasible, potential impacts are quantitatively analyzed. For some impacts, quantification is feasible given the existing literature base; for example, the impact of wind on scenic views. Where quantification of the impacts is not possible, impacts are discussed based on an understanding of current wind energy technology, developments since 2003, and consideration for what might occur during the timeframe of the *Wind Vision* study (2014–2050).

The *Study Scenario* calls for large-scale wind deployment that will have numerous and wide-ranging impacts. The *Wind Vision* analysis concludes that, with responsible wind turbine siting, improvements in technology, and a better understanding of potential impacts and mitigation options, it is possible to achieve this scenario. This is in part because of the enormous wind resource base in the United States. Even if large portions of the country with wind potential do not see expanded wind deployment due to different energy choices or local decisions, other wind-rich areas should be able to provide enough wind energy to reach the wind penetration levels of the *Study Scenario*. Expanded impact mitigation and reliance on lower wind resource areas may also help reduce or avoid areas with possible greater negative local impacts. At the same time, such strategies can increase the cost of wind energy. Careful consideration is therefore warranted when balancing positive and negative impacts, mitigation measures, and project economics.

143. These land lease and property tax figures are solely associated with wind capacity additions and do not include related payments that result from wind equipment manufacturing and supply chain investments. This analysis uses JEDI default property tax and land lease figures. Nationally, default annual property tax payments are $7,399/MW. Annual lease payments for land-based wind are $3,000/MW; see Appendix I for more information about the calculation of offshore wind lease payments. All dollar figures are in 2013$.

3.12.1 Local Economic Development Impacts[144]

Local economic development benefits of wind energy can include jobs and additional financial benefits. The gross national economic development, employment, and workforce implications of the *Study Scenario* are described in Section 3.11. These **national** results, however, mask the **local** economic and employment impacts of wind energy.[145]

Although every wind power project is different, a representative 100-MW operational wind project, whether land-based or offshore, is likely to employ 4–6 people on-site for the life of the facility. Land-based plants of this size support an additional 30–80 on-going jobs nationally, through supply chain and subcontracted activities, and as a result of on-site and supply chain worker expenditures (the latter are often called "induced" jobs). Offshore wind projects of a similar size are likely to support a somewhat larger number of these jobs, about 30–110.[146]

Focusing only on on-site construction and operations jobs, Figure 3-47 provides estimated state-by-state gross wind employment numbers in 2050, using the same tools as in Section 3.11.1. Estimated state-level on-site wind jobs are, not surprisingly, directly linked to the geography of the land-based and offshore wind deployment under the *Study Scenario*. Domestic supply chain (e.g., manufacturing) and induced jobs, though analyzed nationally in Section 3.11, are not shown in these figures since the location of these potential future jobs could not be accurately assessed.

In addition to jobs, there are other economic benefits to local communities that host wind projects, such as payments to landowners for land leases and property tax revenue to counties and states. Estimates of total land lease payments and property taxes under the *Study Scenario* are summarized in Section 3.11.2 on a national basis, but these, too, have a local context. Although annual land lease payments vary by project, a typical payment might be $3,000/MW. Property taxes also vary by location, but average annual payments of more than $7,000/MW are common.

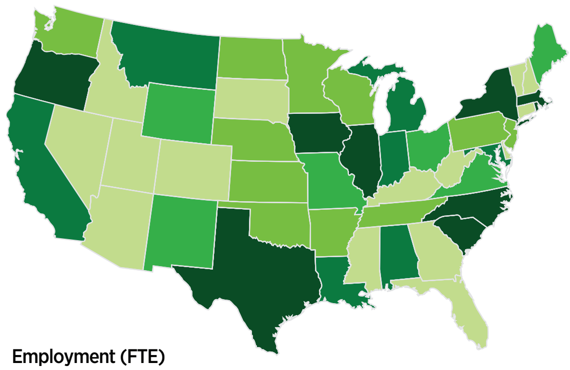


Figure 3-47. Estimated on-site wind project employment, 2050

Wind projects on public lands or in public waters would also provide lease payments to the state and other relevant jurisdictions in close proximity to the installations.[147]

Finally, research shows that the gross economic development impacts from community and distributed wind projects are somewhat more likely to remain in the community within which those projects are located. This is because community and distributed wind feature local ownership. For example, Lantz and Tegen [248] find that community wind projects have construction-phase employment impacts that are 1.1–1.3 times higher than typical utility or investor-owned projects, while operation-phase impacts are 1.1–2.8 times higher. See Section 3.13 for a further discussion of the unique economic development attributes of distributed and offshore wind.

3.12.2 Land and Offshore Use

All electricity generation sources require land—not only for the physical power plant, but also for supply chain activities, fuel extraction, and fuel delivery. The magnitude and nature of these land uses are diverse, making comparisons among different energy sources challenging. Given those challenges, the

144. The analysis and results presented in this section, as in Section 3.11, relies on the NREL JEDI model. For more details, see Appendix I. Also note that the analysis presented here is based on the *Study Scenario* under *Central* assumptions only.

145. As in Section 3.11, the present section does not address "net" impacts, but instead focuses on the local impacts associated with wind power development alone.

146. *http://www.nrel.gov/analysis/jedi/*

147. *http://www.nrel.gov/analysis/jedi/*

present analysis focuses solely on the "gross" land and offshore use that might be required by wind power plants in the *Study Scenario*. The analysis does not evaluate the land savings associated with power plants and fuel usage displaced by wind production. Though the reduced burdens on land use associated with that displacement are not considered here, they can be significant. For example, Fthenakis and Kim [249] estimated the life-cycle land disturbance of wind and solar energy to be lower than the impacts of coal-generated electricity.

The amount of space that a wind power plant requires varies depending on a variety of siting requirements; however, a general value of 0.33 kilometers(km)^2/MW (82.4 acres/MW) constitutes a viable estimate for the facility boundary for both land-based and offshore wind development (see Chapter 2 for details). Within this facility boundary, however, only a relatively small amount of land is actually physically transformed or occupied permanently by turbines and related infrastructure. Analysis using satellite images of operating wind power plants completed by the U.S. Geological Survey, for example, indicates that land impacts for wind turbines as well as additional land use such as tree thinning, roads, and electrical infrastructure varies between 0.0011–0.043 km^2/MW (0.27–10.63 acres/MW) [250], with a mean of .0093 km^2/MW (2.30 acres/MW). The present analysis assumes a mid-point for land transformation of 0.01 km^2/MW (2.47 acre/MW), or approximately 3% of the project boundary area.[148] The remaining land within the overall project boundary can be used for other activities, such as farming and ranching, or left in its natural state.

For offshore wind projects, a range of values have been proposed for the boundary of projects along the Eastern Seaboard, between 0.20–0.60 km^2/MW (50.4–148.8 acres/MW) [251, 252, 253, 254]. For offshore plants, the physically transformed area is much less than for land-based facilities, though actual values for U.S.-based facilities will depend on pending legal and marine public safety issues for offshore wind development in public waters.

Focusing first on the area impacted by the turbine footprint, roads, and associated infrastructure and assuming a land use value of 0.01 km^2/MW, the *Study Scenario*[149] is estimated to require approximately 2,000 km^2 (500,000 acres) by 2030, and 3,200 km^2 (790,000 acres) by 2050. This transformed land is dispersed over a larger area that represents the combined boundary of the projects. Assuming a land use value of 0.33 km^2/MW, this larger area represents 67,000 km^2 (17 million acres) of land by 2030 and 106,000 km^2 (26 million acres) by 2050. Most of this larger area could also be used for other purposes, such as farming or ranching [255], though an even larger area would be impacted visually. Assuming the same boundary usage assumption as for land-based, the offshore wind deployment in the *Study Scenario* covers approximately 7,300 km^2 (1.8 million acres) of offshore area by 2030 and 29,000 km^2 (7.1 million acres) by 2050, only a small fraction of which would be physically transformed.[150] Although only indirectly tied to land use, it should be noted that the wakes produced by wind turbines can persist for several kilometers downwind of the actual wind plant. Impacts to land and other environmental characteristics resulting from downstream wakes are likely negligible, but have not been quantified.

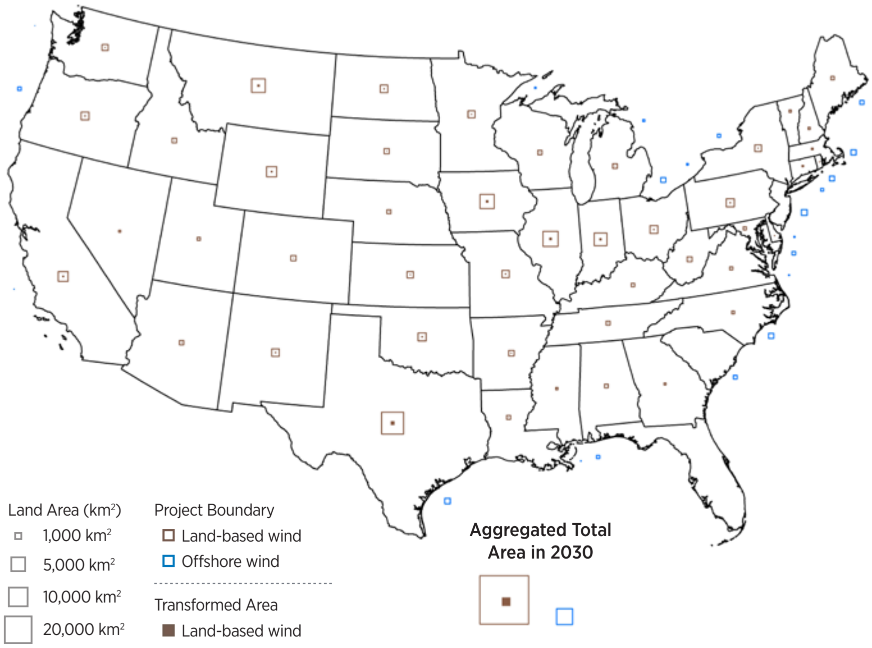
To put these land and offshore areas in context, the total land area affected by wind power installations in the *Study Scenario* is less than 1.5% of the land area of the contiguous United States, with the vast majority (97%) of that land area remaining available for multiple purposes. For comparison, the areas of West Virginia and Kentucky are 63,000 km^2 and 105,000 km^2, respectively, similar to the expected facility boundary for all land-based wind deployments in 2030 and 2050. The area of the nation's golf courses, approximately 10,000 km^2, is three times the estimated transformed land area from wind development by 2050 [256], where "transformation" includes the amount of land impacted by turbine footprints, roads, and associated infrastructure.

Figures 3-48 and 3-49 show the relative size of expected land and offshore areas containing and transformed by wind facilities in the *Study Scenario* for 2030 and 2050, respectively, by state.

148. Denholm et al. [255] find direct land use to equal, on average, just 1% of the project boundary, using a somewhat different definition for land use than that used here.

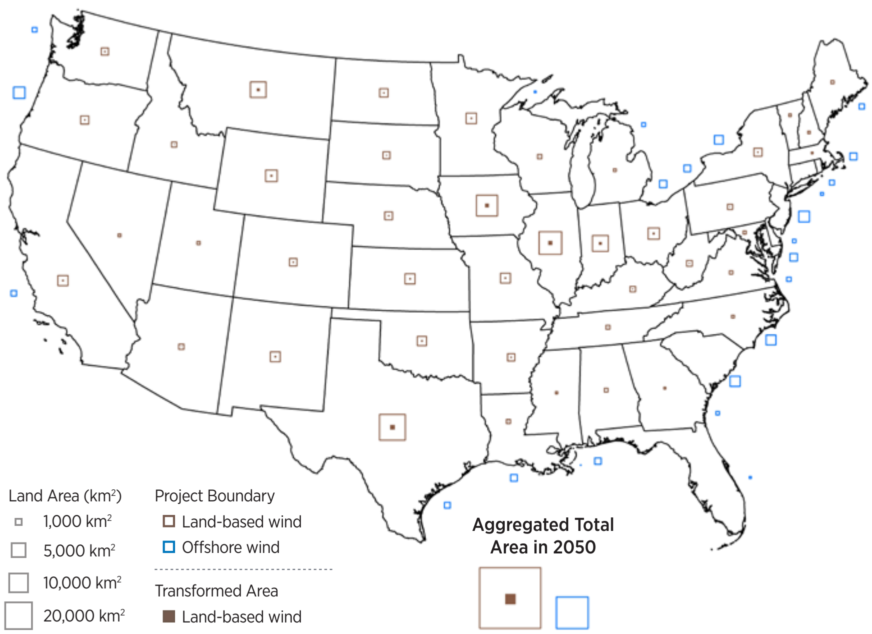
149. The analysis presented in this section is based on the *Study Scenario* under *Central* assumptions only.

150. Given the uncertainties around offshore development due to unresolved legal and marine public safety issues, only the facility boundary offshore area is estimated for the *Study Scenario* and not the transformed area.



Note: Map illustrates expected land and offshore area requirements in 2030 for the *Study Scenario*, by state. Transformed land area is the wind plant area directly impacted by turbines, roads, and other infrastructure. The project boundary area includes spacing between turbines that can be used for other purposes such as ranching and farming.

Figure 3-48. Land-based and offshore area requirements for *Study Scenario,* 2030



Note: Map illustrates expected land and offshore area requirements in 2050 for the *Study Scenario*, by state. Transformed land area is the wind plant area directly impacted by turbines, roads, and other infrastructure. The project boundary area includes spacing between turbines that can be used for other purposes such as ranching and farming.

Figure 3-49. Land-based and offshore area requirements for *Study Scenario,* 2050

3.12.3 Wildlife Impacts

Climate change is considered a significant threat to wildlife, and rapidly replacing fossil fuel-based energy technologies (e.g., coal and gas) with low-carbon options (e.g., wind) has been identified as a crucial step in limiting the impacts of climate change. Like all energy sources, however, electricity generation from wind has impacts on wildlife that must be considered. Although there is no regulated national process regarding pre-construction environmental assessments and the literature remains unclear on how these assessments affect outcomes, concerns about wildlife impacts are reflected in wildlife surveys and assessments typically completed in the siting and permitting of wind projects [257]. With the increased levels of deployment described by the *Study Scenario*, a greater impact on wildlife from wind will be expected. However, impacts can be reduced on a per-turbine basis using improvements in project siting, impact minimization, mitigation, and compensation strategies. Impacts should also be balanced against the wildlife benefits that wind energy might provide through the displacement of other generation options, their direct impacts to wildlife, and their impacts on climate change.

An overview of the current impacts of wind development on avian and bat species is provided in Chapter 2. Increasing wind deployment under the *Study Scenario* through 2050 is not expected to directly and materially impact most common bird species, i.e., passerines. Direct fatalities of as many as 1 million birds per year could be expected in 2030 and 2 million per year in 2050,[151] using current fatality estimates and not taking into consideration additional improvements in siting practices and future avoidance and minimization techniques that could reduce impacts over time. Although general and regionally-specific cumulative impacts must be considered, the direct wildlife impact associated with wind energy development and operation represented by these figures is a small fraction of the birds killed annually by communication towers, power lines, and buildings (See Table 2-7).

Though learning is still needed regarding impacts of wind deployment on common bat species, the overall impact is expected to be low, especially with the development of effective avoidance, minimization, and mitigation strategies over the last few years, as outlined in Section 2.8.1. The general and regional cumulative impacts of White Nose Syndrome as well as anthropogenic causes, however, may be significant, especially for populations that are already imperiled. The impacts of the *Study Scenario* on rare, protected, and endangered species must also be considered. In some instances, future wind project siting might simply avoid areas in which such species live. In other cases, active minimization or compensation strategies can be employed, such as changing operational conditions of wind turbines during periods of high risk associated with bat migration, or supporting species recovery programs to minimize the net species impact, if appropriate. Such strategies will increase the cost of wind energy, and those costs would ideally be balanced against the benefits of wind energy in facilitating a transition away from conventional energy sources and related climate and wildlife impacts [258].

Although the relationship between pre-construction activity and post-construction impacts, particularly for bird and bat collisions, is not well understood [257], the wind industry has and is expected to continue to invest in assessing risks to wildlife, and in avoiding, minimizing, or compensating for predicted project-level impacts. The wind community also continues to help fund larger-scale research to reduce the impact of expanded wind development. For example, the industry co-founded the American Wind Wildlife Institute in 2008 to facilitate research aimed at minimizing impacts to wildlife. Given these efforts, a continuing reduction in the uncertainty around risk assessments is anticipated. This should increase consistency in the protocols for pre-construction wildlife surveys and post-construction monitoring, potentially leading to reductions in per-MW wildlife impacts and a more transparent process for understanding overall impact of expanded wind development. There are also efforts underway to make wildlife data collected

151. Collision fatality rates for birds at land-based facilities average 3–5 birds per year [257, 259, 260, 261]. Estimated annual fatalities in 2030 and 2050 use a conservative high average of 5 birds/MW per year and the *Central Study Scenario* estimate of 224 GW in 2030 and 404 GW in 2050. Specific mortality rates are dependent on the local habitat, and this simple calculation assumes a similar geographic distribution of further wind installations. Additionally, research indicates that avian impacts of offshore wind development will be reduced compared to land-based deployment. This offshore effect is not considered [262], likely leading to an overestimation of the potential impact. Finally, these estimates presume no further improvements in reducing fatality rates over time, which is a conservative conclusion.

at wind power plants available for scientific analysis, with the expectation that analyses of comprehensive datasets will reduce uncertainties about wildlife impacts and improve the ability to predict impacts during the siting process.

The broader, habitat-level impacts of wind energy on wildlife are less understood and are dependent upon numerous site-specific factors. Concerns often focus on indirect effects. For example, the disturbance from operating wind projects is hypothesized to cause species displacement, fragmentation of habitat, and demographic decline. Species of prairie grouse (in particular, greater sage-grouse and both greater and lesser prairie chicken) avoid breeding sites in the proximity of tall structures. Few published studies have tested this hypothesis regarding wind power plants [263, 264], and other studies [265, 266] have called into question whether tall structures themselves or other factors like road noise are the true cause of this effect. Even less is known about the wildlife impacts of offshore wind development in the United States. Existing studies and those anticipated to be done once the U.S. offshore wind industry develops can be expected to bolster data from Europe to facilitate assessing and, to the extent possible, mitigating any identified impacts. Baseline assessments and the mapping of use patterns and habitats of marine organisms that are likely to be impacted by offshore wind energy development are important as well, to allow wind developers to anticipate and mitigate potential impacts.

Though not all impacts can be fully mitigated, the process of siting wind power plants has evolved significantly since the early days of the industry and is expected to continue to do so over the coming decades, decreasing impacts on local wildlife. Further progress can be made with increased research on and information-sharing of the observed impacts of wind energy deployment, particularly in comparison to other energy-generating technologies. This will provide a better understanding of the tradeoffs between development of wind and other energy technology options.

3.12.4 Aviation Safety and Radar Impacts

Wind projects can impact aircraft and weather radar systems and general aviation. Assuming continued minimization of potential impacts and mitigation of any resulting impacts, the wind deployment levels under the *Study Scenario* are not anticipated to have a significant effect on critical missions served by advanced radars, e.g., flight safety, severe weather warnings, commerce, and control of U.S. borders and airspace. The total cost of wind projects may increase, however, to address these local issues through the implementation of increased mitigation measures, reduced site availability, and increased permitting requirements.

Future strategies to minimize and mitigate the effects of wind development on radar systems will likely include improved algorithms such as clutter filters and other filtering techniques, advanced signal processing, and intelligent detection algorithms. Further mitigation may occur through new technologies or variations of old technologies via hardware and software changes, such as the upgrade of Air Route Surveillance Radars, concurrent beam processing, creation of radar networks and fusing of data from multiple radars, or operational data-sharing. Other mitigation techniques that have been or could be used include project developer-supported adaptation (through personnel training) or, in rare instances, radar upgrades, repositioning, or mission relocation. Modeling, simulation, and smarter planning through improved siting tools will be important to remove and mitigate wind turbine and radar interactions. The U.S. Department of Defense has begun negotiating wind project curtailments with developers. These curtailments allow projects to proceed while insuring that the turbines will not impact defense operations during critical times. All of these advancements, combined with a growing understanding of issues and the deployment of new radar systems that are better at eliminating erroneous signals caused by wind turbines, will continue to mitigate the impacts of wind deployment.

Issues related to aircraft safety (beyond possible radar interference) may also be of concern. Although wind turbines may increase to more than 500 feet (152.4 m) in total height, federal permitting and requirements around critical infrastructure are not anticipated to impact overall deployment. Local aviation-related issues will also be addressed through increased mitigation measures such as the use of expanded lighting or flight avoidance technology and through increased permitting requirements. These steps could add modestly to the costs of wind development.

3.12.5 Aesthetics and Public Acceptance

Local community concerns about wind projects can be expected as wind development expands and approaches the levels of the *Study Scenario*. Future wind plants will likely be in closer proximity to larger population centers. A comparison of existing wind deployment by state against the expected deployment under the *Study Scenario* shows that a substantial amount of new wind will be located in states that have already experienced extensive wind deployment. Even in these states, though, significant additional wind deployment would be needed, often in areas without prior wind development. Additionally, many states and offshore areas that have not experienced significant wind development are anticipated to see new wind deployment under the *Study Scenario,* e.g., the southern Atlantic states, such as South Carolina, as well as southern states including Arkansas, Tennessee, and Alabama. Though wind development in remote areas is also anticipated, wind deployment levels under the *Study Scenario* could lead to increased local conflicts over aesthetic and other concerns, given greater development near population centers.

Public attitudes toward land-based and offshore wind are generally supportive [267]. Although not conclusive, research as recent as 2014 suggests that existing wind projects have not led to any widespread reduction in the home values of surrounding properties [268, 269, 270, 271]. Moreover, as previously described, the local positive economic development benefits of wind projects can be substantial, providing not only local jobs, but additional tax revenue and land use payments [210, 213, 245, 248, 272].

Despite these findings, public acceptance in communities that host wind facilities is highly dependent on local conditions and can change depending on whether benefits are provided and whether community members feel that their values are respected during the development process [273, 274]. Community conflicts surrounding potential wind development can and do occur. As a result, early community involvement, careful attention to local concerns, and advancements in development and siting procedures may be needed to achieve the wind deployment levels in the *Study Scenario* while also reducing the prevalence of local conflicts. Expanded community engagement using more accessible peer-reviewed information, increasingly sophisticated assessment tools, and technology advancements to mitigate potential impacts can help reduce local concerns. Ultimately, although doing so would increase the costs of wind deployment, the available U.S. wind resource is more than sufficient to meet the deployment needs outlined in the *Study Scenario* even if areas are removed from consideration or require expanded mitigation.

3.12.6 Potential Health and Safety Impacts

As with other electric generation facilities, there are several health and safety concerns that have been identified in the development and operation of land-based and offshore wind projects, including wind turbine blade-induced shadow flicker, sound, general safety, and marine safety. As described in greater depth in Chapter 2, much is already known and many studies have documented the limited potential impacts of wind development [274, 275, 276, 277, 278, 279]. Most of these issues are addressed through the implementation of thoughtful permitting and zoning guidelines and careful study during the project development process. As has been discussed previously, there are no defined standard guidelines for the permitting of wind power plants, although several examples have been publicly offered [280, 281, 282].

Although some questions remain, numerous state and federal organizations, non-governmental organizations, and the larger wind industry continue to work to understand, document, and mitigate current or future impacts. Over the long-term horizon of the *Wind Vision*, the number of turbines will increase dramatically, potentially increasing health and safety concerns and requiring careful attention. At the same time, with regulatory and statutory oversight, careful and considerate wind development, and use of mitigation strategies, health and safety impacts can be reduced.

This chapter has identified a large number of benefits to wind deployment for the nation as a whole: cleaner air, reduced water stress, stable energy prices and, in the longer term, reduced impacts from climate change. These larger national benefits must also be included in the consideration of the positive and negative local impacts of wind development. Ongoing communication of these benefits at the national and local levels will be essential to maintaining high levels of both general and local support for wind development.

3.13 Unique Benefits of Offshore and Distributed Wind

Offshore and distributed wind have unique benefits that should be considered in evaluating the overall value of wind power to the nation's electricity supply.

3.13.1 Offshore Wind

In order for offshore wind to be economically competitive, the cost of the technology needs to be reduced. Through innovation and increasing scale, however, this market segment could bring notable potential benefits. The attributes for offshore wind's contribution to the *Study Scenario* are characterized by a robust industrial base that evolves from the nascent state of 2013 to supply more than 80 GW of capacity by 2050. This deployment represents about 5.5% of the available offshore resource after exclusions for environmental and other protected areas or just 2% of the gross resource potential, estimated at 4,000 GW for offshore areas adjacent to the 28 coastal states [283]. Under the *Study Scenario*, the offshore wind industry would complement and bolster a strong land-based industry through the use of common supply chain components and the development of workforce synergies. While a sharp decline in offshore wind costs is anticipated with increased industrial scale (see Section 3.2.1.2), the following sections highlight unique cost drivers and benefits of offshore wind not otherwise assessed in Chapter 3 that may contribute to economic viability.

3.13.1.1 Major Renewable Resource for Coastal States

U.S. counties situated on the coasts constitute less than 10% of the country's total land area (excluding Alaska), but almost 40% of the total population [284]. With high land values and an average population density six times greater than in corresponding inland counties, coastal areas frequently lack suitable sites for new utility-scale electric generation facilities. From the perspective of land use and site availability in densely populated coastal states, offshore wind is one of the most potentially viable large-scale renewable energy options. In some cases, offshore wind may be one of the only electric generation options that can be practically developed at a large scale using indigenous energy sources.

3.13.1.2 Reduced Transmission Requirements

Building electric transmission lines from interior land-based wind (or other electric generation) sites to coastal population centers may avoid the need for new local, large-scale generation in these areas. There is, however, significant uncertainty associated with the cost of building new transmission, and even greater uncertainty associated with the feasibility of planning, permitting, and cost recovery [285]. For example, there is no currently accepted method of planning and allocating the cost of multi-state electric transmission projects spanning from the Midwest to the East Coast; in fact, there is evidence that some policy makers in coastal states are opposed to such infrastructure [286]. The development of offshore wind can reduce the need for new investments in long-distance transmission and avoid complex (and sometimes contentious) transmission projects [2, 64, 63]. At the same time, offshore wind does require some offshore transmission infrastructure, and so presents a unique opportunity for efficient centralized management of offshore transmission planning and development. Since the federal government and state governments control most of the offshore space, a new offshore transmission infrastructure could avoid some of the complexity and fragmentation resulting from numerous over-land private property easements and could provide a more robust electric network for congested coastal areas. This would be possible with or without offshore wind development.

3.13.1.3 Lowered Wholesale Electricity Prices

Offshore wind might have a more significant impact in lowering wholesale electric prices in coastal states, at least in the near term, than land-based wind in other regions. In a large portion of the eastern United States, as well as in California and Texas, electric markets feature locational marginal pricing. This leads to wholesale prices that vary along time and geography, and that incorporate three cost components: energy, transmission congestion, and transmission losses. The marginal cost of energy in these markets is set by the highest-priced available unit of electricity required to support load at any given point in time and space (see discussion of merit-order effect in Text Box 3-6). Higher prices are typically experienced during the day and during the summer, when load is high. Pricing is also higher in urban areas; for example, during the day in New York State, prices can average 50–100% higher in New York City and Long Island than in rural upstate areas.

Offshore wind can help lower transmission congestion and losses by taking advantage of relatively short interconnection distances to urban electric grids in coastal and Great Lakes states. This means that offshore wind could help depress locational marginal pricing in these areas, reducing electricity prices to utilities, at least in the short run. Though there are many nuances behind these possible effects (Text Box 3-6), and similar locational marginal pricing effects can apply to any generating source, the impact is potentially stronger for offshore wind due to its proximity to the highest transmission congestion regions, such as the northeastern United States. Research that has explored these effects includes that of Levitan and Associates [287] for New Jersey, Charles River Associates [288] for New England, and GE Energy, EnerNex, and AWS Truepower [63] for New England. Although these more global market price reductions cannot be attributed to lowering the cost of energy for offshore wind projects, they can potentially provide incentives at the utility level to raise the price point for grid parity with other energy sources.

3.13.1.4 Higher Capacity Value Relative to Land-Based Wind

The capacity value of a power plant is the amount of generation that can be relied upon to meet load during critical periods. The variability of wind energy has contributed to a general perception that it has a low capacity value. Indeed, some land-based wind energy projects have shown a poor correlation with peak demand, and the ReEDS modeling for the *Study Scenario* shows a steep decline in the capacity value of wind as penetrations increase toward 2050 (see Section 3.6.1). Notwithstanding these concerns, studies show that offshore wind in the mid-Atlantic, South Atlantic and New England regions has a higher capacity value than typical land-based wind sites. This is partly because the geophysical weather patterns responsible for peak electric loads on the East Coast often also enhance wind flows over adjacent offshore waters; offshore winds often peak in the afternoon and evening, whereas land-based winds often peak at night [63, 64, 289, 290]. As a result, the market value of offshore wind may be higher than that of land-based wind in the same region.

3.13.1.5 Fuel Diversity and Risk Reduction

As discussed in Section 3.10, the *Study Scenario* offers potential energy diversity and risk reduction benefits. Offshore wind, in particular, can help diversify coastal states' fuel mix and help them hedge against future price increases or supply disruptions of natural gas. Coastal states have among the highest electricity prices in the nation [4], driven in part by constraints in gas pipeline infrastructure coupled with congestion in the electric transmission system. In New England, for example, greater diversity would help alleviate the region's heavy reliance on natural gas, the supply of which has become constrained especially in winter months [4, 291]. As noted by ISO New England [291], "over-reliance on natural gas subjects the New England region to substantial price fluctuations that are influenced by a variety of market-based factors (i.e. exercising of natural gas contractual rights, tight gas spot-market trading), and technical factors (i.e. pipeline maintenance requirements and limited pipeline capacity)." DOE has also previously highlighted this issue in a 2004 report, stating: "To alleviate New England's volatile energy market and reduce its over-reliance on natural gas, the region needs to pursue an energy policy that is focused on fuel diversity. Increased use of renewable energy will enable New England to diversify the region's energy portfolio, thereby increasing electric reliability and lowering energy costs by utilizing local resources in the generation of electricity [292]." On the Atlantic, offshore wind tends to be winter-peaking, so it is well matched to compensate for cold-weather natural gas shortages.

3.13.1.6 Wind-Related Jobs and Local Economic Development

Due to its physical scale and local infrastructure requirements, offshore wind can bring significant wind-related jobs and local economic activity to coastal states, and government support for offshore wind has often hinged on these potential benefits [293, 294, 295, 296]. In 2012, Europe had approximately 58,000 workers employed in the offshore wind sector; the European Wind Industry Association notes that the industry, which barely existed a decade ago, has helped revitalize certain coastal cities as industrial hubs [297]. The same could be true in the United States. Studies of the potential local economic development and gross employment impacts of offshore wind in the United States include those by Keyser et al. [244], Flores et al. [242], and Navigant [240]. As discussed in Section 3.11, the offshore wind deployment envisioned in the *Study Scenario* results in an estimated 32,000–34,000 offshore wind-related jobs in 2020, increasing to 76,000–80,000 in 2030 and 170,000–181,000 in 2050.

3.13.1.7 Environmental Impacts and Siting Challenges

Offshore wind was formally introduced to the United States through the Energy Policy Act of 2005, known as EPAct. The Bureau of Ocean Energy Management was assigned regulatory jurisdiction, and stakeholders have cautiously welcomed offshore wind as a potential new member of the ocean use community. Nevertheless, some offshore wind projects have faced opposition from stakeholder groups that cite possible impacts ranging from degradation of the view-scape to avian mortality. As of 2014, carefully vetted offshore wind energy areas have emerged through federal and state marine spatial planning processes [298], especially in the Atlantic and Great Lakes. Relative to land-based projects in densely populated communities, large offshore wind projects can be located at sea, away from people, thereby potentially reducing the impacts to project neighbors from project construction and operation. There is also the potential that with projects located farther offshore, the risk to wildlife and sensitive environmental receptors such as birds and bats may be diminished as many sensitive ecosystems are closer to shore. Even far from shore, however, there are siting issues to address, including the migratory pathways, feeding, breeding, and nursery habitats of marine mammals as well as birds, bats, and fish (see Section 3.12).

3.13.2 Distributed Wind

Distributed wind applications, including customer-sited wind and wind turbines embedded in distribution networks, offer a number of unique benefits not otherwise analyzed in the *Wind Vision*. More specifically, distributed wind turbines give individuals and communities an opportunity to learn directly about wind power, empowering more localized discussion and growth for all wind power projects. The following sections highlight more examples of benefits resulting from distributed wind.

3.13.2.1 Economic Development

Distributed wind creates local economic development and job opportunities linked to the manufacturing, sales, installation, and maintenance of wind turbines used in distributed applications. Installation materials, services, and labor account for about 30% of the total installed cost for small wind turbines [299]. Domestic distributed wind investments in 2012 totaled $410 million. Of that amount, $101 million is attributed to the small wind turbine market segment, and an estimated $30 million of that value was therefore invested in installation materials, services, and labor from small turbines. U.S. suppliers dominate the domestic small wind turbine market, claiming 93% of 2013 sales on a unit basis and 88% on a capacity basis [15].U.S. small wind turbine suppliers also source most of their turbine components from domestic supply chain vendors, maintaining domestic content levels of 80–95% for turbine and tower hardware [300].

3.13.2.2 Utility Bill Reduction and Risk Protection

On-site distributed wind turbines allow farmers, schools, small businesses, and other energy users to benefit from reduced utility bills and predictable controlled costs and to hedge against the possibility of rising retail electricity rates. Once the wind system is paid off, the cost of the electricity produced is minimal, reflecting only the cost of ongoing maintenance. Distributed wind systems can also provide the owner with a sense of self-reliance.

The implementation of distributed wind on a community basis—whether through development by municipal utilities, local government organizations, or in isolated community power systems— can also provide wider community benefits of lower energy costs, higher reliability, and reduced sensitivity to fuel commodity prices. Of course, distributed wind is a highly location-dependent energy source, as its energy generation potential relies on the quality of the site's wind resource. The technology is therefore not appropriate for every community.

3.13.2.3 Electric Grid Benefits

Decentralized generation such as distributed wind can benefit the electrical grid. Distributed wind turbines installed in strategic locations can provide reactive power support and thereby benefit weak distribution grids that experience voltage-regulation problems [301]. Distributed wind systems do not require the construction of new transmission capacity, usually relying instead on available capacity on local distribution grids. In fact, distributed wind may at times lessen or mitigate a utility's need for distribution grid upgrades (if the output of such systems correlates well with the peak load on the distribution circuit), and it can help reduce transmission congestion [301]. While distributed wind systems utilize existing distribution grids, many distribution systems—particularly rural ones—would benefit from upgrades and modernization to improve their efficiency [302] and the integration of increasing amounts of distributed generation. This is true even though such upgrades could be costly. Utilities see the rise in distributed generation as both a threat to the traditional utility model as well as an opportunity for utility growth [303, 304].

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