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2016 **Wind Technologies Market Report**

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2016 Wind Technologies Market Report

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Table of Contents

Table of Contents i
Acknowledgments i
Acronyms and Abbreviations ii
Executive Summary iv
1. Introduction 1
2. Installation Trends 4
3. Industry Trends 12
4. Technology Trends 26
5. Performance Trends 36
6. Cost Trends 47
7. Wind Power Price Trends 57
8. Policy and Market Drivers 65
9. Future Outlook 73
References 75
Appendix: Sources of Data Presented in this Report 78

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Acronyms and Abbreviations

AWEA	American Wind Energy Association
BNEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
BOEM	Bureau of Ocean Energy Management
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EDPR	EDP Renováveis
EEI	Edison Electric Institute
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
GE	General Electric Corporation
GW	gigawatt
HTS	Harmonized Tariff Schedule
ICE	Intercontinental Exchange
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
ITC	investment tax credit
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
m^2	square meter
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	operations and maintenance
OEM	original equipment manufacturer
PJM	PJM Interconnection
POU	publicly owned utility
PPA	power purchase agreement
PTC	production tax credit
REC	renewable energy certificate

RGGI	Regional Greenhouse Gas Initiative
RPS	renewables portfolio standard
RTO	regional transmission organization
SPP	Southwest Power Pool
USITC	U.S. International Trade Commission
W	watt
WAPA	Western Area Power Administration

Executive Summary

Wind power capacity in the United States experienced strong growth in 2016. Recent and projected near-term growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Wind additions have also been driven by improvements in the cost and performance of wind power technologies, yielding low power sales prices for utility, corporate, and other purchasers. At the same time, the prospects for growth beyond the current PTC cycle remain uncertain, given declining federal tax support, expectations for low natural gas prices, and modest electricity demand growth.

Key findings from this year's *Wind Technologies Market Report* include:

Installation Trends

- **Wind power additions continued at a rapid pace in 2016, with 8,203 MW of new capacity added in the United States and $13.0 billion invested.** Supported by favorable tax policy and other drivers, cumulative wind power capacity grew by 11%, bringing the total to 82,143 MW. The nation's first offshore project was also commissioned in 2016, the 30 MW Block Island project in Rhode Island.
- **Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2016, behind solar and natural gas.** Wind power constituted 27% of all capacity additions in 2016. Over the last decade, wind represented 31% of all U.S. capacity additions, and an even larger fraction of new capacity in the Interior (56%) and Great Lakes (48%) regions. Its contribution to generation capacity growth over the last decade is somewhat smaller in the Northeast (21%) and West (20%), and considerably less in the Southeast (2%). [See Figure 1 for regional definitions].
- **The United States ranked second in annual wind additions in 2016, but was well behind the market leaders in wind energy penetration.** Global wind additions equaled 54,600 GW in 2016, 14% below the record-level in 2015, yielding a cumulative total of 486,700 MW. The United States is the second-leading market in terms of cumulative capacity and 2016 annual wind energy production, behind China. A number of countries have achieved high levels of wind penetration; end-of-2016 wind power capacity is estimated to supply the equivalent of more than 40% of Denmark's electricity demand, and between 20% and 35% of demand in Portugal, Ireland, and Spain. In the United States, the wind capacity installed by the end of 2016 is estimated, in an average year, to equate to 6.4% of electricity demand.
- **Texas installed the most capacity in 2016 with 2,611 MW, while fourteen states exceeded 10% wind energy penetration.** New utility-scale wind turbines were installed in 23 states in 2016. On a cumulative basis, Texas remained the clear leader, with 20,320 MW. Notably, the wind capacity installed in Iowa and South Dakota supplied more than 36% and 30%, respectively, of all in-state electricity generation in 2016, with Kansas close behind at nearly 30%. A total of nine states have achieved wind penetration levels of 15% or higher.
- **Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration.** At the end of 2016, there were 142 GW of wind power capacity seeking transmission interconnection, representing 34% of all generating capacity in the reviewed interconnection queues—higher than all other generating sources. In 2016, 67 GW of wind power capacity entered interconnection queues (the largest annual

sum since 2009), compared to 83 GW of solar and 40 GW of natural gas. The Midwest and Southern Power Pool experienced especially sizable additions in 2016.

Industry Trends

- **Vestas and GE captured 85% of the U.S. wind power market in 2016.** In 2016, Vestas captured 43% of the U.S. market for turbine installations, just edging out GE at 42% and followed more distantly by Siemens at 10%. Vestas was also the leading wind supplier worldwide in 2016, followed by GE, Goldwind, Gamesa, and Enercon. Chinese manufacturers continued to occupy positions of prominence in the global ratings, with four of the top 10 spots; to date, their growth has been based almost entirely on sales in China.
- **The manufacturing supply chain continued to adjust to swings in domestic demand for wind equipment.** Domestic wind sector employment reached a new high of more than 101,000 full-time workers in 2016. Moreover, the profitability of turbine suppliers has rebounded over the last four years. Although there have been a number of plant closures over the last 5+ years, each of the three major turbine manufacturers serving the U.S. market has domestic manufacturing facilities. Domestic nacelle assembly capability stood at roughly 11.7 GW in 2016, and the United States had the capability to produce approximately 8 GW of blades and 7 GW of towers annually. The domestic supply chain faces conflicting pressures, including significant near- to medium-term growth, but also strong international competitive pressures and an anticipation of reduced demand over time as the PTC is phased down. As a result, though some manufacturers increased the size of their U.S. workforce in 2016, expectations for significant supply-chain expansion have become less optimistic.
- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports**. The United States is reliant on imports of wind equipment from a wide array of countries, with the level of dependence varying by component. Domestic content is highest for nacelle assembly (>90%), towers (65-80%), and blades and hubs (50-70%). Exports of wind-powered generating sets from the United States rose from $16 million in 2007 to $488 million in 2014, but fell back to $17 million in 2016.
- **The project finance environment remained strong in 2016.** The U.S. wind market raised more than $6 billion of new tax equity in 2016, on par with the two previous years. Debt finance increased slightly to $3.4 billion. Tax equity yields drifted slightly higher to just below 8% (in unlevered, after-tax terms), while the cost of term debt fell below 4% for much of the year, before rising back above that threshold towards the end of the year. Looking ahead, 2017 should be another busy year, given the abundance of safe-harbored turbines (those committed to prior to the end of the year to qualify for the full PTC) to be deployed.
- **IPPs own the vast majority of wind assets built in 2016.** Independent power producers (IPPs) own 87% of the new wind capacity installed in the United States in 2016, with the remaining assets owned by investor-owned utilities (12%) and other entities (1%). On a cumulative basis through 2016, IPPs own 83% and utilities own 15% of U.S. wind capacity, with the remaining 2% owned by entities that are neither IPPs nor utilities (e.g., towns, schools, businesses, farmers).
- **Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales gained ground.** Electric utilities continued to be the dominant off-takers of wind power in 2016, either owning wind projects (12%) or buying

electricity from projects (40%) that, in total, represent 52% of the new capacity installed last year. Direct retail purchasers—including corporate off-takers—account for 24% (a share that should continue to increase next year). Merchant/quasi-merchant projects (22%) and power marketers (1%) make up the remainder. On a cumulative basis, utilities own (15%) or buy (51%) power from 66% of all wind capacity in the United States, with merchant/quasi-merchant projects accounting for 23%, power marketers 6%, and direct retail buyers 4% (and likely to increase in the coming years).

Technology Trends

- **Average turbine capacity and rotor diameter saw significant increases in 2016, while hub height increased only slightly; all have grown over the long term.** The average rated (nameplate) capacity of newly installed wind turbines in the United States in 2016 was 2.15 MW, up 11% from the average over the previous 5 years (2011–2015). The average rotor diameter in 2016 was 108 meters, a 13% increase over the previous 5-year average, while the average hub height in 2016 was 83 meters, up just 1% over the previous 5-year average.
- **Year over year growth in rotor diameters has continued unabated for more than a decade, and has outpaced growth in nameplate capacity and hub height.** Rotor scaling has been especially significant in recent years, and has outpaced increases in turbine capacity and hub heights. In 2008, no turbines employed rotors that were 100 meters in diameter or larger; by 2016, 97% of newly installed turbines featured rotors of at least that diameter, with over 50% of newly installed turbines featuring rotor diameters of 110 meters or larger.
- **Turbines originally designed for lower wind speed sites have rapidly gained market share.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average "specific power" [i] (in W/m^2), from 394 W/m^2 among projects installed in 1998–1999 to 233 W/m^2 among projects installed in 2016. In general, turbines with low specific power were originally designed for lower wind speed sites. Another indication of the increasing prevalence of lower wind speed turbines is that, in 2016, the overwhelming majority of new installations used IEC Class 3 and Class 2/3 turbines—turbines specifically certified for lower wind speed sites.
- **Turbines originally designed for lower wind speeds are regularly employed in both lower and higher wind speed sites; taller towers predominate in the Great Lakes and Northeast.** Low specific power and IEC Class 3 and 2/3 turbines are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites. In parts of the Interior region, in particular, turbines designed for lower wind speeds have been deployed across a wide range of resource conditions. The tallest towers, meanwhile, have principally been deployed in the Great Lakes and Northeastern regions, in lower wind speed sites, with specific location decisions likely driven by the wind profile at the site.
- **Pending and proposed wind power projects continue the trend of ever-taller turbines as lower wind resource sites appear to be targeted.** Federal Aviation Administration data on not-yet-built "pending" and "proposed" turbines suggest that future wind projects will deploy progressively taller turbines, continuing the historical trend. Based on the locations of the

[i] A wind turbine's specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.

pending and proposed turbines, it appears that these turbines will be deployed in lower-quality wind resource areas than were built out in 2014–2016.

- **A large number of wind power projects in 2016 employed multiple turbine configurations from a single turbine supplier.** In what may be a new trend, nearly a quarter of the larger projects built in 2016 utilized turbines with multiple hub heights, rotor diameters and/or capacities—all supplied by the same original equipment manufacturer (OEM). This development may reflect increasing sophistication with respect to turbine siting and wake effects, coupled with an increasing willingness among turbine suppliers to provide multiple turbine configurations, leading to increased site optimization.

Performance Trends

- **Sample-wide capacity factors have gradually increased, but have been impacted by curtailment and inter-year wind resource variability.** Wind project performance, as illustrated with data on capacity factors, has generally increased over time. However, inter-year variations in the strength of the wind resource and changes in the amount of wind energy curtailment have partially masked the positive influence of turbine scaling on wind project performance. On average across the United States and for 2016 as a whole, wind speeds were near-normal, while wind energy curtailment remained modest at ~2%.
- **The impact of technology trends on capacity factors becomes more apparent when parsed by project vintage.** Focusing only on performance in 2016 and analyzing capacity factors by project vintage tells a more interesting story, wherein rotor scaling over the past few years has clearly driven capacity factors higher. The average 2016 capacity factor among projects built in 2014 and 2015 was 42.5%, compared to an average of 32.1% among projects built from 2004–2011 and just 25.4% among projects built from 1998 to 2001. The ongoing decline in specific power, however, has been offset to some degree by a trend—especially from 2009 to 2012—towards building projects at lower-quality wind sites. Controlling for these two influences shows that turbine design changes are driving capacity factors significantly higher over time among projects located in given wind resource regimes. Though many caveats are in order, older wind projects appear to suffer from performance degradation, particularly as they approach and enter their second decade of operations.
- **Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology.** Based on a sub-sample of wind projects built in 2014 or 2015, average capacity factors in 2016 were the highest in the Interior region (43.7%). Not surprisingly, the regional rankings are roughly consistent with the relative quality of the wind resource in each region, and they reflect the degree to which each region has adopted turbines with lower specific power or taller towers. For example, the Great Lakes has thus far adopted these new designs—and especially taller towers—to a much larger extent than some other regions, with corresponding implications for average regional capacity factors.

Cost Trends

- **Wind turbine prices remained well below levels seen a decade ago.** After hitting a low of roughly $800/kW from 2000 to 2002, average turbine prices increased to roughly $1,600/kW by the end of 2008. Wind turbine prices have since dropped substantially, despite increases in hub heights and especially rotor diameters. Recent data suggest pricing most-typically in the

$800–$1,100/kW range. These price reductions, coupled with improved turbine technology, have exerted downward pressure on project costs and wind power prices.

- **Lower turbine prices have driven reductions in reported installed project costs.** The capacity-weighted average installed project cost within our 2016 sample stood at roughly $1,590/kW. This is down $780/kW from the apparent peak in average reported costs in 2009 and 2010, but is roughly on par with—or even somewhat higher than—the installed costs experienced in the early 2000s. Early indications from a preliminary sample of projects currently under construction and anticipating completion in 2017 suggest no material change in installed costs in 2017.
- **Installed costs differed by project size, turbine size, and region.** Installed project costs exhibit some economies of scale, at least at the lower end of the project size range. Additionally, among projects built in 2016, the windy Interior region of the country was the lowest-cost region, with a capacity-weighted average cost of $1,530/kW.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, it appears that projects installed over the past decade have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first several years of operation. O&M costs increase as projects age.

Wind Power Price Trends

- **Wind power purchase agreement (PPA) prices remain very low.** After topping out at $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to around the $20/MWh level—though this latest nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country, where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from ~$55/MWh among contracts executed in 2009 to ~$20/MWh today. Today's low PPA prices have been enabled by the combination of higher capacity factors, declining costs, and record-low interest rates documented elsewhere in this report.
- **The relative economic competitiveness of wind power has been affected by the continued decline in wholesale power prices.** A continued decline in wholesale power prices in 2016 made it somewhat harder for wind power to compete, notwithstanding the low wind energy PPA prices available to purchasers. This is particularly true in light of the continued expansion of wind development in the Interior region, where wholesale power prices are among the lowest in the nation. That said, the average future stream of wind PPA prices from contracts executed in 2014–2017 compares very favorably to the EIA's latest projection of the fuel costs of gas-fired generation extending out through 2050.

Policy and Market Drivers

- **The federal production tax credit remains a core motivator for wind power deployment.** In December 2015, Congress passed a 5-year phased-down extension of the PTC, which provides the full PTC to projects that start construction prior to the end of 2016, before dropping in increments of 20 percentage points per year for projects starting construction in 2017 (80% PTC), 2018 (60%), and 2019 (40%). In May 2016, the IRS issued favorable guidance allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. According to various sources, 30-70 GW of wind turbine capacity had been qualified for the full PTC by the end of 2016, for deployment over the coming four years.

- **State policies help direct the location and amount of wind power development, but current state policies cannot support continued growth at recent levels.** As of June 2017, RPS policies existed in 29 states and Washington D.C. Of all wind capacity built in the United States from 2000 through 2016, roughly 51% is delivered to load-serving entities with RPS obligations. Among wind projects built in 2016, this proportion fell to 21%. Existing RPS programs are projected to require average annual renewable energy additions of roughly 3.9 GW/year through 2030, only a portion of which will come from wind. These additions are well below the average growth rate in wind power capacity in recent years.
- **System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain.** Studies show that wind energy integration costs are almost always below $12/MWh—and often below $5/MWh—for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. System operators and others continue to implement a range of methods to accommodate increased wind energy penetrations. About 1,000 miles of transmission lines came on-line in 2016—less than in previous years. The wind industry, however, has identified 14 near-term transmission projects that—if all were completed—could carry 52 GW of additional wind capacity.

Future Outlook

Analysts project that annual wind power capacity additions will continue at a rapid clip for the next several years, before declining, driven by the 5-year extension of the PTC signed in December 2015 and the progressive reduction in the value of the credit over time. Additionally, near-term additions are impacted by improvements in the cost and performance of wind power technologies, which contribute to low power sales prices. Demand drivers also include corporate wind energy purchases and state-level renewable energy policies. As a result, various forecasts for the domestic market show expected capacity additions averaging more than 9,000 MW/year from 2017 to 2020 (a pace that is supported by the amount of PTC-qualified wind turbine capacity that was reportedly safe-harbored by the end of 2016). Forecasts for 2021 to 2025, on the other hand, show a downturn in part due to the PTC phase-out. Expectations for continued low natural gas prices, modest electricity demand growth, and lower near-term demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and competition from solar energy in certain regions of the country. At the same time, the potential for continued technological advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and continued state RPS requirements. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse underlying potential trends, wind capacity additions—especially after 2020—remain deeply uncertain.

1. Introduction

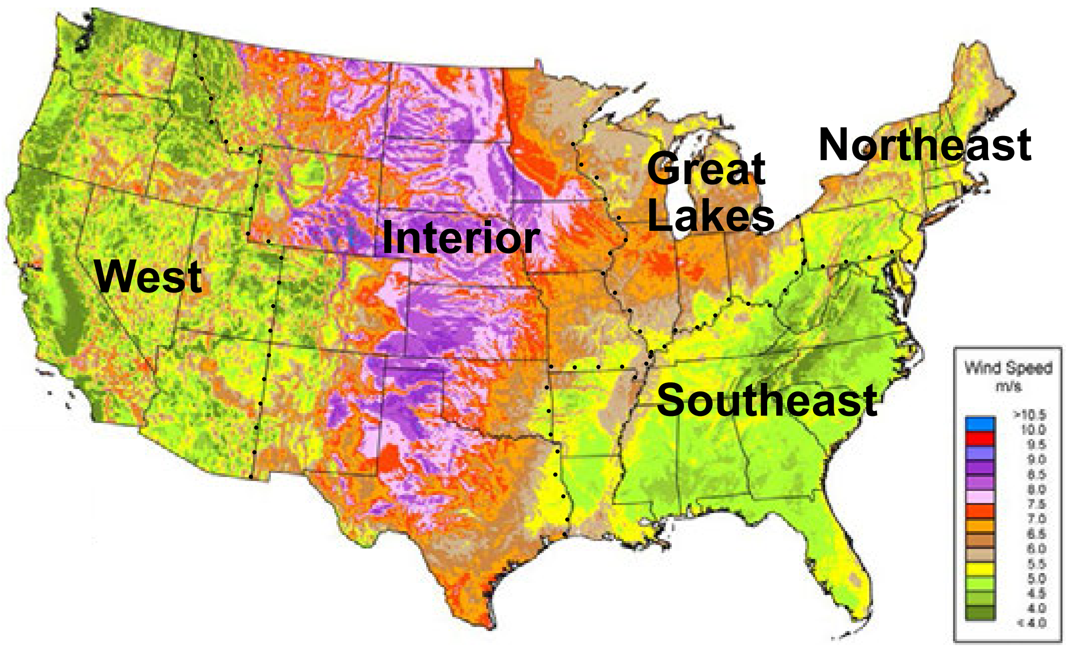
Wind power capacity additions in the United States continued at a rapid pace in 2016. Recent and projected near-term growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—having been extended (with a phase-down schedule) through 2019 as well as a myriad of state-level policies. Wind additions have also been driven by improvements in the cost and performance of wind power technologies, yielding low power sales prices for utility, corporate, and other purchasers. At the same time, the prospects for growth beyond the current PTC cycle remain uncertain, given declining federal tax support, expectations for continued low natural gas prices, and modest electricity demand growth.

This annual report—now in its eleventh year—provides an overview of developments and trends in the U.S. wind power market, with a particular focus on 2016. The report begins with an overview of installation-related trends: U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual states; and the quantity of proposed wind power capacity in various interconnection queues in the United States. Next, the report covers an array of wind industry trends: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into and exports from the United States; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a summary of wind turbine technology trends: turbine size, hub height, rotor diameter, specific power, and IEC Class. After that, the report discusses wind power performance, cost, and pricing. In so doing, it describes trends in project-level capacity factors, wind turbine transaction prices, installed project costs, and operations and maintenance (O&M) expenses. It also reviews the prices paid for wind power through power purchase agreements (PPAs) and how those prices compare to short-term wholesale electricity prices and forecasts of future natural gas prices. Next, the report examines market and policy factors impacting the domestic wind industry, including federal and state policy as well as transmission and grid integration issues. The report concludes with a preview of possible near-term market developments based on the findings of other analysts.

Many of these trends vary somewhat by state or region, depending in part on the strength of the local wind resource. To that end, Figure 1 superimposes the boundaries of five broad regions on a map of average annual U.S. wind speed at 80 meters above the ground.[1] These five regions will be referenced on many occasions throughout this report, whenever regional breakdowns or analysis is warranted, and so are defined here up front. Also note that any such breakdowns, regional or otherwise, may not always add to 100% due to the effect of rounding.

[1] The regional boundaries shown in Figure 1 have been delineated in an attempt to simultaneously satisfy three goals: having relative uniformity in average annual wind speed within each individual region, including enough states in each region to enable sufficient wind project sample size for regional breakdowns and analysis, and adhering as closely as possible to traditional regional boundaries.

This edition of the annual report updates data presented in previous editions while highlighting trends and new developments in 2016. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[2] The U.S. wind power sector is multifaceted, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Further information on *distributed wind power*, which includes smaller wind turbines as well as the use of larger turbines in distributed applications, is available through a separate annual report funded by the U.S. Department of Energy (DOE).[3] Additionally, because this report has an historical focus—and because only one offshore wind project is operational in the United States, having come online in late 2016—its treatment of trends in the offshore wind power sector is limited. A companion report funded by DOE that focuses exclusively on *offshore wind power* is also available.[4]



Source: AWS Truepower, National Renewable Energy Laboratory

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 80 meters

Much of the data included in this report were compiled by DOE's Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the U.S. Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the American Wind Energy Association (AWEA). The Appendix provides a summary of the many data sources used in the report, and a list of specific references follows the Appendix. In some cases, the data shown here represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. As such, emphasis should be placed on overall

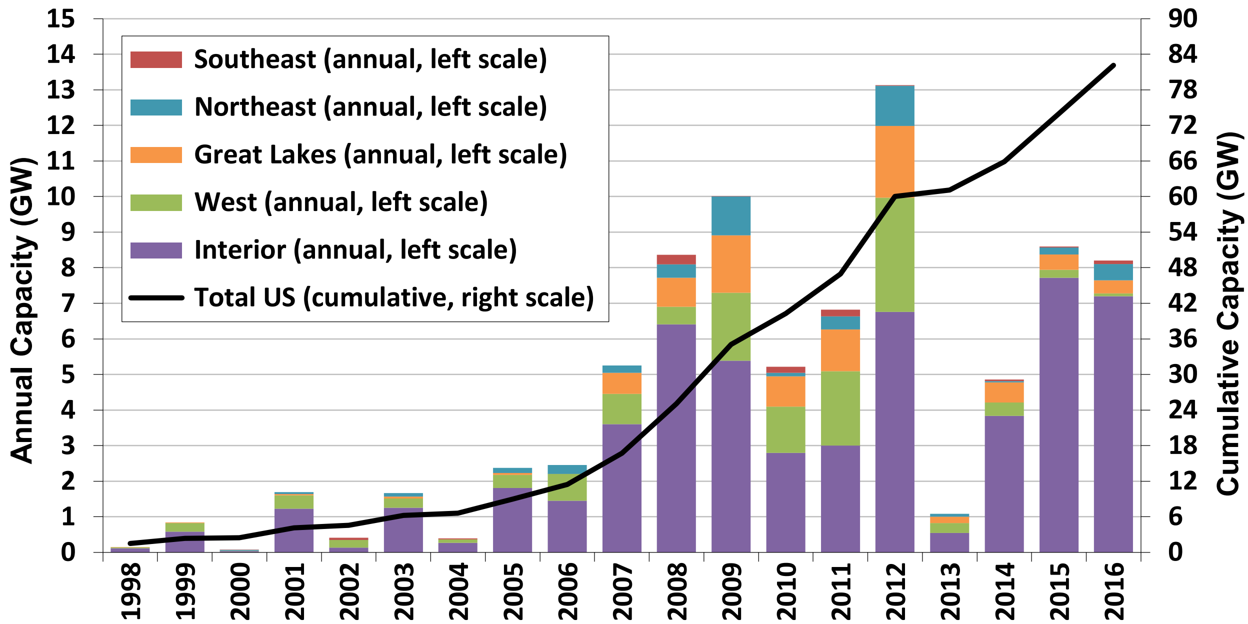
[2] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match AWEA's historical methodology, and is also justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, different cut-offs are used to better match AWEA's reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.
[3] See: https://energy.gov/eere/wind/downloads/2016-distributed-wind-market-report
[4] See: https://energy.gov/eere/wind/downloads/2016-offshore-wind-market-report

trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market information, with an emphasis on 2016. With some limited exceptions—including the final section of the report—the report does not seek to forecast trends.

2. Installation Trends

Wind power additions continued at a rapid pace in 2016, with 8,203 MW of new capacity added in the United States and $13.0 billion invested

U.S. wind power capacity additions equaled 8,203 MW in 2016, bringing the cumulative total to 82,143 MW (Figure 2).[5] This growth represented $13.0 billion of investment in wind power project installations in 2016, for a cumulative investment total of roughly $166 billion since the beginning of the 1980s.[6,7] For the second year in a row, almost 90% of the new wind power capacity installed in 2016 is located within the Interior region (as defined in Figure 1). In addition, the first offshore wind project in the United States—the 30 MW Block Island project in Rhode Island—was commissioned in 2016. With 48 MW of wind capacity decommissioned in 2016, cumulative "net" capacity in 2016 grew by 11%, to 82,143 MW.



Source: AWEA project database

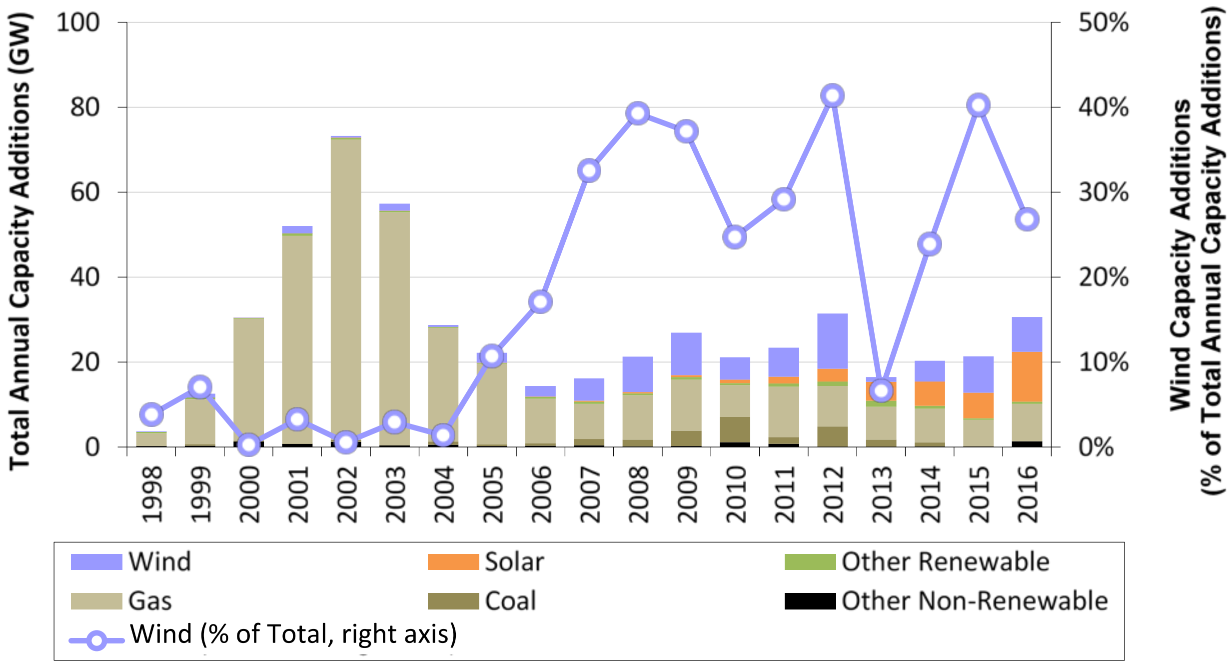
Figure 2. Annual and cumulative growth in U.S. wind power capacity

In 2016, growth was driven by recent improvements in the cost and performance of wind power technologies. State renewables portfolio standards (RPS) and corporate demand also played a role. Another key factor was the PTC, which, in December 2015, was extended for an additional 5 years—applying to projects that begin construction before January 1, 2020, but with a progressive reduction in the value of the credit for projects starting construction after 2016.

[5] When reporting annual wind power capacity additions, this report focuses on *gross* capacity additions. The *net* increase in capacity each year can be somewhat lower, reflecting turbine decommissioning.
[6] All cost and price data are reported in real 2016 dollars.
[7] These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs.

Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2016, behind solar and natural gas

Wind power has comprised a sizable share of generation capacity additions in recent years. In 2016, it constituted 27% of all U.S. capacity additions and was the third-largest source of new capacity, behind solar and natural gas (Figure 3).[8] Although the number of MW of new wind power capacity added in 2016 was roughly on par with the year before, wind power's share of overall annual capacity additions declined from 2015, owing primarily to the surge in new solar capacity.



Source: ABB, AWEA, GTM Research, Berkeley Lab

Figure 3. Relative contribution of generation types in annual capacity additions

Over the last decade, wind power represented 31% of total U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (56%) and Great Lakes (48%) regions (Figure 4; see Figure 1 for regional definitions). Wind power's contribution to generation capacity growth over the last decade is somewhat smaller—but still significant—in the Northeast (21%) and West (20%), and considerably less in the Southeast (2%).

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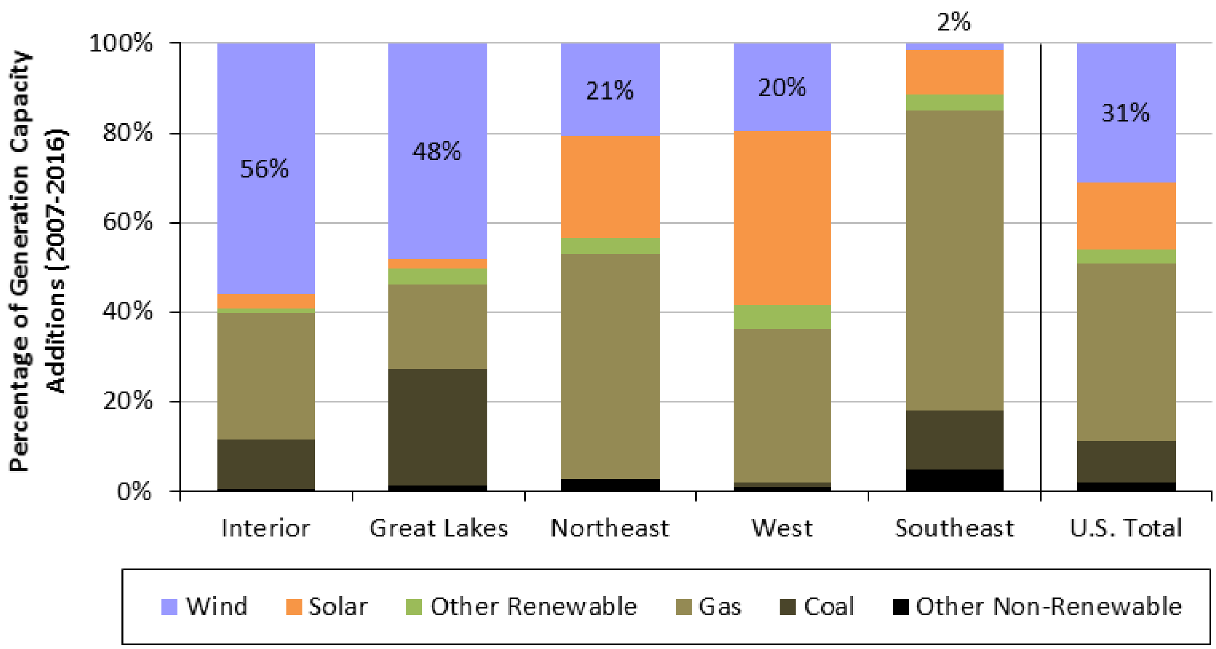
[8] Data presented here are based on gross capacity additions, not considering retirements. Furthermore, they include only the 50 U.S. states, not U.S. territories.



Source: ABB, AWEA, GTM Research, Berkeley Lab

Figure 4. Generation capacity additions by region (2007–2016)

The United States ranked second in annual wind additions in 2016, but was well behind the market leaders in wind energy penetration

Global wind additions equaled roughly 54,600 GW in 2016, 14% below the record of 63,600 MW added in 2015. With its 8.2 GW representing 15% of new global installed capacity in 2016, the United States maintained its second-place position behind China (Table 1, on the next page). Cumulative global capacity grew by 13% and stood at 486,700 MW at the end of the year (GWEC 2017),[9] with the United States' ~82 GW representing 11% year-over-year growth and accounting for 17% of global capacity—a distant second to China by this metric (Table 1).[10] On the basis of annual wind electricity production (as opposed to capacity), the United States lost its lead in 2016, also to China (AWEA 2017a).

A number of countries have achieved relatively high levels of wind energy penetration in their electricity grids. Figure 5 presents data on end-of-2016 (and end-of-2015) installed wind power capacity, translated into projected annual electricity supply based on assumed country-specific capacity factors and then divided by projected 2017 (and 2016) electricity consumption. The figure focuses only on the 22 countries with the greatest cumulative installed wind power capacity; a number of other countries—e.g., Uruguay—also have high wind energy penetrations, but are not among the leaders in installed capacity and so are not included in the figure.

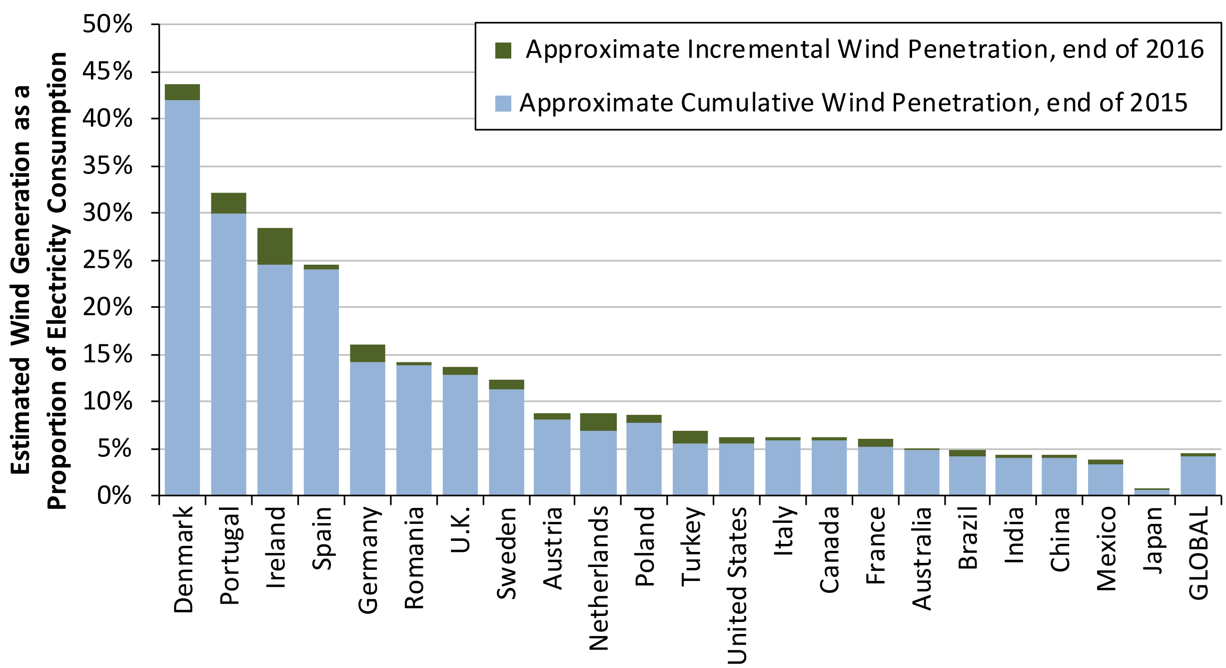
[9] Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from GWEC (2017) but are updated with the U.S. data presented here. Some disagreement exists among these data sources and others.

[10] Wind power additions and cumulative capacity in China include capacity that was installed but that had not yet begun to deliver electricity by the end of 2016, due to a lack of coordination between wind developers and transmission providers and the lengthier time that it takes to build transmission and interconnection facilities. All of the U.S. capacity reported here, on the other hand, was capable of electricity delivery.

Table 1. International Rankings of Wind Power Capacity

Annual Capacity (2016, MW)		Cumulative Capacity (end of 2016, MW)	
China	23,370	China	168,732
United States	**8,203**	**United States**	**82,143**
Germany	5,443	Germany	50,018
India	3,612	India	28,700
Brazil	2,014	Spain	23,074
France	1,561	United Kingdom	14,543
Turkey	1,387	France	12,066
Netherlands	887	Canada	11,900
United Kingdom	736	Brazil	10,740
Canada	702	Italy	9,257
Rest of World	6,727	*Rest of World*	75,576
TOTAL	**54,642**	**TOTAL**	**486,749**

Source: GWEC (2017); AWEA project database for U.S. capacity



Source: Berkeley Lab estimates based on data from GWEC, EIA, and elsewhere

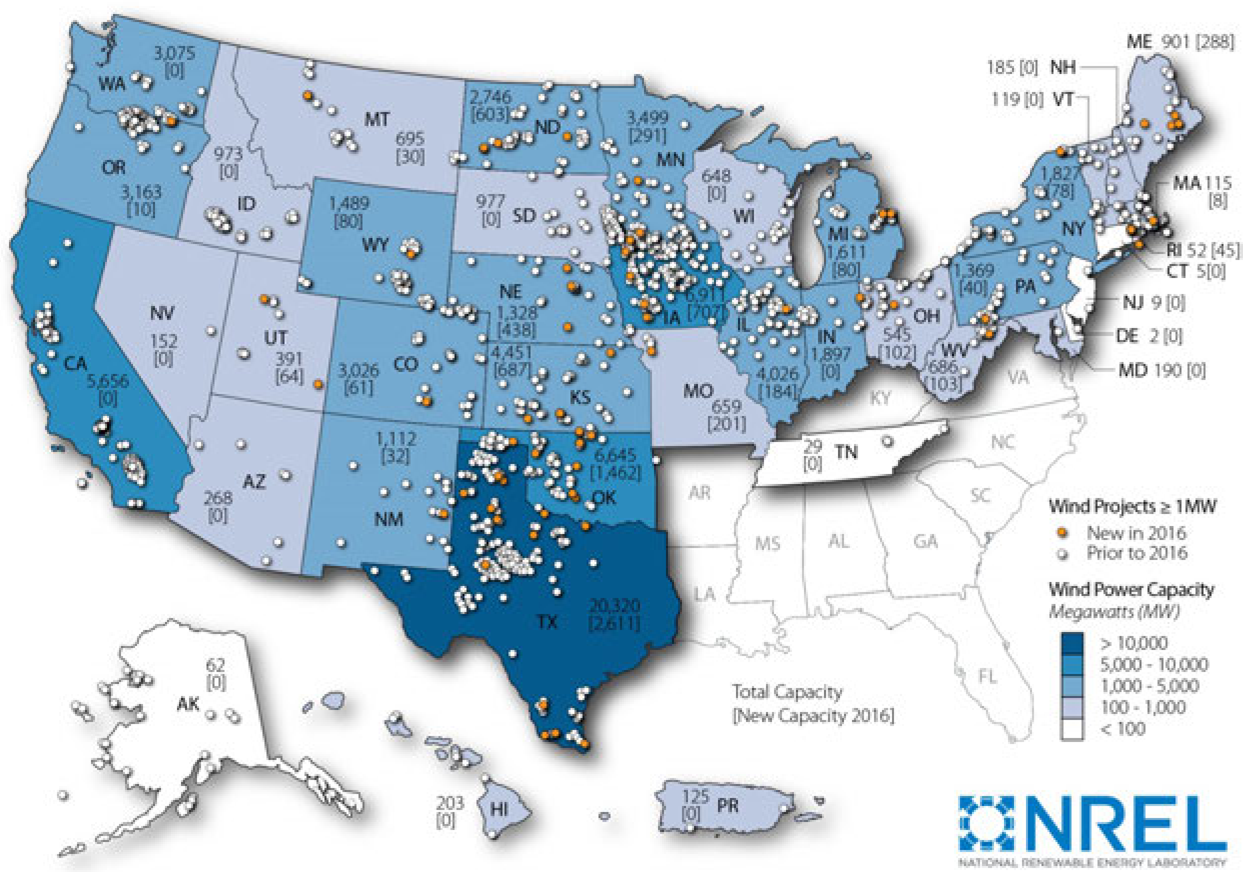
Figure 5. Approximate wind energy penetration in the 22 countries with the greatest installed wind power capacity

Using this approach and approximations for the contribution of wind power to electricity consumption, end-of-2016 installed wind power is estimated to supply the equivalent of more than 40% of Denmark's electricity demand, and between 20% and 35% of electricity demand in Portugal, Ireland, and Spain. In the United States, the cumulative wind power capacity installed at the end of 2016 is estimated, in an average year, to equate to 6.2% of the nation's electricity demand. On a global basis, wind energy's contribution is estimated at approximately 4.6%.

Texas installed the most capacity in 2016 with 2,611 MW, while fourteen states exceeded 10% wind energy penetration

New utility-scale wind turbines were installed in 23 states in 2016. Once again (for the third year in a row), Texas installed the most new wind capacity of any state, adding 2,611 MW. As shown in Figure 6 and Table 2, other leading states in terms of new capacity included Oklahoma (1,462 MW), Iowa (707 MW), Kansas (687 MW), and North Dakota (603 MW).

On a cumulative basis, Texas remained the clear leader among states, with 20,320 MW installed at the end of 2016—nearly three times as much as the next-highest state (Iowa, with 6,911 MW). In fact, Texas has more wind capacity than all but five countries—including the rest of the United States—worldwide. States distantly following Texas in cumulative installed capacity include Iowa, Oklahoma, California, Kansas, and Illinois—all with more than 4,000 MW. Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2016, with 26 of these topping 500 MW, 18 topping 1,000 MW, 11 topping 2,000 MW, and 10 topping 3,000 MW. Finally, one of the smallest states in terms of both geographic size and installed wind capacity marked a major milestone in 2016, as the nation's first offshore wind project—the 30 MW Block Island project in Rhode Island—achieved commercial operation.



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2016.

Figure 6. Location of wind power development in the United States

Some states have realized high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2016 divided by total in-state electricity generation in 2016.[11] Iowa leads the list, with 36.6% wind penetration, followed by South Dakota (30.3%) and Kansas (29.6%). A total of fourteen states have achieved wind penetration levels of 10% or higher.

Table 2. U.S. Wind Power Rankings: the Top 20 States

Installed Capacity (MW)				Percentage of In-State Generation	
Annual (2016)		Cumulative (end of 2016)		Actual (2016)*	
Texas	2,611	Texas	20,320	Iowa	36.6%
Oklahoma	1,462	Iowa	6,911	South Dakota	30.3%
Iowa	707	Oklahoma	6,645	Kansas	29.6%
Kansas	687	California	5,656	Oklahoma	25.1%
North Dakota	603	Kansas	4,451	North Dakota	21.5%
Nebraska	438	Illinois	4,026	Minnesota	17.7%
Minnesota	291	Minnesota	3,499	Colorado	17.3%
Maine	288	Oregon	3,163	Vermont	15.4%
Missouri	201	Washington	3,075	Idaho	15.2%
Illinois	184	Colorado	3,026	Maine	13.9%
West Virginia	103	North Dakota	2,746	Texas	12.6%
Ohio	102	Indiana	1,897	Oregon	12.1%
Michigan	80	New York	1,827	New Mexico	10.9%
Wyoming	80	Michigan	1,611	Nebraska	10.1%
New York	78	Wyoming	1,489	Wyoming	9.4%
Utah	64	Pennsylvania	1,369	Montana	7.6%
Colorado	61	Nebraska	1,328	Washington	7.1%
Rhode Island	45	New Mexico	1,112	California	6.9%
Pennsylvania	40	South Dakota	977	Hawaii	6.7%
New Mexico	32	Idaho	973	Illinois	5.7%
Rest of U.S.	48	*Rest of U.S.*	6,041	*Rest of U.S.*	1.0%
TOTAL	**8,203**	**TOTAL**	**82,143**	**TOTAL**	**5.6%**

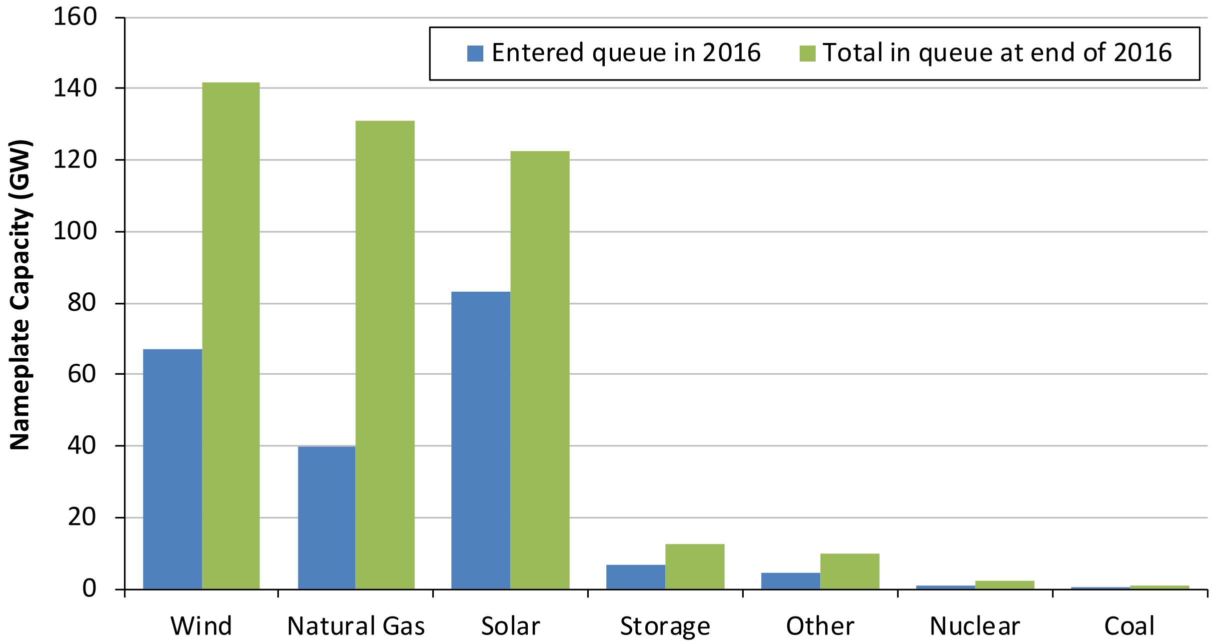
* Based on 2016 wind and total generation by state from EIA's *Electric Power Monthly*.

Source: AWEA project database, EIA

[11] Wind energy penetration can either be expressed as a percentage of in-state load or in-state generation. In-state generation is used here, primarily because wind energy (like other energy resources) is often sold across state lines, which tends to distort penetration levels expressed as a percentage of in-state load. Also note that by focusing on generation in 2016, Table 2 does not fully capture the impact of new wind power capacity added during 2016 (particularly if added towards the end of the year).

Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration

One testament to the continued interest in land-based wind energy is the amount of wind power capacity currently working its way through the major transmission interconnection queues across the country. Figure 7 provides this information for wind power and other resources aggregated across 35 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.[12] These data should be interpreted with caution: placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built.



Source: Exeter Associates review of interconnection queues

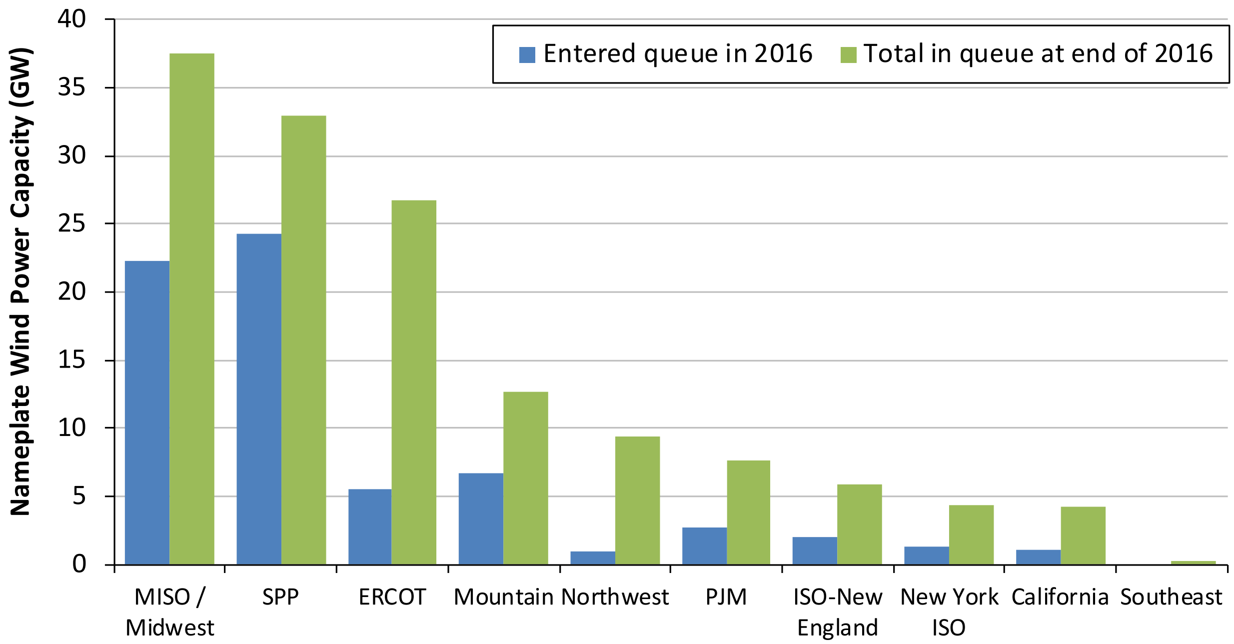
Figure 7. Generation capacity in 35 selected interconnection queues, by resource type

Even with this important caveat, the amount of wind capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2016, there were nearly 142 GW of wind power capacity in the interconnection queues reviewed for this report—more than one-and-a-half times the installed wind power capacity in the United States. This 142 GW is a sizable increase from the end of 2015 (110 GW), and represented 34% of all capacity in these selected queues at the end of 2016, higher than all other generating sources. In 2016, 67 GW of wind power capacity entered the interconnection queues,

[12] The queues surveyed include PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), New York ISO (NYISO), ISO-New England (ISO-NE), California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and 25 other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of over 85% of the U.S. total. Figures 7 and 8 only include projects that were active in the queue at the end of 2016 but that had not yet been built; suspended projects are not included.

a figure lower than solar (83 GW) but higher than natural gas (40 GW). The 67 GW of new wind capacity entering the queues in 2016 was the largest annual sum since 2009.

The wind capacity in the interconnection queues is spread across the United States, as shown in Figure 8, with larger amounts in the Midwest (26%), Southwest Power Pool (SPP) (23%), ERCOT (19%), the Mountain region (9%), and the Northwest (7%). Smaller amounts are found in the PJM Interconnection (5%), ISO-New England (4%), New York ISO (3%), California (3%), and the Southeast (0.2%). The Midwest and SPP experienced especially sizable annual additions in 2016.



Source: Exeter Associates review of interconnection queues

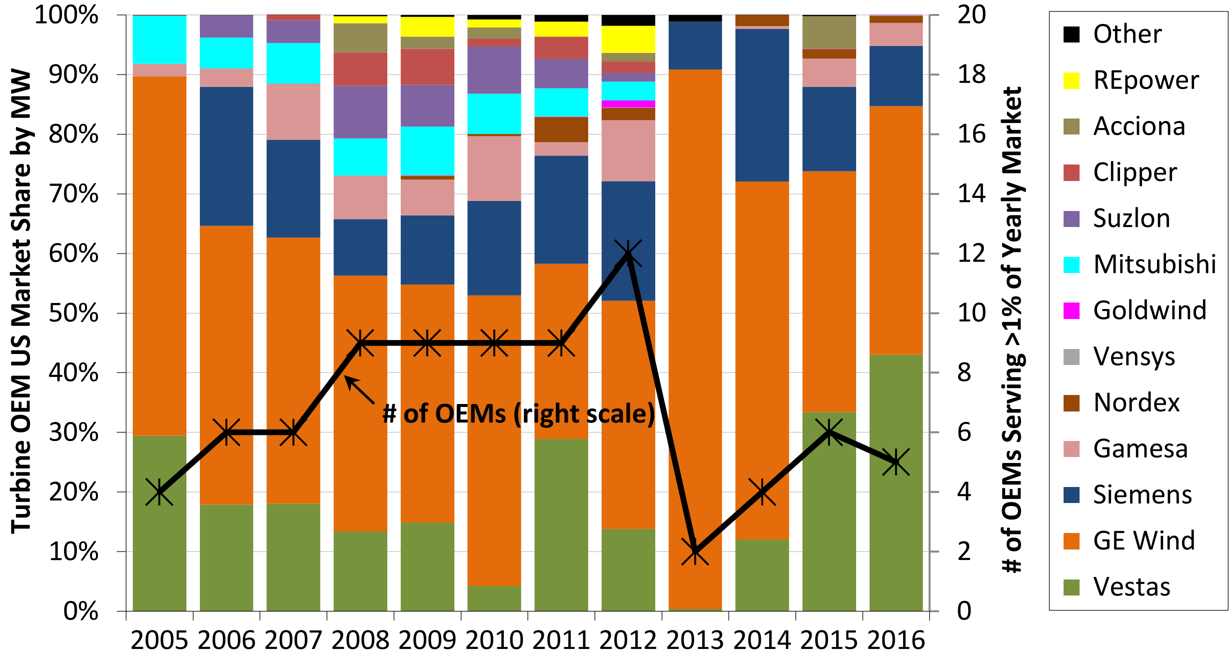
Figure 8. Wind power capacity in 35 selected interconnection queues, by region

As a measure of the near-term development pipeline, ABB (2017) estimates that, as of June 2017, approximately 32 GW of wind power capacity could be characterized in one of three ways: (a) under construction or in site preparation (9 GW); (b) in development and permitted (12 GW); or (c) in development with a pending permit and/or regulatory applications (12 GW). These totals are similar to last year at approximately the same time, indicating that the development pipeline remains strong. AWEA (2017b), meanwhile, reports that ~21 GW of wind power capacity was under construction or at an advanced stage of development at the end of the first quarter of 2017. EIA (2017b) lists 19 GW of planned additions for 2017 and 2018.

3. Industry Trends

Vestas and GE captured 85% of the U.S. wind power market in 2016

Of the 8,203 MW of wind installed in 2016, 43% (3,530 MW) used turbines from Vestas, with GE Wind coming in a very close second (3,415 MW, 42% market share), followed more distantly by Siemens (829 MW, 10%) (Figure 9 and Table 3).[13] Other suppliers included Gamesa (318 MW), Nordex (93 MW), Vensys (15 MW), and Goldwind (1.5 MW).



Source: AWEA project database

Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2016

The black line in Figure 9 shows the number of turbine manufacturers serving more than 1% (by capacity) of the U.S. market in each year. As shown, the base of turbine suppliers expanded from just four original equipment manufacturers (OEMs) in 2005 to nine from 2008 to 2011 and twelve in 2012. Since 2012, however, the U.S. turbine market has been dominated by just a handful of OEMs—a trend that may be supported in the future by ongoing consolidation. For example, the Nordex/Acciona merger took effect in April 2016 (in Figure 9 and Table 3, their combined operations are referred to solely as Nordex starting in 2016), while Siemens Wind Power and Gamesa consolidated their operations in April 2017 (and are broken out separately in 2016).

According to BNEF (2017c), Vestas was the leading supplier of turbines worldwide in 2016, followed by GE, Goldwind, Gamesa, and Enercon. On a worldwide basis, Chinese turbine manufacturers continued to occupy positions of prominence, with four of the top 10 spots in the ranking. To date, however, the growth of Chinese turbine manufacturers has been based almost

[13] Market share is reported in MW terms and is based on project installations in the year in question.

exclusively on sales to the Chinese market. GE is the only U.S.-owned utility-scale turbine manufacturer playing a meaningful role in global or U.S. large-wind-turbine supply.

Table 3. Annual U.S. Turbine Installation Capacity by Original Equipment Manufacturer (OEM)

OEM	Turbine Installations (MW)											
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Vestas	699	439	948	1,120	1,489	221	1,969	1,818	4	584	2,870	3,530
GE Wind	1,431	1,146	2,342	3,585	3,995	2,543	2,006	5,016	984	2,912	3,468	3,421
Siemens	0	573	863	791	1,162	828	1,233	2,638	87	1,241	1,219	829
Gamesa	50	74	494	616	600	566	154	1,341	0	23	402	318
Nordex	0	0	3	0	63	20	288	275	0	90	138	93
Vensys	0	0	0	1	3	0	6	3	0	0	0	15
Goldwind	0	0	0	0	5	0	5	155	0	0	8	2
Mitsubishi	190	128	356	516	814	350	320	420	0	0	0	0
Suzlon	0	92	198	738	702	413	334	187	0	0	0	0
Clipper	3	0	48	470	605	70	258	250	0	0	0	0
Acciona	0	0	0	410	204	99	0	195	0	0	465	NA
REpower	0	0	0	94	330	68	172	595	0	0	0	0
Other	2	2	2	22	35	41	76	241	12	2	21	0
TOTAL	2,374	2,457	5,253	8,362	10,005	5,216	6,820	13,131	1,087	4,854	8,598	8,203

Source: AWEA project database

The manufacturing supply chain continued to adjust to swings in domestic demand for wind equipment

As wind power capacity in the United States has grown, foreign and domestic turbine equipment manufacturers have localized some operations in the United States. Yet, the wind industry's domestic supply chain continues to deal with conflicting pressures: an upswing in near- to medium-term expected growth, but also strong international competitive pressures and expected reduced demand over time as the PTC is phased down. As a result, though some manufacturers increased the size of their U.S. workforce in 2016, market expectations for significant supply-chain expansion are less optimistic.

Figure 10 presents a non-exhaustive list of the more than 150 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2016, focusing on the utility-scale wind market.[14] Figure 11 segments those facilities by major component.

[14] The data on manufacturing facilities presented here differ from those presented in AWEA (2017a) due, in part, to methodological differences. For example, AWEA includes data on a large number of smaller component suppliers that are not included in this report; the figure presented here also does not include research and development and logistics centers, or materials suppliers. As a result, AWEA (2017a) reports a much larger number of wind-related manufacturing facilities, over 500 in total.

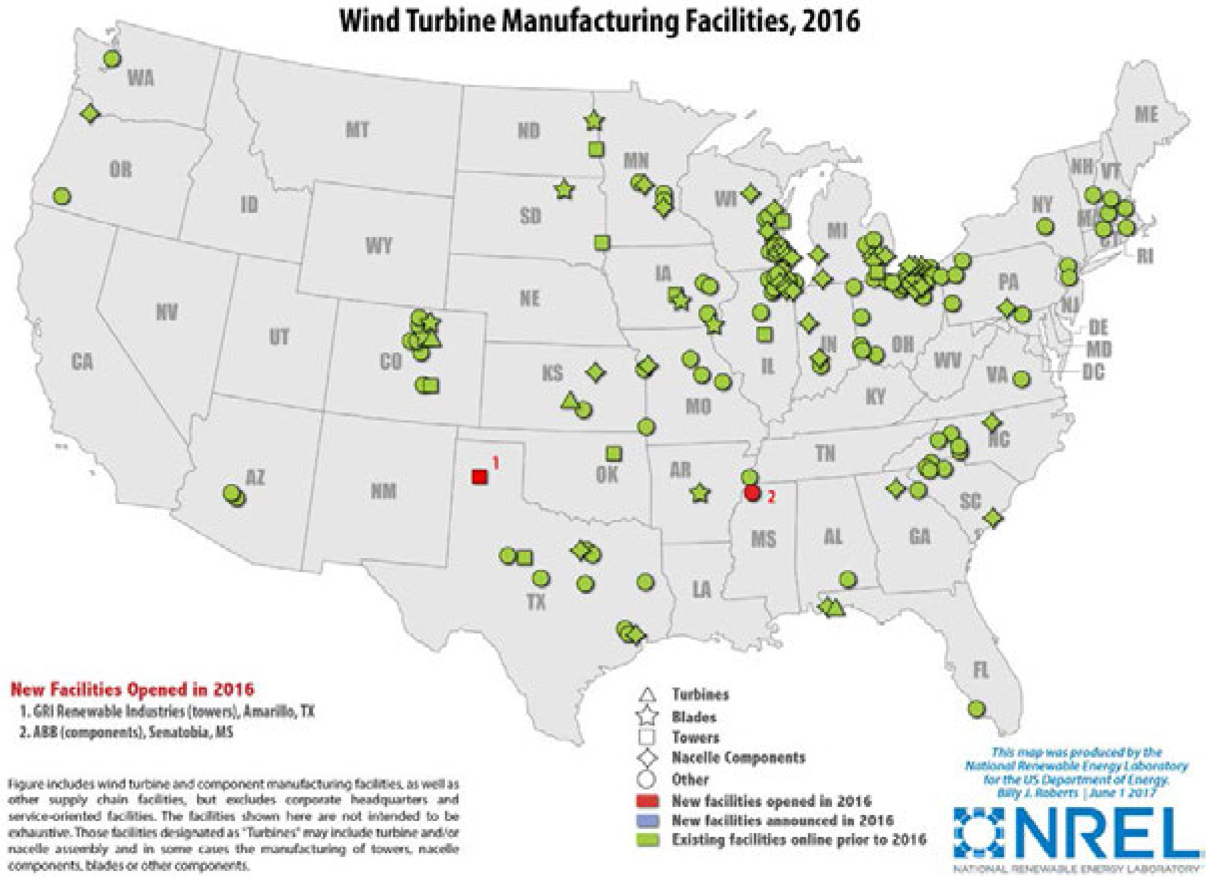


Figure 10. Location of existing and new turbine and component manufacturing facilities

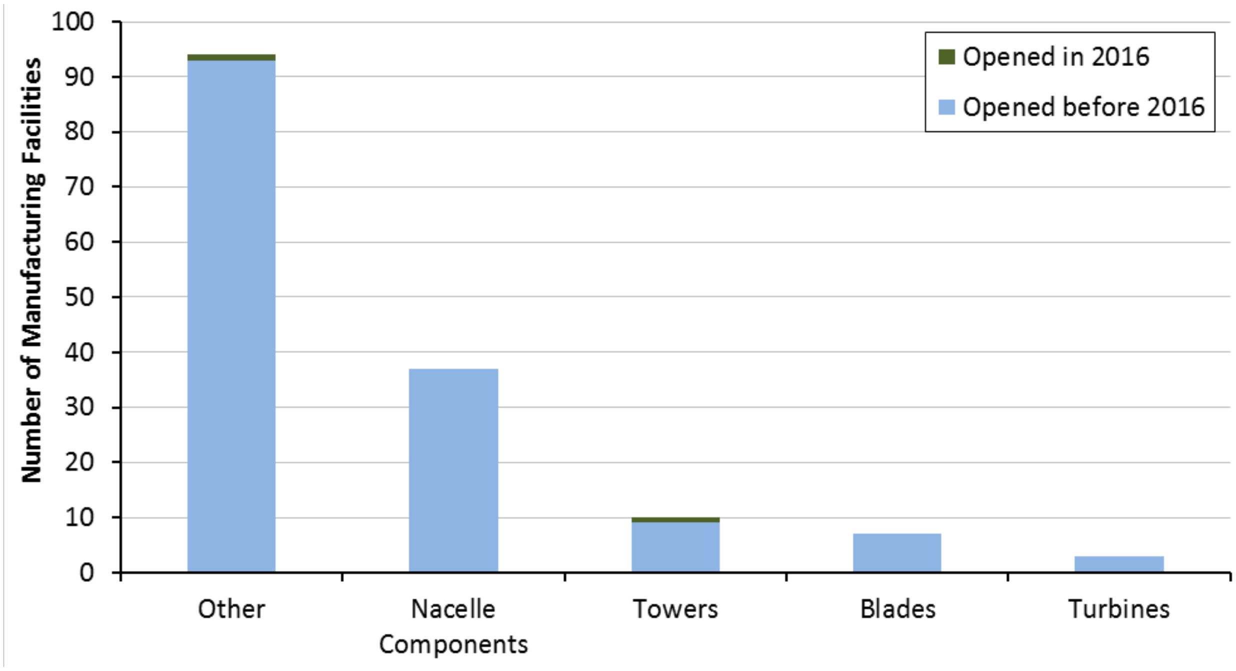
Two new wind-related facilities opened in 2016. GRI Renewables—a tower manufacturer located in Amarillo, TX—is expected to employ up to 300 workers and manufacture up to 400 towers annually when it reaches full production. And ABB—a component manufacturer with multiple locations in the United States—opened a facility in Senatobia, MS that will focus on a variety of electrical components for a wide range of industries, including wind. Operations began in October 2016, with the facility expected to support 200 new jobs by its third year.[15] At the same time, at least three existing turbine or component manufacturing facilities were consolidated, closed, or stopped serving the industry in 2016.[16]

Notwithstanding the loss of a number of facilities in the supply chain over the last several years and the relatively slow pace of new facility additions, there remain a large number of domestic manufacturing plants. Additionally, multiple existing manufacturers expanded their workforce in 2016 to meet demand (e.g., Vestas, Vest-Fiber), began expansions of existing facilities (e.g.,

[15] In 2016, replacement part manufacturers and component remanufacturers increased. Though not tracked within the wind turbine and component manufacturing and assembly facilities dataset otherwise used in this report, two new facilities opened that provide replacement part manufacturing or component re-manufacturing. In May 2016, Gearbox Express, a gearbox re-manufacturer, opened a new 75,000 sq. ft. facility in Mukwanago, WI that was expected to support up to 40 employees by mid-2017. Wind Solutions in Sanford, NC opened a second facility in 2016 to further support its aftermarket component fabrication capabilities.

[16] Cast-Fab (foundry, Ohio), Brevini Wind (gearboxes, Indiana), and Trinity Structural Towers (towers, North Dakota).

Vestas, LM Wind Power, Creative Foam, Siemens, Broadwind), or completed facility upgrades to expand product reach (e.g., TPI Composites completed a rail connection).



Note: Manufacturing facilities that produce multiple components are included in multiple bars. "Other" includes facilities that produce items such as: enclosures, power converters, slip-rings, inverters, electrical components, tower internals, climbing devices, couplings, castings, rotor hubs, plates, walkways, doors, bearing cages, fasteners, bolts, magnetics, safety rings, struts, clamps, transmission housings, embed rings, electrical cable systems, yaw/pitch control systems, bases, generator plates, slew bearings, flanges, anemometers, and template rings.

Source: National Renewable Energy Laboratory

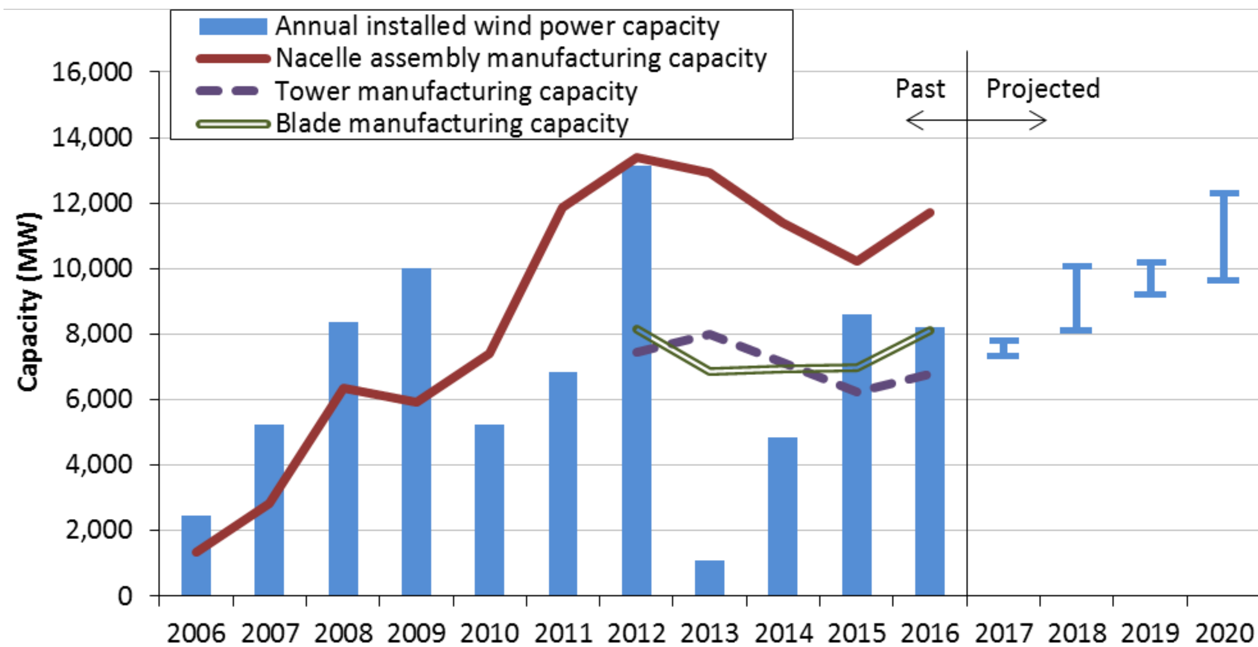
Figure 11. Number of wind turbine and component manufacturing facilities in the United States

Figure 10 also highlights the geographic spread of turbine and component manufacturing facilities across the country. Many manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers (OEMs). However, even states that are relatively far from major wind power markets have manufacturing facilities. Most states in the Southeast, for example, have wind manufacturing facilities despite the fact that there are few wind power projects in that region. Workforce considerations, transportation costs, and state and local incentives are among the factors that typically drive location decisions.

Among the many other facets of the domestic supply chain, in 2010, 9 of the 11 wind turbine OEMs with the largest shares of the U.S. market owned at least one domestic manufacturing facility (Acciona, Clipper, DeWind, Gamesa, GE, Nordex, Siemens, Suzlon, and Vestas). Since that time, a number of these facilities have closed, in part reflecting the increased concentration of the U.S. wind industry among the three top OEMs, long-term demand uncertainty, and a desire to consolidate production at centralized facilities overseas in order to gain economies of scale. For example, the Nordex/Acciona merger that was completed in 2016 has left the future of the Acciona West Branch, Iowa facility in question. For now, manufacturing at the plant is idled, though the facility still houses sales, office, and wind project maintenance personnel.

A new merger between Siemens Wind Power and Gamesa was announced in June of 2016 that will further consolidate the global wind turbine market. Finalized in April 2017, the newly merged company employs approximately 21,000 people worldwide. No expected impacts from the merger regarding Siemens' Hutchinson, KS turbine facility have been reported. GE's acquisition of blade manufacturer LM Wind Power, meanwhile, was finalized in April 2017. With LM having two locations in the United States (Little Rock, AR and Grand Forks, ND) the move is expected to strengthen GE's presence in the country. No expected impacts from the merger on LM Wind Power's U.S. facilities or workforce have been publicly reported.

Even with a consolidated market, the three largest OEMs that serve the U.S. wind industry—GE, Vestas, and Siemens—each had one or more operating manufacturing facilities in the country at the end of 2016. In contrast, 12 years earlier (2004), there was only one active utility-scale wind energy OEM assembling nacelles[17] in the United States (GE).



Note: Data on blade and tower manufacturing capability are only available from 2012 to 2016

Source: AWEA, BNEF, IHS, Navigant, MAKE, Berkeley Lab

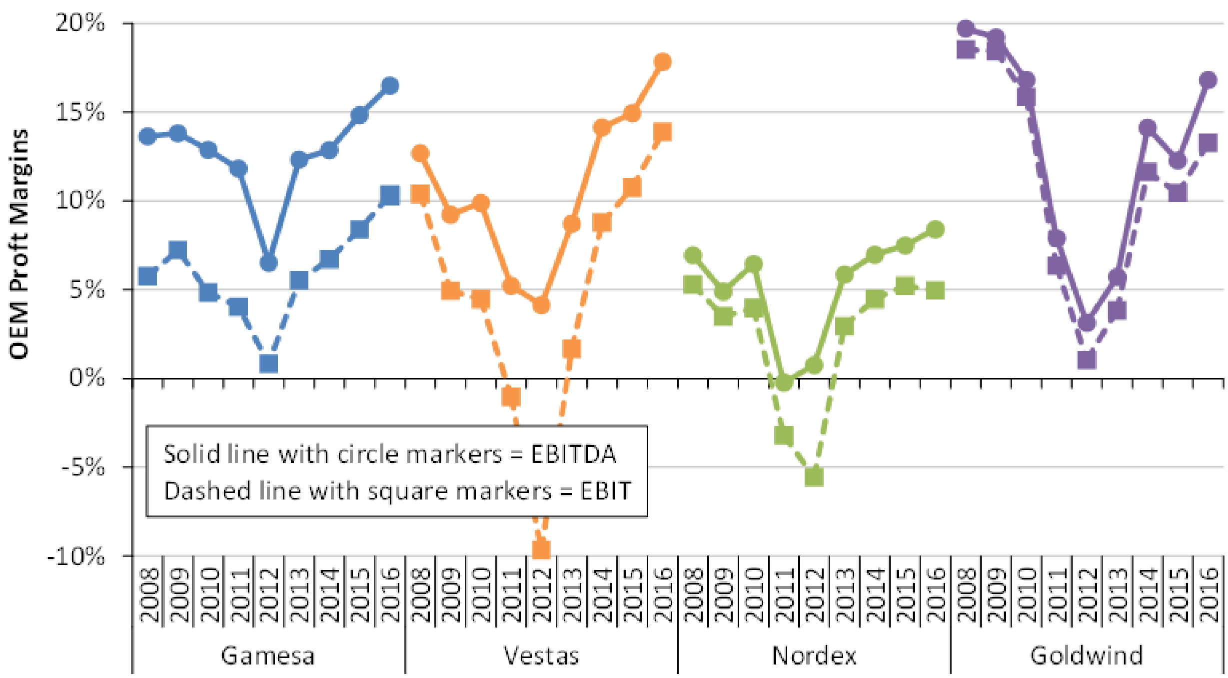
Figure 12. Domestic wind manufacturing capability vs. U.S. wind power installations

In aggregate, domestic turbine nacelle assembly capability—defined here as the "maximum" nacelle assembly capability of U.S. plants if all were operating at maximum utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, before dropping to roughly 11.7 GW in 2016 (Figure 12; AWEA 2017a). In addition, AWEA (2017a) reports that U.S. manufacturing facilities have the capability to produce 11,300 individual blades (~8.1 GW) and 3,150 towers (~6.8 GW) annually, with relatively little change since 2012 (note that data on blade and tower manufacturing capability only goes back to 2012). Figure 12 contrasts available data on equipment manufacturing capability with past U.S. wind additions as well as near-term

[17] Nacelle assembly is defined here as the process of combining the multitude of components included in a turbine nacelle, such as the gearbox and generator, to produce a complete turbine nacelle unit.

forecasts of future U.S. installations (see Chapter 9, “Future Outlook”). It demonstrates that domestic manufacturing capability for blades, towers, and nacelle assembly is reasonably well balanced against historical market demand, though growth in domestic capability or imports will be necessary to fulfill total anticipated demand of blades and towers in the coming four years.

Fierce competition throughout the supply chain has caused many manufacturers to execute cost-cutting measures globally and domestically in recent years. As a result of these cost savings, coupled with strong demand, the profitability of turbine OEMs has generally rebounded over the last four years, after a number of years in decline (Figure 13).[18] Moreover, with recent and near-term expected continued growth in U.S. wind installations, wind-related job totals in the United States reached a new all-time high in 2016. The U.S. Department of Energy (DOE) estimates that the wind industry employed 101,738 full-time workers in the United States in 2016—a 32% increase from 2015 (DOE 2017). The more than 101,000 jobs include, among others, those in construction (~38,000), manufacturing (~29,500), and plant operations (~22,100).



Note: EBITDA = earnings before interest, taxes, depreciation and amortization; EBIT = earnings before interest and taxes
Source: OEM annual reports and financial statements

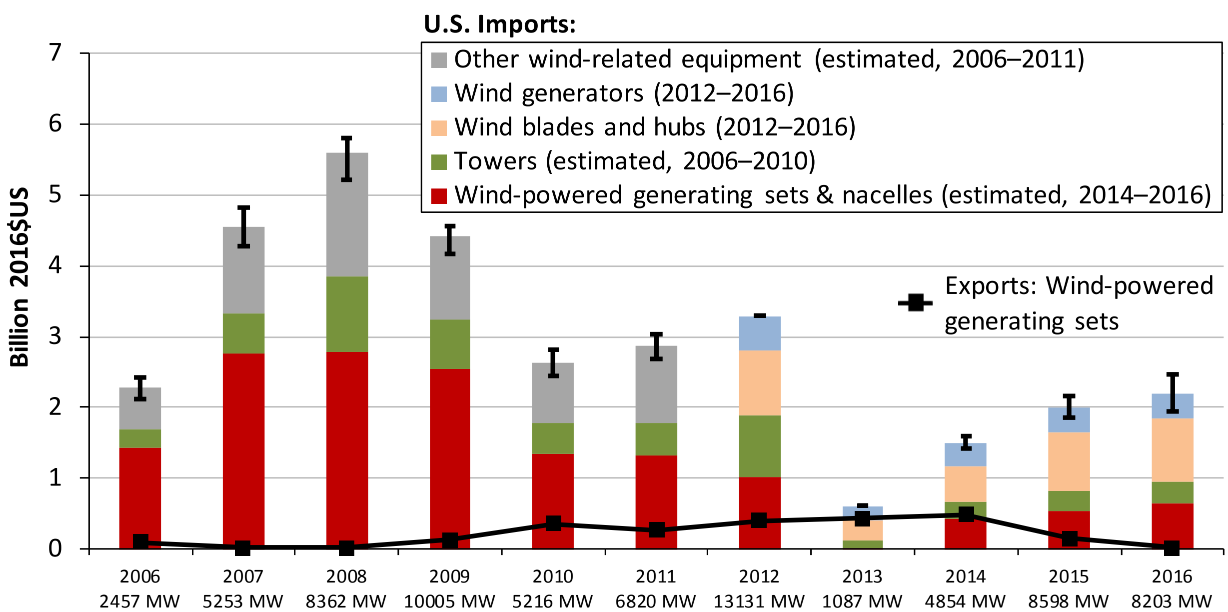
Figure 13. Turbine OEM global profitability over time

[18] Figure 13 only reports data for those OEMs that are “pure-play” wind turbine manufacturers. GE and Siemens—among the largest turbine suppliers in the U.S. market (along with Vestas)—are not included because they are multi-national conglomerates that do not report segmented financial data for their wind turbine divisions. Figure 13 depicts both EBIT (i.e., “earnings before interest and taxes,” also referred to as “operating profit”) and EBITDA (i.e., “earnings before interest, taxes, depreciation, and amortization”) margins.

Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports

The U.S. wind sector is reliant on imports of wind equipment, though the level of dependence varies by component: some components have a relatively high domestic share, whereas other components remain largely imported. These trends are revealed, in part, by data on wind power equipment trade from the U.S. Department of Commerce.[19]

Figure 14 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating sets and nacelles (i.e., nacelles with blades, nacelles without blades, and, when imported as part of the same transaction, other turbine components) as well as imports of select turbine components that are shipped separately from the generating sets and nacelles.[20] The selected wind turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (and generator parts), and blades and hubs.



Source: Berkeley Lab analysis of data from USITC DataWeb: http://dataweb.usitc.gov

Figure 14. Estimated imports of wind-powered generating sets, towers, generators, and blades and hubs, as well as exports of wind-powered generating sets and towers and lattice masts

Import estimates should be viewed with particular caution because the underlying data used to produce Figure 14 are based on trade categories that are not all exclusive to wind. Some of the import estimates shown in Figure 14 therefore required assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. The error bars in Figure 14 account for uncertainty in these assumed fractions. In 2012 and 2013, all trade categories shown

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[19] See the appendix for further details on data sources and methods used in this section, including the specific trade codes considered.

[20] Wind turbine components such as blades, towers, and generators are included in the data on wind-powered generating sets and nacelles if shipped in the same transaction. Otherwise, these component imports are reported separately.

were either specific to or largely restricted to wind power, and so no error bars are shown. After 2013, only nacelles (when shipped alone) are included in a trade category that is not largely exclusive to wind, and so the error bars shown for 2014 through 2016 only reflect the uncertainty in nacelle imports. More generally, as noted earlier, Figure 14 does not show comprehensive data on the import of all wind equipment, as not all such equipment is clearly identified in trade categories. The impact of this omission on import and domestic content is discussed later.

As shown, the estimated imports of tracked wind-related equipment into the United States substantially increased from 2006 to 2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then dropping sharply in 2013 with the simultaneous drop in U.S. wind installations. In 2014 through 2016, as U.S. wind installations bounced back, so did imports of wind-related turbine equipment. These overall trends are driven by a combination of factors: changes in the share of domestically manufactured wind turbines and components (versus imports), changes in the annual rate of wind installations (shown textually on the x-axis of Figure 14), and changes in wind turbine prices. Because imports of wind turbine component parts occur in additional, broad trade categories different from those included in Figure 14, the data presented here understate the aggregate amount of wind equipment imports.

Figure 14 also shows that exports of wind-powered generating sets from the United States generally increased through 2014, rising from just $16 million in 2007 to $488 million in 2014. There has been a steep decline in exports since then, however, falling to $151 million in 2015 and then to just $17 million in 2016. The largest destination markets for these exports over the entire 2006–2016 timeframe were Canada (59%) and Brazil (28%); the modest exports in 2016 were also dominated by Canada (44%) and Brazil (56%), though the respective export levels fell by 68% and 91% from the previous year. U.S. exports of 'towers and lattice masts' in 2016 totaled an additional $46 million (down from a peak of $172 million in 2012), with 47% of these exports going to Canada. The trade data for tower exports do not differentiate between tubular towers (primarily used in wind power applications) and other types of towers, unlike the import classification for towers from 2011 to 2016, which does differentiate. Although some of the tower exports are wind-related, the exact proportion is not known. Other wind-turbine component exports are not reported because such exports are likely a small and/or uncertain fraction of broader trade category totals. Despite overall growth in exports from 2007 to 2014, the United States remained a sizable net importer of wind turbine equipment over this period. The sharp decrease in exports in 2015 and 2016 may indicate that the growing U.S. wind market absorbed much of the local production of wind turbine equipment.

Figure 15 shows the total value of selected, tracked wind-specific imports to the United States in 2016, by country of origin, as well as the main "districts of entry"[21]: 46% of the import value in 2016 came from Asia (led by China), 40% from Europe (led by Spain), and 14% from the

[21] The trade categories included here are all of the wind-specific import categories for 2016 (see the appendix for details), and so the 2016 total import volume considered in Figure 15 differs from that in Figure 14. As noted earlier, imports of many wind turbine component parts occur in broad trade categories not captured by those included in this analysis; additionally, in the case of nacelles without blades, the trade code is not exclusive to wind and so related imports are not included in Figure 15 (though they are included in Figure 14). As such, the data presented in Figure 15 understate the aggregate amount of wind equipment imports into the United States. Note also that "districts of entry" as used here refers to, in some cases, multiple points of entry located in the same geographic region; note also that goods may arrive at districts of entry by land, air, or sea.

Americas (led by Brazil). The principal districts of entry for all of this wind equipment were Houston-Galveston, TX (21%), Port Arthur, TX (14%), and Laredo, TX (9%).

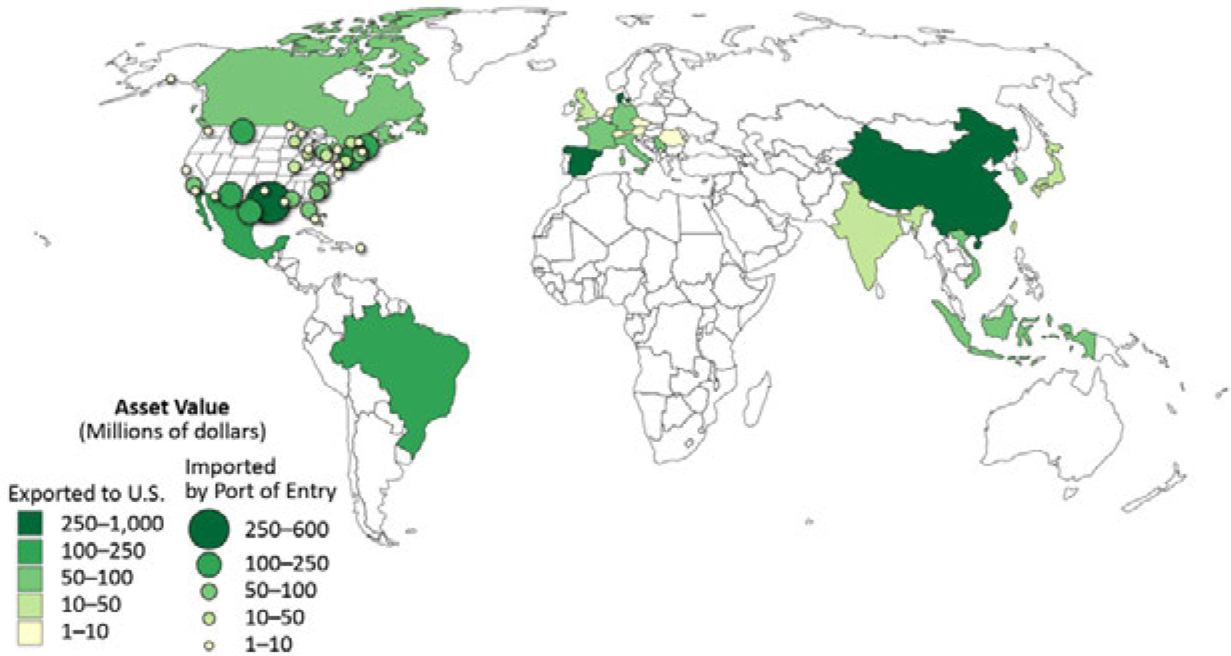


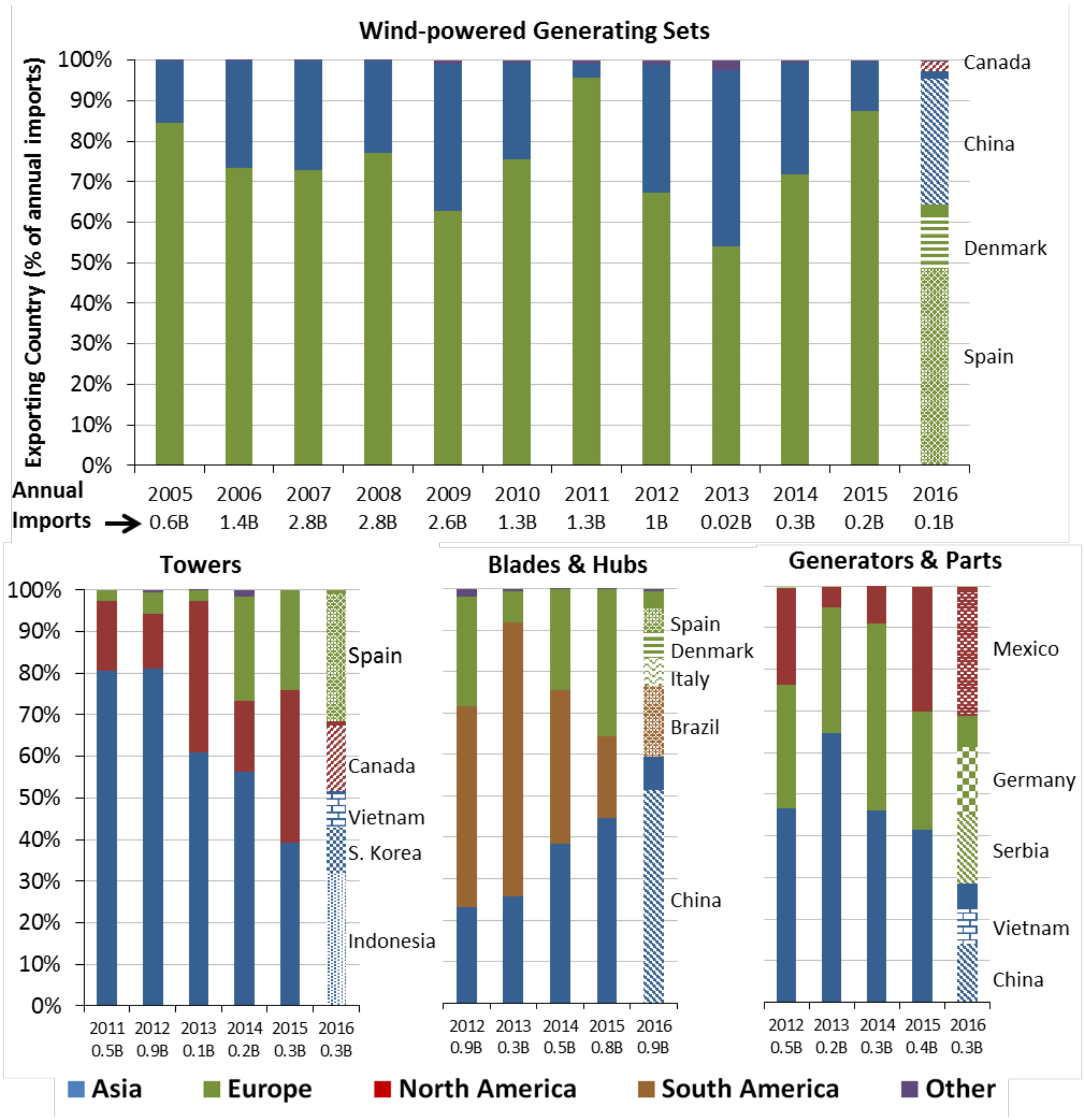
Figure 15. Summary map of tracked wind-specific imports in 2016: countries of origin and U.S. districts of entry

Looking behind the import data in more detail, and focusing on those trade codes that are largely exclusive to wind equipment, Figure 16 shows a number of trends over time in the origin of U.S. imports of wind-powered generating sets, tubular towers, wind blades and hubs, and wind generators and parts.

For wind-powered generating sets, the primary source markets during calendar years 2005–2016 have been Europe and, to a lesser extent, Asia, with leading countries largely being those that have been home to the major international turbine manufacturers: Denmark, Spain, Japan, India, and Germany. In 2016, imports of wind-powered generating sets were dominated by Spain, China, and Denmark, though the total import value was relatively low ($117 million). The share of imports of tubular towers from Asia was over 80% in 2011 and 2012 (almost 50% from China), with much of the remainder from Canada and Mexico. From 2013 to 2016, not only did the total import value decline relative to earlier years, but there were almost no imports from China and Vietnam from 2013 to 2015—likely a result of the tariff measures that were imposed on wind tower manufacturers from these countries.[22] Tower imports in 2016 came from a mix of countries from Asia (e.g., Indonesia, South Korea, and Vietnam), Europe (principally Spain), and North America (principally Canada). With regard to wind blades and hubs, China has become the dominant source market, with Brazil and various European countries playing somewhat lesser roles. Finally, the import origins for wind-related generators and generator parts were

[22] In 2016, the Department of Commerce decided to reduce the anti-dumping duties to zero for a single company, which led to a large increase in tower imports from Vietnam in 2016.

distributed across a number of largely Asian and European countries, in addition to Mexico, from 2012 through 2016; the role of Asian imports, however, has decreased somewhat in recent years.



Note: On x-axis, B = billion 2016$

Source: Berkeley Lab analysis of data from USITC DataWeb: http://dataweb.usitc.gov

Figure 16. Origins of U.S. imports of selected wind turbine equipment

Because trade data do not track all imports of wind equipment, it is not possible to use those data to establish a clear overall distinction between imported and domestic content. The trade data also do not allow for a precise estimate of the domestic content of specific wind turbine components. Nonetheless, based on those data and a variety of assumptions, Table 4 presents rough estimates of the domestic content for a subset of the major wind turbine components used in U.S. wind power projects in 2016. As shown, domestic content is relatively strong for large, transportation-intensive components such as towers, blades and hubs, and nacelle assembly.

Table 4. Approximate Domestic Content of Major Components in 2016

Towers	Blades & Hubs	Nacelle Assembly
65-80%	50-70%	> 90% of nacelle assembly

These figures, however, understate the wind industry's reliance on turbine and component imports. This is because significant wind-related imports occur under trade categories not captured in Table 4, including wind equipment (such as generators, mainframes, converters, pitch and yaw systems, main shafts, bearings, bolts, controls) and manufacturing inputs (such as foreign steel in domestic manufacturing).[23] A now-dated interview-based approach to estimating domestic content, for example, revealed that domestic content was relatively high for blades, towers, nacelle assembly and nacelle covers in 2012, supporting the results depicted in Table 4. The domestic content of most of the equipment internal to the nacelle—much of which is not tracked in wind-specific trade data—was considerably lower, however, often well below 20%.[24]

The project finance environment remained strong in 2016

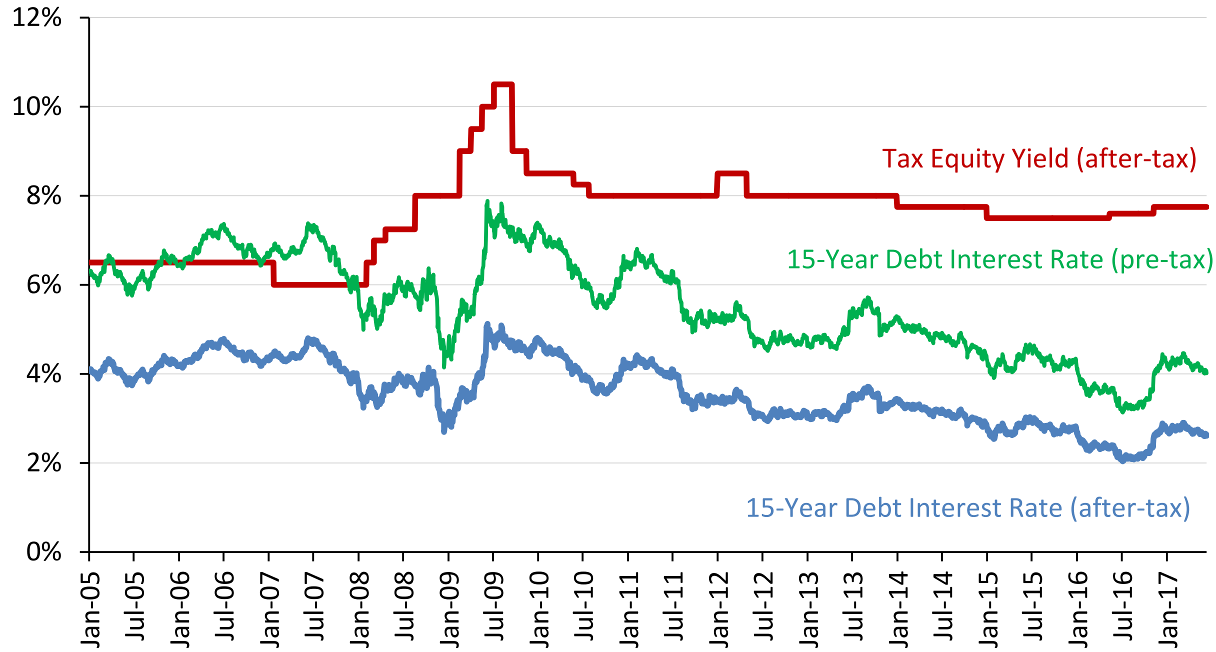
With projects having had to start construction by the end of 2016 in order to qualify for the PTC at 100% of its nominal value, 2016 was another busy year for financiers. But with a 4-year safe harbor window in which to bring any such-qualified projects online, many of the projects financed in 2016 will achieve commercial operations in 2017 or later (see Table 5, later, for details on the PTC phase down schedule).

According to AWEA (2017a), roughly $6.4 billion in third-party tax equity was committed in 2016 to finance 5,538 MW of new wind projects. This total dollar amount is slightly higher than, but largely on par with, the amount of tax equity raised in both 2014 and 2015. Partnership flip structures[25] remained the dominant tax equity vehicle, with indicative tax equity yields drifting slightly higher in 2016, to just below 8% on an after-tax unlevered basis (Figure 17).

On the debt side, AWEA (2017a) reports that 2,677 MW of new and existing wind capacity raised $3.4 billion in debt in 2016, up from the $2.9 billion raised in 2015. As they have in recent years, banks continued to focus more on shorter-duration loans (7–10 year mini-perms remained

[23] On the other hand, this analysis also assumes that all components imported into the United States are used for the domestic market and not used to assemble wind-powered generating sets that are exported from the United States. If this were not the case, the resulting domestic fraction would be slightly higher than that presented here.
[24] The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab.
[25] A "partnership flip" is a project finance structure in which the developer or project sponsor partners with a third-party tax equity investor to jointly invest in and own the project. Initially, allocations of tax benefits are skewed heavily in favor the tax equity partner (which is able to efficiently monetize the tax benefits), but eventually "flip" in favor of the project sponsor partner once the tax benefits have been largely exhausted. Cash is also allocated between the partners, with one or more "flip" events, but in recent years has been increasingly directed towards the project sponsor to the extent possible, in order to support back leverage or dividend payments to YieldCo investors.

the norm[26]), leaving longer-duration, fully amortizing loans to institutional lenders (Chadbourne & Parke 2017a). As shown in Figure 17, all-in interest rates on benchmark 15-year debt were below 4% through most of 2016—a level not previously breached in the prior 11 years of the graph—before rising by roughly 50 basis points to back above 4%. Short-term interest rates have also begun to rise, as the U.S. Federal Reserve Bank has ratcheted up the federal funds rate by 25 basis points on four separate occasions since mid-December of 2015 (after seven straight years of holding it at 0%). For the most part, long-term interest rates seem to have shrugged off the Federal Reserve's rate hikes to date, with the Fed's rate-hikes not flowing through one-for-one to benchmark all-in interest rates for long-term debt.



Source: Intercontinental Exchange Benchmark Administration (2017), BNEF (2017e)

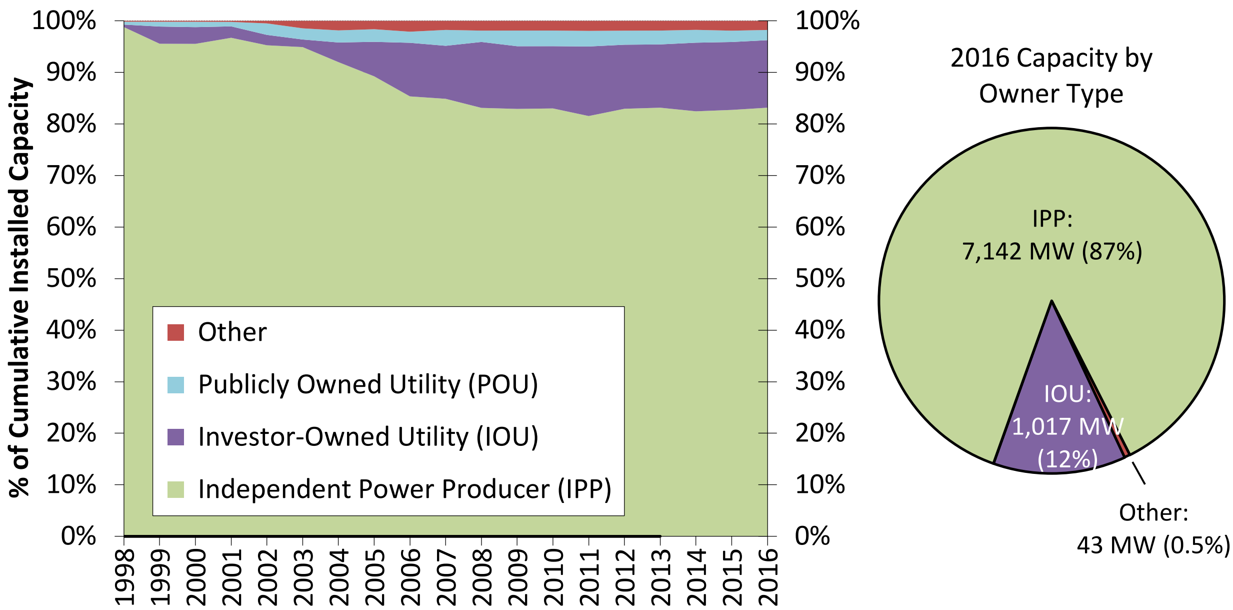
Figure 17. Cost of 15-year debt and tax equity for utility-scale wind projects over time

Looking ahead, large numbers of safe-harbored wind turbines seeking deployment in viable projects will keep financiers busy for the foreseeable future. One potential wrinkle involves the prospect of federal tax reform, which (among other things) could alter both the availability and returns of third-party tax equity, depending on the nature of any such reforms. Financiers have reportedly been modifying term sheets to include indemnities, cash sweeps, and other documentation that allocates the risk of tax reform among the various parties (Chadbourne & Parke 2017b).

[26] A "mini-perm" is a relatively short-term (e.g., 7–10 years) loan that is sized based on a much longer tenor (e.g., 15–17 years) and therefore requires a balloon payment of the outstanding loan balance upon maturity. In practice, this balloon payment is often paid from the proceeds of refinancing the loan at that time. Thus, a 10-year mini-perm might provide the same amount of leverage as a 17-year fully amortizing loan but with refinancing risk at the end of 10 years. In contrast, a 17-year fully amortizing loan would be repaid entirely through periodic principal and interest payments over the full tenor of the loan (i.e., no balloon payment required and no refinancing risk).

IPPs own the vast majority of wind assets built in 2016

Independent power producers (IPPs) own 7,142 MW or 87% of the 8,203 MW of new wind capacity installed in the United States in 2016 (Figure 18). Investor-owned utilities (IOUs), meanwhile, installed more than 1,000 MW (12%); this includes MidAmerican (706 MW), Xcel Energy (200 MW), DTE Energy (51 MW), and Black Hills Energy (61 MW). Publicly owned utilities (POUs) do not own any of the new wind power capacity brought online in 2016. Finally, 43 MW (0.5%) fall into the "other" category of projects owned by neither IPPs nor utilities (e.g., towns, schools, businesses, farmers).[27] Of the cumulative installed wind power capacity at the end of 2016, IPPs own 83% and utilities own 15% (13% IOU and 2% POU), with the remaining 2% falling into the "other" category.



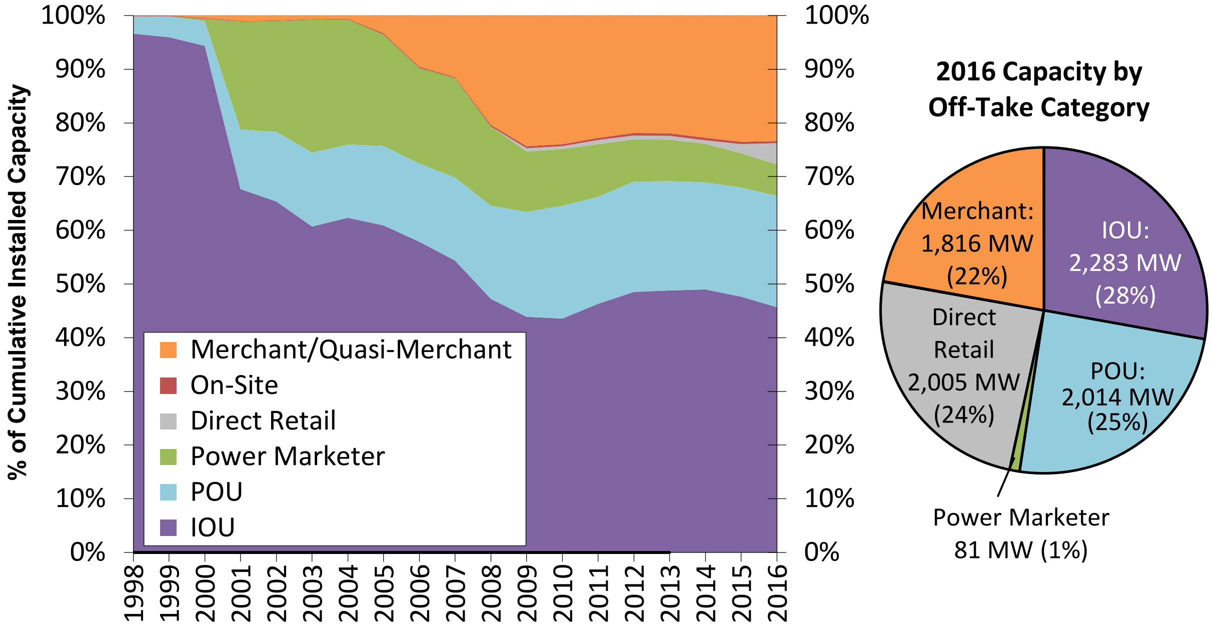
Source: Berkeley Lab estimates based on AWEA project database

Figure 18. Cumulative and 2016 wind power capacity categorized by owner type

Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales gained ground

Electric utilities continued to be the dominant off-takers of wind power in 2016 (Figure 19), either owning wind projects (12%) or buying the electricity from wind projects (40%) that, in total, represent 52% of the new capacity installed last year (with the 52% split between 28% IOU and 25% POU). On a cumulative basis, utilities own (15%) or buy (51%) power from 66% of all wind power capacity installed in the United States (with the 66% split between 46% IOU and 21% POU).

[27] Many of the "other" projects, along with some IPP- and POU-owned projects, might also be considered "community wind" projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project. According to AWEA (2017a), 68.5 MW (0.8%) of 2016 wind capacity additions qualified as community wind projects.



Source: Berkeley Lab estimates based on AWEA project database

Figure 19. Cumulative and 2016 wind power capacity categorized by power off-take arrangement

Merchant/quasi-merchant projects accounted for 22% of all new 2016 capacity and 23% of cumulative capacity. Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracts and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 10- to 12-year period[28]) rather than being locked in through a long-term PPA.

Direct retail purchasers of wind power, including both corporate and non-corporate off-takers, are supporting 2,005 MW or 24% of the new wind power capacity installed in the United States in 2016 (up from 10% of new capacity installed in 2015). Direct retail sales should continue to make inroads in the coming years, based on AWEA (2017a) estimates that 39% of all wind PPAs that were *executed* in 2016 were with non-utility purchasers (following 52% in 2015 and 18% for 2014—not all of which have yet achieved commercial operations).

Power marketers were very active throughout the first decade of this century following the initial wave of electricity market restructuring, but their influence has waned in recent years: just 6% of cumulative wind power capacity in the United States sells to power marketers, down from more than 20% in the early 2000s. Power marketers are defined here to include commercial intermediaries that purchase power under contract and then resell that power to others.[29]

Finally, just 3 MW of the wind power additions in 2016 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.

[28] Hedges are often structured as a "fixed-for-floating" power price swap—a purely financial arrangement whereby the wind power project swaps the "floating" revenue stream that it earns from spot power sales for a "fixed" revenue stream based on an agreed-upon strike price. For some projects, the hedge is structured in the natural gas market rather than the power market.
[29] These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.

4. Technology Trends

Average turbine capacity and rotor diameter saw significant increases in 2016, while hub height increased only slightly; all have grown over the long term

The average nameplate capacity of the newly installed wind turbines in the United States in 2016 was 2.15 MW, up more than 200% since 1998–1999 and 11% over the previous 5-year (2011–2015) average (Figure 20).[30] The average hub height of turbines installed in 2016 was 83.0 meters, up 49% since 1998–1999 and 1% over the previous 5-year average. Average rotor diameters have increased at a more rapid pace than hub heights, especially in recent years. The average rotor diameter of wind turbines installed in 2016 was 108.0 meters, up 127% since 1998–1999, and 13% over the previous 5-year average; this translates to a 413% (relative to 1998–1999) and 27% (relative to 2011–2015) growth in rotor swept area. Trends in hub height and rotor scaling are two of several factors impacting the project-level capacity factors highlighted later in this report.

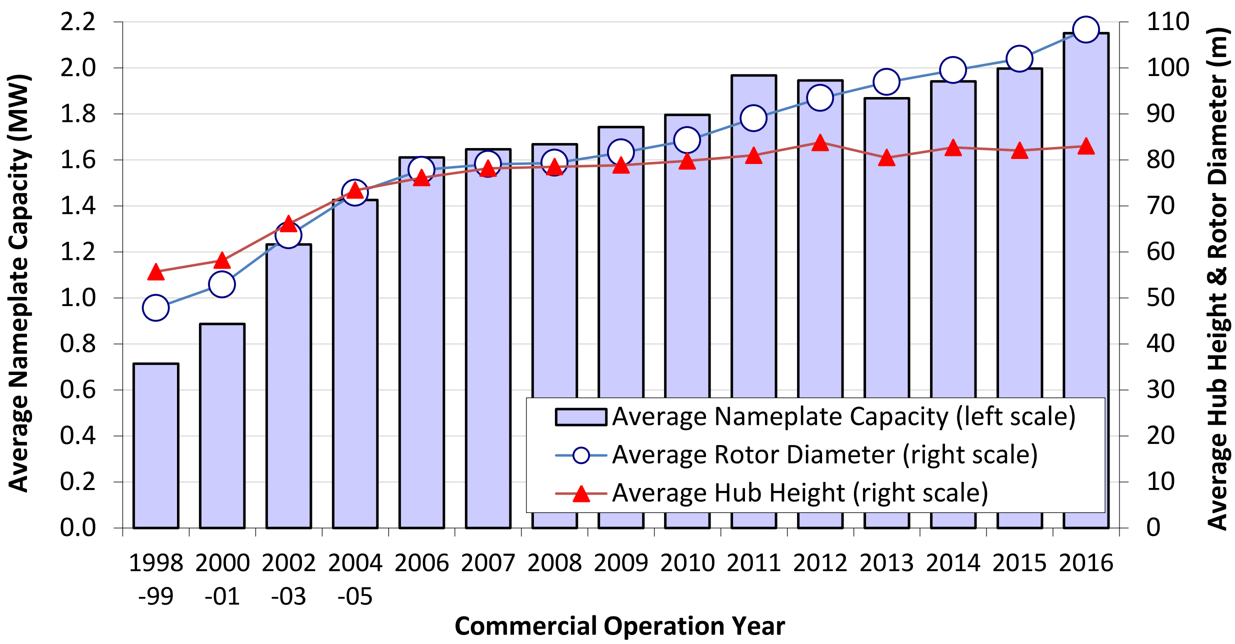


Figure 20. Average turbine nameplate capacity, rotor diameter, and hub height

Year over year growth in rotor diameters has continued unabated for more than a decade, and has outpaced growth in nameplate capacity and hub height

As indicated in Figure 20, and as detailed in Figures 21–23, increases in nameplate capacity and hub height have been outpaced by rotor scaling in recent years.

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[30] Figure 20, as well as a number of the other figures and tables included in this report, combines data into both 1- and 2-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004; although not a PTC lapse year, 1998 is grouped with 1999 due to the small sample of 1998 projects. Though 2013 was a slow year for wind additions, it is shown separately here despite the small sample size.

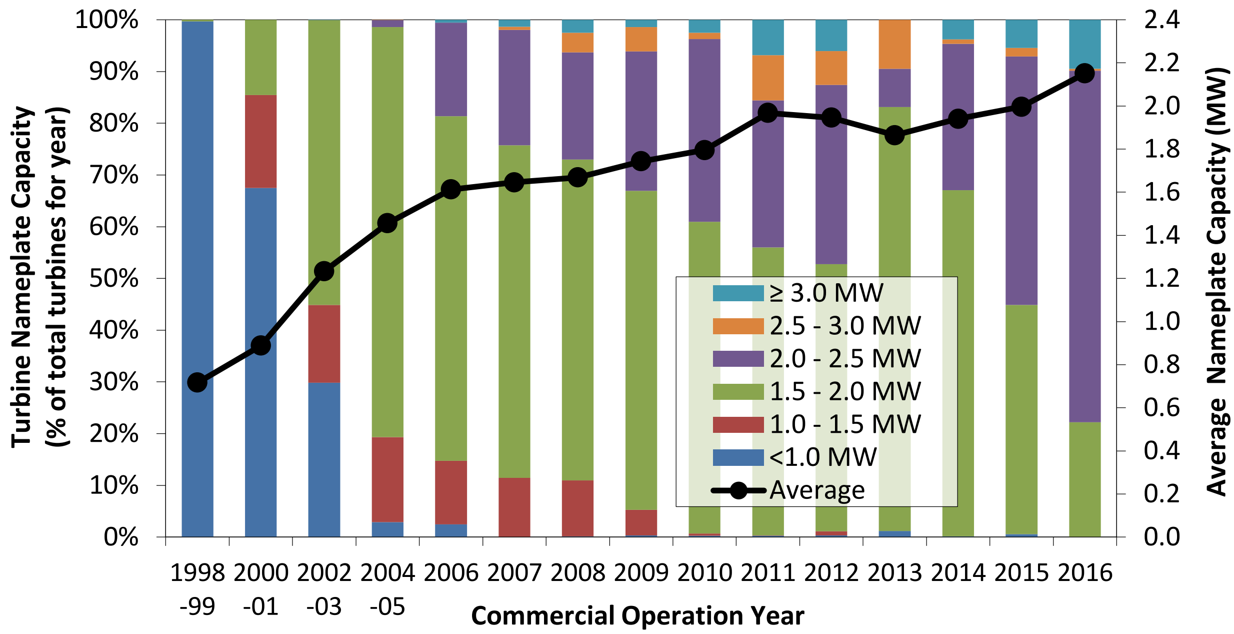


Figure 21. Trends in turbine nameplate capacity

Starting with turbine nameplate capacity, Figure 21 presents not only the trend in average nameplate capacity (as also shown earlier, in Figure 20) but also how the prevalence of different turbine capacity ratings has changed over time. The average nameplate capacity of newly installed wind turbines had largely held steady since 2011, but in 2016 saw a significant uptick. While it took just six years (2000–2005) for MW-class turbines to almost totally displace sub-MW-class turbines, it took another seven years (2006–2012) for multi-MW-class turbines (i.e., 2 MW and above) to gain nearly equal market share with MW-class turbines. In 2016, 2-2.5 MW turbines dominated the market, with 3+ MW turbines also making up a notable portion (9%).

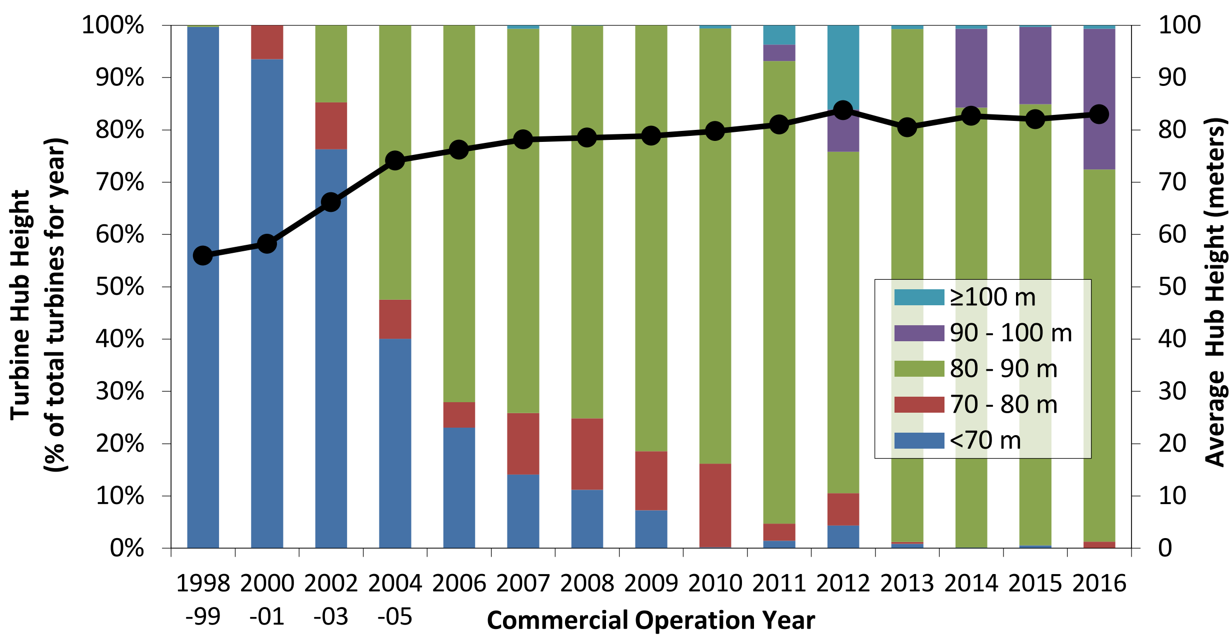


Figure 22. Trends in turbine hub height

The average hub height of wind turbines had held roughly constant from 2011 through 2015, but saw a slight increase in 2016 (Figure 22). More generally, growth in average hub height has been slow since 2005, with 80-meter towers dominating the overall market. Towers that are 90 meters and taller started to penetrate the market in 2011; in 2016, they represented greater than 25% of the market. Finally, although we saw the emergence of >100 meter towers as early as 2007, that segment of the market peaked (at least temporarily) in 2012 when 16% of newly installed turbines were taller than 100 meters. Since 2012, only 1% or less of newly installed turbines in each year (including 2016) have featured towers that tall.

The movement towards larger-rotor machines has dominated the industry for some time, with OEMs progressively introducing larger-rotor options for their standard offerings and introducing new turbines that feature larger rotors. As shown in Figure 23, this increase has been especially apparent since 2009, with further acceleration in 2016. In 2008, no turbines employed rotors that were 100 meters in diameter or larger. By 2012, 47% of newly installed turbines featured rotors of at least that diameter, and in 2016 the percentage grew to 97%. Rotor diameters of 110 meters or larger started penetrating the market in 2012; in 2016 they represented over 50% of the market. The percent of turbines with rotor diameters over 120 meters nearly doubled in 2016 from the previous year but still represented only a small portion (<3%) of the market.

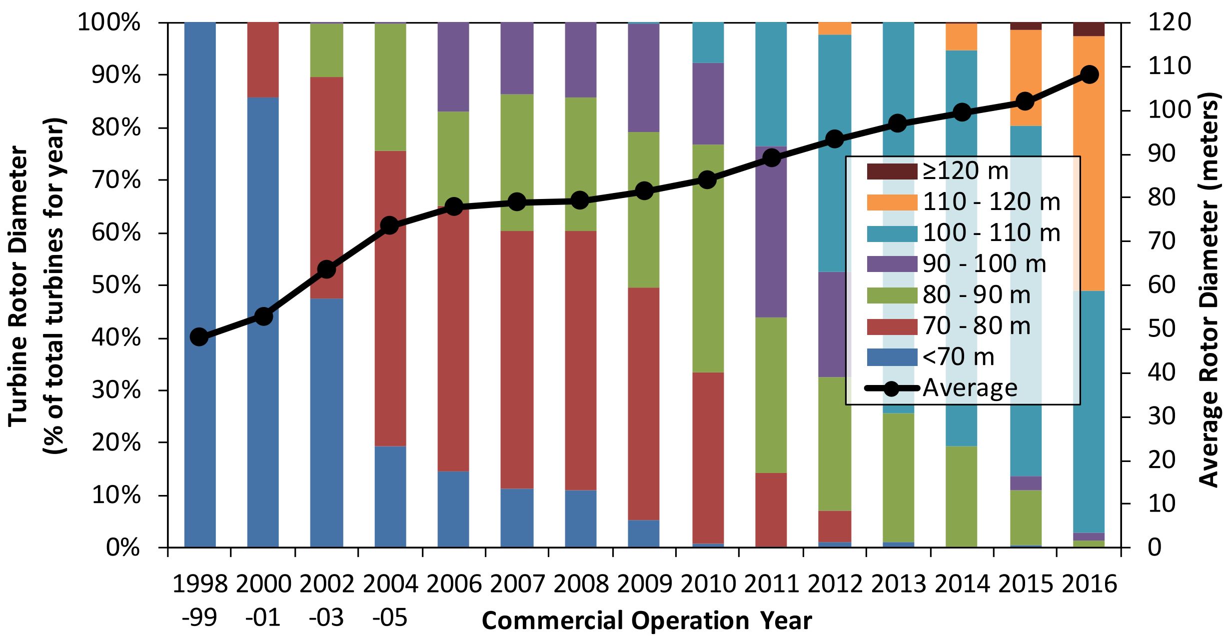


Figure 23. Trends in turbine rotor diameter

Turbines originally designed for lower wind speed sites have rapidly gained market share

Though the above-mentioned growth trends have been notable, the growth in the swept area of the rotor has been particularly rapid. With growth in average swept area (in m^2) outpacing growth in average nameplate capacity (in W), there has been a decline in the average "specific power" (in W/m^2) among the U.S. turbine fleet over time, from 394 W/m^2 among projects installed in 1998–1999 to 233 W/m^2 among projects installed in 2016 (Figure 24). The decline in specific power was especially rapid from 2001 to 2005 and, more recently, from 2011 to 2016.

All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. In general, turbines with low specific power were originally designed for lower wind speed sites; they were intended to maximize energy capture in areas where the wind resource is modest, and where large rotor machines would not be placed under excessive physical stress due to high or turbulent winds. As suggested in Figure 24 and as detailed in the next section, however, such turbines are now in widespread use in the United States—even in sites with high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.

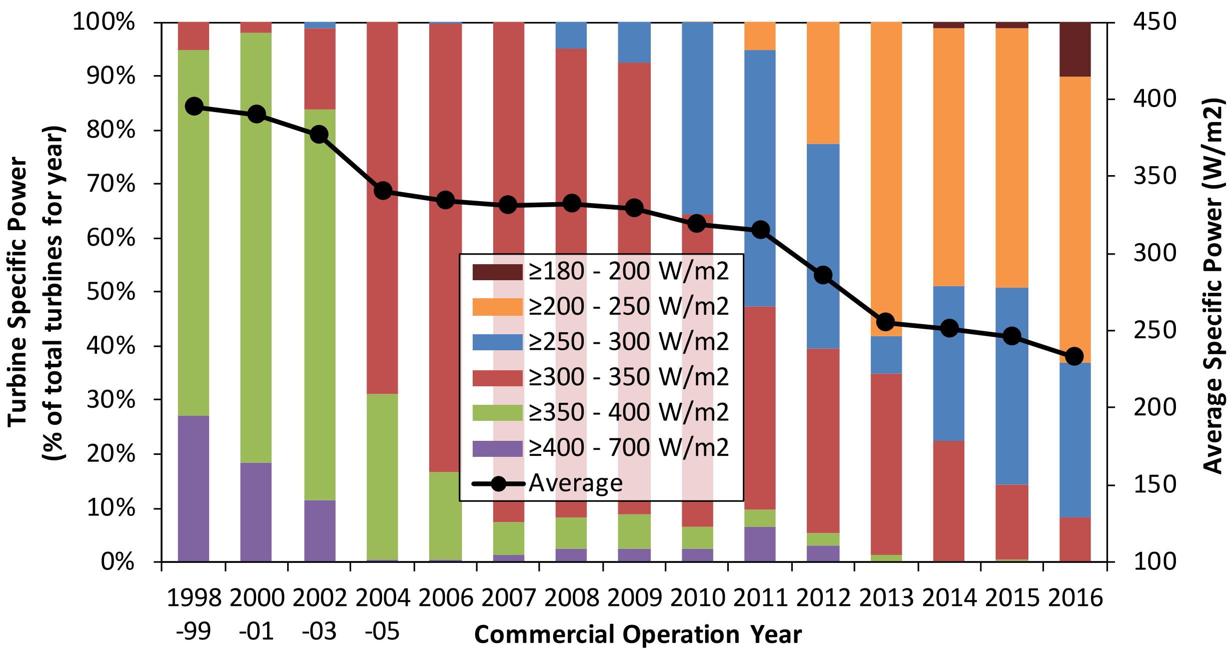
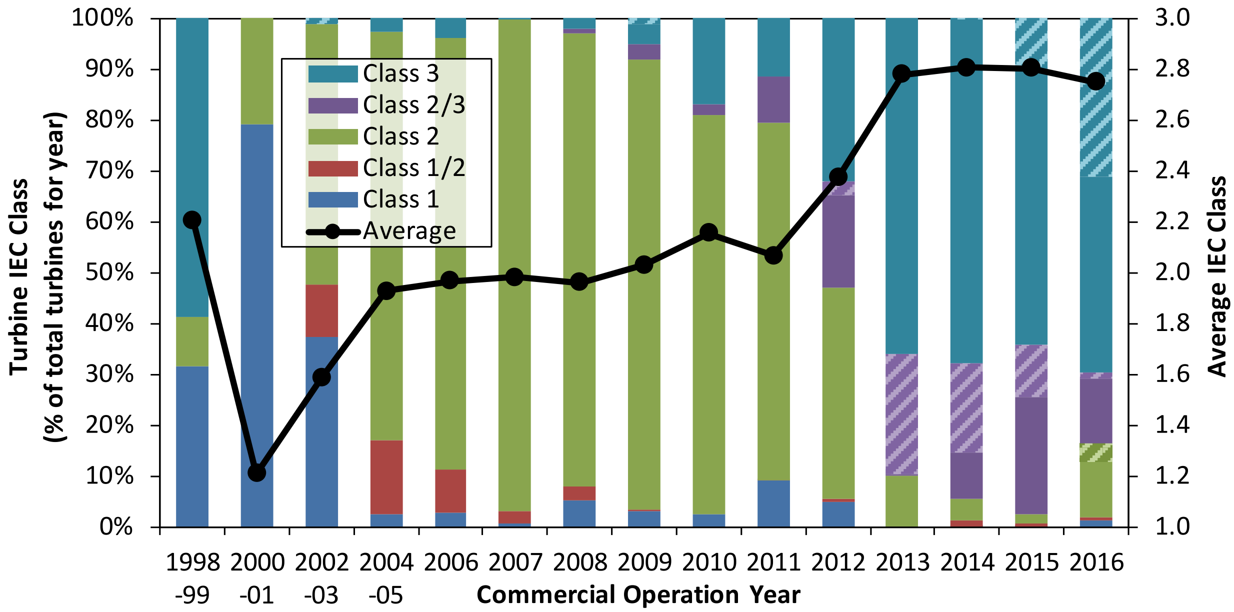


Figure 24. Trends in turbine specific power

Another indication of the increasing prevalence of machines initially designed for lower wind speeds is revealed in Figure 25, which presents trends in wind turbine installations by IEC Class. The IEC classification system considers multiple site characteristics, including wind speed, gusts, and turbulence. Class 3 turbines are generally designed for lower wind speed sites (7.5 m/s and below), Class 2 turbines for medium wind speed sites (up to 8.5 m/s), and Class 1 turbines for higher wind speed sites (up to 10 m/s). Some turbines are designed at the margins of two classifications, and are labeled as such (e.g., Class 2/3). Additionally, a significant portion of the turbines installed in 2016 were Class S-2, S-2/3, or S-3, which fall outside the standard IEC rating for those classes for one reason or another as specified by the turbine design (and are depicted with hash marks in the figure).[31]

The U.S. wind market has clearly become increasingly dominated by IEC Class 3 turbines in recent years. In 2000–2001, Class 1 machines were prevalent. From 2002 through 2011, Class 2 machines dominated the market. Since 2011, there has been a substantial decline in the use of Class 2 turbines, and a concomitant increasing market share of Class 2/3 and Class 3 turbines. In 2016, 69% of the newly installed turbines were Class 3 machines, 14% were Class 2/3 machines, and 17% of turbines were Class 2 or lower (each including S turbines rated similarly).



Note: Class S-2, S-2/3 and S-3 turbines are shown with hash marks in their respective bins, which are also used to calculate the average.

Figure 25. Trends in turbine IEC class

Moreover, Class 2, 2/3, and 3 turbine technology has not remained stagnant. Figure 26 shows the trend in average specific power across all turbines installed in each year (regardless of IEC Class, matching the average line shown in Figure 24) and also the average specific power ratings of Class 2, 2/3, and 3 (i.e., medium and lower wind speed) turbines installed in the United States. Through 2011, the progressively lower specific power of Class 2 turbines, which dominated the market, drove the overall decline in fleet-wide specific power. Since 2012, the continued drop in fleet-wide specific power has been spurred on by both the penetration of Class 3 and Class 2/3 machines, and by the lower specific powers of all three classes. The overall trend in fleet-wide specific power has, therefore, been driven not only by the increased penetration of, initially, Class 2 and then, later, Class 2/3 and 3 turbines, but also by the progressively lower specific power ratings of turbines within each of these IEC classes.[32]

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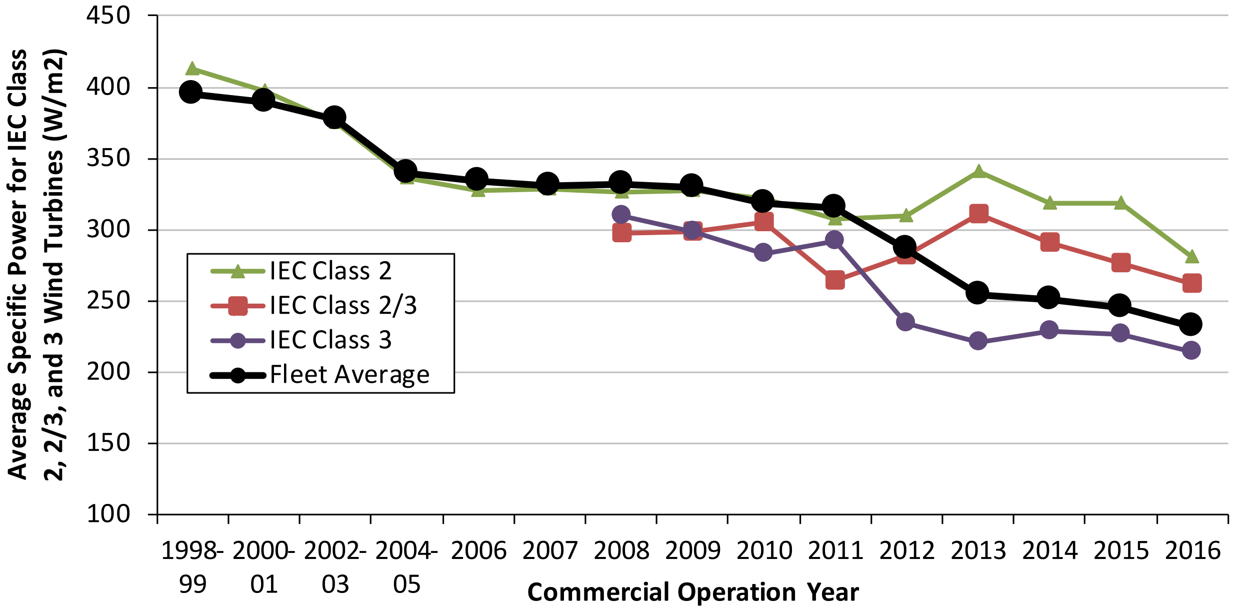
[31] The IEC Class S-2, S-2/3, or S-3 turbines are almost all manufactured by GE Wind. For example, GE rates its 1.7-103 turbine, with a 1.7 MW capacity and a 103 meter rotor diameter, as S-3, indicating that it most closely resembles an IEC Class 3 turbine. Others include GE 1.85-87 (S-2/3) and GE 2.4-107 (S-2). All of the “S” turbines are included in the reported average IEC class over time using their closest class.

[32] Class S turbines are included in this figure in their corresponding class.



Note: Specific power averages are shown only for years where there were at least 40 turbines in the respective IEC Class

Figure 26. Trends in specific power for IEC class 2, 2/3, and 3 turbines

Turbines originally designed for lower wind speeds are regularly employed in both lower and higher wind speed sites; taller towers predominate in the Great Lakes and Northeast

One might expect that the increasing market share of turbines designed for lower wind speeds would be due to a movement by wind developers to deploy turbines in lower wind speed sites. Though there is some evidence of this movement historically (see Chapter 5), it is clear in Figures 27 and 28 that turbines originally designed for lower wind speeds are now regularly employed in all regions of the United States, in both lower and higher wind speed sites.

Figure 27 presents the percentage of turbines installed in four distinct regions of the United States[33] (see Figure 1 for regional definitions) that have one or more of the following three attributes: (a) relatively higher hub height, (b) relatively lower specific power, and (c) relatively higher IEC Class. It focuses solely on turbines installed in the 2014–2016 time period. Figure 28 presents similar information, but segments the data by the wind resource quality of the site rather than by the region in which the turbines are located.

Taller towers (i.e., 90 meters and above) saw higher market share during the 2014–2016 period in the Great Lakes (56%) and Northeast (55%) than in the Interior (16%) and West (0%) (Figure 27), often in sites with lower wind speeds (Figure 28). This is largely due to the fact that such towers are most commonly used in sites with higher-than-average wind shear (i.e., greater increases in wind speed with height) to access the better wind speeds that are typically higher up. Sites with higher wind shear are prevalent in the Great Lakes and Northeast.

[33] Due to very limited sample size, we exclude the Southeast region from these graphs and related discussion.

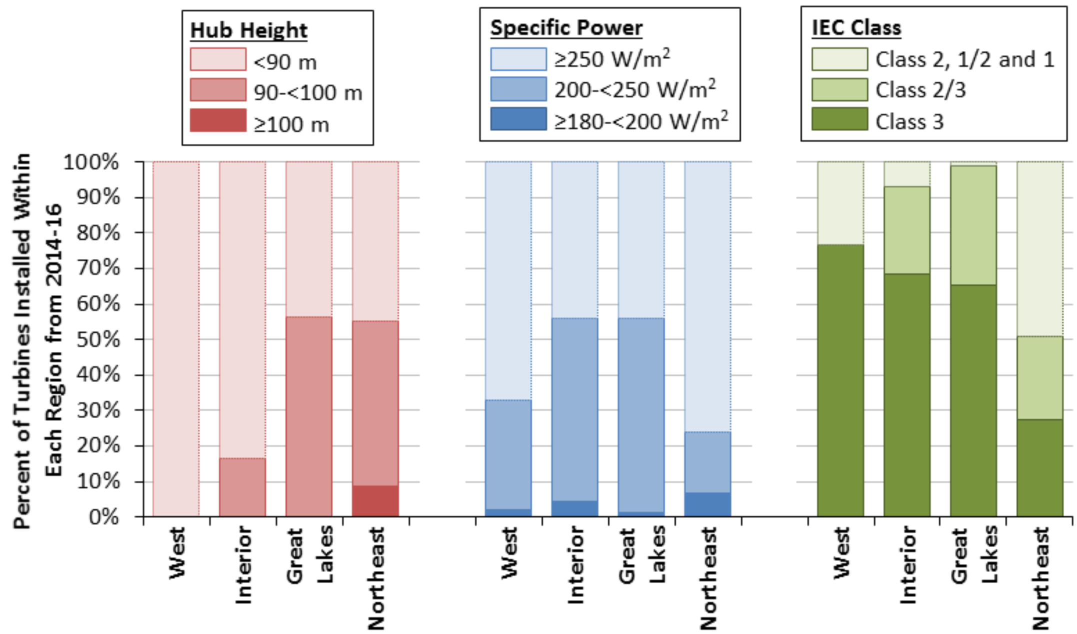
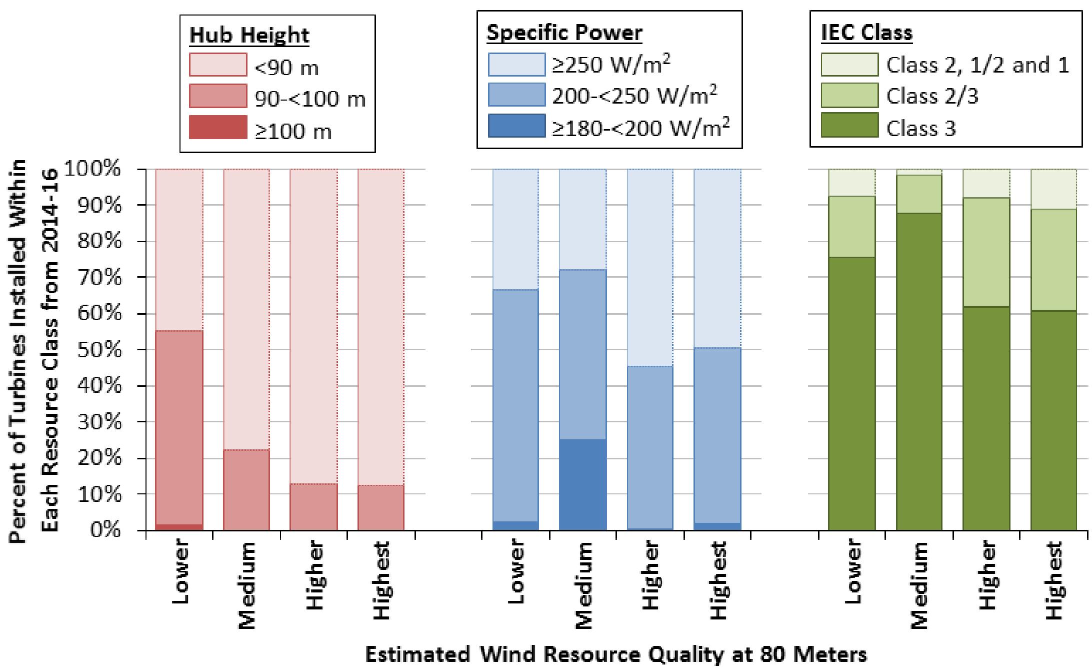


Figure 27. Deployment of turbines originally designed for lower wind speed sites, by region



Note: Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The "lower" category includes all projects with an estimated gross capacity factor of <40%, the "medium" category corresponds to 40%–45%, the "higher" category corresponds to 45%–50%, and the "highest" category includes projects with gross capacity factors at or exceeding 50%. A single, common wind-turbine power curve is used across all sites and timeframes, and no losses are assumed. Further details are found in the Appendix.

Figure 28. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality

Low specific power machines installed over this four-year period have been regularly deployed in all regions of the country, though their market share in the Great Lakes (56%) and Interior (56%) exceeds that in the West (33%) and Northeast (24%) (Figure 27). Similarly, these turbines have been commonly used in all resource regimes including at sites with very high wind speeds, though there is some drop-off in the deployment of low specific power turbines as wind speed increases (Figure 28).

Turning to IEC Class, we see a somewhat similar story. Over this period, Class 3 and Class 2/3 machines had the largest market share in the Great Lakes (99%) and Interior (93%) regions, but also gained significant market share in the West (77%) and Northeast (51%) (Figure 27). Moreover, these turbines have been regularly deployed in both lower- and higher-quality resources sites (Figure 28).

In combination, these findings demonstrate that low specific power and Class 3 and 2/3 turbines, originally designed for lower wind speed sites, have established a strong foothold across the nation and over a wide range of wind speeds. In many parts of the Interior region, in particular, relatively low wind turbulence has allowed turbines designed for low wind speeds to be deployed across a wide range of site-specific resource conditions.

Pending and proposed wind power projects continue the trend of ever-taller turbines as lower wind resource sites appear to be targeted

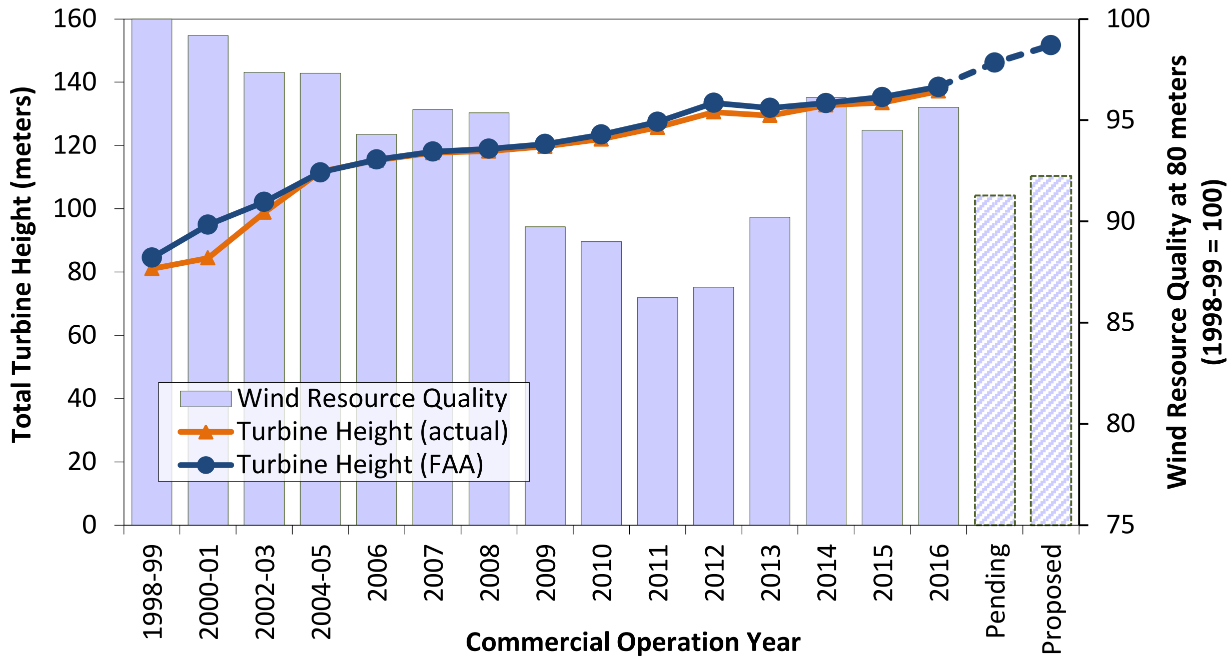
Federal Aviation Administration (FAA) data on not-yet-built "pending" and "proposed" turbines suggest that future wind projects will deploy progressively taller turbines, continuing the historical trend (see the blue line in Figure 29). "Pending" turbines—i.e., those that have been determined by the FAA to be "no hazard" (*n* = 23,976)—have an average total height of 146 meters, as compared to the 2016 average of 139 meters. "Proposed" turbines—i.e., those that the FAA is currently studying (*n* = 8,678)—have an even higher average total height of 152 meters. Note that these data represent total turbine height, not hub height, and so consider the combined effect of both tower and rotor size.[34]

Turbine heights reported in FAA applications can differ from what is ultimately installed, but at least historically the actual and FAA datasets have strongly conformed on average (compare the blue and orange lines in Figure 29). This provides some confidence that the projected trends shown in the FAA "pending" and "proposed" data will come to pass.[35] In addition, there is

[34] To provide some context about possible hub heights and rotor diameters that—combined—might roughly meet these total height estimates, we can review the characteristics of installed projects that feature roughly similar total heights. In particular, four of the more common and similar total heights for existing projects are: 138 meters (9 projects, 586 turbines already installed); 145 meters (20 projects, 1,027 turbines); 146 meters (15 projects, 476 turbines); and 150 meters (37 projects, 1,506 turbines). The hub heights and rotor diameters for these turbines are, respectively: 80 and 116 meters for the turbines with 138-meter total heights, and 96 and 100 meters for the turbines with 146-meter total heights. For the 145- and 150-meter turbines, the hub height and rotor diameter combinations are more varied. Nonetheless, the most-common hub heights and rotor diameters for the 145-meter turbines are 95 meters and 100 meters, respectively, whereas the 150-meter turbines are most commonly 100 meters in height with 100-meter rotor diameters.

[35] Pending and proposed turbines may not all ultimately be built. However, analysis of 2015 FAA data that would have been characterized as pending or proposed at that time was found to be a reasonable proxy for what actually was built in subsequent years.

anecdotal evidence that there might historically have been a “soft cap”, recently dampening what might otherwise be even higher total heights. Specifically, the FAA requires a public comment period on any turbine proposed over 500 feet, causing some developers to want to stay under that cap, in some cases by using non-standard hub and rotor combinations (note that the average among “proposed” turbines is 152 meters, or 499 feet—just less than 500 feet).



Source: FAA, AWS Truepower, AWEA, Berkeley Lab

Figure 29. Actual and estimated turbine height and average wind resource quality at 80 meters

Based on the locations of the pending and proposed turbines in the FAA database, it appears that these turbines will be deployed in somewhat lower-quality wind resource areas than were built out in 2014–2016. The bars in Figure 29 depict a wind resource quality index (1998–1999=100) that is based on site estimates of *gross* capacity factors at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower (see Appendix for details). After a marked dip in average site quality from 2009 to 2013 in particular,[36] developers returned to

[36] Several factors could have driven the downward trend in average site quality, and the notable decline during the 2009–2013 period in particular. First, the increased availability of low-wind-speed turbines that feature higher hub heights and a lower specific power may have enabled the economic build-out of lower-wind-speed sites. Second, developers may have reacted to increasing transmission constraints over this period (or other siting constraints, or even just regionally differentiated wholesale electricity prices) by focusing on those projects in their pipeline that may not be located in the best wind resource areas but that do have access to transmission (or higher-priced markets, or readily available sites without long permitting times). Federal and/or state policy could also be partly responsible. For example, wind projects built in the 4-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC and, according to the 2012 edition of this report (Wiser and Bolinger 2013), more than 20.6 GW, or nearly 60% of all new wind capacity installed during that four-year window, did so. Because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that developers seized this limited opportunity to build out the less-energetic sites in their development pipelines. Finally, state RPS requirements sometimes require or motivate in-state or in-region wind development in lower wind resource regimes.

building out more energetic sites in 2014–2016. The pending and proposed turbines, however, are to be sited in lower-quality wind resource areas (at least at 80 meters)—perhaps enabled by their ability to capture stronger winds at higher heights than 80 meters.

A large number of wind power projects in 2016 employed multiple turbine configurations from a single turbine supplier

Nearly a quarter of the projects containing at least six turbines that were built in 2016 utilized multiple turbines with different hub heights, rotor diameters and/or capacities—all supplied by the same OEM. As shown in Figure 30, this relatively high degree of intra-OEM turbine specialization within individual projects had not previously been experienced in the U.S. market, with 2012 being the next highest year at 13%. More than half of these 2016 projects used GE turbines, but both Vestas and Siemens had such projects. Most of these turbines, meanwhile, differed by all three of the major characteristics: hub height, rotor diameter, and capacity rating.

There are several possible explanations for this development. First, like 2012, 2016 was initially expected to be a PTC expiration year. The resulting high demand for turbines may have left developers more willing to take what they could get, even if it meant several different turbine models within a single project. Second, increasing sophistication with respect to intra-project turbine siting and wake effects, coupled with an increasing willingness among OEMs to provide multiple turbine configurations, may be leading to greater site optimization. Finally, the perceived FAA "soft cap" of 500 feet may be influencing the number of different turbine configurations requested by developers as they attempt to optimize output at a given site while remaining below 500 feet total height.

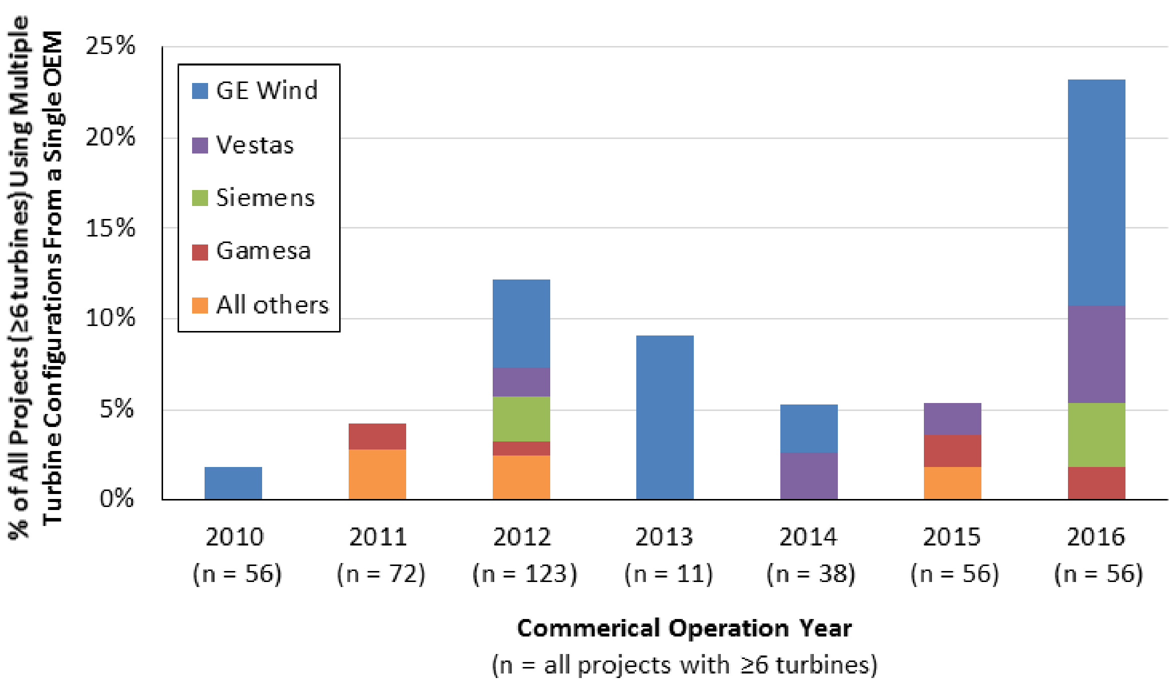


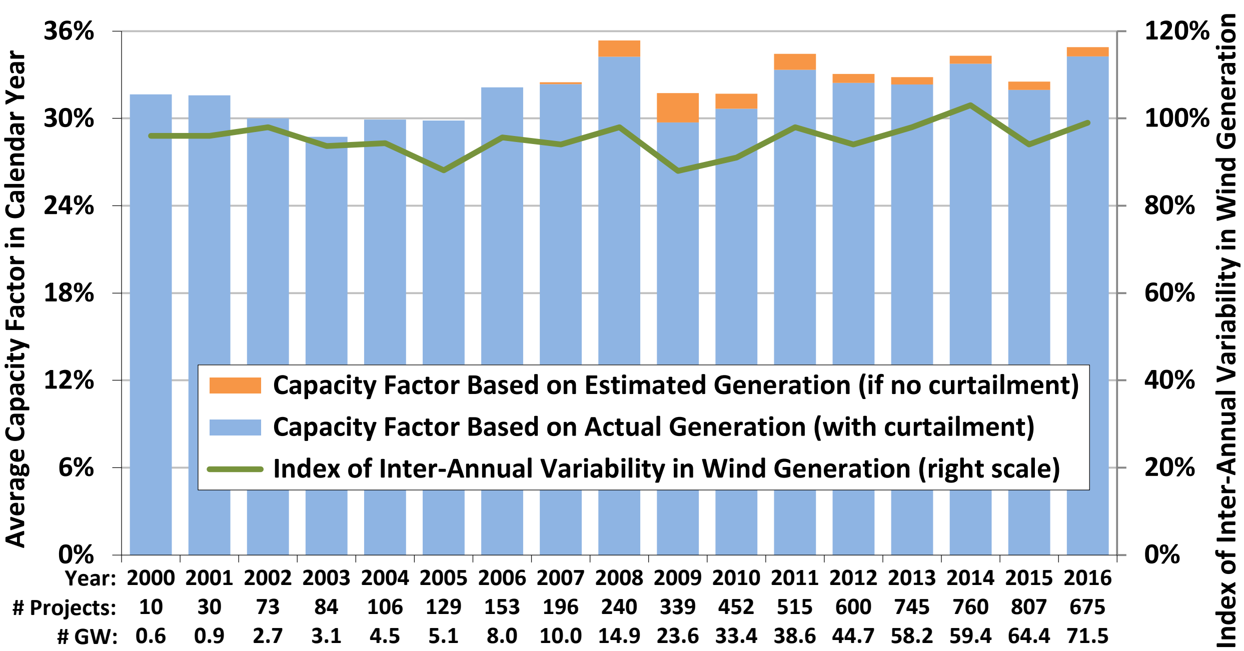
Figure 30. Percent of larger projects employing multiple turbine configurations from a single OEM

5. Performance Trends

Following the previous discussion of technology trends, this chapter presents data from a compilation of project-level capacity factors. The full data sample consists of 675 wind projects built between 1998 and 2015 totaling 71,510 MW (96.6% of nationwide installed wind capacity at the end of 2015).[37] Excluded from this assessment are older projects, installed prior to 1998. The discussion is divided into three subsections: the first analyzes trends in sample-wide capacity factors over time; the second looks at variations in capacity factors in 2016 by project vintage; and the third focuses on regional variations. Unless otherwise noted, all capacity factors in this chapter are reported on a net (i.e., taking into account losses from curtailment, less-than-full availability, wake effects, icing and soiling, etc.) rather than gross basis.

Sample-wide capacity factors have gradually increased, but have been impacted by curtailment and inter-year wind resource variability

The blue bars in Figure 31 show the average sample-wide capacity factor of wind projects in each calendar year among a progressively larger cumulative sample in each year, focusing on projects installed from 1998 through 2015.[38]



Source: Berkeley Lab; measure of inter-annual variability is from NextEra

Figure 31. Average sample-wide capacity factors by calendar year

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[37] Although some performance data for wind power projects installed in 2016 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on projects with commercial operation dates from 1998 through 2015, often focusing on 2016 capacity factors for those projects.

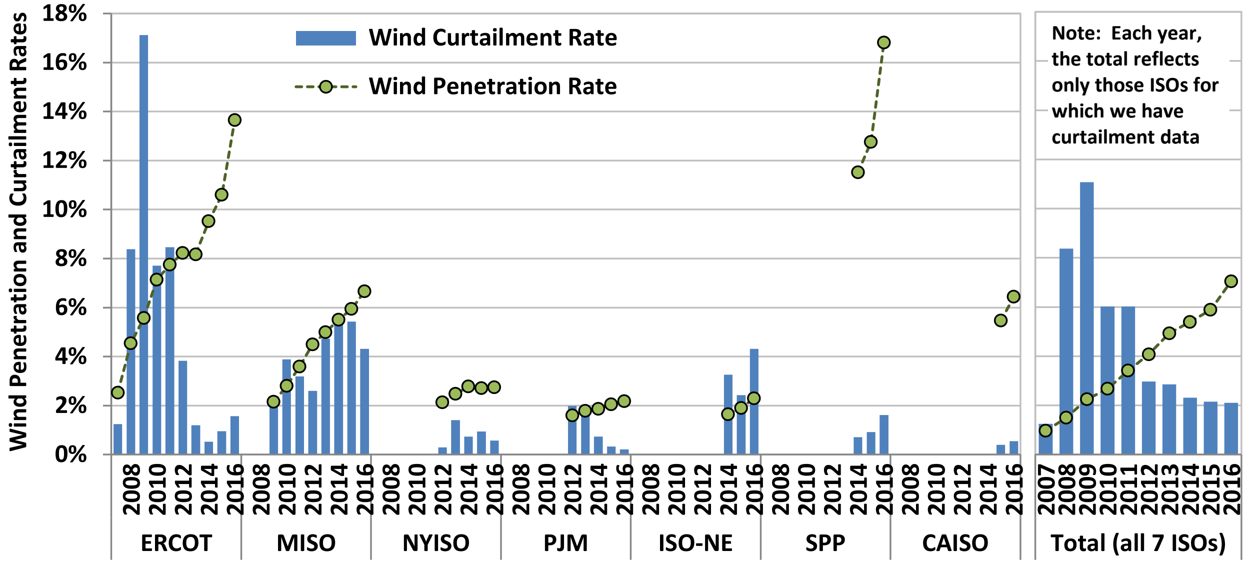
[38] There are fewer individual projects—although more capacity—in the 2016 cumulative sample than there are in 2015. This is due to the sampling method used by EIA, which focuses on a subset of larger projects throughout the year, before eventually capturing the entire sample some months after the year has ended. As a result, it might be late 2017 before EIA reports 2016 performance data for all of the wind power projects that it tracks, and in the meantime this report is left with a smaller sample consisting mostly of the larger projects in each state.

Viewed this way—on a cumulative, sample-wide basis—one might expect to see a gradual improvement in capacity factor over time, as newer turbines with taller towers and lower specific power are added to the fleet. In general, the data appear to support this trend, with somewhat higher capacity factors in the later years. But there is considerable year-to-year variability in the data, and several factors influence the apparent strength of this time-based trend. Two of those factors are discussed below—wind energy curtailment (the orange bars in Figure 31) and inter-year variability in the strength of the wind resource (the green line in Figure 31). Two additional factors—the average quality of the resource in which projects are located (e.g., recall from Figure 2 that most new capacity in recent years has been added to the windy Interior region) and performance degradation as projects age—are discussed in the next section. The next section also addresses more-directly the impact of wind turbine technology on project performance.

Wind Power Curtailment. Curtailment of wind project output happens because of transmission inadequacy and other forms of grid and generator inflexibility. For example, over-generation can occur when wind generation is high but transmission capacity is insufficient to move excess generation to other load centers, or thermal generators cannot feasibly ramp down any further or quickly enough. This can push local wholesale power prices negative, thereby potentially triggering curtailment for economic reasons—particularly among wind projects that do not receive the PTC. Curtailment might be expected to increase as wind energy penetrations rise, though as shown in Figure 32, this has not always been the case. For example, in areas where curtailment has been particularly problematic in the past—principally in Texas—steps taken to address the issue have significantly mitigated the concern, even as wind penetration has increased. Figure 32 shows that 1.6% of potential wind energy generation within the main Texas grid (ERCOT) was curtailed in 2016, down sharply from 17% in 2009, roughly 8% in both 2010 and 2011, and nearly 4% in 2012. Primary causes for the decrease in wind curtailment were the Competitive Renewable Energy Zone transmission line upgrades, most of which were completed by the end of 2013, and a move to more-efficient wholesale electric market designs.

Like ERCOT, the Southwestern Power Pool (SPP) also experienced wind curtailment of 1.6% in 2016, while the Midcontinent Independent System Operator (MISO) and New England ISO (ISO-NE) both came in higher at 4.3%. All other regions in Figure 32 were under 1%, leaving the overall wind power curtailment rate across regions at 2.1%. Curtailment rates for all regions shown in Figure 32 include both "forced" (i.e., required by the grid operator for reliability reasons) and "economic" (i.e., voluntary as a result of wholesale market prices) curtailment.

In aggregate, assuming a 33% average capacity factor, the total amount of curtailed wind generation tracked in Figure 32 for 2016 equates to the annual output of roughly 1,360 MW of wind capacity. Looked at another way, wind power curtailment has reduced sample-wide capacity factors in recent years. While the blue bars in Figure 31 reflect actual capacity factors—i.e., including the negative impact of curtailment events—the orange bars add back in the estimated amount of wind generation that has been curtailed within the seven areas shown in Figure 32, to estimate what the sample-wide capacity factors would have been absent this curtailment. As shown in Figure 31, sample-wide capacity factors would have been on the order of 0.5–2 percentage points higher nationwide from 2008 through 2016 absent curtailment in just these ISOs. Estimated capacity factors would have been even higher if comprehensive forced and economic curtailment data were available for all areas of the country.[39]



Note: All curtailment percentages shown in the figure represent both forced and economic curtailment. PJM's 2012 curtailment estimate is for June through December only.

Source: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

Figure 32. Wind curtailment and penetration rates by ISO

Inter-Year Wind Resource Variability. The strength of the wind resource varies from year to year, partly in response to significant persistent weather patterns such as El Niño/La Niña. Across the continental United States, below-normal wind speeds during the first half of 2016 gave way to above-normal winds for the remainder of the year, leading to a "near-normal" year overall (AWS Truepower 2017).

The green line in Figure 31 also shows that 2016 was generally an average wind year, at least in terms of the national average wind energy resource as measured by one large project sponsor.[40] It is also evident from Figure 31 that movements in sample-wide capacity factor from year to year are influenced by the natural inter-year variability in the strength of the national wind resource.

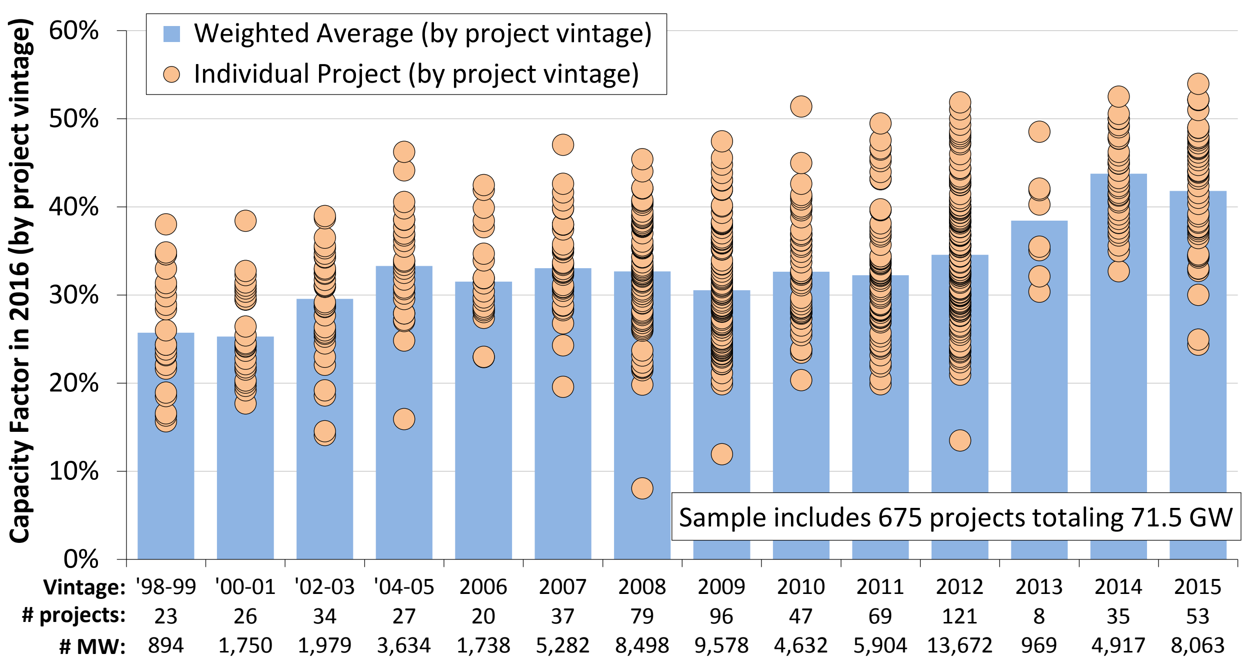
[39] The seven ISOs included in Figure 32 collectively contributed 81% of total U.S. wind generation in 2016.

[40] The green line in Figure 31 estimates changes in the strength of the average "nationwide" (to the extent that NextEra's wind project portfolio is representative of the entire U.S. fleet) wind resource from *year to year* and is derived from data presented by NextEra Energy Resources in its quarterly earnings reports. Because NextEra's indexing methodology it is not entirely transparent and has changed on several occasions, inter-year directional trends are likely more reliable than the absolute level of the index itself (which seems to fall below 100% in an abnormally large number of years). Note that this NextEra index of inter-annual variability differs from the AWS Truepower wind resource quality data presented elsewhere, which focuses on the multi-year average wind resource at specific wind project sites.

The impact of technology trends on capacity factors becomes more apparent when parsed by project vintage

One way to partially control for the time-varying influences described in the previous section (e.g., annual wind resource variations or changes in the amount of wind curtailment) is to focus exclusively on capacity factors in a single year, such as 2016.[41] As such, while Figure 31 presents sample-wide capacity factors in each calendar year, Figure 33 instead shows only capacity factors in 2016, broken out by project vintage. Wind power projects built in 2016 are again excluded, as full-year performance data are not yet available for those projects.

Figure 33 shows an increase in weighted-average 2016 capacity factors when moving from projects installed in the 1998–2001 period to those installed in the 2004–2005 period. Subsequent project vintages through 2011 show little if any improvement in average capacity factors recorded in 2016. This pattern of stagnation is finally broken by projects installed in 2012, and even more so by 2013–2015-vintage projects. The average 2016 capacity factor among projects built in 2014 and 2015 was 42.6%, compared to an average of 32.1% among all projects built from 2004 to 2011, and 25.4% among all projects built from 1998 to 2001.



Source: Berkeley Lab

Figure 33. Calendar year 2016 capacity factors by project vintage

The trends in average capacity factor by project vintage seen in Figure 33 can largely be explained by several underlying influences shown in Figure 34. First, there has been a trend towards progressively lower specific power ratings (note that Figure 34 actually shows the

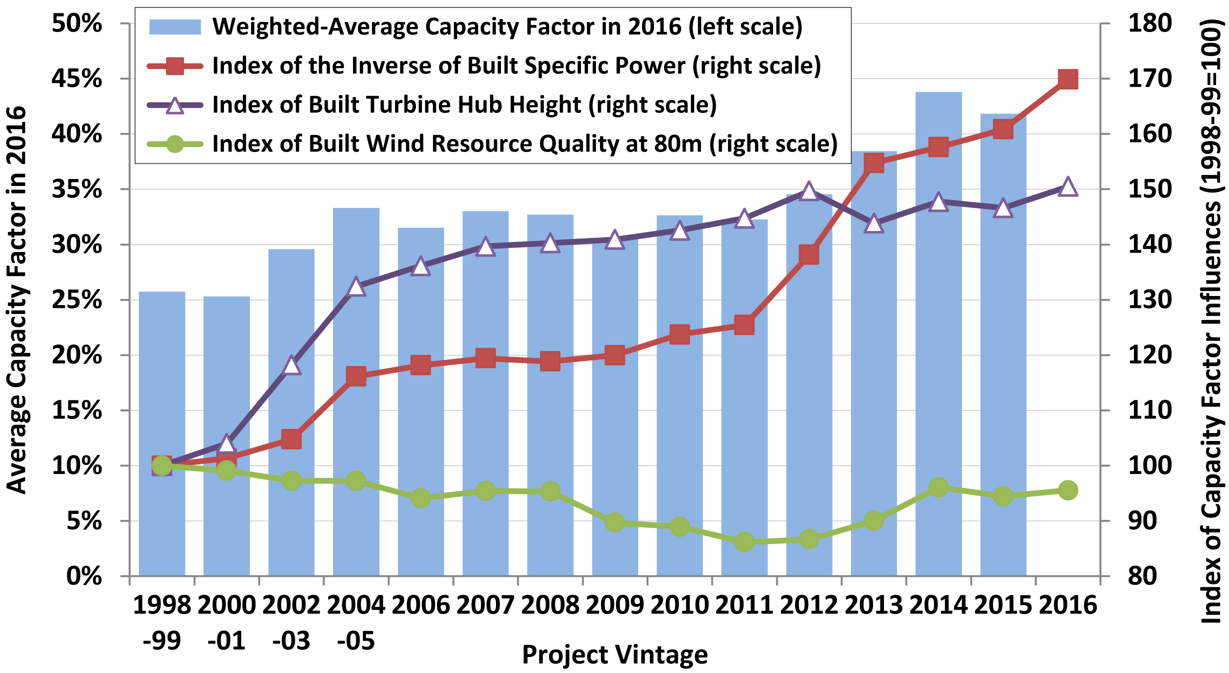
[41] Although focusing just on 2016 does control (at least loosely) for some of these known time-varying impacts, it also means that the *absolute* capacity factors shown in Figure 34 may not be representative over longer terms if 2016 was not a representative year in terms of the strength of the wind resource (though as mentioned above, 2016 was a fairly average wind year in the United States overall) or wind power curtailment.

inverse of specific power, so that a declining specific power is correlated directionally with a higher capacity factor) and higher hub heights—both of which should boost capacity factors, all else equal. Second, there was a progressive build-out of lower-quality wind resource sites through 2012 (which should hurt capacity factors, all else equal), followed by deployment at more energetic sites thereafter. Finally, as shown later in Figure 37, project vintage itself could be a fourth driver, given the possible degradation in performance among older projects.

The first two of these influences—the decline in average specific power and the increase in average hub height among more recent turbine vintages—have already been well-documented in Chapter 4. They are shown yet again in Figure 34 in index form, relative to projects built in 1998–1999 (with specific power shown in inverse form, to correlate with capacity factor movements). All else equal, a lower average specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. Meanwhile, at sites with positive wind shear, increasing turbine hub heights can help the rotor to access higher wind speeds.

Counterbalancing the decline in specific power and the increase in hub height, however, has been a tendency to build new wind projects in lower-quality wind resource areas,[42] especially among projects installed from 2009 through 2012[43] as shown by the wind resource quality index in Figure 34. This trend reversed course in 2013 and 2014, and has largely held steady in 2015 and 2016, both years in which nearly 90% of all new installed wind capacity has been located in the windy Interior region (see Figure 2).

[42] As described earlier relating to Figure 29 (with further details found in the Appendix), estimates of wind resource quality are based on site estimates of *gross* capacity factor at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower. We index the values to those projects built in 1998-99.
[43] Footnote 36 lists several possible explanations for the buildout of less-energetic sites from 2009-2012.



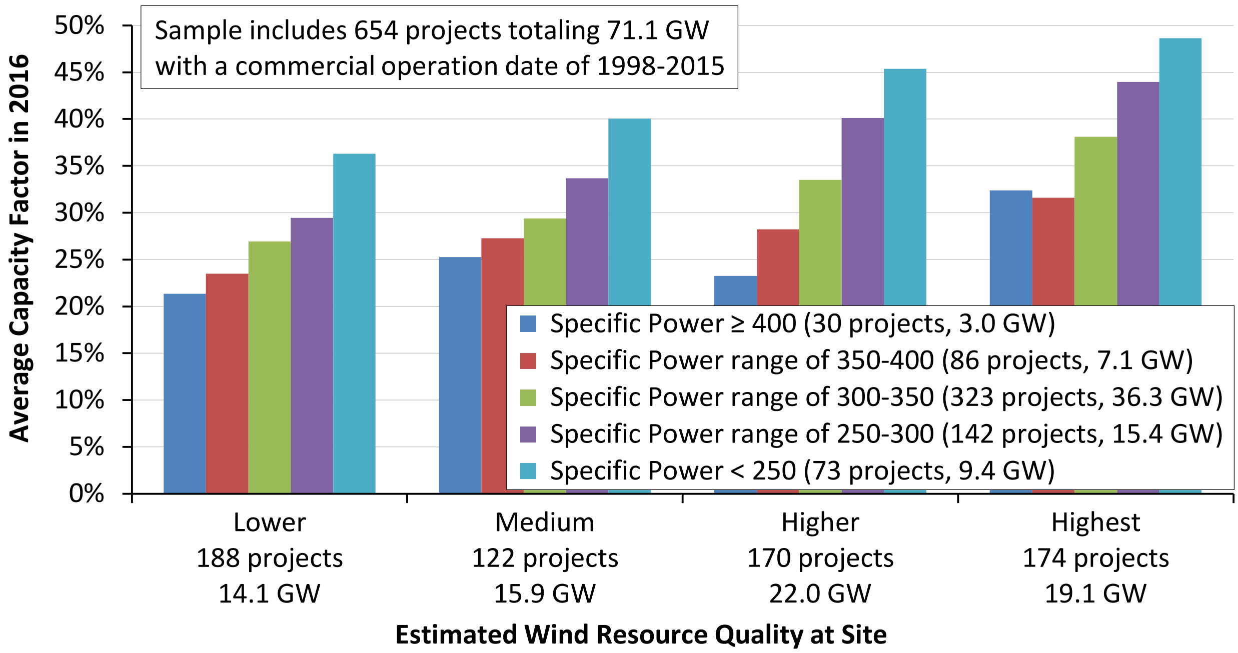
Note: In order to have all three indices be directionally consistent with their influence on capacity factor, this figure indexes the inverse of specific power (i.e., a decline in specific power causes the index to increase rather than decrease).

Source: Berkeley Lab

Figure 34. 2016 capacity factors and various drivers by project vintage

In Figure 34, the significant improvement in average 2016 capacity factors from those projects built in 1998–2001 to those built in 2004–2005 is driven by both an increase in hub height and a decline in specific power, despite a shift towards somewhat-lower-quality wind resource sites. The stagnation in average capacity factor that subsequently persists through 2011-vintage projects reflects relatively flat trends in both hub height and specific power, coupled with an ongoing decline in wind resource quality at built sites. Finally, the sharp increase in average capacity factors among projects built post-2011 is driven by a steep reduction in average specific power coupled with a marked improvement in the quality of wind resource sites (while average hub height remained relatively constant over this period). Looking ahead to 2017, 2016-vintage projects are perhaps likely to record higher capacity factors than those built in 2015 on average, in light of an ongoing reduction in average specific power, an uptick in average hub height, and a slight rebound in average site quality.

To help disentangle the competing influences of turbine design evolution and lower wind resource quality on capacity factor, Figure 35 controls for each. Across the x-axis, projects are grouped into four different categories, depending on the wind resource quality estimated for each site. Within each wind resource category, projects are further differentiated by their specific power. As one would expect, projects sited in higher wind speed areas generally realized higher 2016 capacity factors than those in lower wind speed areas, regardless of specific power. Likewise, within each of the four wind resource categories along the x-axis, projects that fall into a lower specific power range realized significantly higher 2016 capacity factors than those in a higher specific power range.



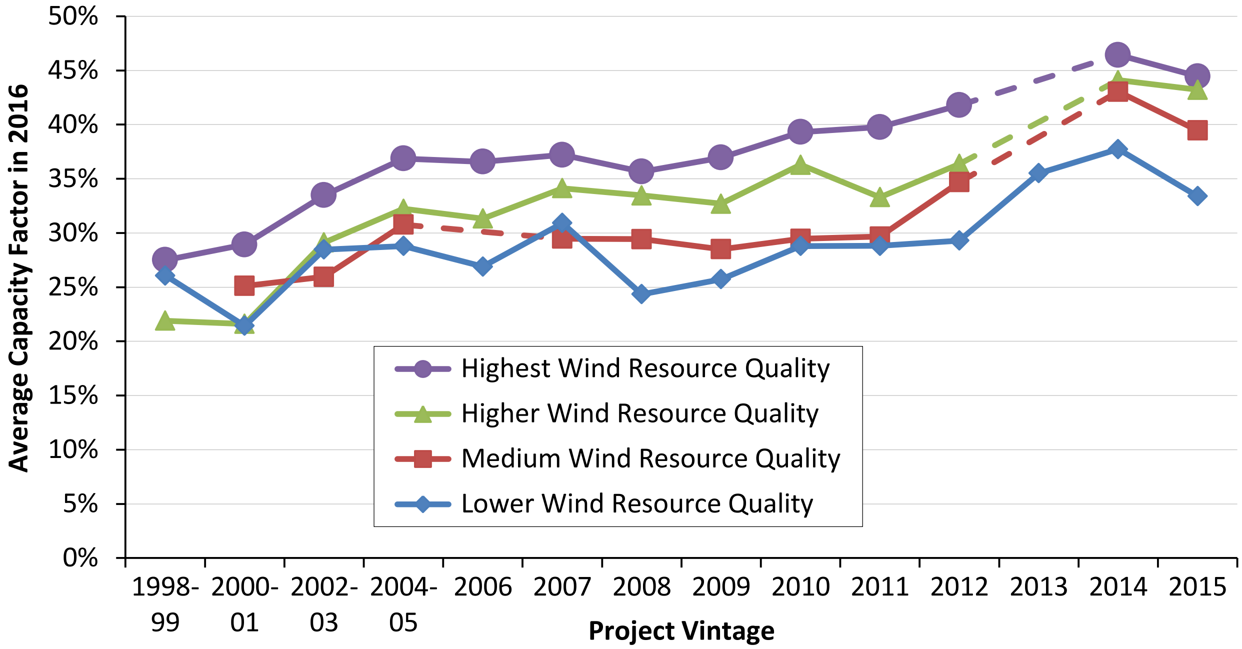
Note: Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The "lower" category includes all projects with an estimated gross capacity factor of <40%, the "medium" category corresponds to 40%–45%, the "higher" category corresponds to 45%–50%, and the "highest" category includes projects with gross capacity factors at or exceeding 50%. A single, common wind-turbine power curve is used across all sites and timeframes, and no losses are assumed. Further details are found in the Appendix.

Source: Berkeley Lab

Figure 35. Calendar year 2016 capacity factors by wind resource quality and specific power

As a result, it is clear that turbine design changes (specifically, lower specific power, but also, to a lesser extent, higher hub heights) are driving realized capacity factors higher among projects located within a given wind resource regime. This finding is further illustrated in Figure 36, which again groups projects into the same four different categories of wind resource quality, and then reports average realized 2016 capacity factors by commercial operation date within each category.[44] As before, projects sited in higher wind speed areas have, on average, higher capacity factors. More importantly, although there is some variability in the year-to-year trends, it is clear that within each of the four wind resource categories there has been an improvement in capacity factors over time, by commercial operation date.

[44] The figure only includes those data points representing at least three projects in any single resource-year pair. Among 2013-vintage projects, only the "lower" wind resource quality grouping meets this sample size threshold. In addition, the "medium" wind resource quality grouping lacks sufficient sample size in 2006. In years where insufficient sample size prohibits the inclusion of a data point, dashed lines are used to interpolate from the prior year to the subsequent year.

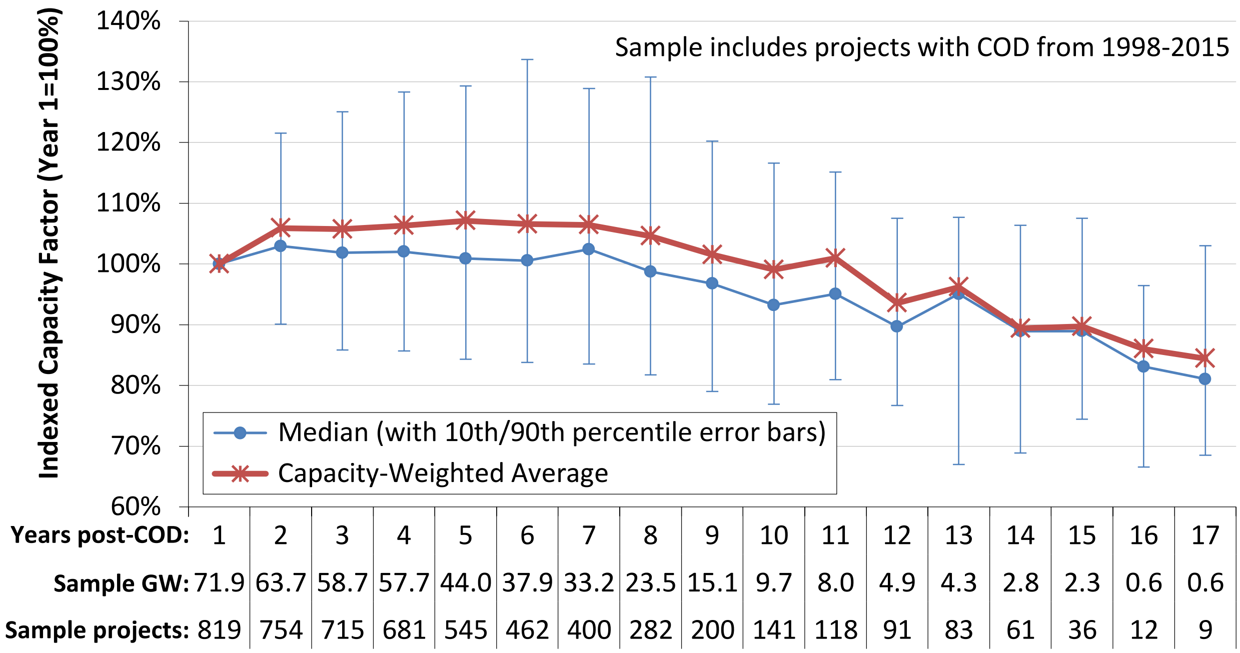


Source: Berkeley Lab

Figure 36. Calendar year 2016 capacity factors by project vintage and wind resource quality

One final variable that could be influencing the apparent improvement in 2016 capacity factors among more recent project vintages is project age. If wind turbine (and project) performance tends to degrade over time, then older projects—e.g., those built from 1998 to 2001—may have performed worse than more recent vintages in 2016 simply due to their relative age. Figure 37 explores this question by graphing both median (with 10^{th} and 90^{th} percentile bars) and capacity-weighted average capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values).

Figure 37 suggests some amount of performance degradation, though perhaps only once projects age beyond 7–10 years—i.e., a period that roughly corresponds to the initial warranty period, as well as the PTC period. Such degradation among older projects could help to partially explain why, for example, in Figure 31 the sample-wide capacity factors in 2000 and 2001 exceeded 30%, while in Figure 33 the 1998–2001 project vintages (i.e., consisting of essentially the same set of projects) posted average capacity factors of just 25% in 2016.



Source: Berkeley Lab

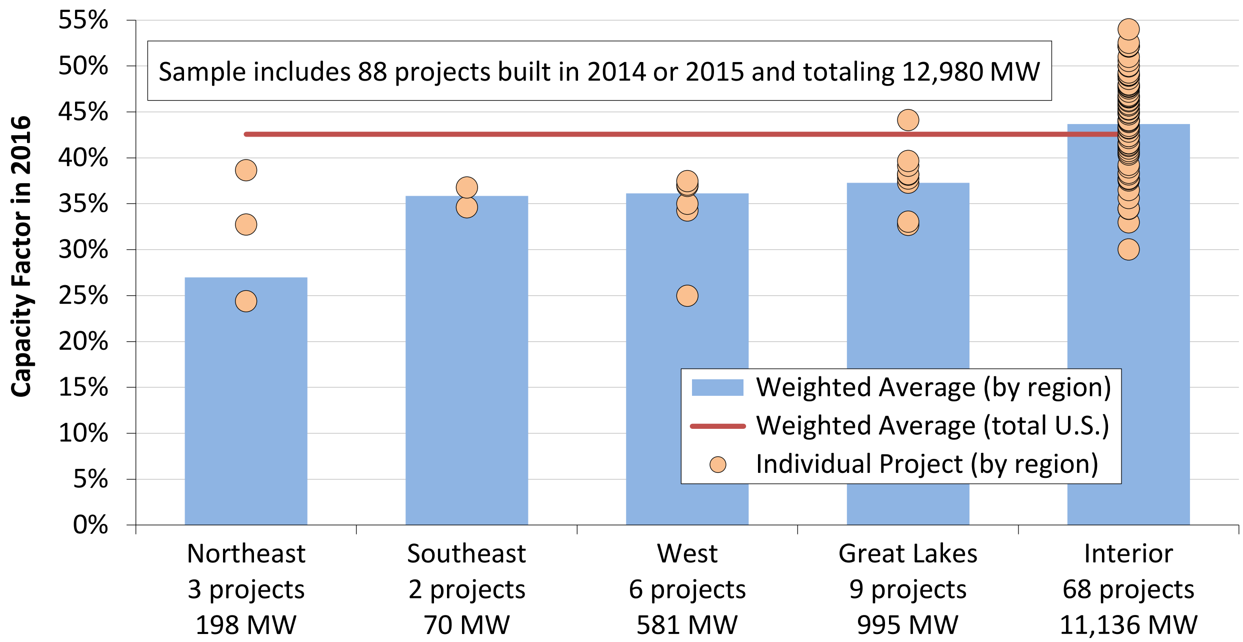
Figure 37. Post-COD changes in capacity factors over time suggest performance degradation

The median values in Figure 37 regularly fall below the capacity-weighted average values, suggesting that smaller projects tend to degrade more, and more rapidly, than larger projects. This difference could perhaps be attributable to less-stringent or -responsive O&M protocols (and therefore lower availability) among smaller projects. The PTC could be another influence, if smaller projects have instead more commonly opted for the ITC or its cash counterpart, the Section 1603 grant—neither of which depends on performance. Finally, the up-tick in year two for both the median and capacity-weighted average values could partly reflect the initial production ramp-up period that is commonly experienced by wind projects as they work through and resolve initial "teething" issues during their first year of operations.

Although all of these suppositions surrounding Figure 37 are intriguing and worthy of further study, a number of caveats are in order. First, no attempt was made to correct for inter-year variation in the strength of the wind resource. Although the potential impact of this omission is likely muted by the fact that year five (for example) for one project will be a different calendar year than year five for another project, inter-year resource variation could still play a role. Second, the sample is not the same in each year. The sample shrinks as the number of post-COD years increases, and is increasingly dominated by older projects using older turbine technology that may not be representative of today's turbines. Third, as with all figures presented in this chapter, turbine decommissioning is accounted for by adjusting the nameplate project capacity as appropriate over time (all the way to zero if a project is fully decommissioned), such that each figure, including Figure 37, shows the performance of those turbines that are operating in each period, rather than relative to the original nameplate capacity. Similarly, repowered projects are considered to be new projects in the year in which the repowered capacity comes online.

Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology

The project-level spread in capacity factors shown in Figure 33 is enormous, with 2016 capacity factors ranging from a minimum of 24% to a maximum of 54% among those projects built in 2015 (this spread is even wider for projects built in earlier years). Some of the spread in project-level capacity factors—for projects built in 2015 and earlier—is attributable to regional variations in average wind resource quality. As such, Figure 38 shows the regional variation in 2016 capacity factors (using the regional definitions shown in Figure 1, earlier) based on just the sample of wind power projects built in 2014 or 2015.



Source: Berkeley Lab

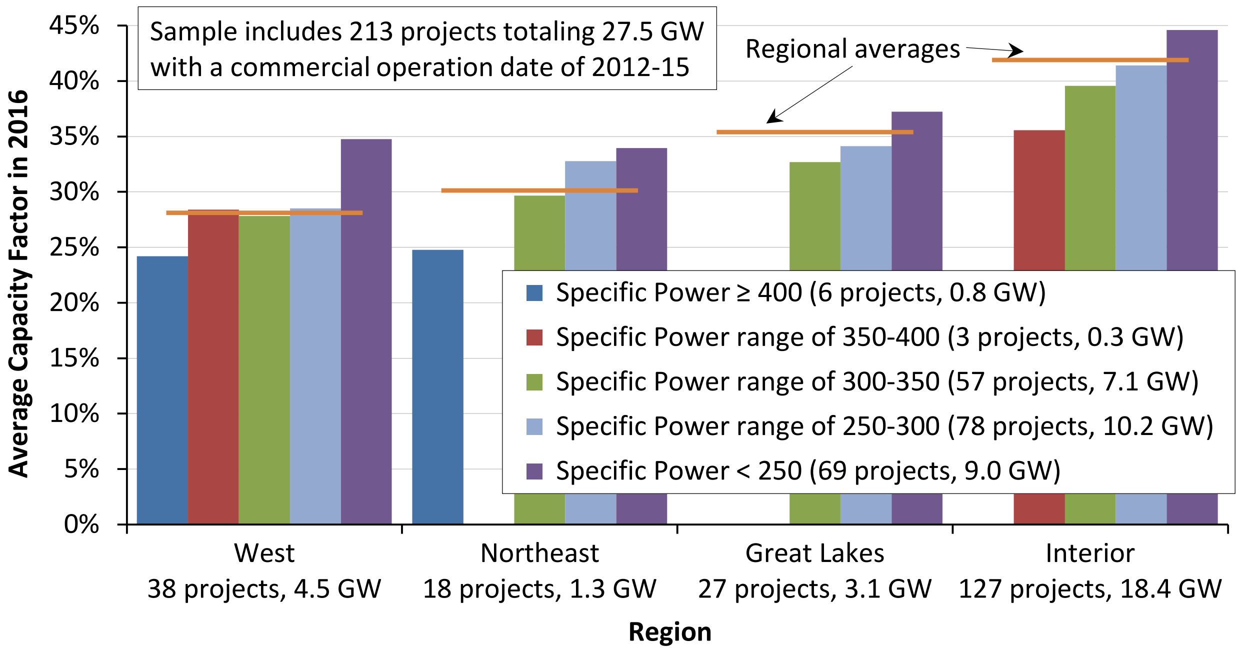
Figure 38. Calendar year 2016 capacity factors by region: 2014–2015 vintage projects only

Four of the five regions have a very limited sample, due to the fact that 86% of the total capacity installed in 2014 and 2015 was located in the Interior region. Nonetheless, generation-weighted average capacity factors appear to be highest in the Interior region (43.7%) and lowest in the Northeast (27%), with the other three regions in the mid-30% range.[45] Even within these regions, however, there can still be considerable spread—e.g., 2016 capacity factors range from 30% up to 54% among projects installed in the Interior region in 2014 or 2015.

Some of this intra-regional variation can be explained by turbine technology. Figure 39 also provides a regional breakdown, although in this case it includes projects built from 2012 to 2015, which are further differentiated by average specific power. Including older vintages (i.e., back to 2012) in Figure 39 is necessary in order to have sufficient sample within each region to enable a specific power breakout. As one would expect, within each of the four regions along the x-axis,

[45] Care should be taken in extrapolating these results, given the relatively small sample size in many regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2016.

projects using turbines that fall into a lower specific power range generally have higher realized capacity factors than those in a higher specific power range.



Source: Berkeley Lab

Figure 39. Calendar year 2016 capacity factors by region and specific power

As shown earlier in Chapter 4 ("Technology Trends"), the rate of adoption of turbines with lower specific power ratings has varied by region. For example, Figure 27 (earlier) shows that 56% of all turbines installed in the Great Lakes region from 2014 to 2016 have a specific power rating of less than 250 W/m^2, while the comparable number in the West is 33%. Similarly, 56% of all turbines installed in the Great Lakes region from 2014 to 2016 have tower heights of at least 90 meters, compared to 0% in the West. The relative degree to which projects in each region have employed these turbine design options (which is driven, in part, by the wind resource conditions in each region) influences, to some extent, their capacity factors shown in Figures 38 and 39.

Taken together, Figures 31–39 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of factors. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—such as the quality of the wind resource where projects are located, inter-year wind resource variability, and even project age.

6. Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally operations and maintenance (O&M) costs. Sample size varies among these different datasets, and is therefore discussed in each section of this chapter.

Wind turbine prices remained well below levels seen a decade ago

Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Further decreases occurred in 2016, with wind turbines sold at price points similar to the early 2000s.

Berkeley Lab has gathered price data for 122 U.S. wind turbine transactions totaling 30,780 MW announced from 1997 through 2016. This sample includes three transactions (620 MW) announced in 2015 or 2016. Sources of turbine price data vary, including financial and regulatory filings, as well as press releases and news reports. Most of the transactions included in the Berkeley Lab dataset include turbines, towers, delivery to site, and limited warranty and service agreements.[46] Nonetheless, wind turbine transactions differ in the services included (e.g., whether towers and installation are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices.

Unfortunately, collecting data on U.S. wind turbine transaction prices is a challenge, in that only a fraction of the announced turbine transactions have publicly revealed pricing data. Partly as a result, Figure 40—which depicts these U.S. wind turbine transaction prices—also presents data from three other sources: (1) Vestas, on that company's global average turbine pricing from 2005 through 2016, as reported in Vestas' financial reports; (2) BNEF (2017b), on that company's global average turbine price index by contract signing date; and (3) MAKE (2017a), on that company's index of average U.S. sales prices from major wind turbine suppliers.

After hitting a low of roughly $800/kW from 2000 to 2002, average wind turbine prices increased by approximately $800/kW (more than 100%) through 2008, rising to an average of about $1,600/kW. The increase in turbine prices over this period was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth; and increased costs for turbine warranty provisions (Moné et al. 2017).

Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher (Moné et al. 2017) as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 40, our limited sample of recently announced U.S. turbine transactions, along with data from Vestas, BNEF, and MAKE, signal average pricing in the range of $800/kW to $1,100/kW. A typical 2 MW turbine would therefore sell for roughly $1.6–2.2 million.

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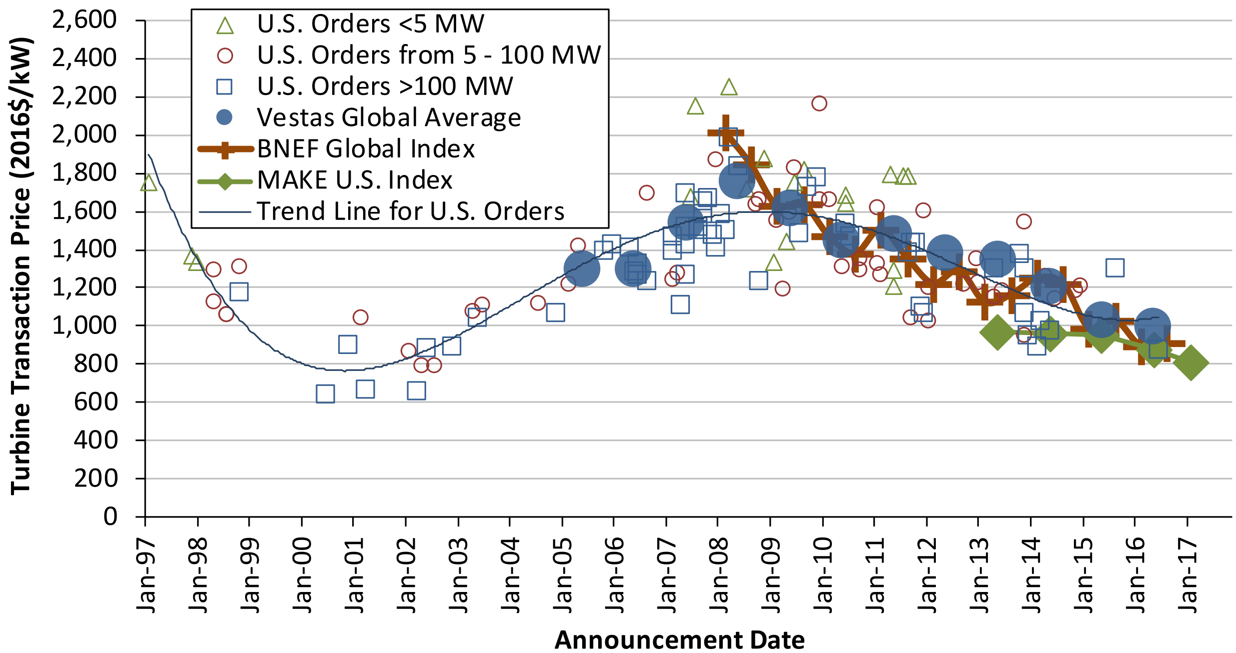
[46] Because of data limitations, the precise content of many of the individual transactions is not known.



Source: Berkeley Lab

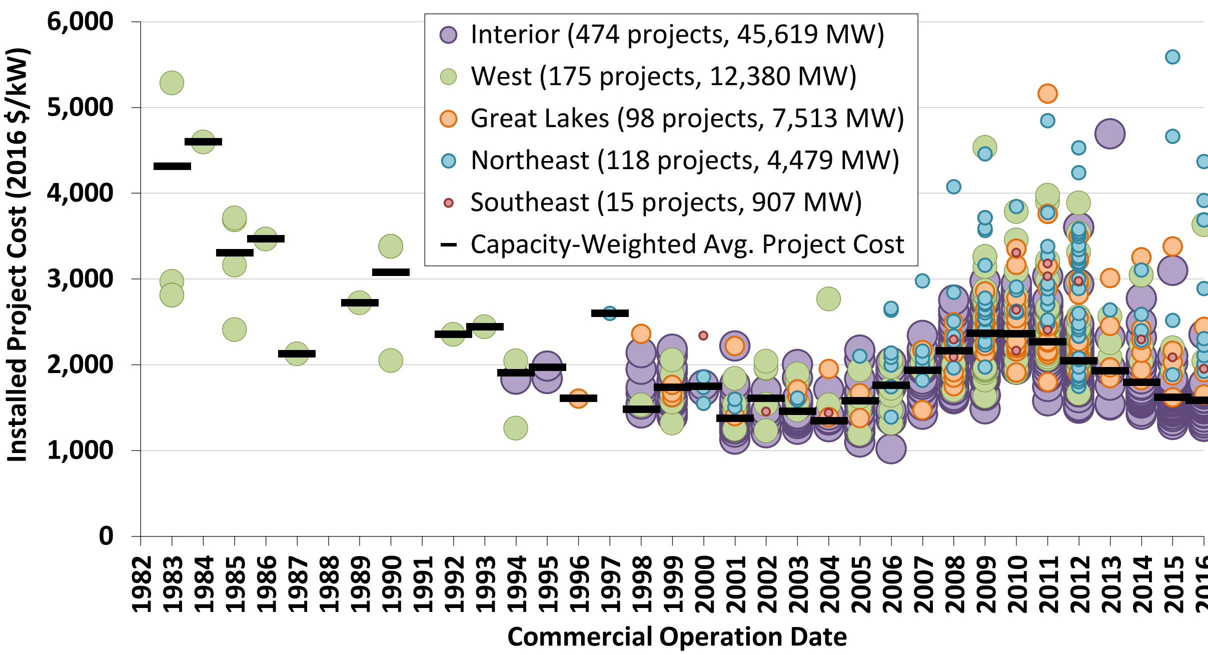
Figure 40. Reported wind turbine transaction prices over time

Overall, these figures suggest price declines of as much as 50% since late 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., the recent growth in average hub heights and rotor diameters shown in Chapter 4) and, in some cases, more favorable terms for turbine purchasers (e.g., reduced turbine delivery lead times and less need for large frame-agreement orders, longer initial O&M contract durations, and more-stringent performance guarantees). These turbine price trends have exerted downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights are improving capacity factors and further reducing wind power prices. At the same time, it is important to acknowledge that these comparisons are to a peak in the market in terms of turbine pricing, 2008. Looking farther back in time, one observes that turbine prices have only recently fallen to levels that approach those experienced in the early 2000s.

Lower turbine prices have driven reductions in reported installed project costs

Berkeley Lab also compiles data on the total installed cost of wind power projects in the United States, including data on 54 projects completed in 2016 totaling 7,135 MW, or 87% of the wind power capacity installed in that year. In aggregate, the dataset (through 2016) includes 880 completed wind power projects in the continental United States totaling 70,897 MW and equaling roughly 86% of all wind power capacity installed in the United States at the end of 2016. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data rather than on individual project-level estimates.[47]

As shown in Figure 41, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s,[48] and then increased—reflecting turbine price changes—through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs appear to have peaked in 2009/2010, with steady declines since that time. That changes in average installed project costs would lag behind changes in average turbine prices is not surprising and reflects the normal passage of time between when a turbine supply agreement is signed (the time stamp for Figure 40) and when those turbines are actually installed and commissioned (the time stamp for Figure 41).



Source: Berkeley Lab (some data points suppressed to protect confidentiality), Energy Information Administration

Figure 41. Installed wind power project costs over time

In 2016, the capacity-weighted average installed project cost within our sample stood at roughly $1,590/kW. This is down $780/kW or 33% from the apparent peak in average reported costs in 2009 and 2010, but is roughly on par with—or even somewhat higher than—the installed costs experienced in the early 2000s. All of the lowest-cost projects in recent years are located in the Interior region, which dominates the sample (with 45.6 GW of capacity) and where average costs have fallen by more than $800/kW since 2010. Early indications from a limited sample of 20 projects (totaling 3.0 GW) currently under construction and anticipating completion in 2017 suggest that capacity-weighted average installed costs in 2017 will be similar to those in 2016.

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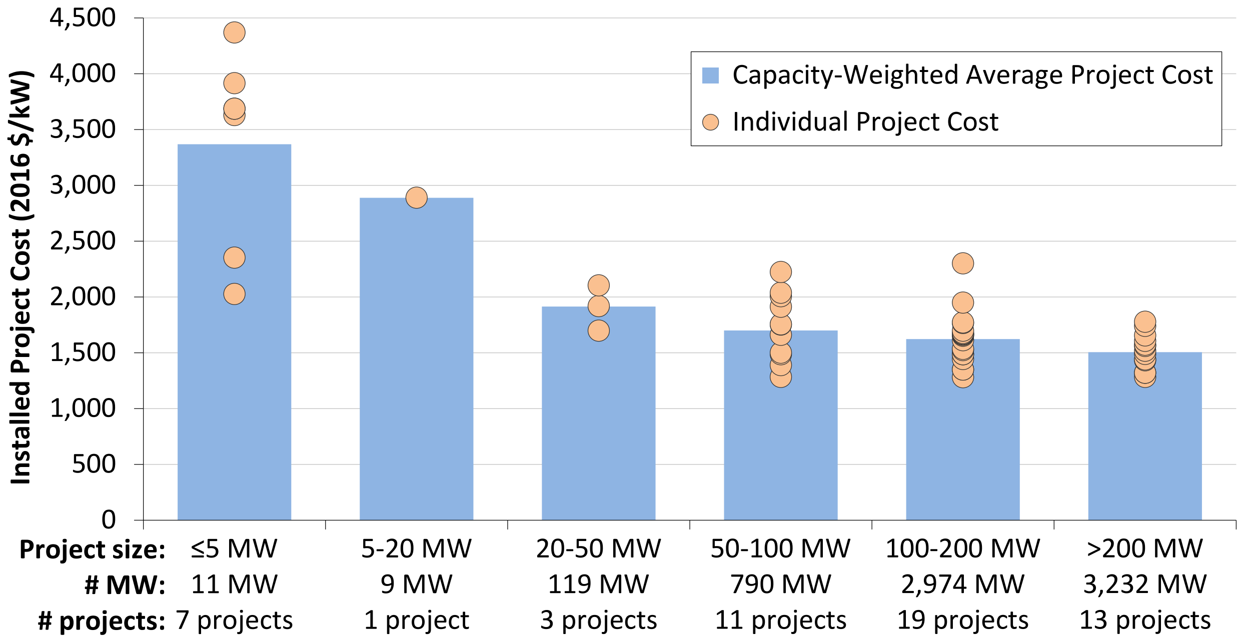
[47] New to the 2016 edition of this report is the inclusion of confidential project-level installed cost data for projects built in 2013-2015, obtained from the EIA under a non-disclosure agreement.

[48] Although our sample size in the 1980s and 1990s is relatively sparse compared to more recent years, for the most part, the individual project-level data and capacity-weighted averages for projects built in the 1980s and 1990s are largely consistent with average cost data for a subset of those years reported by the California Energy Commission (1998) and Gipe (1995).

Installed costs differed by project size, turbine size, and region

Average installed project costs exhibit economies of scale, especially at the lower end of the project size range. Figure 42 shows that among the sample of projects installed in 2016, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 20–50 MW range. Economies of scale continue, though to a lesser degree, as project size increases beyond 50 MW.

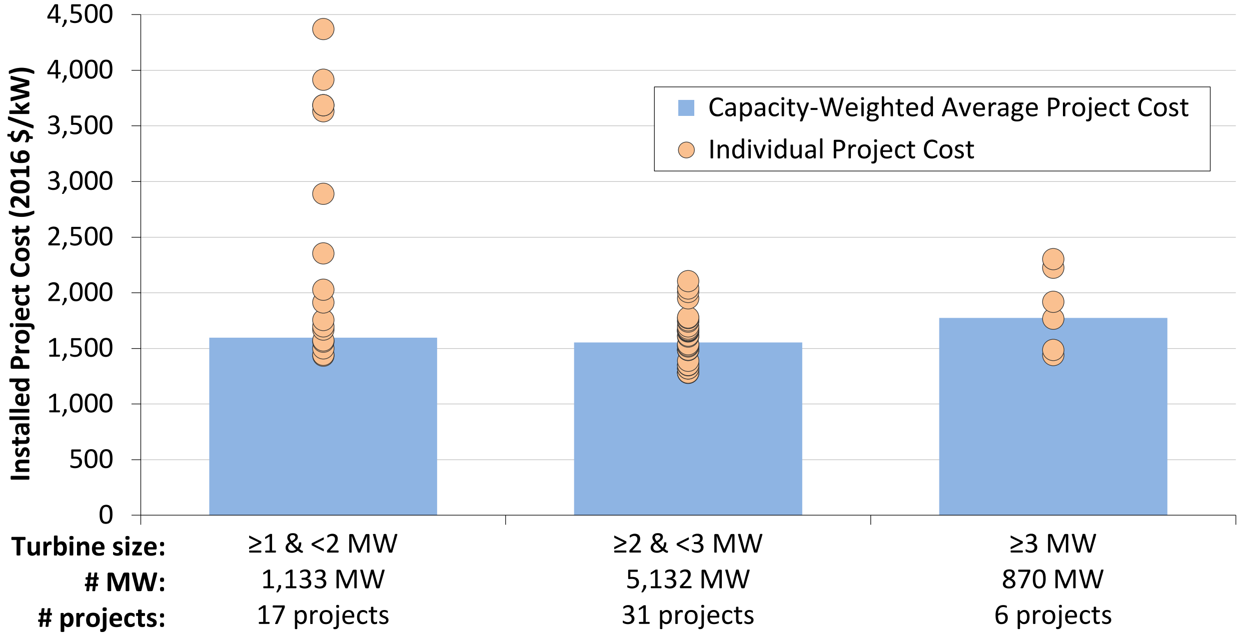


Source: Berkeley Lab

Figure 42. Installed wind power project costs by project size: 2016 projects

Another way to look for economies of scale is by turbine size (rather than by project size), on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines as opposed to more, smaller turbines. Figure 43 explores this relationship and finds mixed results. Although some projects using smaller turbines (between 1 and 2 MW) are clearly more expensive, the capacity-weighted average costs do not vary significantly across the three turbine size bins.[49]

[49] There is some correlation between turbine size and project size, at least at the low end of the range of each. For example, within the sample of 2016 projects for which we have CapEx data, all projects under 40 MW are using turbines of less than 2 MW. As such, Figures 42 and 43—both of which show a handful of high-cost projects in the smallest project or turbine size bin—could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size.



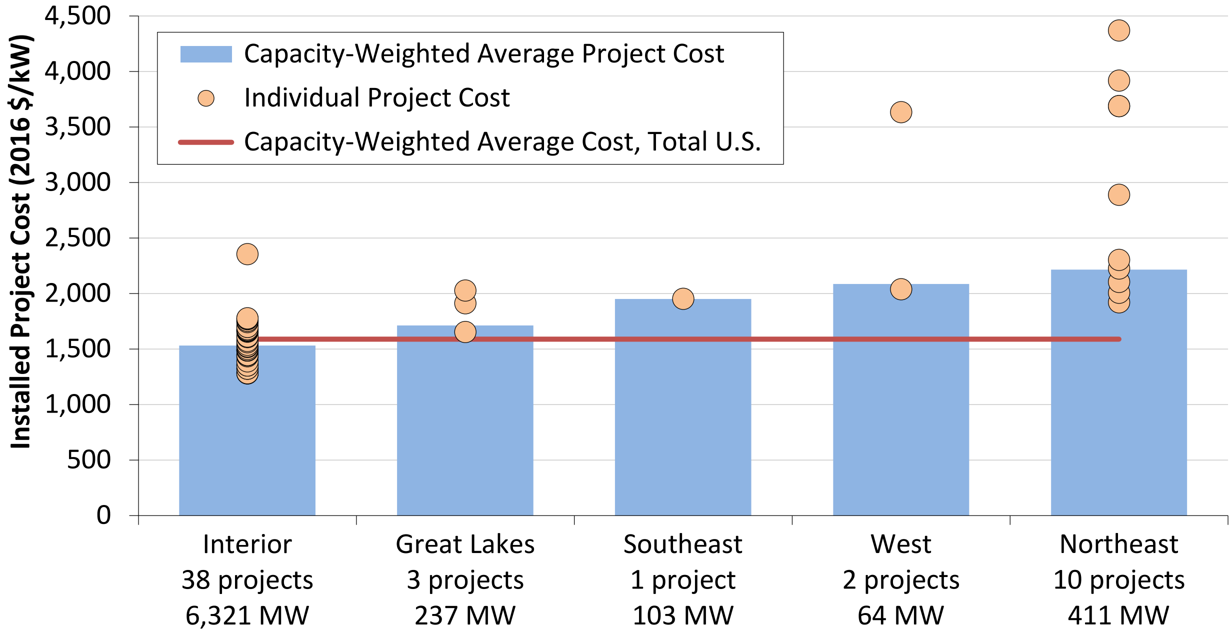
Source: Berkeley Lab

Figure 43. Installed wind power project costs by turbine size: 2016 projects

As intimated earlier in Figure 41, regional differences in average project costs are also apparent and may occur due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures—as well as variations in the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources). Considering only projects in the sample that were installed in 2016, Figure 44 breaks out project costs among the five regions defined in Figure 1.[50] The Interior region—with by far the largest sample—was the lowest-cost region on average, with an average cost of $1,530/kW, while the Northeast was the highest-cost region.[51] The other three regions have very limited sample size.

[50] For reference, the 82,143 MW of wind installed in the United States at the end of 2016 is apportioned among the five regions shown in Figure 1 as follows: Interior (65%), West (17%), Great Lakes (11%), Northeast (6%), and Southeast (1%). The remaining installed U.S. wind power capacity is located in Hawaii, Alaska, and Puerto Rico and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

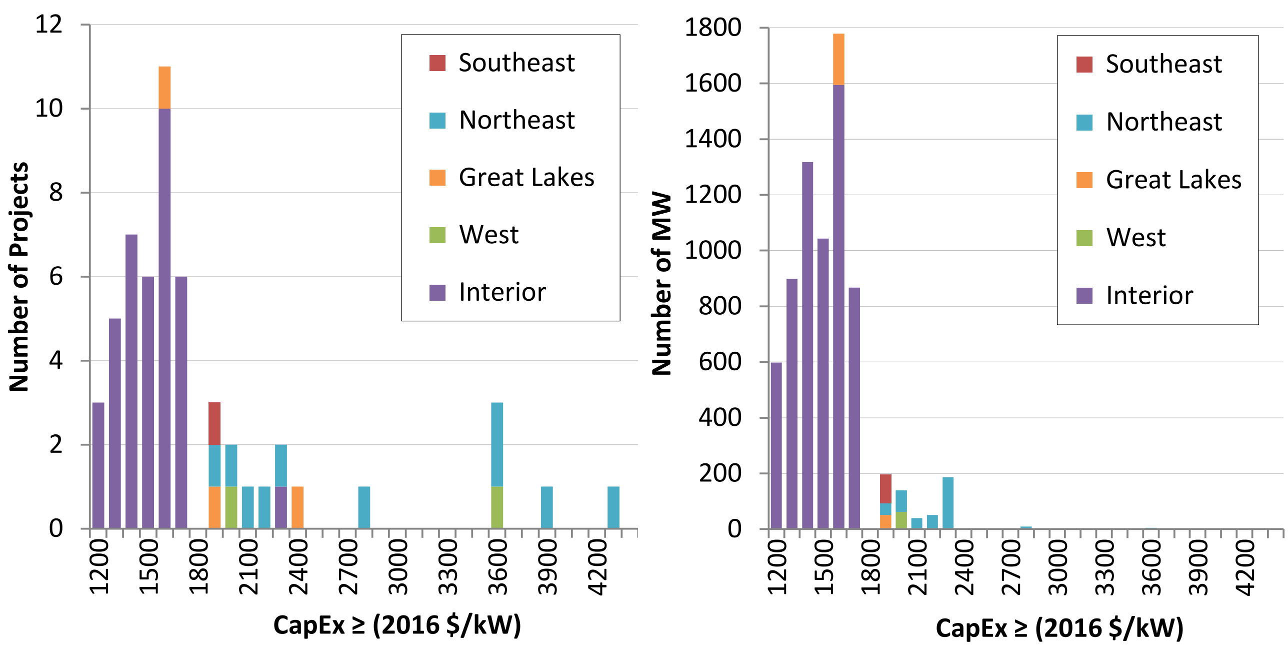
[51] Graphical presentation of the data in this way should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 44.



Source: Berkeley Lab

Figure 44. Installed wind power project costs by region: 2016 projects

Finally, Figure 45 shows two histograms that present the distribution of installed project costs among 2016 projects, in terms of both number of projects and capacity. Most of the projects—and all of the low-cost projects—are located in the Interior region, where the distribution is centered on the $1,600–$1,700/kW bin. Projects in other regions have higher costs.



Source: Berkeley Lab

Figure 45. Histogram of installed costs by MW and projects: 2016 projects

Operations and maintenance costs varied by project age and commercial operations date

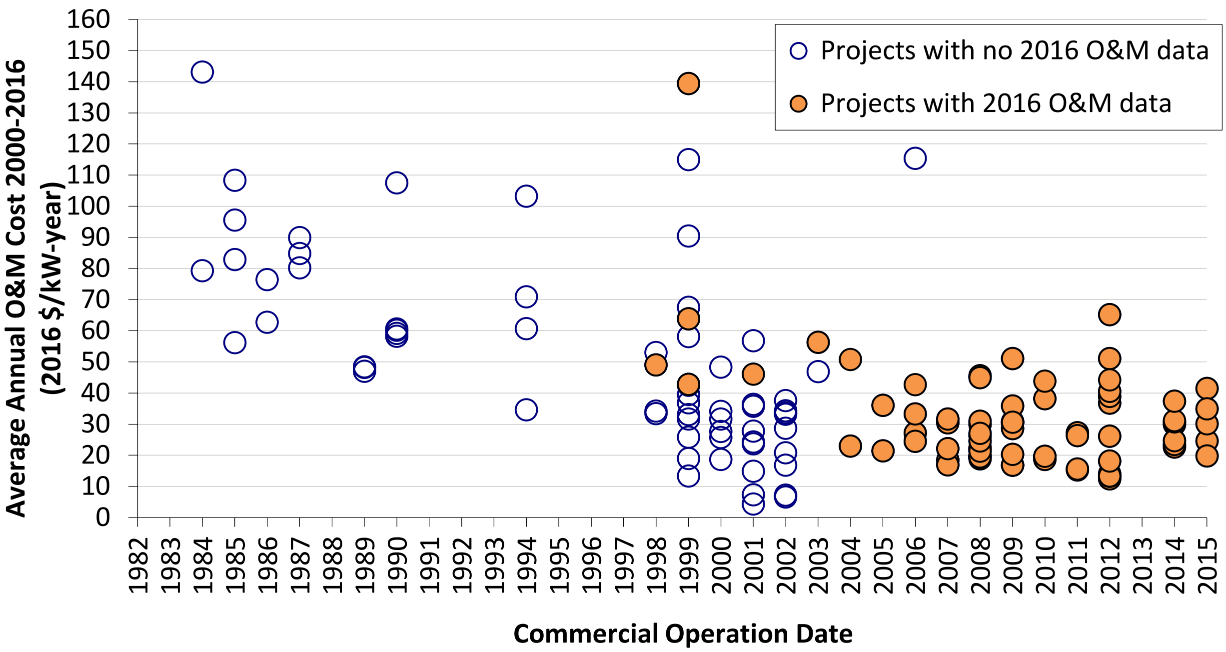
Operations and maintenance costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available market data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 159 installed wind power projects in the United States, totaling 13,120 MW with commercial operation dates of 1982 through 2015. These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M data are available for just a subset of years of project operations. Although the data sources do not all clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the wind project, as well as rent.[52] Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance, are generally not included. As such, Figures 46 and 47 are not representative of total operating expenses for wind power projects; the last paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow should be taken as indicative of potential overall trends. Note finally that the available data are presented in $/kW-year terms, as if O&M represents only a fixed cost. In fact, O&M costs are in part variable and in part fixed. Although not presented here, expressing O&M costs in units of $/MWh yields qualitatively similar results to those presented in this section.

Figure 46 shows project-level O&M costs by commercial operation date.[53] Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2016, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2015, only year 2016 data are available, and that is what is shown in the figure.[54] Many other projects only have data for a subset of years during the 2000–2016 timeframe, either because they were installed after 2000 or because a full time series is not available, so each data point in the chart may represent a different averaging period within the overall 2000–2016 timeframe. The chart highlights the 75 projects, totaling 9,479 MW, for which 2016 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

[52] The vast majority of the recent data derive from FERC Form 1, which uses the Uniform System of Accounts to define what should be reported under "operating expenses"—namely, those operational costs associated with supervision and engineering, maintenance, rents, and training. Though not entirely clear, there does appear to be some leeway within the Uniform System of Accounts for project owners to capitalize certain replacement costs for turbines and turbine components and report them under "electric plant" accounts rather than maintenance accounts.
[53] For projects installed in multiple phases, the commercial operation date of the largest phase is used. For re-powered projects, the date at which re-powering was completed is used.
[54] Projects installed in 2016 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2016 would be year 2017.

The data exhibit considerable spread, demonstrating that O&M costs (and perhaps also how O&M costs are reported by respondents) are far from uniform across projects. However, Figure 46 also suggests that projects installed in the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2016 O&M costs for the 24 projects in the sample constructed in the 1980s equal $69/kW-year, dropping to $57/kW-year for the 37 projects installed in the 1990s, to $28/kW-year for the 65 projects installed in the 2000s, and to $27/kW-year for the 33 projects installed since 2010.[55,56] This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as turbines age, component failures become more common, and manufacturer warranties expire;[57] and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a $/kW-year basis.



Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure 46. Average O&M costs for available data years from 2000 to 2016, by COD

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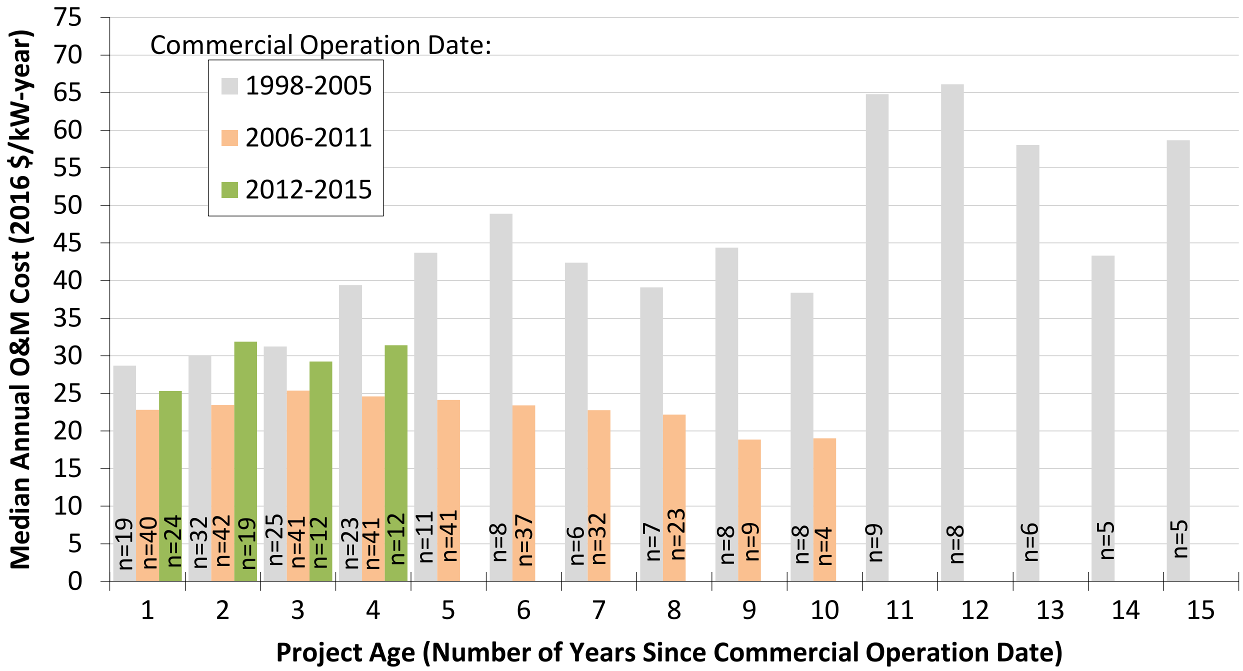
[55] Somewhat consistent with these observed O&M cost magnitudes (if not necessarily time trends), BNEF (2017d) reports that the average cost from a sample of initial full-service O&M contracts (only a small portion of which involves North American projects) that were signed in 2016 was 27.7 Euro/kW-year (~$30.7/kW-year). An NREL analysis based on data from DNV KEMA and GL Garrad Hassan covering roughly 5 GW of operating wind projects (with only about half that amount having been operable for longer than five years) also shows average levels of expenditure consistent with the Berkeley Lab dataset, at least when focusing on turbine and balance-of-plant O&M costs for projects commissioned in the 2000s (Lantz 2013).

[56] If the data in Figure 46 were expressed instead in terms of $/MWh, capacity-weighted average 2000–2016 O&M costs were $35/MWh for projects in the sample constructed in the 1980s, dropping to $24/MWh for projects constructed in the 1990s, to $10/MWh for projects constructed in the 2000s, and to $9/MWh for projects constructed since 2010.

[57] Many of the projects installed more recently may still be within their turbine manufacturer warranty period, and/or may have capitalized O&M service contracts within their turbine supply agreement. Projects choosing the Section 1603 cash grant over the PTC may have had a particular incentive to capitalize service contracts (29 projects totaling 44% of the sample capacity installed since 2000 were installed between 2009 and 2012—i.e., within the period of eligibility for the Section 1603 grant—though only five of these 29 projects actually elected the grant over the PTC). In either case, reported O&M costs will be artificially low.

Although limitations in the underlying data do not permit the influence of these two factors to be unambiguously distinguished, to help illustrate key trends, Figure 47 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings that are intended to reflect relatively distinct periods in the evolution of turbine design.[58] Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale, which reportedly can be significant (BNEF 2017d). Note that, at each project age increment and for each of the three project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially.



Source: Berkeley Lab; medians shown only for groups of two or more projects, and only projects >5 MW are included

Figure 47. Median annual O&M costs by project age and commercial operation date

With these limitations in mind, Figure 47 shows an upward trend in project-level O&M costs as projects age, at least among the oldest projects in our sample—i.e., those built from 1998 to 2005—although the sample size after year 4 is rather limited for these earliest projects. This upward trend is consistent with BNEF (2017d) data showing that O&M contract renewals are more expensive than initial service agreements. In addition, Figure 47 shows that projects installed more recently (2006-2011 and/or 2012-2015) have had, in general, lower O&M costs than those installed in earlier years (1998-2005), at least for the first 10 years of operation. Parsing this "recent project" cohort into two sub-periods, however, reveals that this trend towards lower costs has not necessarily continued with the most recent projects in the sample, as

[58] As shown earlier in Figure 24, both 1998-2005 and 2012-2015 were periods in which the average specific power rating of turbines installed in the United States declined rapidly, while 2006-2011 was a period of relative stability in specific power.

projects built from 2012-2015 illustrate higher costs (at least during the first four years of operations) than projects built from 2006-2011.[59]

As indicated previously, the data presented in Figures 46 and 47 include only a subset of total operating expenses. In comparison, the financial statements of EDP Renováveis (EDPR), a public company that owned more than 4.6 GW of U.S. wind project assets at the end of 2016 (all of which have been installed since 2000), indicate markedly higher total operating costs.[60] Specifically, EDPR (2017) reported total operating expenses of $55/kW-year for its U.S. portfolio in 2016[61]—roughly twice the ~$27/kW-year average O&M cost reported above for the 98 projects in the Berkeley Lab data sample installed since 2000.

This disparity in operating costs between EDPR and the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, EDPR breaks out its total U.S. operating costs in 2016 ($55/kW-year) into three categories: supplies and services, which "includes O&M costs" ($34/kW-year); personnel costs ($11/kW-year); and other operating costs, which "mainly includes operating taxes, leases, and rents" ($10/kW-year). Among these three categories, the $34/kW-year for supplies and services is probably closest in scope to the Berkeley Lab data. Confirming these basic findings (i.e., that turbine and balance-of-plant O&M costs make up only about half of total operating costs), NREL analysis based on data from the energy consultancy DNV KEMA on plants commissioned before 2009 shows total operating expenditures of $40–$60/kW-year (in 2011 dollars) depending on project age, with turbine and balance-of-plant O&M costs representing roughly half of those expenditures (Lantz 2013).

[59] One possible, yet unsubstantiated, explanation for this apparent cost increase among the most recent projects is that the average turbine kW rating remained relatively constant among projects built from 2012-2015, while the average rotor diameter increased significantly (i.e., specific power declined), perhaps leading to higher O&M costs on a $/kW-year basis.

[60] Past editions of this report also reported O&M costs for Infigen, but in October 2015, Infigen's U.S. wind assets were sold to a privately held company that does not file public financial statements.

[61] Though not entirely clear, EDPR's reported operating expenses may exclude any repair or replacement costs that have been capitalized rather than expensed. Also, it should be noted that EDPR added a 30 MW PV project to its U.S. portfolio in late 2014, which means that the O&M costs reported here for 2016 include a very small (<1%) PV component. Given that PV O&M costs are thought to be lower than wind O&M costs on average, the impact on overall costs is presumed to be negligible, and if anything presumably nudges EDPR's reported overall O&M costs lower rather than higher.

7. Wind Power Price Trends

Earlier sections documented trends in capacity factors, wind turbine prices, installed project costs, O&M costs, and project financing—all of which are determinants of the wind power purchase agreement (PPA) prices presented in this chapter. In general, higher-cost and/or lower-capacity-factor projects will require higher PPA prices, while lower-cost and/or higher-capacity-factor projects can have lower PPA prices.

Berkeley Lab collects data on wind PPA prices from the sources listed in the Appendix, resulting in a dataset that currently consists of 414 PPAs totaling 38,819 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation later in 2017 or beyond. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs), and most of them have a utility as the counterparty.[62]

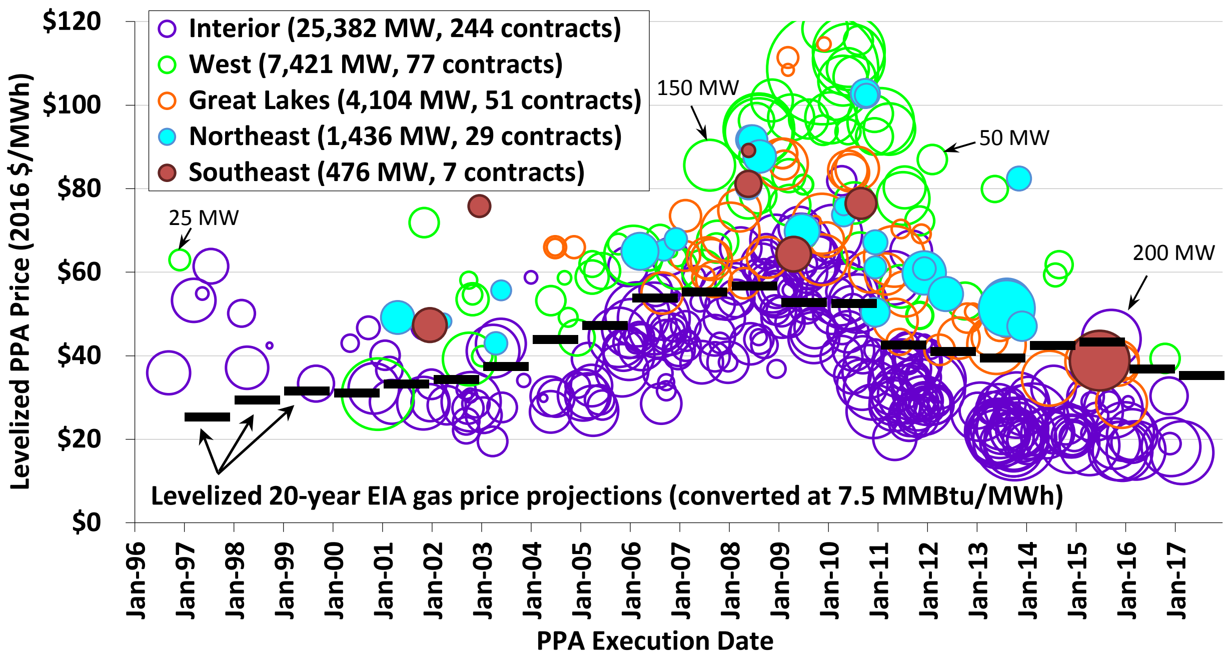
Except where noted, PPA prices are expressed throughout this chapter on a levelized basis over the full term of each contract, and are reported in real 2016 dollars.[63] Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.[64] Whenever they are broken out by time, the date on (or year in) which the PPA was signed or executed is used, as that date provides the best indication (i.e., better than commercial operation date) of market conditions at the time. Finally, because the PPA prices in the Berkeley Lab sample are reduced by the receipt of state and federal incentives (e.g., the levelized PPA prices reported here would be at least $15/MWh higher without the PTC, ITC, or Treasury Grant[65]) and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs. That said, we loosely estimate the levelized cost of energy for a large sample of U.S. wind projects in a text box on page 62.

[62] Though we do have pricing details for some PPAs with corporate off-takers, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a "contract for differences" with the corporate off-taker around an agreed-upon strike price. Because the strike price is not directly linked to the sale of electricity, it is rarely disclosed (at least through traditional sources, like regulatory filings). Though only a minor omission at present, this distinction could limit our sample more severely in the future if corporate offtake agreements remain popular.
[63] Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 35 years, with 20 years being by far the most common (at 58% of the sample; 89% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 7% real discount rate.
[64] Generation weighting is based on the empirical project-level performance data analyzed earlier in this report and assumes that historical project performance (in terms of annual capacity factor as well as daily and/or seasonal production patterns where necessary) will hold into the future as well. In cases where there is not enough operational history to establish a "steady-state" pattern of performance, we used discretion in estimating appropriate weights (to be updated in the future as additional empirical data become available).
[65] The estimated levelized PPA price impact of $15+/MWh is less than the PTC's 2016 face value of $23/MWh for several reasons. First, the PTC is a 10-year credit, whereas most PPAs are for longer terms (e.g., 20 years). Second, the PTC is a tax credit, and must be converted to pre-tax equivalent terms before being compared to PPA prices. Finally, the presence of the PTC constrains financing choices for many wind project owners and drives up the project's weighted average cost of capital. In other words, if not for the PTC, projects could be financed more cheaply; this difference in the weighted average cost of capital with and without the PTC erodes some of the PTC's value (for more information, see Bolinger (2014)).

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to wholesale power prices, and compared to future natural gas prices. In addition, REC prices are presented in a text box on page 61.

Wind power purchase agreement (PPA) prices remain very low

Figure 48 plots contract-level levelized wind PPA prices by contract execution date, showing a clear decline in PPA prices since 2009–2010—both overall and by region (see Figure 1 for regional definitions).[66] Because of the relatively larger sample of PPAs, this trend is particularly evident in the Interior region, which—as a result of its low average project costs and high average capacity factors shown earlier in this report—also tends to be the lowest-priced region over time. Prices generally have been higher in the rest of the United States.[67]



Note: Area of "bubble" is proportional to contract nameplate capacity

Source: Berkeley Lab, Energy Information Administration

Figure 48. Levelized wind PPA prices by PPA execution date and region

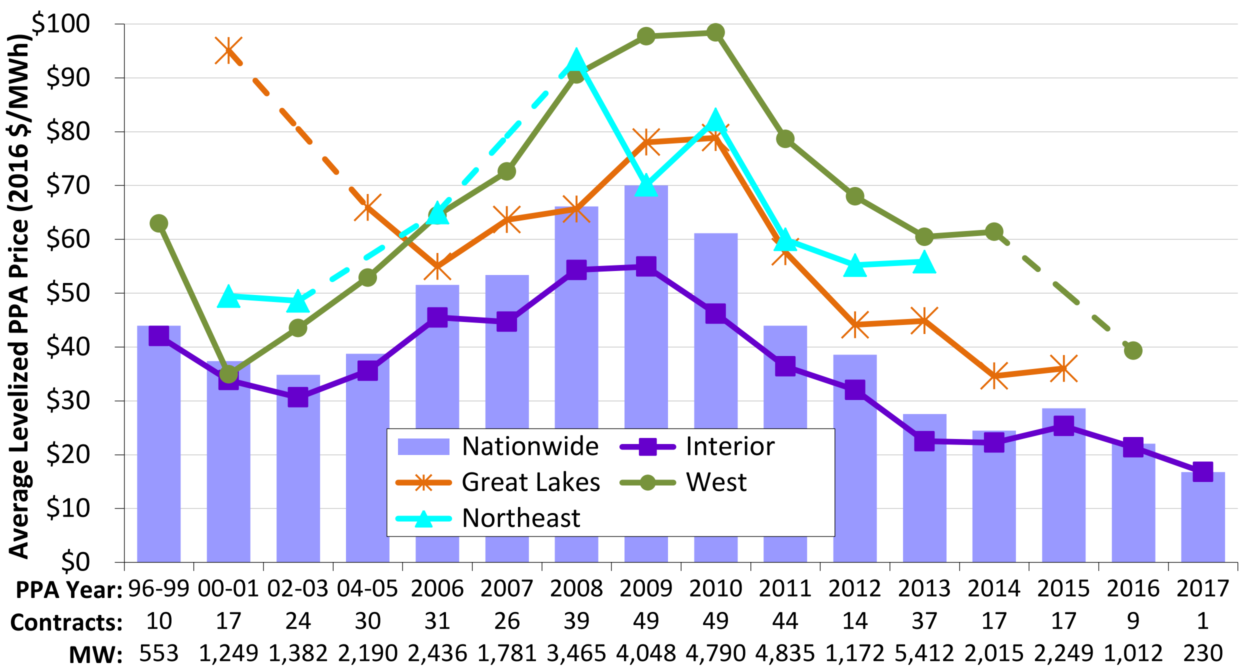
Figure 48 also shows that wind power PPA prices—particularly in the U.S. interior, but also in other regions in some cases—have been competitive with the projected fuel costs of gas-fired combined cycle generators over time. Specifically, the black dash markers show the 20-year levelized fuel costs (converted from natural gas to power terms at an assumed heat rate of 7.5 MMBtu/MWh) from then-current EIA projections of natural gas prices delivered to electricity

[66] Roughly 99% of the contracts that are depicted in Figure 48 are from projects that are already online. For the most part, only the most recent contracts in the sample are from projects that are not yet online.

[67] Regional differences can affect not only project capacity factors (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region's physical geography, population density, labor rates, or even regulatory processes). It is also possible that regions with higher wholesale electricity prices or with greater demand for renewable energy will, in general, yield higher wind energy contract prices due to market influences.

generators.[68] The fact that wind PPA price trends roughly follow the projected gas price trends suggest that wind developers have kept an eye on the competition when negotiating PPA prices (though the rise and fall of turbine prices and project costs over this same period no doubt exerted a similarly strong influence on wind PPA prices).

Figure 49 provides a smoother look at the time trend nationwide and regionally by averaging the individual levelized PPA prices shown in Figure 48 by year. After topping out at $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to around $20/MWh—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from ~$55/MWh among contracts executed in 2009 to ~$20/MWh today. Prices declined especially rapidly from 2009 to 2013, and appear to have been generally stable or to have declined more modestly since that time.



Source: Berkeley Lab

Figure 49. Generation-weighted average levelized wind PPA prices by PPA execution date and region

The trend of rising PPA prices from 2003 to 2009 and then falling prices since then is directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent project vintages, as documented in Chapter 5. This combination of declining costs and improved performance—along with historically low interest rates (as shown earlier in Figure 17) and natural gas prices (as shown in Figure 48)—has driven wind PPA prices to today's record-low levels.

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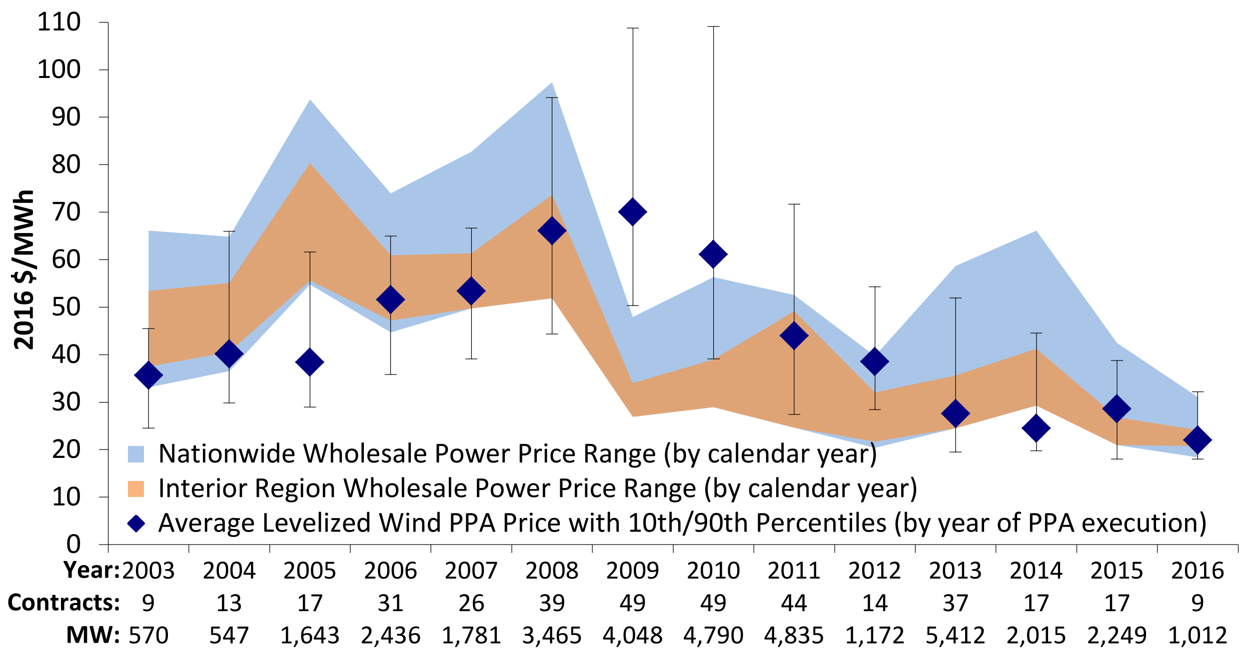
[68] For example, the black dash marker in 1997 shows the 20-year levelized gas price projection from Annual Energy Outlook 1997, while the black dash in 2017 shows the same from Annual Energy Outlook 2017 (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh).

Figure 49 also shows trends in the generation-weighted average levelized PPA price over time among four of the five regions broken out in Figure 1 (the Southeast region is omitted from Figure 49 owing to its small sample size). Figures 48 and 49 both demonstrate that, based on our contract sample, PPA prices are generally lower in the U.S. Interior, higher in the West, and moderate in the Great Lakes and Northeast regions. As shown by the close agreement between the two, the large Interior region—where much of U.S. wind project development occurs—dominates the nationwide sample, particularly in recent years.

The relative economic competitiveness of wind power has been affected by the continued decline in wholesale power prices

The blue-shaded area of Figure 50 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power[69] going back to 2003 at 23 different pricing nodes located throughout the country. (Refer to the Appendix for the names and approximate locations of the 23 pricing nodes represented by the blue-shaded area). The orange-shaded area, meanwhile, depicts the subset of those pricing nodes that are located within the Interior region. Our PPA price sample is increasingly dominated by projects in this region. Finally, the dark diamonds represent the generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) in the years in which contracts were executed (consistent with the nationwide averages presented in Figure 50).



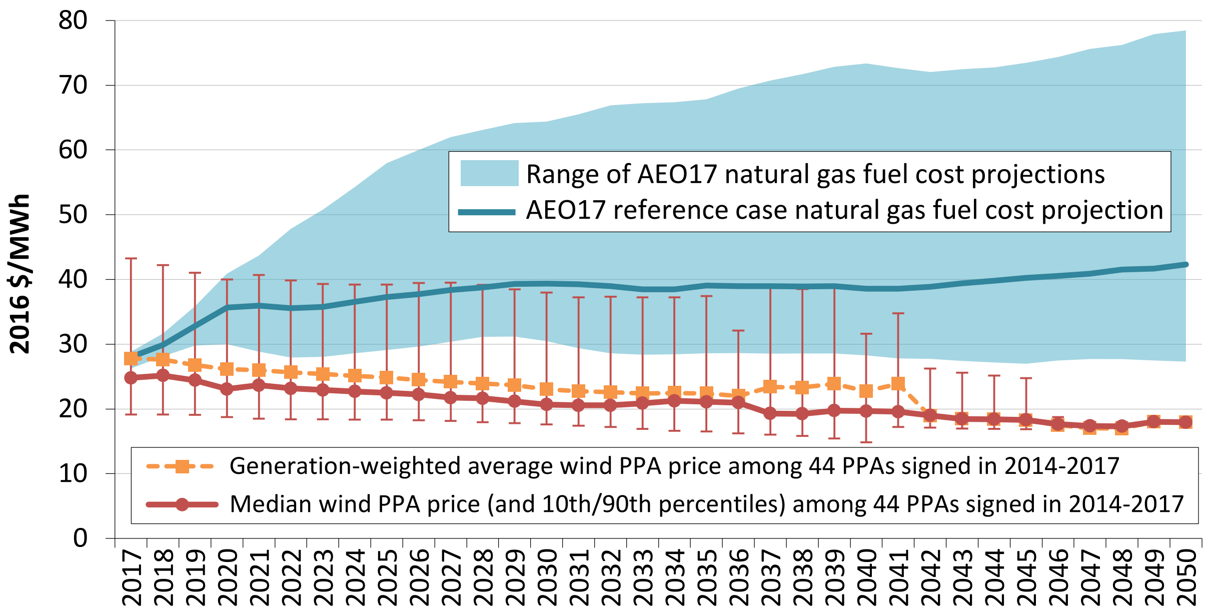
Source: Berkeley Lab, FERC, ABB, IntercontinentalExchange

Figure 50. Average levelized long-term wind PPA prices and yearly wholesale electricity prices over time

[69] A flat block of power is defined as a constant amount of electricity generated and sold over a specified period. Although wind power projects do not provide a flat block of power, as a common point of comparison a flat block is not an unreasonable starting point. In other words, the time variability of wind energy is often such that its wholesale market value is somewhat lower than, but not too dissimilar from, that of a flat block of (non-firm) power, at least at lower levels of wind penetration (Fripp and Wiser 2008; Wiser et al. 2017).

At least within the sample of projects reported here, average long-term wind PPA prices compared favorably to yearly wholesale electricity prices from 2003 through 2008 for a flat-block of power. Starting in 2009, however, the sharp drop in wholesale electricity prices (driven primarily by lower natural gas prices) squeezed average wind PPA prices out of the wholesale power price range on a nationwide basis. Wind PPA prices have since fallen, however, and in 2011 and 2012 reconnected with the upper end of the wholesale power price range, before moving more firmly into competitive territory in subsequent years. Even so, the much narrower and lower range of wholesale power prices in the Interior region is arguably the more relevant comparison in recent years, as project development has been largely concentrated in that region.

The comparison between levelized wind PPA and wholesale power prices in Figure 50 is imperfect, in part because the levelized wind PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale power prices are pertinent to just the single year in question. Figure 51 attempts to remedy this temporal mismatch by presenting an alternative (yet still imperfect) way of looking at how wind stacks up relative to its competition.



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles.
Source: Berkeley Lab, EIA

Figure 51. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Rather than levelizing the wind PPA prices, Figure 51 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown, along with a generation-weighted average) from PPAs executed in 2014–2017 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[70] As shown, the median and generation-weighted average wind

[70] The fuel cost projections come from the EIA's *Annual Energy Outlook 2017* publication, and increase from around \$3.53/MMBtu in 2017 to \$6.13/MMBtu (both in 2016 dollars) in 2050 in the reference case. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from \$/MMBtu into \$/MWh using the heat rates implied by the modeling output (which start at roughly 7.9 MMBtu/MWh in 2017 and gradually decline to roughly 6.9 MMBtu/MWh by 2050).

PPA prices from contracts executed in the past 3+ years are consistently below the low end of the projected natural gas fuel cost range over the entire period, while the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall within the overall range by 2020 and below the reference case projection after 2028.

Figure 51 also hints at the long-term value that wind power might provide as a "hedge" against rising and/or uncertain natural gas prices. The wind PPA prices that are shown have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain. Actual fuel costs could ultimately be lower or much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

Important Note: Notwithstanding the comparisons made in this section, neither the wind nor wholesale electricity prices (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind PPA and wholesale power prices in this manner are the following:

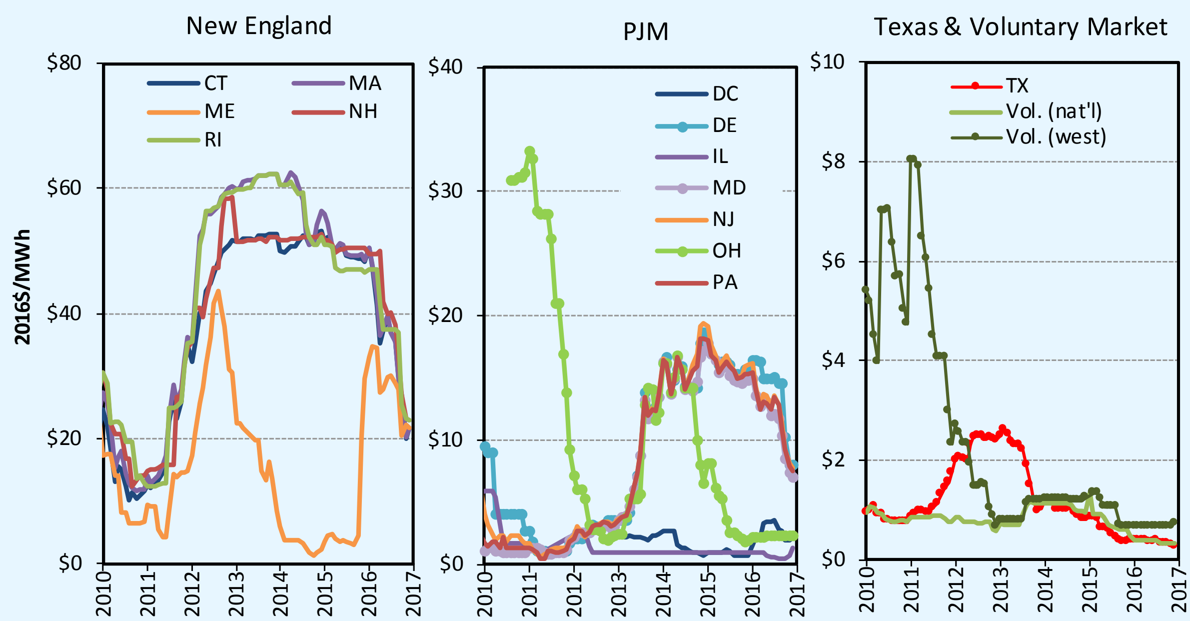
- Wind PPA prices are reduced by virtue of federal and, in some cases, state tax and financial incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by virtue of any financial incentives provided to fossil-fueled generation and its fuel production, as well as by not fully accounting for the health and environmental costs of fossil generation.
- Wind PPA prices do not fully reflect integration, resource adequacy, or transmission costs, while wholesale electricity prices (or fuel cost projections) also do not fully reflect transmission costs, and may not fully reflect capital and fixed operating costs.
- Wind PPA prices—once established—are fixed and known, whereas wholesale electricity prices are short-term and subject to change. As shown in Figure 51, EIA projects natural gas prices to rise from current levels, resulting in an increase in wholesale electricity prices.
- The location of the sampled wholesale electricity nodes and the assumption of a flat block of power are not perfectly consistent with the location and output profile of the sample of wind power projects. Especially at higher penetrations and in locations where wind generation profiles are poorly correlated with local load profiles, excessive wind generation during times of peak output and/or low load can push the wholesale market value of wind power well below that of a flat block of power. In ERCOT, for example, the wholesale market value of wind in 2016 averaged ~80% that of a flat block of power; in CAISO, the wholesale market value of wind was more than 90% that of a flat block of power (Wiser et al. 2017).

In short, comparing levelized long-term wind PPA prices with either yearly wholesale electricity prices or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to its competition. Nonetheless, these comparisons still provide some sense for the short-term competitive environment facing wind energy, and convey how that environment has shifted over time.

REC Prices in Key RPS Compliance Markets Fell Significantly in 2016, Reflecting Growing Supplies

The wind power sales prices presented in this report reflect bundled sales of both electricity and RECs; excluded are projects that sell RECs separately from electricity, thereby generating two sources of revenue. REC markets are somewhat fragmented in the United States but consist of two distinct segments: compliance markets, in which RECs are purchased to meet state RPS obligations, and green power markets, in which RECs are purchased on a voluntary basis.

The figures below present indicative data of spot-market REC prices in both compliance and voluntary markets. Clearly, spot REC prices have varied substantially, both over time and across states, though prices within regional power markets (New England and PJM) are linked to varying degrees. In general, REC prices reflect the balance of available supply and demand within a given market. Accordingly, REC prices in many compliance markets fell substantially over the course of 2016, as regional supplies grew faster than RPS demand. In particular, REC prices for most New England states fell from roughly $50/MWh at the beginning of 2016 to $20/MWh by year-end, while REC prices in some PJM states (DE, MD, NJ, and PA, which have more-restrictive eligibility rules and thus higher prices than other states in the region) fell from roughly $15/MWh to $8/MWh over the course of the year. Prices for RECs offered in the national and western voluntary markets and for RPS compliance in Texas remained below $1/MWh throughout the year, reflecting sustained over-supply.



Notes: Data for compliance markets focus on "Class I" or "Tier I" RPS requirements; these are the requirements for more-preferred resource types or vintages and are therefore the markets in which wind would typically participate. Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded.

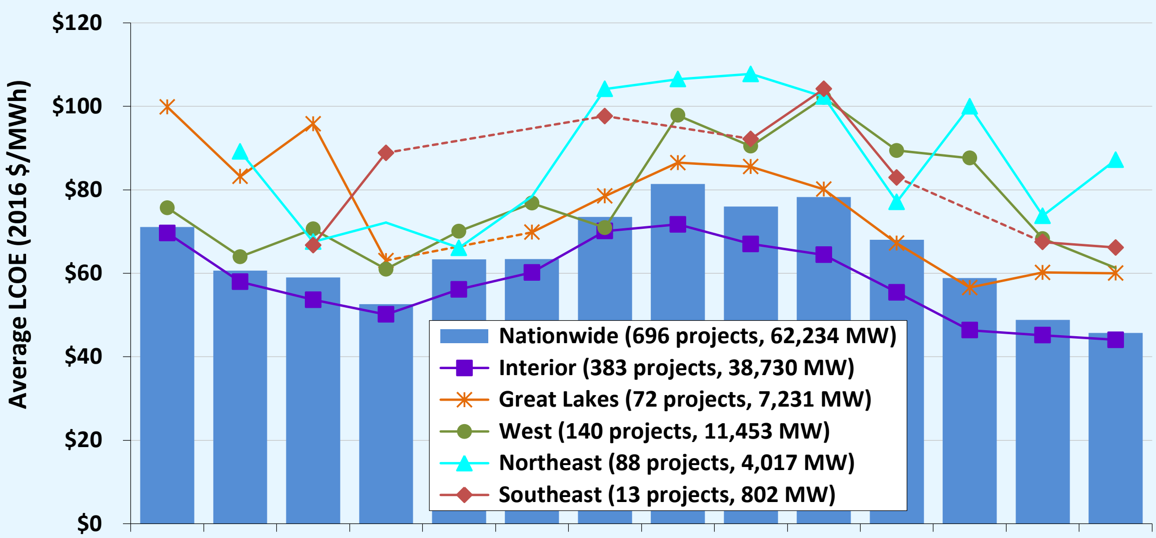
Source: Marex Spectron.

Estimating the Levelized Cost of Wind Energy

In a competitive market, bundled long-term PPA prices can, at the most basic level, be thought of as reflecting the levelized cost of energy (LCOE) reduced by the levelized value of any incentives received. Hence, as a first-order approximation, LCOE can be estimated simply by adding the levelized value of incentives received to levelized PPA prices. LCOE can also be estimated more directly from its components, however, and Berkeley Lab has data on the installed cost and capacity factor of more than 62 GW of wind power installed from 1998 through 2015, representing 85% of all capacity built over that period. Here we use those data (while holding all other inputs constant across projects) to estimate the LCOE of wind energy over time and by region, in real 2016 dollars (we do not have capacity factor data for projects built in 2016, so the analysis only extends through 2015). One benefit of this approach to estimating LCOE is that it relies on a large sample of project-level installed cost and performance data, covering more projects than the Berkeley Lab PPA sample.

Absent better data, and consistent with NREL assumptions, we assume that all plants have common total operating costs, at $51/kW-yr (Moné et al. 2017). We similarly assume that all plants can access low-cost financing in the *absence* of the PTC: a nominal weighted-average cost of capital of 5.4% is used, consistent with the current low-interest-rate environment and a scenario in which more-traditional finance absent the PTC is used. This enables the estimation of LCOE values that do not include the value of the PTC, that assume more-traditional finance, and that are not subject to fluctuations in financing rates as impacted by macroeconomic trends. We assume standardized tax rates (40% combined state and federal), project life (20 years), and 5-year accelerated depreciation. For capacity factors, we use an average of available project-level data; as such, projects installed in 1998 may have 19 years of data to average, whereas projects installed in 2015 will have one year.

The figure depicts the resulting generation-weighted average LCOE values over time, nationwide and by region. Just like the PPA prices shown earlier, LCOE values span a wide range—even though we only vary project-level installed costs and capacity factors when estimating LCOE. Not surprisingly, the LCOE trends closely follow the PPA price trends shown earlier: LCOEs generally decrease from 1998 to 2005, rise through 2009, and then decline through 2015. Nationwide (and Interior region) LCOE values for projects installed in 2015 are the lowest on record. Regionally, the lowest values are found in the Interior, with a 2015 average of $44/MWh and with some projects as low as $36/MWh.



COD Year:	98-99	00-01	02-03	04-05	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Projects:	26	26	30	29	23	30	64	103	63	85	109	12	46	50
MW:	849	1,694	1,885	2,005	1,820	3,597	6,305	9,575	5,129	6,281	9,378	852	5,100	7,763

8. Policy and Market Drivers

The federal production tax credit remains a core motivator for wind power deployment

Various policies at both the federal and state levels, as well as federal investments in wind energy research and development (R&D), have contributed to the expansion of the wind power market in the United States. At the federal level, the most impactful policy incentives in recent years have been the PTC (or, if elected, the ITC) and accelerated tax depreciation.

Initially established in 1994, the PTC provides a 10-year, inflation-adjusted credit that stood at $23/MWh in 2016, but was raised to $24/MWh in early 2017 (Table 5). The historical impact of the PTC on the U.S. wind industry is illustrated by the pronounced lulls in wind additions in the 4 years (2000, 2002, 2004, 2013) during which the PTC lapsed, as well as by the increased development activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 2).

In December 2015, Congress passed a 5-year extension of the PTC (or, if elected, the ITC). To qualify, projects must begin construction before January 1, 2020. Moreover, in May 2016, the IRS issued guidance allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. This new guidance lengthened the "safe harbor" completion period from the previous term of two years.

In extending the PTC, Congress also established a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC will phase down in 20%-per-year increments for projects starting construction in 2017 (80% PTC value), 2018 (60%), and 2019 (40%). Under the current schedule, projects that commence construction in 2020 and after will no longer receive the federal PTC.

Developers have reportedly qualified a significant amount of new wind turbine capacity for the full PTC by starting construction (as per the IRS safe harbor guidelines) prior to the end of 2016. Chadbourne & Parke (2017a) reports two such estimates of PTC-qualified capacity—30-58 GW and 40-70 GW—while consultant MAKE pegs the number at 45 GW (Recharge 2017). A single developer/sponsor—NextEra Energy—has stated that it qualified more than 10 GW on its own.

In addition to the PTC, a second form of federal tax support for wind is accelerated tax depreciation, which historically has enabled wind project owners to depreciate the vast majority of their investments over a 5- to 6-year period for tax purposes. Even shorter "bonus depreciation" schedules have been periodically available, since 2008.

The availability of federal tax incentives underpins recent low-priced power purchase agreements for wind energy, and is a significant contributor to the near-term expected surge in wind capacity additions. The PTC phase down, on the other hand, imposes risks to the industry's competitiveness in the mid- to long-term.

Table 5. History of Production Tax Credit Extensions

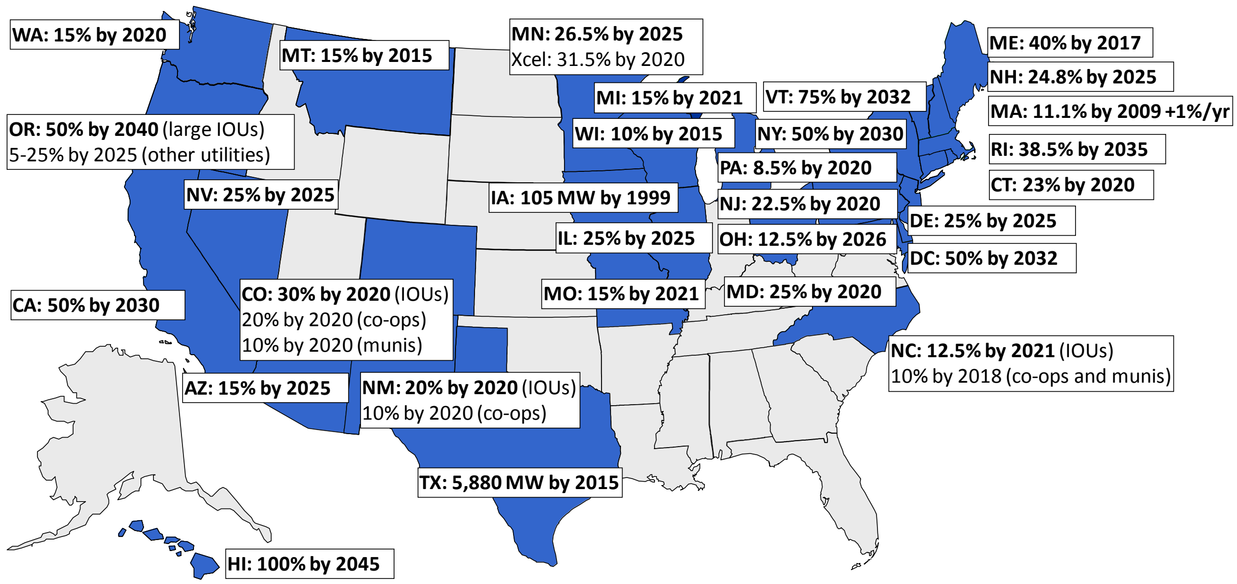
<table>
<tr><th>Legislation</th><th>Date Enacted</th><th>Start of PTC Window</th><th>End of PTC Window</th><th>Effective PTC Planning Window (considering lapses and early extensions)</th></tr>
<tr><td>Energy Policy Act of 1992</td><td>10/24/1992</td><td>1/1/1994</td><td>6/30/1999</td><td>80 months</td></tr>
<tr><td colspan="5">>5-month lapse before expired PTC was extended</td></tr>
<tr><td>Ticket to Work and Work Incentives Improvement Act of 1999</td><td>12/19/1999</td><td>7/1/1999</td><td>12/31/2001</td><td>24 months</td></tr>
<tr><td colspan="5">>2-month lapse before expired PTC was extended</td></tr>
<tr><td>Job Creation and Worker Assistance Act</td><td>3/9/2002</td><td>1/1/2002</td><td>12/31/2003</td><td>22 months</td></tr>
<tr><td colspan="5">>9-month lapse before expired PTC was extended</td></tr>
<tr><td>The Working Families Tax Relief Act</td><td>10/4/2004</td><td>1/1/2004</td><td>12/31/2005</td><td>15 months</td></tr>
<tr><td>Energy Policy Act of 2005</td><td>8/8/2005</td><td>1/1/2006</td><td>12/31/2007</td><td>29 months</td></tr>
<tr><td>Tax Relief and Healthcare Act of 2006</td><td>12/20/2006</td><td>1/1/2008</td><td>12/31/2008</td><td>24 months</td></tr>
<tr><td>Emergency Economic Stabilization Act of 2008</td><td>10/3/2008</td><td>1/1/2009</td><td>12/31/2009</td><td>15 months</td></tr>
<tr><td>The American Recovery and Reinvestment Act of 2009</td><td>2/17/2009</td><td>1/1/2010</td><td>12/31/2012</td><td>46 months</td></tr>
<tr><td colspan="5">2-day lapse before expired PTC was extended</td></tr>
<tr><td>American Taxpayer Relief Act of 2012</td><td>1/2/2013</td><td>1/1/2013</td><td>Start construction by 12/31/2013</td><td>12 months (in which to start construction)</td></tr>
<tr><td colspan="5">>11-month lapse before expired PTC was extended</td></tr>
<tr><td>Tax Increase Prevention Act of 2014</td><td>12/19/2014</td><td>1/1/2014</td><td>Start construction by 12/31/2014</td><td>2 weeks (in which to start construction)</td></tr>
<tr><td colspan="5">>11-month lapse before expired PTC was extended</td></tr>
<tr><td rowspan="4">Consolidated Appropriations Act of 2016</td><td rowspan="4">12/18/2015</td><td rowspan="4">1/1/2015</td><td>Start construction by 12/31/2016</td><td>12 months to start construction and receive 100% PTC value</td></tr>
<tr><td>Start construction by 12/31/2017</td><td>24 months to start construction and receive 80% PTC value</td></tr>
<tr><td>Start construction by 12/31/2018</td><td>36 months to start construction and receive 60% PTC value</td></tr>
<tr><td>Start construction by 12/31/2019</td><td>48 months to start construction and receive 40% PTC value</td></tr>
</table>

Notes: Although the table pertains only to PTC eligibility, the *American Recovery and Reinvestment Act of 2009* enabled wind projects to elect a 30% investment tax credit (ITC) in lieu of the PTC starting in 2009; though it is rarely used, this ITC option has been included in all subsequent PTC extensions (and will follow the same phase down schedule as the PTC, as noted in the table: from 30% to 24% to 18% to 12%). Section 1603 of the same law enabled wind projects to elect a 30% cash grant in lieu of either the 30% ITC or the PTC; this option was only available to wind projects that were placed in service from 2009 to 2012 (and that had started construction prior to the end of 2011), and was widely used during that period. Finally, beginning with the *American Taxpayer Relief Act of 2012*, which extended the PTC window through 2013, the traditional "placed in service" deadline was changed to a more-lenient "construction start" deadline, which has persisted in the two subsequent extensions. Related, the IRS initially issued safe harbor guidelines providing projects that meet the applicable construction start deadline up to two full years to be placed in service (without having to prove continuous effort) in order to qualify for the PTC. In May 2016, the IRS lengthened this safe harbor window to four full years.

Source: Berkeley Lab

State policies help direct the location and amount of wind power development, but current state policies cannot support continued growth at recent levels

As of July 2017, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 52).[71] Attempts to weaken RPS policies have been initiated in a number of states, and in limited cases—thus far only Ohio in 2014 and Kansas in 2015—have led to a temporary freeze or repeal of RPS requirements. In contrast, other states—including, most recently, California, Hawaii, Maryland, Michigan, New York, Oregon, Rhode Island, and Washington, DC—have increased their RPS targets. Vermont has created a new RPS.



Notes: The figure does not include mandatory RPS policies established in U.S. territories or non-binding renewable energy goals adopted in U.S. states and territories. Note also that many states have multiple sub-requirements or "tiers" within their RPS policies, though those details are not summarized in the figure.

Source: Berkeley Lab

Figure 52. State RPS policies as of July 2017

Of all wind power capacity built in the United States from 2000 through 2016, roughly 51% is delivered to load serving entities (LSEs) with RPS obligations. In recent years, however, the role of state RPS programs in driving incremental wind power growth has diminished, at least on a national basis; 21% of U.S. wind capacity additions in 2016 serves RPS requirements. Outside of the wind-rich Interior region, however, RPS requirements continue to form a strong driver for wind growth, with 90% of 2016 wind capacity additions in those regions serving RPS demand.

In aggregate, existing state RPS policies will require 450 terawatt-hours (TWh) of RPS-eligible renewable electricity by 2030, at which point most state RPS requirements will have reached their maximum percentage targets. Based on the mix and capacity factors of resources currently used or contracted for RPS compliance, this equates to a total of roughly 144 GW of RPS-

[71] Although not shown in Figure 52, mandatory RPS policies also exist in a number of U.S. territories, and non-binding renewable energy goals exist in a number of U.S. states and territories.

eligible renewable generation capacity needed to meet RPS demand in 2030.[72] Of that total, Berkeley Lab estimates that existing state RPS programs will require roughly 55 GW of renewable capacity additions by 2030, relative to the installed base at year-end 2016.[73] This equates to an average annual build-rate of roughly 3.9 GW per year, not all of which will be wind. By comparison, over the past decade, U.S. wind power capacity additions averaged 7.1 GW per year, and total U.S. renewable capacity additions averaged 11.3 GW per year. Clearly, current RPS policies cannot—alone—support continued wind power growth at recent levels.

In addition to state RPS policies, utility resource planning requirements—principally in Western and Midwestern states—have motivated wind power additions in recent years. So has voluntary customer demand for "green" power. State renewable energy funds provide support (both financial and technical) for wind power projects in some jurisdictions, as do a variety of state tax incentives—though one state, Oklahoma, recently eliminated its wind power production tax credit. Finally, some states and regions have enacted carbon reduction policies that may help to support wind power development. The Northeast's Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy, for example, has been operational for a number of years, and California's greenhouse gas cap-and-trade program commenced operation in 2012, although carbon pricing in these programs has generally been too low to drive significant wind energy growth thus far.

[72] Berkeley Lab's projections of new renewable capacity required to meet each state's RPS requirements assume different combinations of renewable resource types for each RPS state. Those assumptions are based, in large part, on the actual mix of resources currently used or under contract for RPS compliance in each state or region. To the extent that RPS requirements are met with a larger proportion of high-capacity-factor resources than assumed in this analysis, or are met with biomass co-firing at existing thermal plants, the required new renewable capacity would be lower than the projected amount presented here.

[73] Berkeley Lab's estimate of required renewable capacity additions is derived by first estimating incremental renewable generation needed to meet RPS requirements in 2030, relative to available supplies as of year-end 2016. These estimates are performed on a utility-by-utility basis for regulated states, and on a regional basis for restructured states within regional REC markets. These estimates account for the ability of LSEs to bank excess RECs for compliance in future years, including any specific banking limitations in individual states. From the incremental renewable generation needs for each state, the corresponding capacity additions are estimated based on the mix and capacity factors of resources currently used or contracted for RPS compliance. This analysis ignores several complexities that could result in either higher or lower incremental capacity needs, including retirements of existing renewable capacity (which would result in higher incremental RPS needs) and the possibility that resources currently serving renewable energy demand outside of RPS requirements (e.g., voluntary corporate procurement) might become available for RPS demand in the future (which would result in lower incremental RPS needs).

System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain

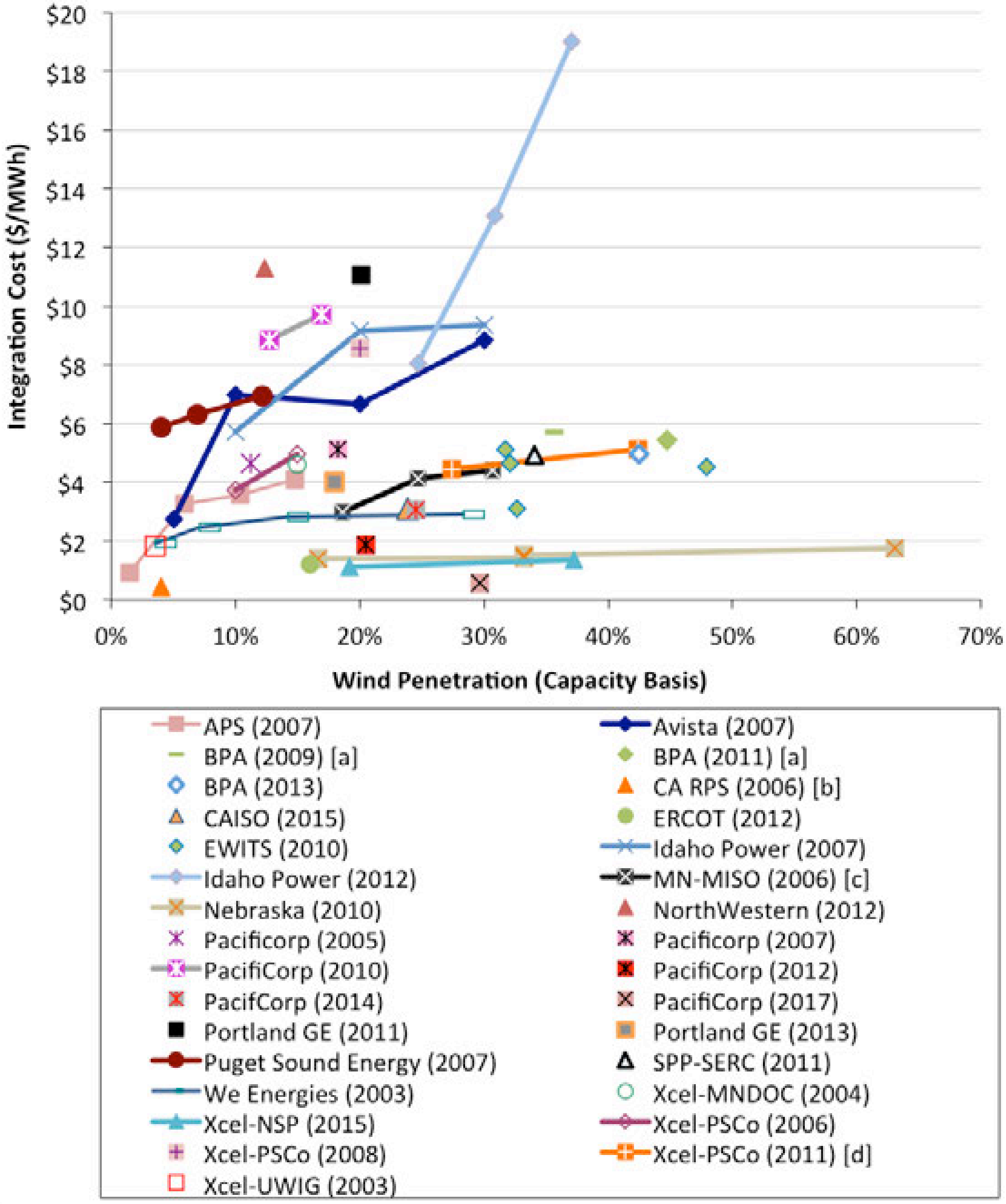
Wind energy output is variable and often the areas with the best wind speeds are distant from load centers. As a result, integration with the power system and provision of adequate transmission capacity are particularly important for wind energy. Concerns about, and solutions to, these issues have affected, and continue to impact, the pace of wind power deployment. Experience in operating power systems with wind energy is also increasing worldwide, leading to an evolving set of best practices (e.g., Jones 2014, Milligan et al. 2015, Du et al. 2017).

Figure 53 provides a selective listing of estimated wind integration costs at various levels of wind capacity penetration from studies completed from 2003 through 2016. While studies differ in how they define integration costs, the impacts assessed typically include additional balancing costs associated with managing increased forecast errors and balancing reserves, and some may also include the difference in the value of wind with a time-varying profile compared to a more conventional dispatch profile. The wind integration costs in these studies do not include those costs associated with incremental transmission or the lower capacity contribution of wind, costs that are sometimes included in other integration cost estimates (e.g., Heptonstall et al. 2017).

With one exception, integration costs estimated by the studies reviewed are below $12/MWh—and often below $5/MWh—for wind power capacity penetrations up to and even exceeding 40% of the peak load of the system in which the power is delivered. Costs tend to increase with wind penetration levels. Other variations in estimated costs are due, in part, to differences in methods, definitions of integration costs, power system and market characteristics, fuel price assumptions, wind output forecasting details, and the degree to which thermal plant cycling costs are included.

One new integration cost study was completed in 2016 as part of PacifiCorp's 2017 Integrated Resource Plan (PacifiCorp 2017). PacifiCorp's cost estimate of $0.57/MWh is lower than the costs in previous PacifiCorp assessments due to lower electricity prices and more resources being available to provide reserves. PacifiCorp defines integration costs to include both the cost of additional regulating reserves and the cost of managing day-ahead forecast errors.

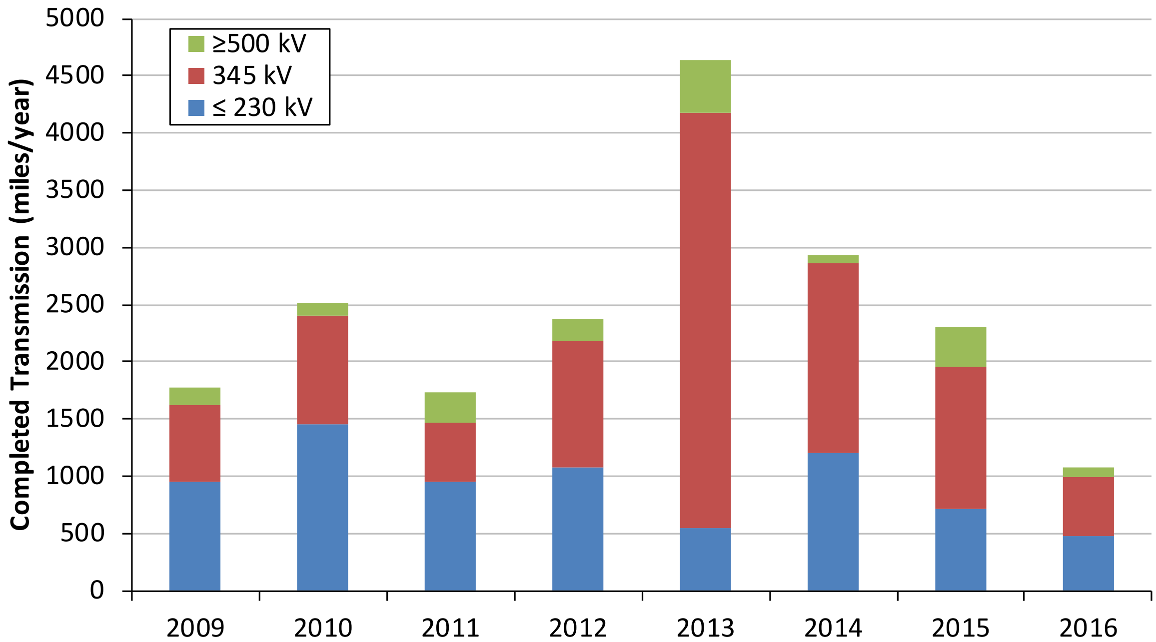
System operators and planners continue to make progress integrating wind into the power system, though in some areas there is growing concern that "out-of-market" support for resources is altering the revenue of market participants that do not receive out-of-market support. This issue is most prominent in the three Eastern ISOs that also include capacity markets: PJM, NYISO, and ISO-NE. A recent FERC technical conference (FERC 2017a) was organized around identifying the pros and cons of either altering wholesale markets such that they can help achieve state policy goals (e.g., internalizing the cost of carbon) or designing wholesale markets to avoid conflict with state policies that are achieved outside of those markets. Overall, the conference suggested that states' desires for resources with different attributes than provided by current wholesale markets may drive changes to energy, capacity, and ancillary service market designs—though little agreement emerged on the specific nature of those design changes.



Notes: [a] Costs in $/MWh assume 31% capacity factor; [b] Costs represent 3-year average; [c] Highest over 3-year evaluation period; [d] Cost includes the coal cycling costs found in Xcel Energy (2011). Listed below the figure are the organizations for which each study was conducted, and the year in which the analysis was conducted or published.

Figure 53. Integration costs at various levels of wind power capacity penetration

The best wind energy resources are often located far from load centers, and so transmission is particularly important for the wind power industry. Transmission additions, meanwhile, were limited in 2016: roughly 1,000 miles of transmission lines came online, the lowest amount since FERC began publishing these data in 2009 (see Figure 54). The decline since the peak in 2013 is, in part, due to the completion of the Texas CREZ lines in 2013. As of April 2017, FERC (2017b) finds that another 8,200 miles of new transmission (or upgrades) are proposed to come online by April 2019, with 4,900 miles of those lines having a higher probability of completion—this amount of new transmission would be reasonably consistent with the average annual historical transmission amounts depicted in Figure 54. The Edison Electric Institute, meanwhile, projects that annual transmission investment will amount to $22.5 billion in 2017, $21 billion in 2018, and $18.5 billion in 2019 (EEI 2016; dollar values presented in nominal terms). If achieved, these investment volumes would be on par with what was observed in 2014 to 2016, and considerably higher than 2010 to 2013 (EEI 2016).



Source: FERC monthly infrastructure reports

Figure 54. Miles of transmission projects completed, by year and voltage

Four significant transmission projects that may, in part, transport wind energy were completed in 2016 and are listed in Table 6. Moreover, AWEA (2017a) has identified 14 additional near-term transmission projects (some alternating current (AC), and some direct current (DC)) that, if all were completed, could transmit roughly 52 GW of new wind capacity (Table 7).

Table 6. Transmission Projects Completed in 2016

Transmission Project Name (State)	Voltage (kilovolts)
Nebraska City—Mullin Creek—Sibley (NE-MO; SPP Priority Project component)	345
Tehachapi Phases 2-3 (CA)	500
Rio Grande Valley Upgrades (TX)	345
Hampton-Rochester-LaCrosse (MN, WI; CapX component)	Mostly 345, some 161

Source: AWEA (2017a)

Table 7. Planned Near-Term Transmission Projects and Potential Wind Capacity

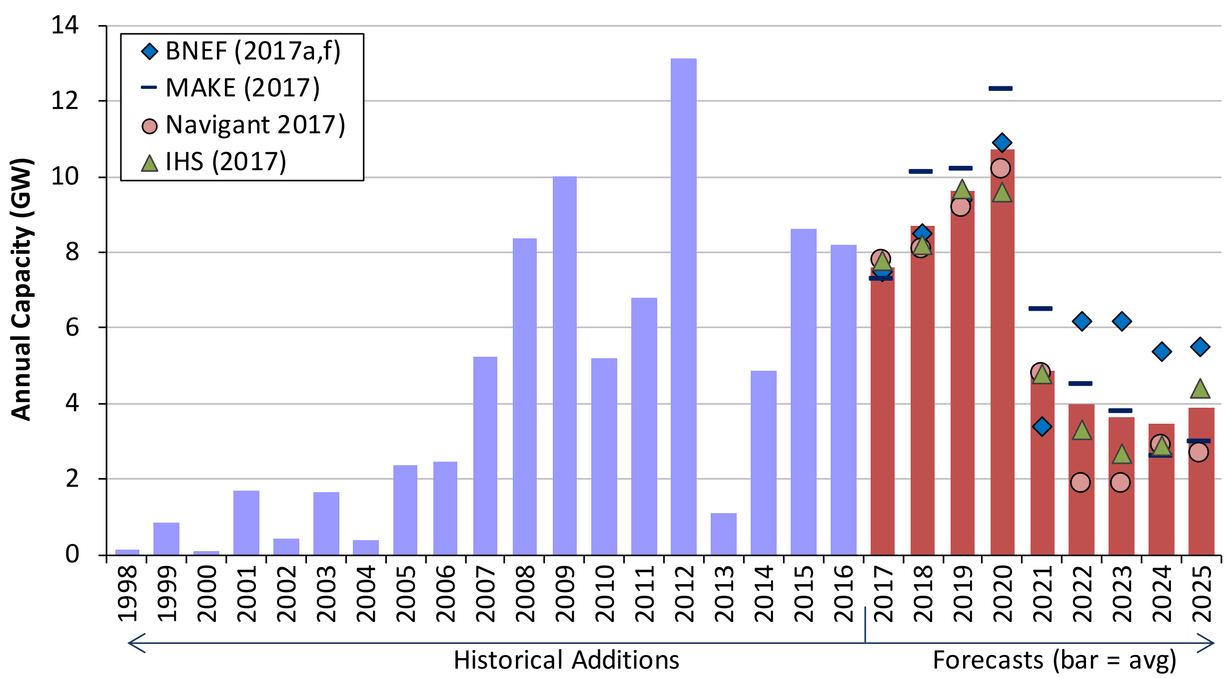
Transmission Project Name (State)	Voltage (kilovolts)	Estimated In-service Date	Estimated Potential Wind Capacity, MW
MISO Multi-Value Projects (ND, SD, IA, MN, WI, IL, MO, MI)	345, one 765 line	2015–2020	14,000
Grand Prairie Gateway (IL)	345	2017	1,000
Southline Transmission Project (NM, AZ)	345, 230	2018–2020	1,000
Power for the Plains (NM, TX, OK)	115, 230, 345	2016–2020	1,230
Pawnee—Daniels Park (CO)	345	2019	600
Gateway West (WY, ID)	500	2019–2021	3,000
Empire State Connector (NY)	320 DC	2020	1,000
Transwest Express (WY)	600 DC	2020	3,000
Sunzia (NM, AZ)	500	2020	3,000
Clean Line Projects (KS, OK, IA, NM, AZ)	600 DC	2020+	16,000
Southern Cross (TX)	500 DC	2021	2,000
SPP 2012 ITP10 Projects (TX, OK, KS, MO)	345	2018–2022	3,500
Gateway South (WY, UT)	500	2020–2024	1,500
Boardman-Hemingway (OR, ID)	500	2022	1,000
Total Potential Wind Capacity			**~52,000**

Source: AWEA (2017a)

9. Future Outlook

Analysts project that annual wind power capacity additions will continue at a rapid clip for the next several years, before declining, driven by the 5-year extension of the PTC signed in December 2015 and the progressive reduction in the value of the credit over time. Additionally, near-term additions are impacted by improvements in the cost and performance of wind power technologies, which contribute to low power sales prices. Demand drivers also include corporate wind energy purchases and state-level renewable energy policies.

Among the forecasts for the domestic market presented in Figure 55, expected capacity additions increase from 2017 through 2020, averaging more than 9,000 MW/year during that period (a pace that is supported by the amount of PTC-qualified wind turbine capacity that was reportedly safe-harbored by the end of 2016). Forecasts for 2021 to 2025, on the other hand, show a downturn in additions in part due to the PTC phase-out. Expectations for continued low natural gas prices, modest electricity demand growth, and lower near-term renewable energy demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and competition from other resources (natural gas and solar, in particular) in certain regions of the country. At the same time, declines in the price of wind energy over the last half decade have been substantial, helping to improve the economic position of wind even in the face of challenging competitive pressures. The potential for continued technological advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and continued state RPS requirements. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse and contrasting underlying potential trends, wind additions, especially after 2020, remain deeply uncertain.



Source: AWEA (historical additions), individual analyst forecasts

Figure 55. Wind power capacity additions: historical installations and projected growth

In 2015, the DOE published its *Wind Vision* report (DOE 2015), which analyzed a scenario in which wind energy reaches 10%, 20%, and 35% of U.S. electric demand in 2020, 2030, and 2050, respectively. Actual and projected wind additions from 2014 through 2020 (58 GW, in total) are slightly greater than the pathway envisioned in the DOE report (54 GW). Projected growth from 2021 through 2025, however, is well below the *Wind Vision* pathway. As discussed in DOE (2015), and as further suggested by these comparisons, achieving 20% and 35% wind energy on the timeframe analyzed by the DOE is likely to require efforts that go beyond business as usual expectations. Mai et al. (2017) specifically explore the role of wind technology advancement, finding that aggressive continued cost reductions will be necessary to achieve the *Wind Vision* deployment pathway absent substantial changes in policy or market conditions.

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Appendix: Sources of Data Presented in this Report

Installation Trends

Data on wind power additions in the United States (as well as certain details on the underlying wind power projects) largely come from AWEA (2017a). Annual wind power capital investment estimates derive from multiplying these wind power capacity data by weighted-average capital cost data, provided elsewhere in the report. Data on non-wind electric capacity additions come from ABB's Velocity database, except that solar data come from GTM Research.

Global cumulative (and 2016 annual) wind power capacity data come from GWEC (2017) but are revised to include the U.S. wind power capacity used in the present report. Wind energy as a percentage of country-specific electricity consumption is based on year-end wind power capacity data and country-specific assumed capacity factors that come from Navigant (2016), as revised based on a review of EIA country-specific wind power data. For the United States, the performance data presented in this report are used to estimate wind energy production. Country-specific projected wind generation is then divided by country-specific electricity consumption. The latter is estimated based on actual past consumption as well as forecasts for future consumption based on recent growth trends (these data come from EIA).

The wind project installation map was created by NREL, based in part on AWEA's project database. Wind energy as a percentage contribution to statewide electricity generation is based on EIA data for wind generation divided by in-state total electricity generation in 2016.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO, RTO, or utility. Only projects that were active in the queue, but not yet built, at the end of 2016 are included. Suspended projects are not included.

Industry Trends

Turbine manufacturer market share data are derived from the AWEA wind power project database, with some processing by Berkeley Lab.

Information on wind turbine and component manufacturing comes from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. Data on recent U.S. nacelle assembly capability come from AWEA (2017a), as do data on U.S. tower and blade manufacturing capability. The listings of manufacturing and supply-chain facilities are not intended to be exhaustive. OEM profitability data come from a Berkeley Lab review of turbine OEM annual reports (where necessary, focusing only on the wind energy portion of each company's business).

Data on U.S. imports and exports of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. International Trade Commission (USITC), and can obtained from the USITC's DataWeb (http://dataweb.usitc.gov/). The analysis of USITC trade data relies on the "customs value" of imports as opposed to the "landed value" and hence does not include costs relating to shipping or duties. The table below lists the specific trade codes used in the analysis presented in this report.

Table A1. Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis

HTS Code	Description	Years applicable	Notes
8502.31.0000	wind-powered generating sets	2005-2016	includes both utility-scale and small wind turbines
7308.20.0000	towers and lattice masts	2006-2010	not exclusive to wind turbine components
7308.20.0020	towers - tubular	2011-2016	virtually all for wind turbines
8501.64.0020	AC generators (alternators) from 750 to 10,000 kVA	2006-2011	not exclusive to wind turbine components
8501.64.0021	AC generators (alternators) from 750 to 10,000 kVA for wind-powered generating sets	2012–2016	exclusive to wind turbine components
8412.90.9080	other parts of engines and motors	2006-2011	not exclusive to wind turbine components
8412.90.9081	wind turbine blades and hubs	2012–2016	exclusive to wind turbine components
8503.00.9545	parts of generators (other than commutators, stators, and rotors)	2006-2011	not exclusive to wind turbine components
8503.00.9546	parts of generators for wind-powered generating sets	2012–2016	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014-2016	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[74]

Some trade codes are exclusive to wind, whereas others are not. Assumptions are made for the proportion of wind-related equipment in each of the non-wind-specific HTS trade categories. These assumptions are based on: an analysis of trade data where separate, wind-specific trade categories exist; a review of the countries of origin for the imports; personal communications with USITC and wind industry experts; USITC trade cases; and import patterns in the larger HTS trade categories. The assumptions reflect the rapidly increasing imports of wind equipment from 2006 to 2008, the subsequent decline in imports from 2008 to 2010, and the slight increase from 2010 to 2012. To account for uncertainty in these proportions, a ±10% variation is applied to the larger trade categories that include wind turbine components for all HTS codes considered, except for nacelles shipped under 8503.00.9560. For nacelles, the variation applied is ±50% of the total estimated wind import value under HTS code 8503.00.9560.

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from AWEA and Chadbourne and Park LLP. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of the AWEA project database.

[74] This was effective in 2014 as a result of Customs and Border Protection ruling number HQ H148455 (April 4, 2014). That ruling stated that nacelles alone do not constitute wind-powered generating sets, as they do not include blade assembly—which are essential to wind-powered generating sets as defined in the HTS.

Wind Turbine Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, specific power, and IEC Class was compiled by Berkeley Lab based on information provided by AWEA, turbine manufacturers, standard turbine specifications, the Federal Aviation Administration (FAA), web searches, and other sources. The data include projects with turbines greater than or equal to 100 kW that began operation in 1998 through 2016. Some turbines—especially in 2016—have not been rated within a formal numerical IEC Class, but are instead designated as Class "S-2," "S-2/3," or "S-3" for special. These turbines were recoded to their respective numerical class for purposes of analysis but are also broken out where appropriate. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

FAA "Obstacle Evaluation / Airport Airspace Analysis (OE/AAA)" data containing prospective turbine locations and total proposed heights were used to estimate future technology trends. Any data with expiration dates between December 31, 2016 and July 31, 2018 were binned into "pending" turbines, for those that already had received an evaluation of "no hazard," and "proposed" turbines, for those that are currently being evaluated.

Performance, Cost, and Pricing Trends

Wind project performance data were compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment of Berkeley Lab staff. Data on curtailment are from ERCOT (for Texas), MISO (for the Midwest), PJM, NYISO, SPP (for the Great Plains states), ISO-New England, and CAISO (for California).

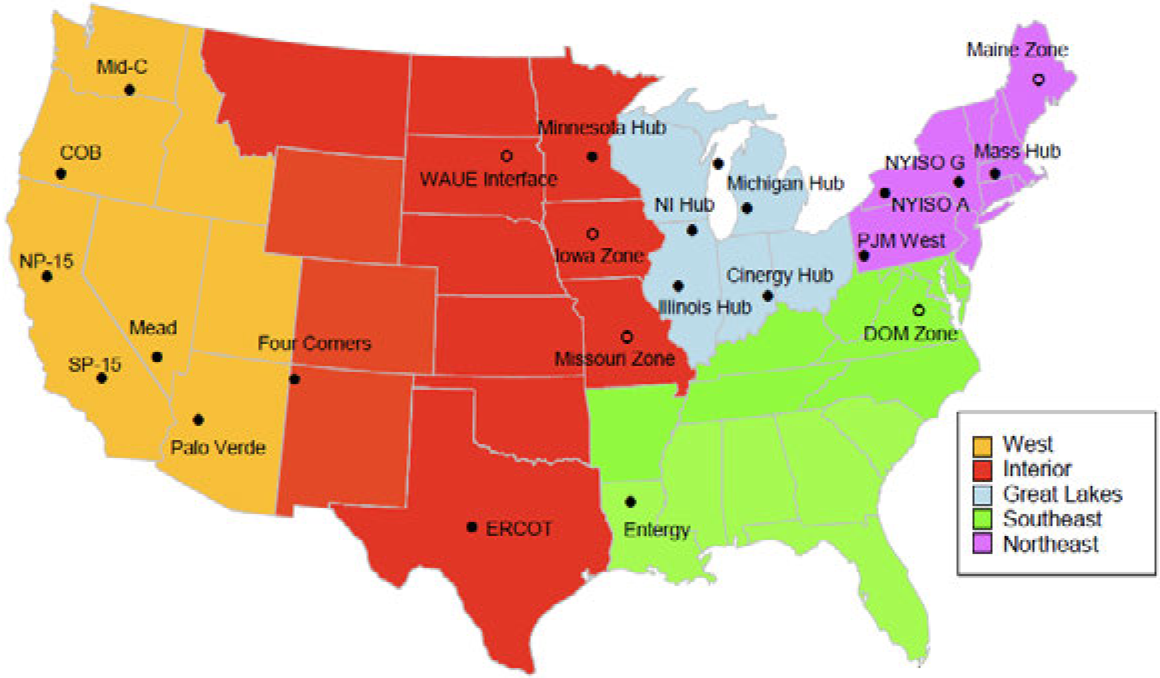
The following procedure was used to estimate the quality of the wind resource in which wind projects are (or are planned to be) located. First, the location of individual wind turbines and the year in which those turbines were (or are planned to be) installed were identified using FAA Digital Obstacle (i.e., obstruction) files and FAA OE/AAA files, combined with Berkeley Lab and AWEA data on individual wind projects. Second, NREL used 200-meter resolution data from AWS Truepower—specifically, gross capacity factor estimates—to estimate the quality of the wind resource for each of those turbine locations. These gross capacity factors are derived from average mapped 80-meter wind speed estimates, wind speed distribution estimates, and site elevation data, all of which are run through a standard wind turbine power curve (common to all sites) and assuming no losses. To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100% assigned in that period. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998–1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the "lower" category includes all projects or turbines with an estimated gross capacity factor of less than 40%; the "medium" category corresponds to ≥40%–45%; the "higher" category corresponds to ≥45%–50%; and the "highest" category corresponds to ≥50%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 42,301 turbines of the 46,724 installed from 1998 through 2016 in the continental United States, or 91% overall, though 95% of the turbines in the last 10 years have been mapped.

Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission and other regulatory filings. In part because wind turbine transactions vary in the turbines and services offered, a good deal of intra-year variability in the cost data is apparent. Additional data come from Vestas corporate reports, BNEF, and MAKE.

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, EIA Form 860, FERC Form 1, various Securities and Exchange Commission filings, filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, the DOE and Electric Power Research Institute Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009–2012 projects, data from the Section 1603 Treasury Grant program were used extensively; for projects installed from 2013 through 2015, EIA Form 860 data are extensively used. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not equally credible, little emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer insight. Only cost data from the contiguous lower-48 states are included.

Wind project O&M costs come primarily from two sources: EIA Form 412 data from 2001 to 2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. A small number of data points are suppressed in the figures to protect data confidentiality.

Wind PPA price data are based on multiple sources, including prices reported in FERC's *Electronic Quarterly Reports*, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs. Wholesale electricity price data were compiled by Berkeley Lab from the Intercontinental Exchange (ICE) as well as ABB's Velocity database (which itself derives wholesale price data from the ICE and the various ISOs). Earlier years' wholesale electricity price data come from FERC (2007, 2005). Pricing nodes included in the analysis, and within each region, are identified in the map below. To compare the price of wind to the cost of future natural gas-fired generation, the range of fuel cost projections from the EIA's *Annual Energy Outlook 2017* is converted from \$/MMBtu into \$/MWh using heat rates derived from the modeling output. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.



Note: The pricing nodes represented by an open, rather than closed, bullet do not have complete pricing history back through 2003.

Figure A1. Map of regions and wholesale electricity price nodes used in analysis

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