Exh. DCG-28
Dockets UE-190529/UG-190530 and
UE-190274/UG-190275 (*consolidated*)
Witness: David C. Gomez

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-190529 and UG-190530 *(consolidated)***
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferral Accounting and Ratemaking Treatment for Short-life UT/Technology Investment**	**DOCKETS UE-190274 and UG-190275 (*consolidated*)**

EXHIBIT TO TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

U.S. DOE, Office of Energy Efficiency & Renewable Energy,
2018 Wind Technologies Market Report

November 22, 2019

U.S. DEPARTMENT OF
ENERGY

Office of
ENERGY EFFICIENCY &
RENEWABLE ENERGY

2018 Wind Technologies Market Report

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Preparation and Authorship

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List of Acronyms

AWEA	American Wind Energy Association
BNEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COD	commercial operation date
CCA	community choice aggregator
DOE	U.S. Department of Energy
EDPR	EDP Renováveis
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
IEC	International Electrotechnical Commission
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
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
SGRE	Siemens Gamesa Renewable Energy
SPP	Southwest Power Pool
USITC	U.S. International Trade Commission
USWTDB	United States Wind Turbine Database
W	Watt
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

Wind power capacity in the United States continued to grow robustly in 2018, supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Improvements in the cost and performance of wind power technologies have also driven wind capacity additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. The magnitude of growth beyond the current PTC cycle remains uncertain, however, given declining tax support, expectations for low natural gas prices, and modest electricity demand growth.

Key findings from this year's *Wind Technologies Market Report*—which primarily focuses on land-based, utility-scale wind—include:

Installation Trends

- **Wind power additions continued at a robust pace in 2018, with 7,588 MW of new capacity added in the United States and $11 billion invested.** Supported by favorable tax policy and other factors, cumulative wind power capacity grew to 96,433 MegaWatts (MW). In addition to this newly installed capacity, 1,312 MW of partial wind plant repowering was completed in 2018, mostly involving upgrades to the rotor diameters and major nacelle components of existing turbines in order to access favorable tax incentives, increase energy production with more-advanced technology, and extend project life.
- **Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2018, behind solar and natural gas.** Wind power constituted 21% of all capacity additions in 2018. Over the last decade, wind represented 28% of all U.S. capacity additions, and an even larger fraction of new capacity in the Interior (56%) and Great Lakes (40%) regions. Its contribution to generation capacity growth over the last decade is somewhat smaller in the West (18%) and Northeast (13%), and considerably less in the Southeast (1%). [See Figure 1 for regional definitions].
- **Globally, the United States ranked second in annual wind capacity additions in 2018, but was well behind the market leaders in wind energy penetration.** Global wind additions equaled 50,100 MW in 2018, yielding a cumulative total of approximately 590,000 MW. The United States remained the second-leading market in terms of annual and cumulative capacity as well as annual wind generation, behind China. A number of countries have achieved high levels of wind penetration, with wind supplying over 40% of Denmark's total electricity generation in 2018, and between 20% and 30% in Ireland, Portugal and Germany. In the United States, wind supplied 6.5% of total electricity generation in 2018.
- **Texas installed the most capacity in 2018 with 2,359 MW, while fourteen states exceeded 10% wind energy penetration as a fraction of total in-state generation.** New utility-scale wind turbines were installed in 20 states in 2018. On a cumulative basis, Texas remained the clear leader, with 24,895 MW of capacity. Notably, the wind capacity installed in Oklahoma, Iowa, and Kansas supplied 31%–36% of all in-state electricity generation in 2018. Given the ability to trade power across state boundaries, estimates of wind penetration within entire multi-state markets operated by the major independent system operators (ISOs) are also relevant. In 2018, wind penetration (expressed as a percentage of load) was 23.9% in the Southwest Power Pool (SPP), 18.6% in the Electric Reliability Council of Texas (ERCOT), 7.3% in both the Midcontinent Independent System Operator (MISO) and the California Independent System Operator (CAISO), 2.8% in ISO New England (ISO-NE), 2.7% in the PJM Interconnection (PJM), and 2.5% in the New York Independent System Operator (NYISO).
- **A record level of wind power capacity entered transmission interconnection queues in 2018; solar and storage also reached new highs in 2018.** At the end of 2018, there was 232 GigaWatts (GW) of wind capacity seeking transmission interconnection, representing 36% of all generating capacity in the reviewed queues. In 2018, 92 GW of wind capacity entered interconnection queues, second only to solar capacity additions. Energy storage interconnection requests have also increased in recent years, both for

stand-alone storage and hybrid plants, most-often pairing solar with storage. The Southwest Power Pool, Mountain, and Midwest regions had the greatest quantity of wind in their queues at the end of 2018.

Industry Trends

- **GE and Vestas accounted for 78% of the U.S. wind power market in 2018.** In 2018, GE captured 40% of the U.S. market for turbine installations, edging out Vestas at 38% and followed at a distance by Nordex at 11% and Siemens-Gamesa Renewable Energy (SGRE) at 8%. Vestas was the leading turbine supplier for wind installations worldwide in 2018, followed by Goldwind, SGRE, and GE.
- **The domestic wind industry supply chain was reasonably stable in 2018.** The domestic supply chain for wind equipment faces conflicting pressures, including significant near-term growth, but also strong competitive pressures and an anticipation of reduced demand in the medium term as the PTC is phased out. Domestic wind sector employment reached a new high of 114,000 full-time workers. Although there have been a number of plant closures in recent years, three major turbine manufacturers have domestic manufacturing facilities. Domestic nacelle assembly capability stood at a record 15 GW in 2018, and the United States had the capability to produce blades and towers sufficient for approximately 9.2 GW and 8.9 GW, respectively, of wind capacity annually.
- **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 manufacturing content is highest for nacelle assembly (>85%), towers (75%–90%), and blades and hubs (50%–70%).
- **The project finance environment remained strong in 2018.** Initial concerns over the potential negative impact of the Tax Cuts and Jobs Act on wind project finance in the United States—and on tax equity supply in particular—proved to be largely unfounded. The U.S. wind market raised $6–7 billion of new tax equity in 2018, on par with the four prior years. Tax equity yields declined to around 7% (in unlevered, after-tax terms), while the cost of term debt initially increased, but then returned to around 4% toward the end of 2018. Looking ahead, 2019 and 2020 should continue to be active, given the abundant backlog of turbines that met safe-harbor requirements to qualify for 100% PTC. Post 2020, another reported 10 GW of safe-harbored turbines are available at the 80% PTC, with 6.6 GW of 60% PTC-qualified equipment. Given the safe harbor window in which to bring projects online, these 80%- and 60%-PTC projects might be expected to be online by the end of 2021 and 2022, respectively
- **Independent power producers own the majority of wind assets built in 2018.** Independent power producers (IPPs) own 80% of the new wind capacity installed in the United States in 2018, with the remaining assets owned by investor-owned utilities (19.9%) and other entities (0.1%).
- **Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales and merchant off-take arrangements were both significant.** Electric utilities continued to be the largest off-takers of wind power in 2018, either owning wind projects (20%) or buying electricity from projects (27%) that, in total, represent 47% of the new capacity installed in 2018. Direct retail purchasers—including corporate off-takers—account for 24%. Merchant/quasi-merchant projects (23%) and power marketers (3%) make up the remainder (with 3% undisclosed).

Technology Trends

- **Average turbine capacity, rotor diameter, and hub height increased in 2018, continuing the long-term trend.** To optimize wind project cost and performance, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed wind turbines in the United States in 2018 was 2.43 MW, up 5% from the previous year and 239% since 1998−1999. The average rotor diameter in 2018 was 115.6 meters, a 2% increase over 2017 and 141% over 1998−1999, while the average hub height in 2018 was 88.1 meters, up 2% over the previous year and 57% since 1998−1999.
- **Growth in average rotor diameter and turbine nameplate capacity have outpaced growth in average hub height over the last two decades.** Rotor scaling has been especially significant in recent years. In 2008, no turbines employed rotors that were 100 meters in diameter or larger; in contrast, by

2018, 99% of newly installed turbines featured rotors of at least that diameter. In fact, 87% of newly installed turbines in 2018 featured rotor diameters of greater than or equal to 110 meters, with 30% of turbines having rotors greater than or equal to 120 meters.

- **Turbines originally designed for lower wind speed sites dominate the market, and are being deployed in a range of wind resource conditions.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average "specific power" [1] (in W/m^2), from 395 W/m^2 among projects installed in 1998–1999 to 230 W/m^2 among projects installed in 2018. The trend toward lower specific power machines slowed in 2018. In general, turbines with low specific power were originally designed for lower wind speed sites.
- **Wind turbines continued to be deployed in somewhat lower wind-speed sites.** Wind turbines installed in 2018 were located in sites with an average estimated long-term wind speed of 7.8 meters per second at a height of 80 meters above the ground. These sites have lower wind speeds than those chosen for deployment in the 2014–2016 period, but they are similar to 2017 and have higher wind speeds than where turbines were installed from 2009 to 2013. Federal Aviation Administration (FAA) data suggest that near-future wind projects will be located in similar wind resource areas as those installed in 2018.
- **Low specific power turbines continue to be deployed in both lower and higher wind speed sites; taller towers are more commonly found in the Great Lakes and Northeast.** Low specific power turbines continue to be deployed in all regions of the United States, and at both lower and higher wind speed sites. The tallest towers (i.e., those above 100 meters) are found in greater relative frequency in the Great Lakes and Northeastern regions and in lower wind speed sites.
- **Wind projects planned for the near future continue the trend of ever-taller turbines.** FAA permit data suggest that near-future wind projects will deploy even taller turbines, with a significant portion (44%) of permit applications in early 2019 over 500 feet (152 meters), whereas the average total height for turbines installed in 2018 was 479 feet (146 meters).
- **The number of wind power projects that employed multiple turbine configurations from a single turbine supplier continued to increase.** More than a third of the larger wind projects built in 2018 utilized turbines with multiple hub heights, rotor diameters, and/or capacities—all supplied by the same original equipment manufacturer (OEM). This development primarily reflects efforts to qualify projects for the full PTC by purchasing the minimum required number of turbines prior to the end of 2016, but may also 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.
- **Through 2018, twenty-three wind projects have been partially repowered, most of which now feature significantly larger rotors and lower specific power ratings.** From 2017 through 2018, 23 projects were partially repowered, encompassing 2,425 turbines and totaling 3,445 MW before repowering. Of the changes made to these turbines, larger rotors dominated, increasing the average rotor diameter by 8.1 meters, while reducing specific power by 16%, from 357 to 301 W/m^2. The primary motivation for partial repowering has been to re-qualify for the PTC, while at the same time improving operational performance and extending the useful life of the projects.

Performance Trends

- **The average capacity factor in 2018 exceeded 40% among wind projects built in recent years, and reached 35% on a fleet-wide basis**. The average 2018 capacity factor among projects built from 2014 to 2017 was 41.9%, compared to an average of 30.8% among all projects built from 2004 to 2011, and 23.8% among all projects built from 1998 to 2001. This apparent improvement among more-recently

[1] 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.

built projects has slowly pushed the cumulative fleet-wide capacity factor higher over time, reaching 35% for the first time in 2018.

- **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 2014–2017, average capacity factors in 2018 were highest in the Interior region (43.1%) and lowest in the Northeast (31.3%). Not surprisingly, the regional rankings are roughly consistent with the relative quality of the wind resource in each region. However, they also reflect the degree to which each region has adopted turbines with lower specific power and/or taller towers. For example, the Great Lakes region has thus far adopted these new designs (particularly taller towers) to a larger extent than some other regions, leading to an increase in average regional capacity factors.
- **Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor**. The decline in specific power has been a major contributor to higher capacity factors, but has been offset to a degree by a tendency—especially from 2009 to 2012, when a cash grant was available in lieu of the PTC—toward 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.
- **Wind curtailment can differentially impact project performance across sites and regions**. Across all independent system operators (ISOs), wind energy curtailment in 2018 remained modest at around 2.2%. This average, however, masks variation across regions, and even more so by project—e.g., the average curtailment within ERCOT was 2.5% in 2018, but four wind projects totaling nearly 600 MW experienced curtailment of 18–25%. The amount of curtailment is not necessarily directly related to wind energy penetration within a region, as SPP and ERCOT have by far the highest penetration rates but less curtailment than in some other regions with lower penetration rates. Sample-wide capacity factors in 2018 would have been 0.7 percentage points higher nationwide absent curtailment in the ISOs.
- **Temporal variations in wind speed also impact performance**. The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation, in turn, impacts project performance from year to year. But for the third year in a row, wind speeds across the continental United States in 2018 were generally close to their long-term averages, both within each region and on average across all regions.
- **Wind project performance degradation may also explain why older projects did not perform as well in 2018**. Capacity factor data suggest some amount of performance degradation, though perhaps only once projects age beyond 9 or 10 years. Though the cause is somewhat uncertain, the apparent decline in capacity factors as projects progress into their second decade could partially explain why older projects—e.g., those built from 1998 to 2001—did not perform as well as newer projects in 2018.

Cost Trends

- **Wind turbine prices remained well below levels seen a decade ago.** After hitting a low of roughly $800 per kilowatt (kW) from 2000 to 2002, average turbine prices increased to more than $1,600/kW by 2008.[2] Since then, wind turbine prices have steeply declined, despite increases in size. Recent data suggest pricing most-typically in the $700–$900/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 2018 sample stood at $1,470/kW. This is a decrease of nearly $1,000/kW from the peak in average costs in 2009 and 2010, but is roughly on par with the costs experienced in the early 2000s—albeit with much larger turbines and improved performance. Early

[2] All cost figures presented in the report are denominated in real 2018 dollars.

indications from a sample of projects currently under construction suggest that somewhat lower costs are on the horizon, with some developers reporting costs in the $1,100–$1,250/kW range.

- **Installed costs differed by project size and turbine size.** Installed project costs for plants built in 2018 exhibit economies of scale, with costs declining as project size increases, at least at the lower end of the project size range.
- **Installed costs differed by region.** Among projects built in 2018, the Interior of the country was the lowest-cost region, with a capacity-weighted average cost of $1,400/kW. The number of projects installed in 2018 in other regions is limited, but those projects tended to experience higher installed costs, with an average of $1,740/kW; the Northeast was the highest-cost region.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, 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. The data suggest that O&M costs have increased as projects age for the older projects in the sample, but generally hold steady with age among those projects installed over the last decade.

Wind Power Price Trends

- **Wind power purchase agreement prices are at historical lows.** After topping out above $70 per MegaWatt-hour (MWh) for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to below $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 around $57/MWh among contracts executed in 2009 to below $20/MWh in 2017 and 2018. Today's low PPA prices have been facilitated by the combination of higher capacity factors, declining installed costs and operating costs, and low interest rates documented elsewhere in this report; the PTC has also been a key enabler over time.
- **Recent wind power purchase agreements have been priced in the mid-teens in some cases.** There are a growing number of sub-$20/MWh PPAs. Within our full PPA sample there are 16 projects (all in the Interior region) with levelized pricing below $20/MWh. This subset totals 2,468 MW and sells its output through 22 different PPAs signed since early 2015. The levelized prices of these 22 PPAs range from $9.3/MWh to $19.7/MWh.
- **Despite ultra-low PPA prices, wind faces stiff competition from solar and gas**. The once-wide gap between wind and solar PPA prices has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices. With the support of federal tax incentives, both wind and solar PPA prices are now below the projected cost of burning natural gas in existing gas-fired combined cycle units.
- **The economic competitiveness of wind energy is in part dictated by its grid-system value in wholesale power markets.** Given the location of wind projects and the hourly profile of wind generation, the average wholesale market value of wind has generally declined over the last decade. However, there has been a modest rebound in wind's wholesale market value over the last two years. Following the sharp drop in wholesale electricity prices (and, hence, wind energy market value) in 2009, average wind PPA prices tended to exceed the wholesale market value of wind through 2012. Continued declines in wind PPA prices brought those prices back in line with the market value of wind in 2013, and wind has generally remained competitive in subsequent years. The market value of wind in 2018 was the lowest in SPP, at $17/MWh, whereas the highest-value market was ISO-NE at $41/MWh.
- **PPA price trends reflect the levelized cost of wind energy**. Regional and nationwide trends in the levelized cost of wind energy (LCOE) closely follow the PPA trends described above—i.e., generally decreasing from 1998 to 2005, rising through 2009, and then declining through 2018. The lowest LCOEs are found in the Interior region, with an average of $34/MWh for those projects built in 2018, and with

some projects as low as $27/MWh. The national average LCOE of wind project built in 2018 was at an all-time low of $36/MWh. These LCOE estimates exclude the PTC and any state-level incentives.

Policy and Market Drivers

- **The federal production tax credit remains one of the core motivators for wind power deployment.** In 2015, Congress passed a five-year extension of the PTC that provides the full PTC to projects that started construction prior to the end of 2016, but that phases out the PTC for projects starting construction in subsequent years (e.g., projects that started construction in 2017 get 80% of the PTC, dropping to 60% and 40% for projects starting construction in 2018 and 2019, respectively). In 2016, the IRS issued Notice 2016-31, 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 (presuming commercial operations is achieved by the end of 2020), with another 10 GW qualifying for the 80% PTC (if online prior to the end of 2021) and 6.6 GW for the 60% PTC (if online by the end of 2022).
- **State policies help direct the location and amount of wind power development, but wind power growth is outpacing state targets**. As of May 2019, renewables portfolio standards (RPS) existed in 29 states and Washington, D.C. Of all wind capacity built in the United States from 2000 through 2018, roughly 47% is serving RPS obligations. Among wind projects built in 2018, however, this proportion fell to 19%. Existing RPS programs are projected to require average annual renewable capacity additions of roughly 5 GW/year through 2030.
- **System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain.** Studies show that the cost of integrating wind energy into the grid is 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. Grid system operators and others continue to implement a range of methods to accommodate increased wind energy penetrations. Transmission additions were limited in 2018, with approximately 1,300 miles of transmission lines coming online. The wind industry has identified 27 near-term transmission projects that, if completed, could support considerable amounts of wind capacity.

Future Outlook

Energy analysts project that annual wind power capacity additions will continue at a rapid clip for the next couple years, before declining, driven by the five-year phased expiration of the PTC. Additionally, improvements in the cost and performance of wind power technologies, which contribute to low power sales prices, will impact near-term additions. Other factors positively influencing demand include corporate wind energy purchases and state-level renewable energy policies. As a result, various forecasts show wind capacity additions increasing in the near term, to 9–12 GW in 2019 and 11–15 GW in 2020. Forecasts for 2021 to 2028, on the other hand, show a downturn, in part due to the PTC phase-out. Expectations for continued low natural gas prices and modest electricity demand growth also put a damper on growth expectations, as do limited transmission infrastructure and competition from natural gas and—increasingly—solar energy. At the same time, the potential for continued cost reductions may enhance the prospects for longer-term growth, as might 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 for development. Given these diverse and contrasting underlying potential trends, wind additions—especially after 2020—remain uncertain.

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1 Introduction

Wind power capacity additions in the United States continued at a robust pace in 2018. 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-out schedule) through 2019 as well as a myriad of state-level policies. Continued improvements in the cost and performance of wind power technologies have also driven wind capacity additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. At the same time, the magnitude of growth beyond the current PTC cycle remains uncertain, given declining federal tax support, expectations for continued low natural gas prices, increasing competition from solar, and modest electricity demand growth.

This annual report—now in its thirteenth consecutive year—provides an overview of developments and trends in the U.S. wind power market, with a particular focus on the year 2018. 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 U.S. 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 International Electrotechnical Commission (IEC) Class. After that, the report discusses wind power performance, cost, and pricing. In doing so, 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 the value of wind generation in wholesale energy markets as well as 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 energy analysts.

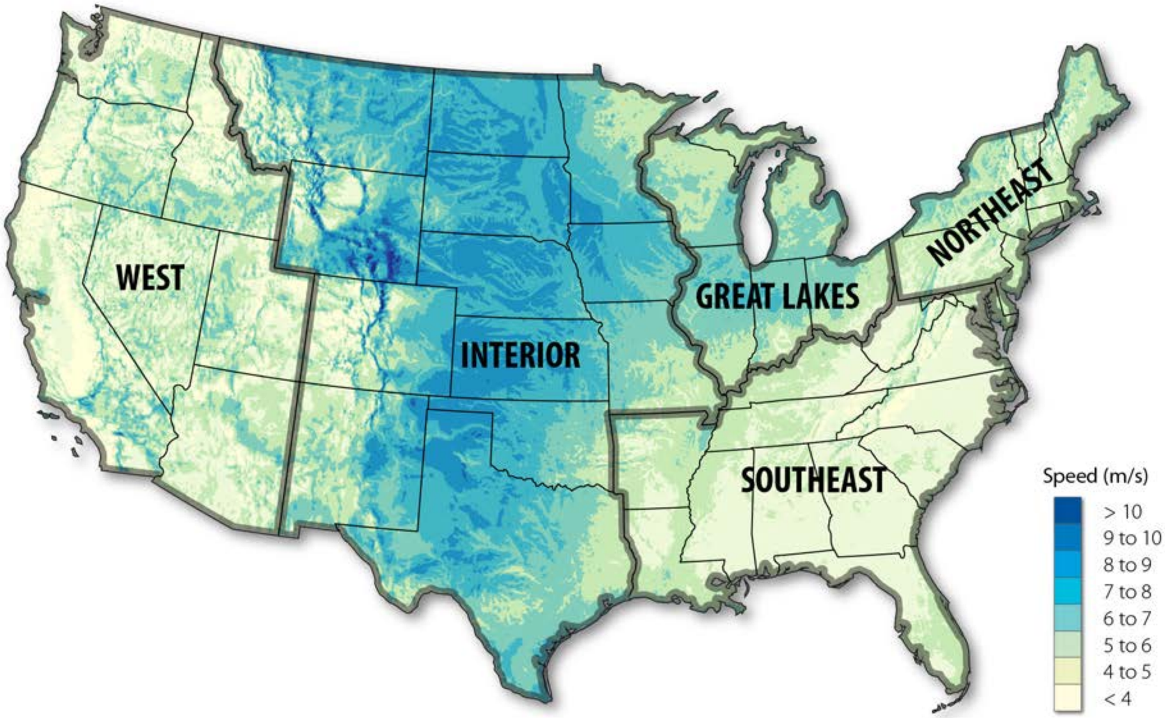
Many of these trends vary by state or region, depending in part on the strength of the local wind resource. To that end, Figure 1 superimposes the boundaries of five broad regions on a map of average annual U.S. wind speed at 80 meters above the ground.[3] These five regions will be referenced on many occasions throughout this report, whenever regional breakdowns or analysis is warranted, so they are defined here. Note that any such breakdowns, regional or otherwise, may not always add up to 100% due to rounding.

This edition of the annual report updates data presented in previous editions while highlighting trends and new developments that were observed in 2018. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[4] 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.

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

[4] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match the American Wind Energy Association'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.

Department of Energy (DOE)—the 2018 Distributed Wind Market Report.[5] Additionally, because this report has a historical focus—and because only one offshore wind project is operational in the United States—this report does not address trends in offshore wind power. A companion study funded by DOE that focuses exclusively on *offshore wind power* is also available—the 2018 Offshore Wind Technologies Market Report.[6]



Sources: AWS Truepower, National Renewable Energy Laboratory (NREL)

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. In some cases, the data shown represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. Emphasis should therefore be placed on overall trends, rather than on individual data points. Finally, each section of this report primarily focuses on historical and recent data. With some limited exceptions—including the final section of the report—the report does not seek to forecast wind energy trends.

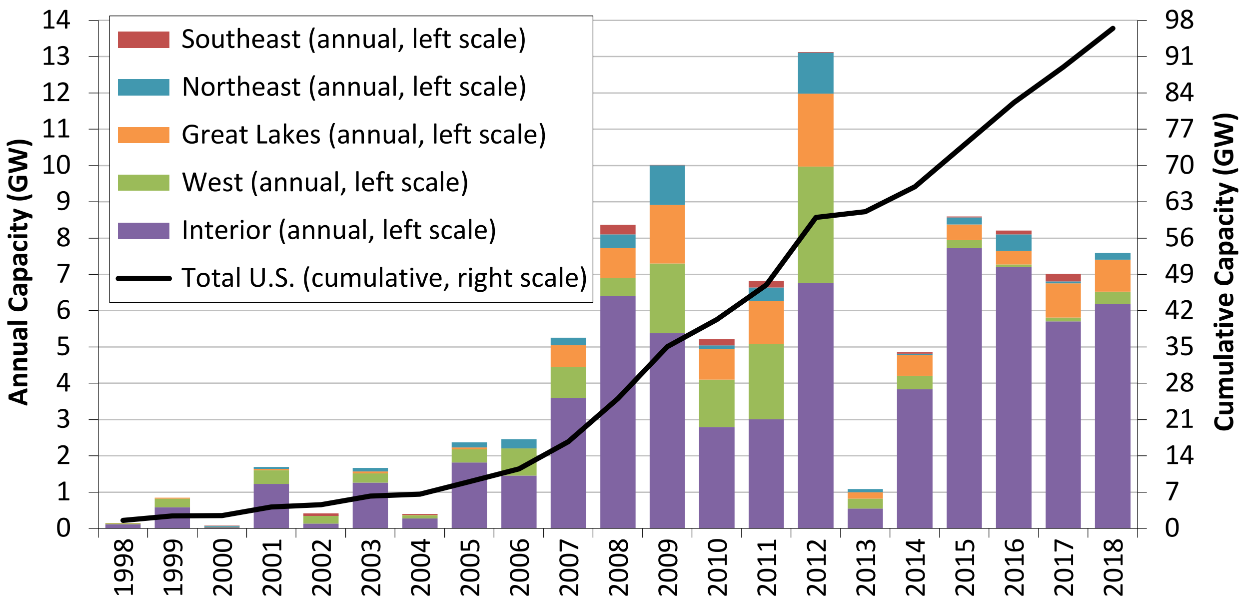
[5] See: https://energy.gov/eere/wind/downloads/2018-distributed-wind-market-report
[6] See: https://energy.gov/eere/wind/downloads/2018-offshore-wind-market-report

2 Installation Trends

Wind power additions continued at a robust pace in 2018, with 7,588 MW of new capacity added in the United States and $11 billion invested

U.S. wind power capacity additions equaled 7,588 MW in 2018, up slightly from 2017 additions and bringing the cumulative total to 96,433 MW (Figure 2).[7] This growth represented $11 billion of investment in new wind power project installations in 2018, for a cumulative investment total of roughly $196 billion since the beginning of the 1980s.[8,9] Over 80% of the new wind power capacity installed in 2018 is located within the Interior region (as defined in Figure 1).

A new trend is that of partial wind project repowering, in which major components of turbines are replaced in order to access favorable tax incentives, increase energy production with more-advanced turbine technology, and extend project life. In addition to the newly installed wind capacity reported above, 1,312 MW of partial repowerings were completed in 2018 across 10 projects, down from the 2,133 MW of partial repowering across 13 projects completed in 2017. Upgrades and refurbishments often lead to increased rotor diameters and the replacement of major nacelle components, with fewer changes to tower heights and nameplate capacity.[10]



Source: AWEA WindIQ

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

As in previous years, growth was driven in part by continued improvements in the cost and performance of wind power technologies. State renewables portfolio standards (RPS) and corporate demand also played a role.

[7] When reporting annual wind power capacity additions, this report focuses on *gross* capacity additions, and does not consider partial repowering. The *net* increase in capacity each year can be somewhat lower, reflecting turbine decommissioning, or higher, reflecting partial repowering that increases nameplate capacities. Reported cumulative capacity does include both decommissioning and repowering.

[8] All cost and price data are reported in real 2018 dollars.

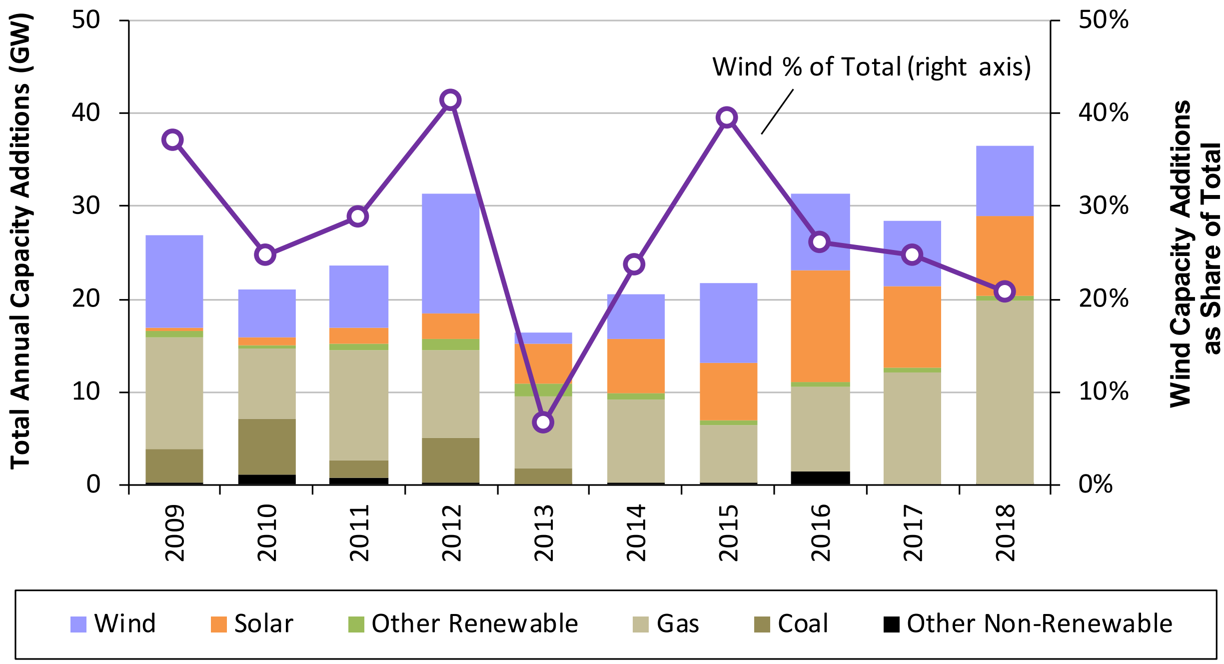
[9] These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

[10] The 1,312 MW and 2,133 MW of partially repowered capacity reflect the initial capacity, prior to refurbishment. Any change in capacity from partial repowering is included in the cumulative data but not the annual data reported in Figure 2.

A crucial factor was the PTC, which, in December 2015, was extended for an additional five 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. Meanwhile, the ability of partially repowered wind projects to access the PTC was the primary motivator for the growth in partial repowering in 2017 and 2018.

Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2018, behind solar and natural gas

Wind power has comprised a sizable share of generation capacity additions in recent years. In 2018, it constituted 21% of all U.S. capacity additions and was the third-largest source of new capacity, behind solar and natural gas (Figure 3).[11] Wind power's share of overall annual capacity additions declined slightly in 2018 relative to 2017, largely due to a sizable increase in natural gas capacity additions.

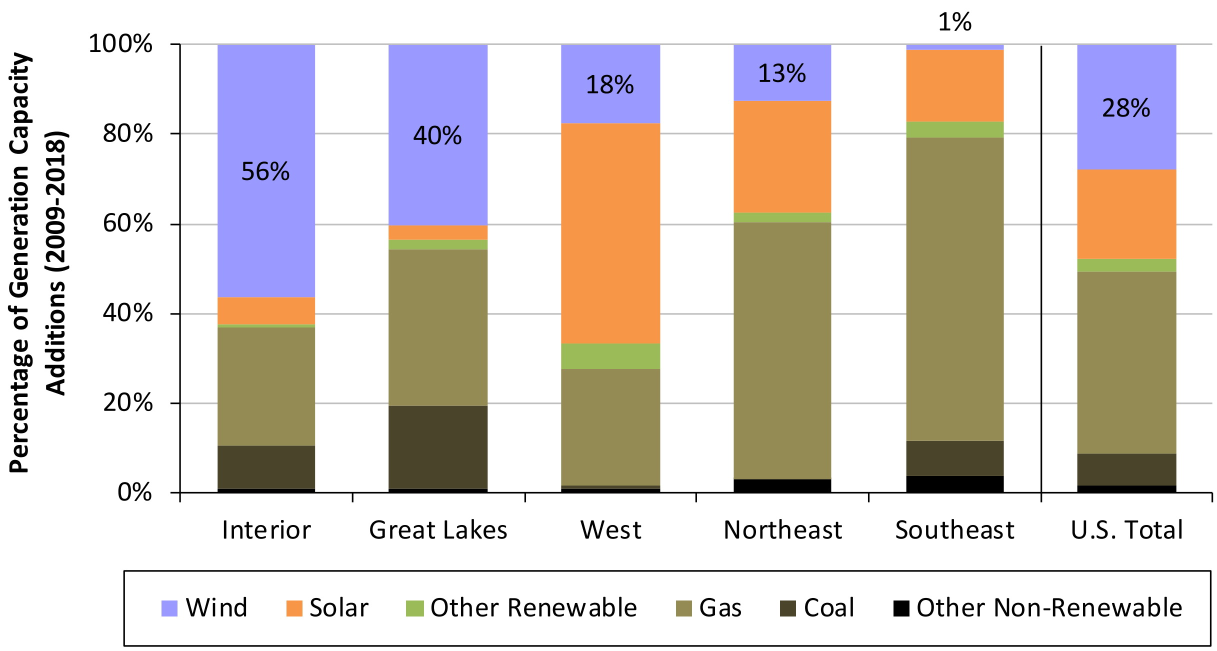


Sources: ABB, AWEA WindIQ, GTM Research, Berkeley Lab

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

Over the last decade, wind power represented 28% of total U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (56%) and Great Lakes (40%) 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 West (18%) and Northeast (13%), and considerably less in the Southeast (1%).

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



Sources: ABB, AWEA WindIQ, GTM Research, Berkeley Lab

Figure 4. Generation capacity additions by region (2009–2018)

Globally, the United States ranked second in annual wind capacity additions in 2018, but was well behind the market leaders in wind energy penetration

Global wind additions equaled roughly 50,100 MW in 2018: approximately 90% of which was land-based, with the remainder offshore wind. This figure is below the 53,500 MW in 2017 and below the record of 63,800 MW added in 2015. With its 7,588 MW representing 15% of new global installed capacity in 2018, the United States continued to maintain its second-place position behind China (Table 1). Cumulative global capacity grew by nearly 10% and totaled approximately 590,000 MW at the end of the year (GWEC 2019),[12] with the United States accounting for 16% of global capacity—a distant second to China by this metric. The United States also remains in second place, behind China, in annual wind electricity generation.

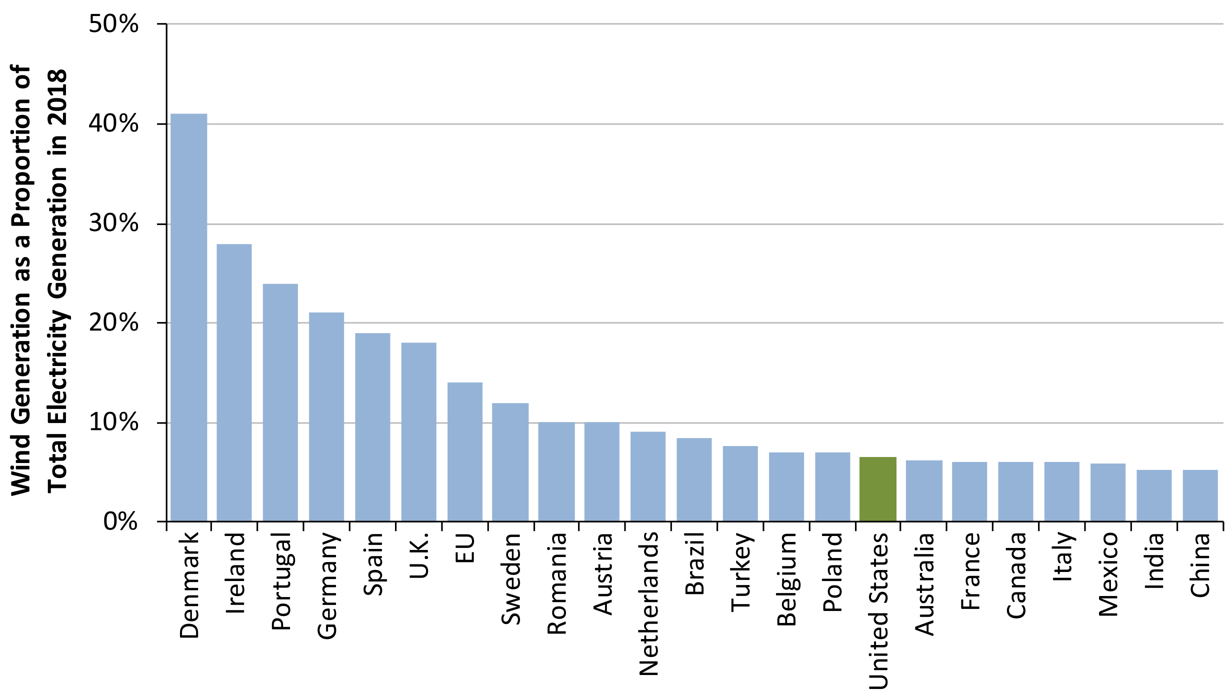
[12] Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from GWEC (2019) but are updated, where necessary, with the U.S. data presented here. Some disagreement exists among these data sources and others.

Table 1. International Rankings of Wind Power Capacity: Land-based and Offshore

Annual Capacity (2018, MW)		Cumulative Capacity (end of 2018, MW)	
China	21,855	China	210,247
United States	7,588	United States	96,433
Germany	3,371	Germany	59,312
India	2,191	India	35,129
Brazil	1,939	Spain	23,531
United Kingdom	1,901	United Kingdom	20,964
France	1,565	France	15,309
Mexico	929	Brazil	14,707
Sweden	720	Canada	12,816
Canada	566	Italy	9,959
Rest of World	7,493	*Rest of World*	91,466
TOTAL	50,118	TOTAL	589,872

Sources: GWEC (2019, updated via personal communication); AWEA WindIQ for U.S.

A number of countries have achieved relatively high levels of wind energy penetration in their electricity grids. Figure 5 presents data on a subset of countries, focusing on those with greater levels of total wind power capacity. Wind penetration exceeded 40% in Denmark in 2018, and was between 20% and 30% in Ireland, Portugal, and Germany. In the United States, wind supplied 6.5% of total electricity generation in 2018 (see Table 2 for additional details).



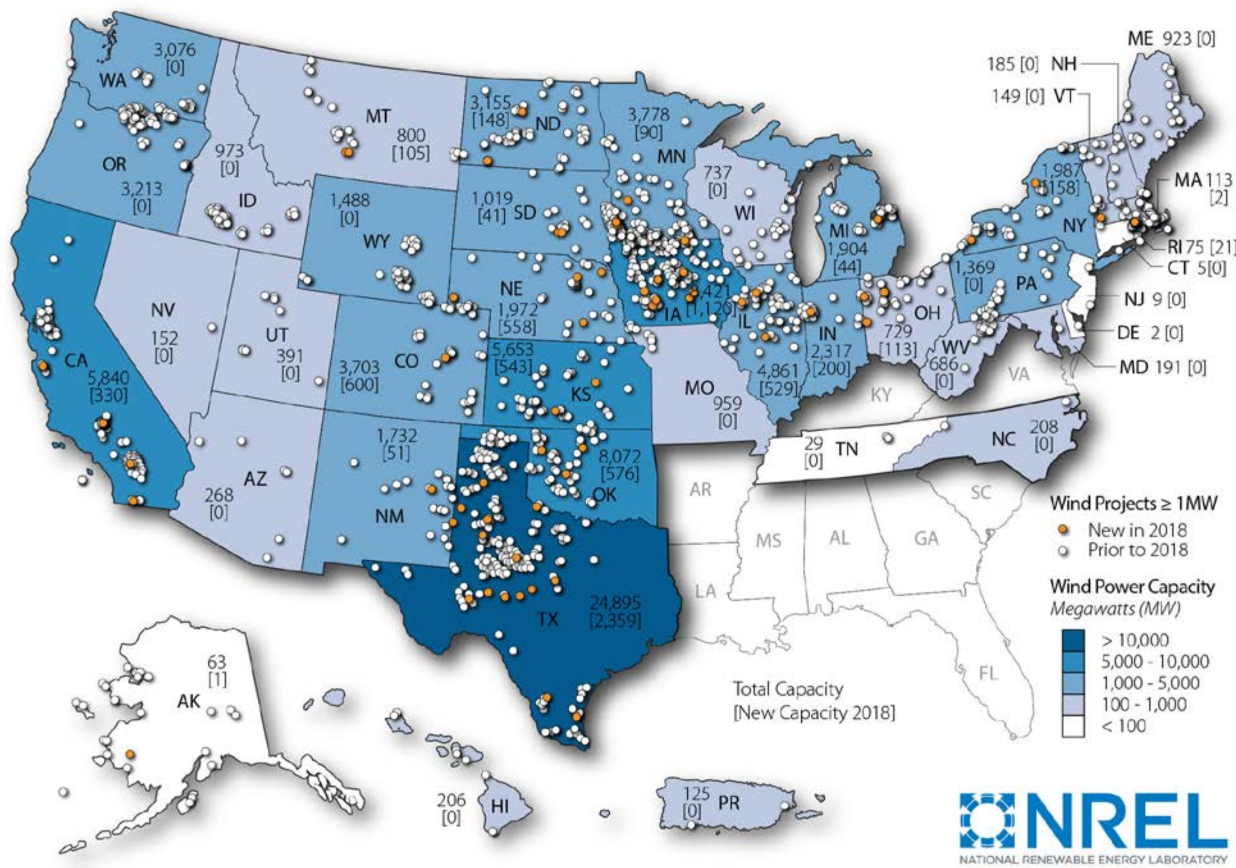
Source: AWEA (2019a)

Figure 5. Wind energy penetration in subset of countries with the greatest installed wind power capacity

Texas installed the most capacity in 2018 with 2,359 MW, while fourteen states exceeded 10% wind energy penetration as a fraction of total in-state generation

New utility-scale wind turbines were installed in 20 states in 2018. Texas once again installed the most new wind capacity of any state, adding 2,359 MW. As shown in Figure 6 and in Table 2, other leading states—in terms of new capacity—included Iowa, Colorado, Oklahoma, Nebraska, Kansas, and Illinois.

On a cumulative basis, Texas remained the clear leader, with 24,895 MW installed at the end of 2018—almost three times as much as the next-highest state (Iowa, with 8,421 MW). In fact, Texas has more wind capacity than all but four countries (including the United States). States distantly following Texas in cumulative installed capacity include Iowa and Oklahoma (both with more than 8,000 MW), as well as California and Kansas (both with more than 5,000 MW). Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2018, with 26 of these above 500 MW, 19 above 1,000 MW, 12 above 2,000 MW, and 11 above 3,000 MW.



Note: Numbers within states represent MegaWatts of cumulative installed wind capacity and, in brackets, annual additions in 2018.

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

Some states have reached high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2018 divided by total in-state electricity generation and by in-state electricity sales in 2018. Electric transmission networks enable most states to both import and export power in real time, and states do so in varying amounts. Denominating in-state wind generation as both a proportion of in-state generation and as a proportion of in-state sales is relevant, but both should be viewed with some caution given varying amounts of imports and exports. As a fraction of in-state generation, Kansas leads the list, with 36.4% of electricity generated in the state coming from wind, followed by Iowa, Oklahoma, North Dakota, and South Dakota. As a fraction of in-state sales, North Dakota is the leading state, with 53.5%

of the electricity sold in the state being met by wind, followed by Kansas, Oklahoma, and Iowa (all above 40%). Fourteen states have achieved wind penetration levels of 10% or higher when expressed as a percentage of generation, whereas 15 states have reached this threshold when expressed as a percentage of sales.

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

Installed Capacity (MW)				2018 Wind Generation as a Percentage of:			
Annual (2018)		Cumulative (end of 2018)		In-State Generation		In-State Sales	
Texas	2,359	Texas	24,895	Kansas	36.4%	North Dakota	53.5%
Iowa	1,120	Iowa	8,421	Iowa	33.7%	Kansas	47.1%
Colorado	600	Oklahoma	8,072	Oklahoma	31.7%	Oklahoma	43.4%
Oklahoma	576	California	5,840	North Dakota	25.8%	Iowa	43.2%
Nebraska	558	Kansas	5,653	South Dakota	24.4%	New Mexico	25.6%
Kansas	543	Illinois	4,861	Maine	21.0%	Wyoming	24.9%
Illinois	529	Minnesota	3,778	New Mexico	18.7%	South Dakota	21.7%
California	330	Colorado	3,703	Minnesota	17.9%	Maine	21.0%
Indiana	200	Oregon	3,213	Colorado	17.3%	Texas	18.6%
New York	158	North Dakota	3,155	Texas	15.9%	Colorado	17.5%
North Dakota	148	Washington	3,076	Vermont	15.8%	Minnesota	17.0%
Ohio	113	Indiana	2,317	Idaho	14.7%	Nebraska	16.9%
Montana	105	New York	1,987	Nebraska	14.1%	Oregon	15.0%
Minnesota	90	Nebraska	1,972	Oregon	11.0%	Montana	14.9%
New Mexico	51	Michigan	1,904	Wyoming	9.0%	Idaho	10.8%
Michigan	44	New Mexico	1,732	Montana	7.9%	Illinois	9.1%
South Dakota	41	Wyoming	1,488	Illinois	6.8%	Washington	8.2%
Rhode Island	21	Pennsylvania	1,369	California	6.5%	Vermont	7.1%
Massachusetts	2	South Dakota	1,019	Washington	6.3%	Hawaii	5.8%
Alaska	1	Idaho	973	Indiana	5.0%	Indiana	5.6%
Rest of U.S.	0	*Rest of U.S.*	7,005	*Rest of U.S.*	1.1%	*Rest of U.S.*	1.5%
TOTAL	7,588	TOTAL	96,433	TOTAL	6.5%	TOTAL	7.3%

Note: Based on 2018 wind and total generation and retail sales by state from EIA's Electric Power Monthly.

Sources: AWEA WindIQ, EIA

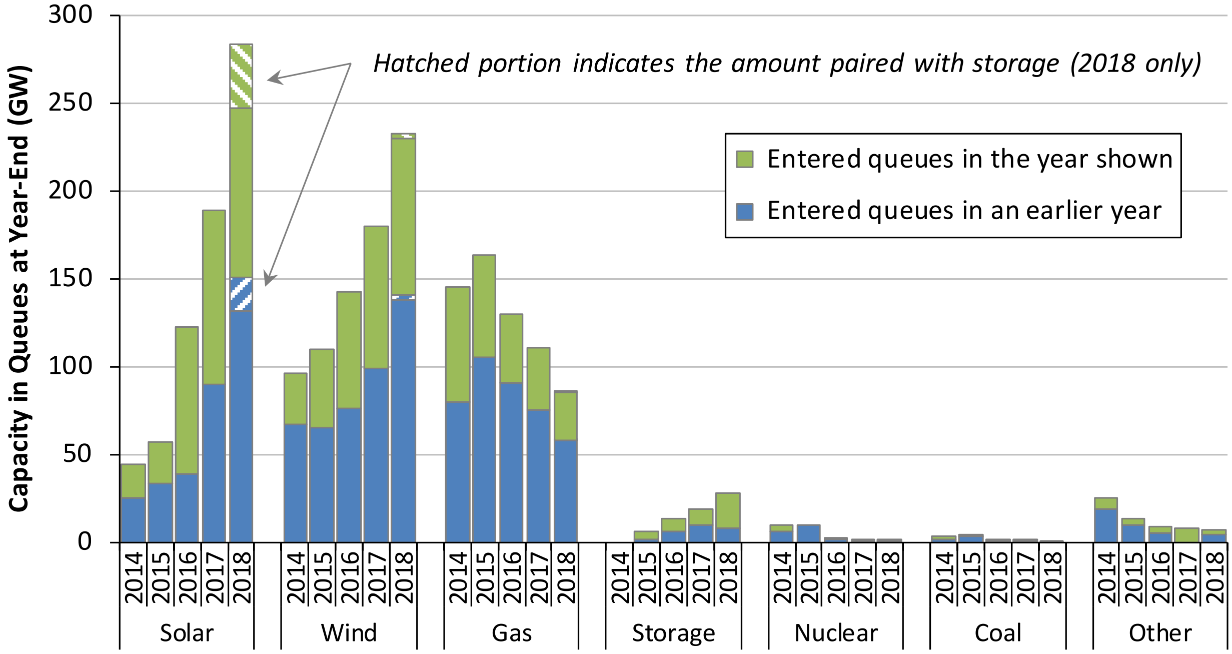
Given the ability to trade power across state boundaries, estimates of wind penetration within entire multi-state markets operated by the major independent system operators (ISOs) are also relevant. In 2018, wind penetration (expressed as a percentage of load) was 23.9% in the Southwest Power Pool (SPP), 18.6% in the Electric Reliability Council of Texas (ERCOT), 7.3% in both the Midcontinent Independent System Operator (MISO) and the California Independent System Operator (CAISO), 2.8% in ISO New England (ISO-NE), 2.7% in the PJM Interconnection (PJM), and 2.5% in the New York Independent System Operator (NYISO).

A record level of wind power capacity entered transmission interconnection queues in 2018; solar and storage also reached new highs in 2018

One testament to the amount of developer and purchaser interest in wind energy is the amount of wind power capacity working its way through the major transmission interconnection queues across the country. Figure 7 provides this information over the last five years for wind power and other resources aggregated across 37 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.[13] These data should be interpreted with caution: placing a project in the

[13] The queues surveyed include PJM, MISO, NYISO, ISO-NE, CAISO, ERCOT, SPP, Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and a large number of 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 80% of the U.S. total. Figures 7 and 8 only include projects that were

interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built (often, fewer than 25% of projects are subsequently built).



Notes: Data on hybrid projects paired with storage were not collected for years prior to 2018. Additionally, the 'storage' data for 2018 reflects stand-alone storage (not hybrid plants), whereas for years prior to 2018 the storage data also include some hybrid facilities.

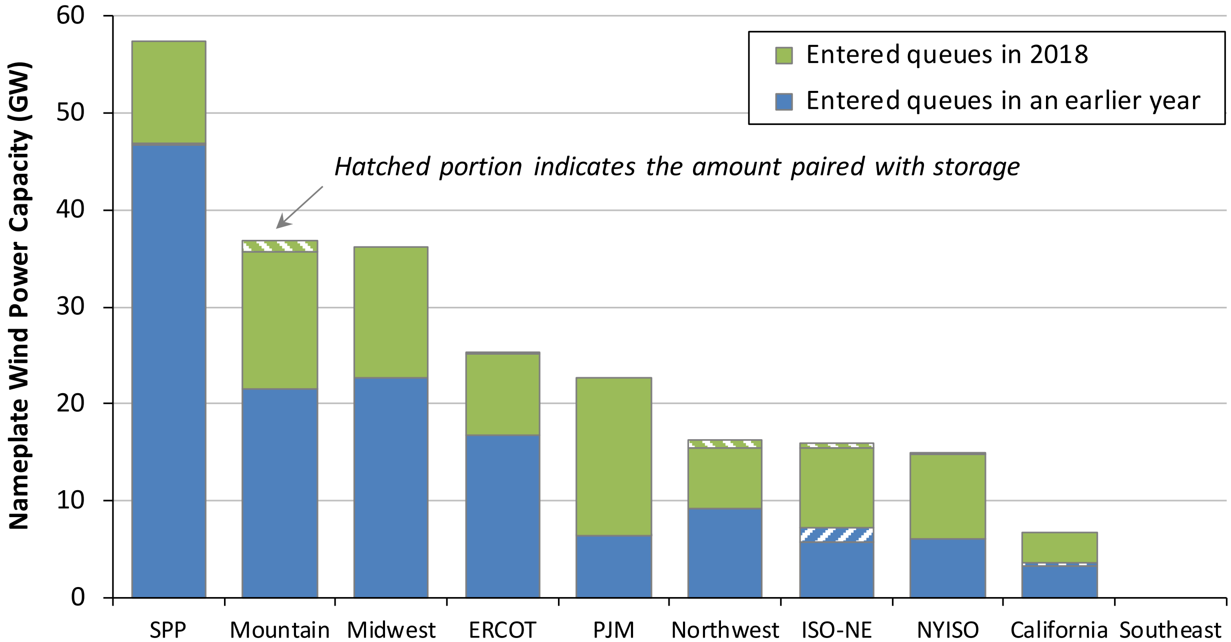
Source: Exeter Associates and Berkeley Lab review of interconnection queues

Figure 7. Generation capacity in 37 selected interconnection queues from 2014 to 2018, 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 2018, there were 232 GW of wind power capacity in the interconnection queues reviewed for this report—a sizable increase from the 180 GW in the same queues just one year earlier and more than at any point since the end of 2011. In fact, a record level of wind power capacity entered interconnection queues in 2018 (at least since 2009, when Berkeley Lab started collecting queue data)—92 GW in total, exceeding the previous record of 81 GW in 2017. Wind was not the only technology to reach a new record in 2018, however, as solar additions outpaced wind, at 133 GW. Storage additions have also increased in recent years. Moreover, for 2018, hybrid plants that include storage are also presented. As shown, 20% of the solar capacity in interconnection queues at the end of 2018 has been proposed as hybrid plants paired with storage, whereas only 2% of the wind capacity is paired with storage. Overall, wind represented 36% of all capacity in the sampled queues, compared to 44% for solar, 13% for natural gas, and 4% for stand-alone storage.

The wind capacity in the interconnection queues is spread across the United States, as shown in Figure 8, with the largest amounts in SPP (25%), the Mountain region (16%), the Midwest (16%), ERCOT (11%), and PJM (10%). Smaller amounts are found in the Northwest (7%), ISO-NE (7%), NYISO (6%), and California (3%), with the Southeast currently having no wind projects in the sampled queues. The PJM, Mountain, and Midwest regions experienced especially large annual additions in 2018.

active in the queues at the times specified but that had not yet been built (or had a completed interconnection agreement); suspended projects are not included.



Source: Exeter Associates review of interconnection queues

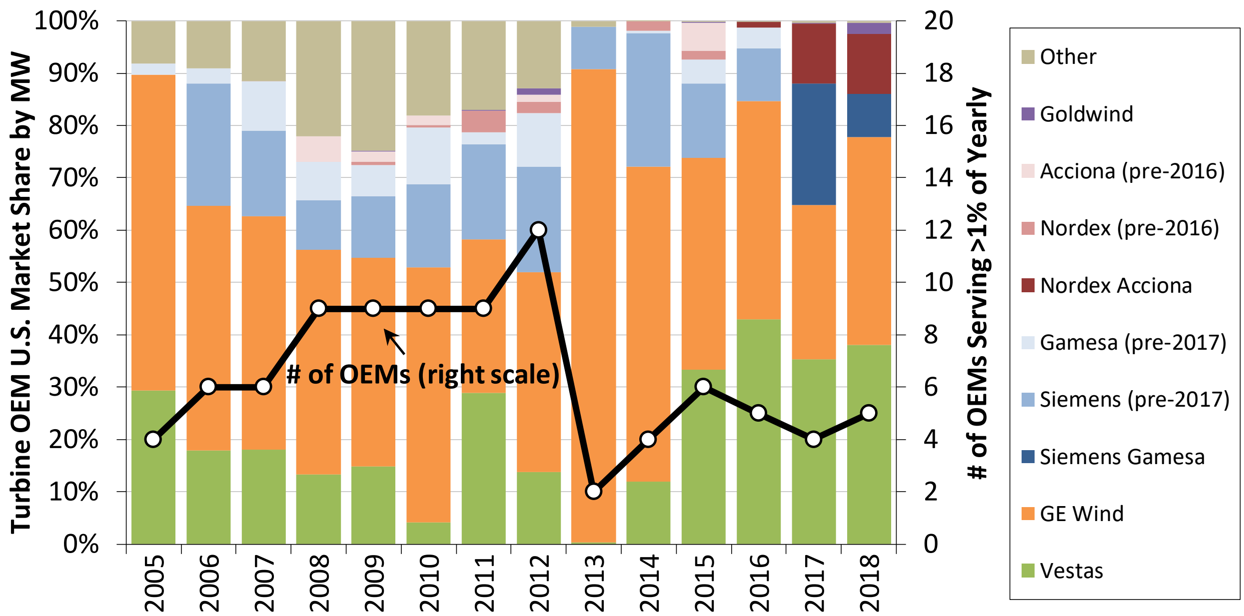
Figure 8. Wind power capacity in 35 selected interconnection queues, by region

As additional measures of the near-term development pipeline, ABB (2019) estimates that, as of May 2019, approximately 49 GW of wind power capacity could be characterized in one of three ways: (a) under construction or in site preparation (10 GW); (b) in development and permitted (16 GW); or (c) in development with a pending permit and/or regulatory applications (23 GW). These totals are approximately 10 GW higher than at the same time last year. AWEA (2019b) reports that more than 39 GW of wind power capacity was under construction or at an advanced stage of development at the end of the first quarter of 2019. EIA (2019b) identifies nearly 22 GW of planned additions for 2019 and 2020 combined.

3 Industry Trends

GE and Vestas accounted for 78% of the U.S. wind power market in 2018

Of the 7,588 MW of wind installed in 2018, GE Wind supplied 40% (3,011 MW), with Vestas coming in second (2,886 MW, 38% market share), followed more distantly by Nordex (866 MW, 11% market share) and Siemens Gamesa Renewable Energy (SGRE, 630 MW, 8% market share) (Figure 9).[14] Other suppliers included Goldwind (171 MW), Vensys (23 MW), and Emergya Wind Technologies (1 MW). GE and Vestas have dominated the U.S. market for some time, with SGRE and—more recently—Nordex vying for third.



Source: AWEA WindIQ

Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2018

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 continue in the future due to consolidation among OEMs. For example, the Nordex/Acciona merger took effect in April 2016 (in Figure 9, their combined operations are reported starting in 2016), while Siemens Wind Power and Gamesa consolidated their operations in April 2017 (and are combined in Figure 9 starting in 2017).

According to the Global Wind Energy Council (GWEC), Vestas was the leading supplier of turbines worldwide in 2018, followed by Goldwind, SGRE, and GE. On a worldwide basis, Chinese turbine manufacturers continued to occupy positions of prominence, with eight of the top fifteen spots in the ranking. To date, however, the growth of Chinese turbine manufacturers has been primarily based on sales to the Chinese market. GE is the only U.S.-based utility-scale turbine manufacturer playing a role in the global supply of large wind turbines.

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

The domestic wind industry supply chain was reasonably stable in 2018

The wind industry's domestic supply chain continues to deal with conflicting pressures: a surge in near-term expected growth from new installations and partial repowering, but also strong competitive pressures and expected reduced demand in the medium-term as the PTC is phased out. As a result, though some manufacturers increased the size of their U.S. workforce in 2018, overall growth has moderated.

Figure 10 presents a non-exhaustive list of approximately 140 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2018, focusing on the utility-scale wind market.[15] Figure 11 segments those facilities by the type of component they primarily supply.

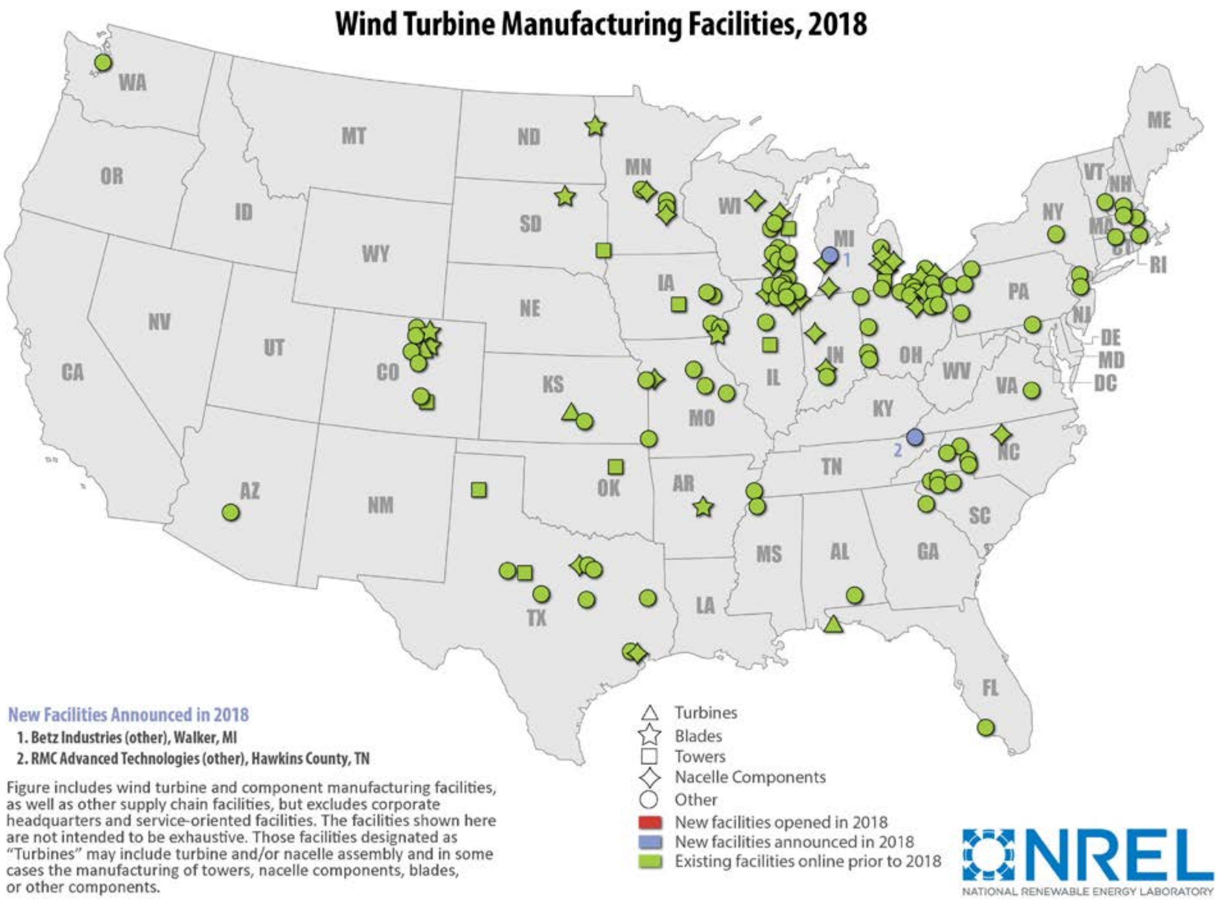
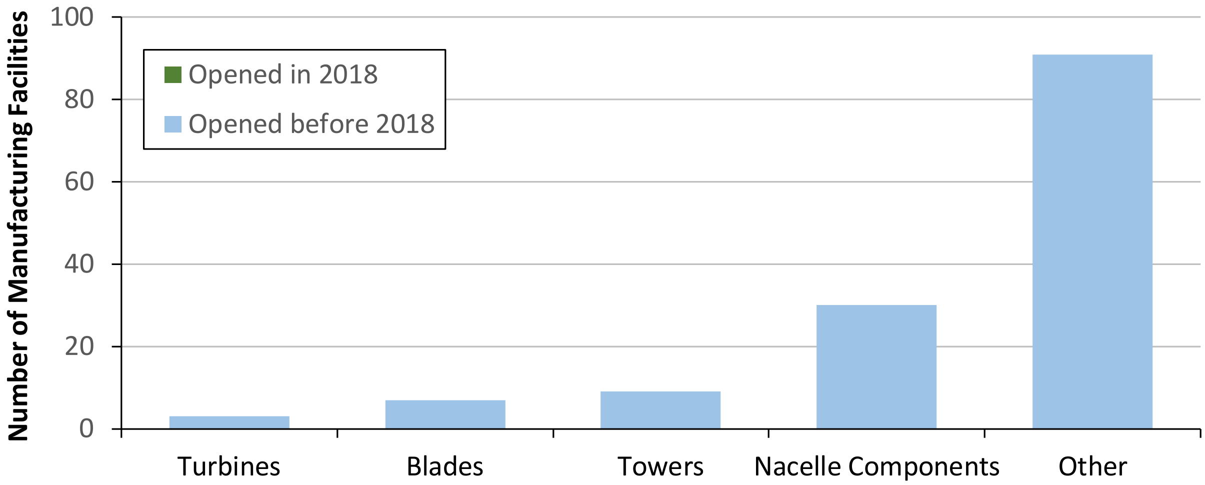


Figure 10. Location of existing and new turbine and component manufacturing facilities

No new wind-related manufacturing facilities opened in 2018, as illustrated in Figure 11. However, two new facilities were announced and are expected to be online by the end of 2019. In August 2018, Betz Industries announced plans to build a new facility in Michigan near the company's existing headquarters that will manufacture iron castings for multiple industries including wind energy. The facility is expected to open in 2019 and employ up to 45 workers at full capacity. Additionally, RMC Advanced Technologies—a subsidiary of Sigma Industries—announced the acquisition of a new facility in Tennessee that will produce composite parts used by the wind energy industry. The facility is expected to open in 2019 and employ 50 when operating

[15] The data on manufacturing facilities presented here differ from those presented in AWEA (2019a) 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 material suppliers. As a result, AWEA (2019a) reports a much larger number of wind-related manufacturing facilities.

at capacity. Meanwhile, at least four existing wind turbine or component manufacturing facilities were consolidated, closed, or stopped serving the industry in 2018 (The Gear Works, Creative Foam, Danfoss Drives, and ZF). In addition, in late 2017, MFG Wind announced that it would be closing its blade manufacturing facility in Aberdeen, South Dakota, though the company has since adjusted the timeframe for the closure and will keep the facility open through 2020.



Notes: No new manufacturing facilities opened in 2018. 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

Notwithstanding the recent supply chain consolidation and slow additions of new facilities, there remain a large number of domestic manufacturing facilities. Additionally, multiple manufacturers either expanded their workforce in 2018 to meet demand (e.g., Vestas, Broadwind, LM Wind Power), or began or completed expansions of existing facilities (e.g., LM Wind Power, Timken).

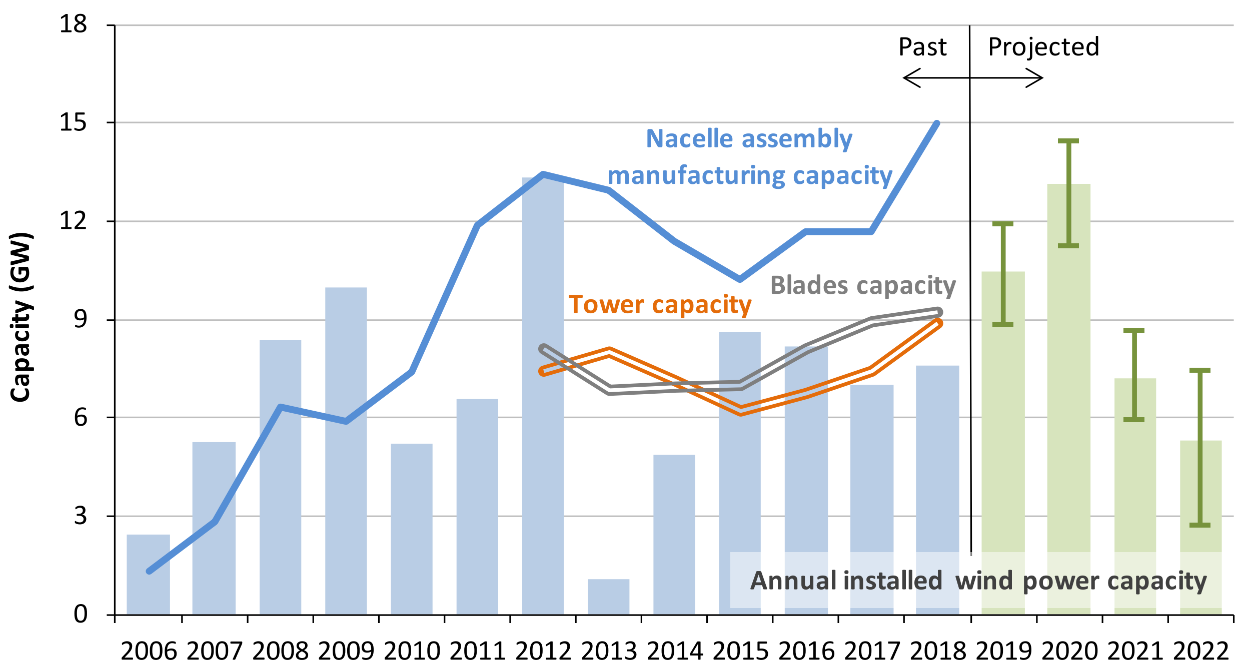
Figure 10 also highlights the spread of turbine and component manufacturing facilities across the country. Many manufacturers have chosen to locate in markets with substantial wind power capacity or near already-established large-scale OEMs. However, even states that are relatively far from major wind markets have manufacturing facilities. For example, most states in the Southeast have wind manufacturing facilities despite the limited number of wind projects in that region. Workforce considerations, transportation costs, and state and local incentives may be some of the factors that drive location decisions.

In 2010, nine out of the eleven 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, reflecting the increased concentration of the U.S. wind industry among the top OEMs, long-term demand uncertainty, mergers among OEMs, and a desire to consolidate production at centralized facilities overseas to gain economies of scale. Even with a consolidated market, however, three major OEMs that serve the U.S. wind industry—GE, Vestas, and SGRE—had one or more operating manufacturing facilities in the country at the end of 2018. In contrast, 14 years ago in 2004, there was only one active OEM (GE) assembling nacelles domestically.[16]

[16] 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.

An additional note of interest from 2018 was the continued entry of new composite producers into the U.S. market. Though not tracked within the wind turbine and component manufacturing and assembly facilities dataset otherwise reported here, composites are used in the manufacturing of some wind turbine components. In 2018, Exel Composites acquired Diversified Structural Composites of Erlanger, Kentucky to gain North American manufacturing capacity, and SKAPS Industries acquired Matrix Composites in Henderson, Kentucky. Additionally, SKAPS announced that it would invest $5 million for upgrades and hire 20 workers. Both of these facilities will supply composite materials for U.S. wind energy component manufacturers.

In aggregate, domestic turbine nacelle assembly capability—defined here as the maximum annual nacelle assembly capability of U.S. plants if all were operating at full utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, fell to roughly 10 GW in 2015, and then rose to a record 15 GW in 2018 (Figure 12; AWEA 2019a). In addition, AWEA (2019a) reports that U.S. manufacturing facilities have the capability to produce 11,400 individual blades (~9.2 GW if using average sized turbines) and 3,700 towers (~8.9 GW) annually. Figure 12 contrasts this equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future new 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. Modest growth in domestic blade and tower manufacturing capability or additional imports may be necessary to fulfill the total anticipated demand of blades and towers in the coming two years, however, especially when also considering expected demand from partial wind project repowering. Given the anticipated decline in wind power capacity additions as the PTC phases out, domestic manufacturing capability may exceed supply needs starting in 2021.

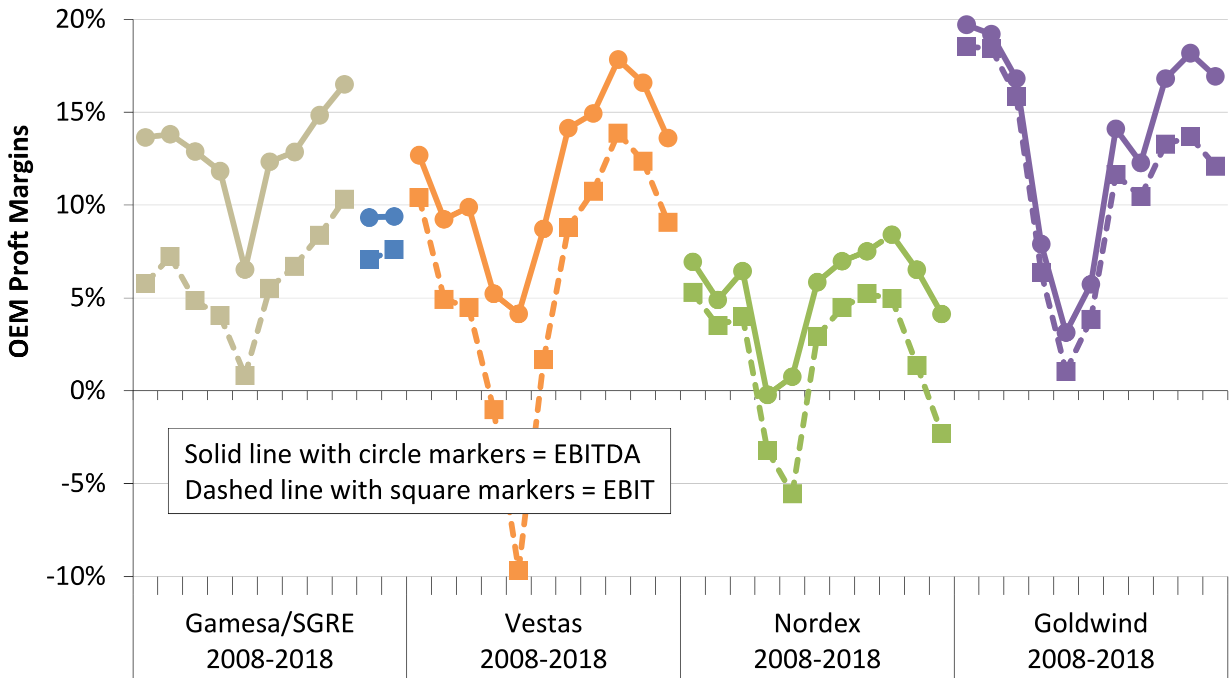


Notes: Data on blade and tower manufacturing capability are only available from 2012 to 2018. Forecasted annual wind power capacity additions from 2019 through 2022 includes simple average, minimum, and maximum value from analyst projections.

Sources: AWEA WindIQ, BNEF (2019), IHS (2019), GWEC (2019), Navigant (2019), Wood Mackenzie (2019), Berkeley Lab

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

Fierce competition throughout the supply chain has caused many manufacturers to execute cost-cutting measures. Nonetheless, the profitability of turbine OEMs has generally declined in the most recent years, following several years of recovery from a low point in 2012 (Figure 13).[17] Moreover, with recent and near-term expected growth in U.S. wind installations, wind-related job totals in the United States reached a new all-time high in 2018, at 114,000 full-time workers, an 8% boost from 2017 (AWEA 2019a). These 114,000 jobs include, among others, those in construction, development and transportation (~45,500), manufacturing and supply chain (~24,000), and operations and maintenance (~21,000).



Notes: EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization; EBIT = Earnings Before Interest and Taxes. Gamesa data shown through 2016, with the merged SGRE shown after 2016.

Sources: OEM annual reports and financial statements

Figure 13. Turbine OEM global profitability over time

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 others remain largely imported. These trends are revealed, in part, by data on wind equipment trade from the U.S. Department of Commerce.[18]

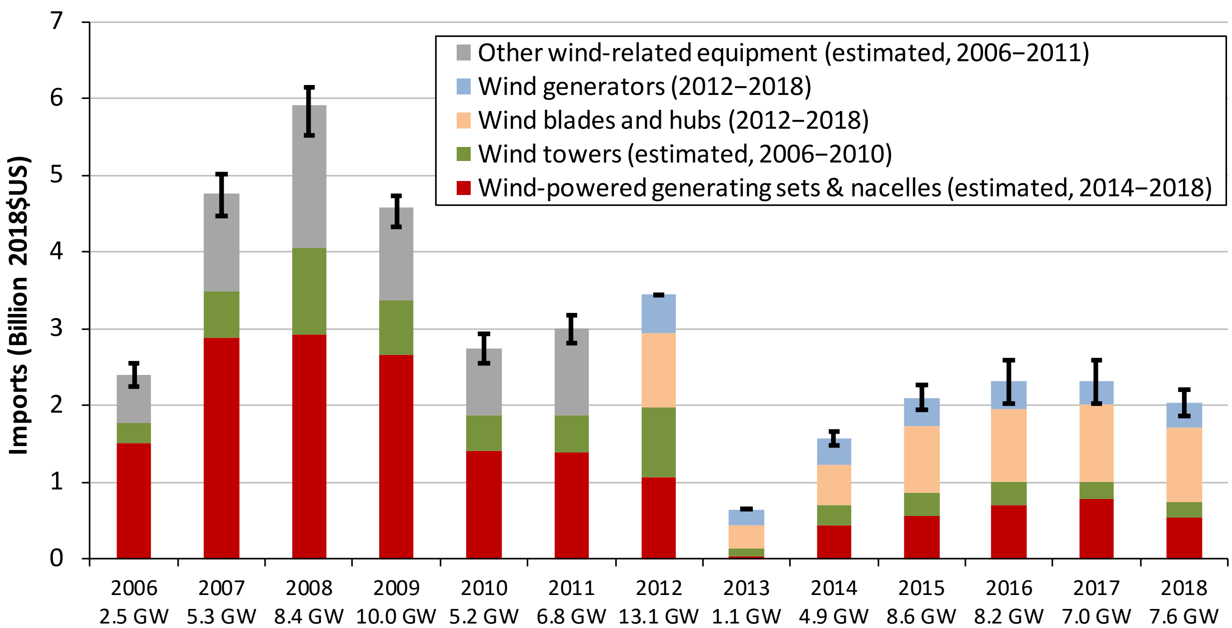
Figure 14 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating

[17] Figure 13 only reports data for those OEMs that are "pure-play" wind turbine manufacturers, or that otherwise report profitability just for their wind business. Although it is one of the largest turbine suppliers in the U.S. market, GE is not included because it is a multi-national conglomerate that does not report segmented financial data for its wind turbine division. 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.

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

sets and nacelles (i.e., nacelles with blades, nacelles without blades, and, in some cases, other turbine components internal to the nacelle) as well as imports of other select turbine components shipped separately from the generating sets and nacelles.[19] The turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (as well as generator parts), and blades and hubs.

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 were either specific to or largely restricted to wind power, and therefore 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[20] and thus the error bars shown for 2014 through 2018 only reflect the uncertainty in nacelle imports (and, in some cases, other turbine components internal to the nacelle shipped under this trade category). 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.



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

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

As shown, the estimated imports of tracked wind-related equipment into the United States increased substantially from 2006 to 2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then plummeting in 2013 with the simultaneous drop in U.S. wind installations. From 2014 through 2018, imports of wind-related turbine equipment generally followed U.S. wind installation trends, bouncing back from the low of 2013. 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

[19] 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.
[20] The trade code for tower imports is also not entirely exclusive to wind, but is believed to be dominated by wind since 2011. We assume that 100% of imports from this trade category, since 2011, represent wind equipment.

(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 15 shows the total value of selected, tracked wind-specific imports to the United States in 2018, by country of origin, as well as the main "districts of entry"[21]: Forty-four percent of the import value in 2018 came from Asia (led by China), 35% from Europe (led by Spain), and 20% from the Americas (led by Mexico). The principal districts of entry were Houston-Galveston, Texas (32%), Port Arthur, Texas (10%), and Great Falls, Montana (8%).

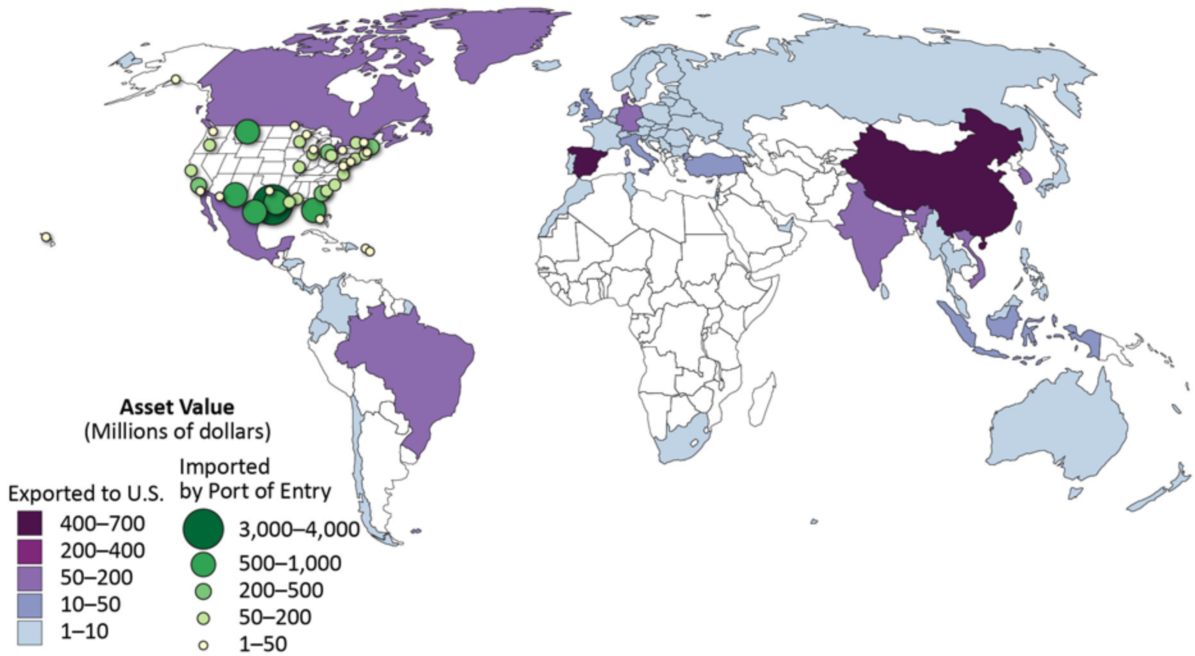
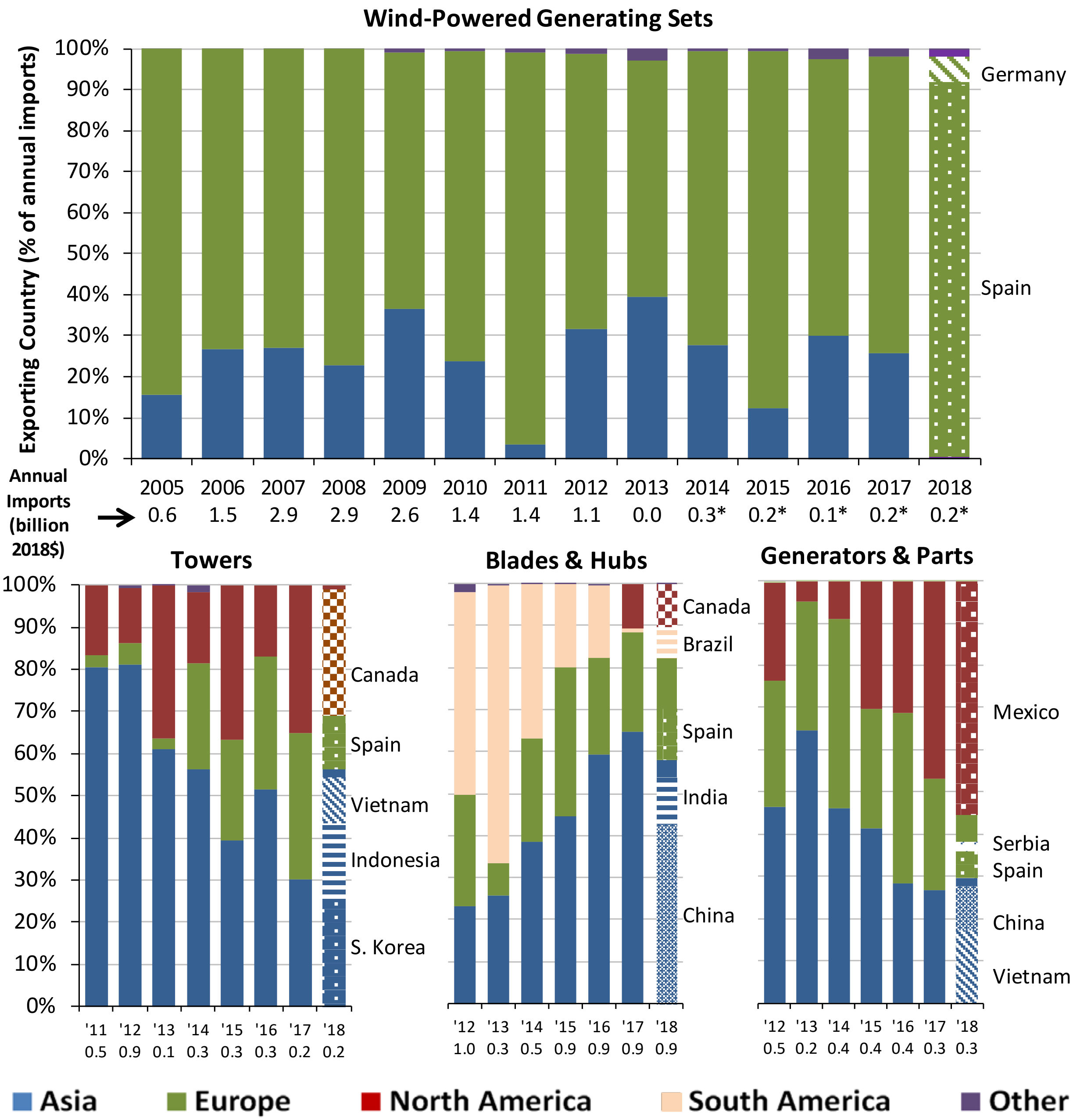


Figure 15. Summary map of tracked wind-specific imports in 2018: countries of origin and U.S. districts of entry

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.

[21] The trade categories included here are all of the wind-specific import categories for 2018, inclusive of towers, which is believed to be primarily related to wind (see the Appendix for details), and so the 2018 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 estimated 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; goods may arrive at districts of entry by land, air, or sea.



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

** Since 2014, some equipment that would previously have been included in the wind-powered generating sets trade category may be included in a different trade category (not wind specific, so not shown here) due to a change in trade category classification.*

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

For wind-powered generating sets, the primary source markets from 2005 to 2018 have been Europe and, to a lesser extent, Asia, with leading countries often being those that have been home to the major international turbine manufacturers such as Denmark, Spain, Japan, India, and Germany. In 2018, imports of wind-powered generating sets were dominated by Spain and Germany, though the total import value was relatively low (at

$199 million).[22] The share of imports of tubular towers from Asia was over 80% in 2011 and 2012 (almost 50% was from China), with much of the remainder from Canada and Mexico. From 2013 to 2018, 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.[23] Tower imports in 2018 came from a mix of countries from Asia (principally South Korea, Indonesia, and Vietnam), Europe (principally Spain), and North America (principally Canada). With regard to blades and hubs, Asia (principally China) has been the dominant source market since 2016, the European share has been relatively stable, and imports from the Americas have decreased from over 65% in 2013 to under 20% in 2018. Finally, the import origins for wind-related generators and generator parts were distributed across a number of Asian, European, and North American countries; in recent years, the role of Asian imports has decreased, while North American imports (especially from Mexico) have increased.

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 turbine components. Nonetheless, based on those data, Table 3 presents rough estimates of the domestic content for a subset of the major wind turbine components used in new (and repowered) U.S. wind projects in 2018. As shown, domestic content is relatively strong for large, transportation-intensive components such as towers and blades. Nacelle assembly also has high domestic content, wherein domestic and imported component are assembled into complete nacelles on U.S. soil.

Table 3. Approximate Domestic Content of Major Components in 2018

Towers	Blades & Hubs	Nacelle Assembly
75%–90%	50%–70%	> 85% of nacelle assembly

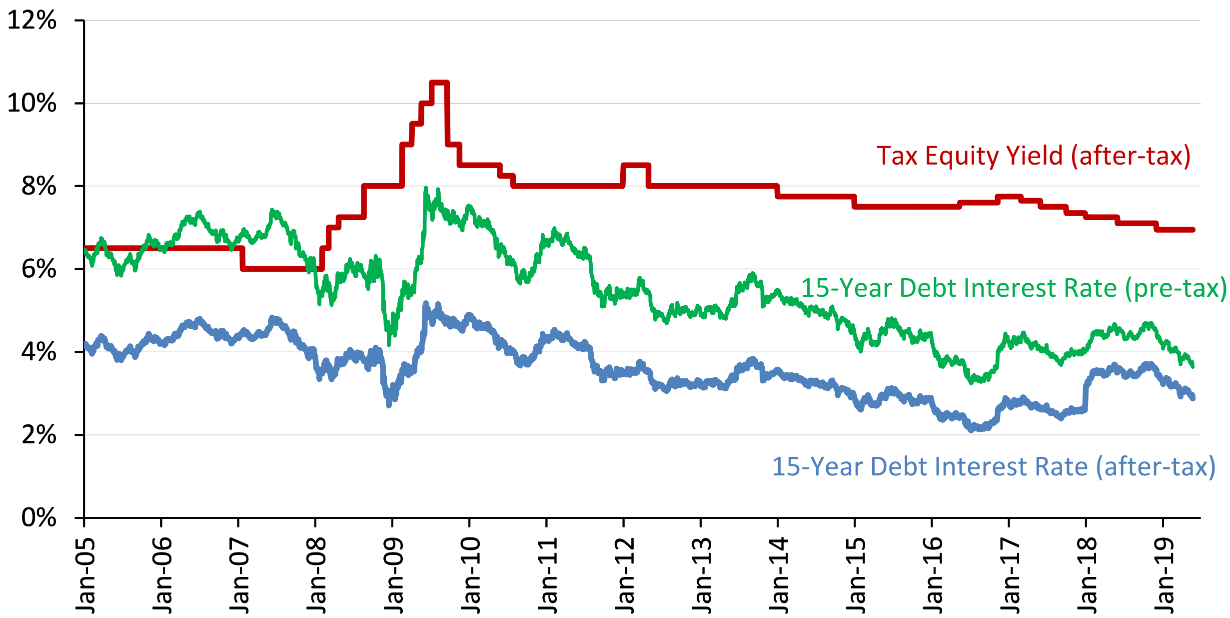
These figures, however, understate the wind industry's reliance on turbine and component imports. This is because significant wind-related imports occur under trade categories not captured in Table 3, including wind equipment (such as mainframes, converters, pitch and yaw systems, main shafts, bearings, bolts, controls) and manufacturing inputs (such as foreign steel in domestic manufacturing).[24] For example, an interview-based approach to estimating domestic content that was conducted in 2012 revealed that domestic content was relatively high for blades, towers, nacelle assembly and nacelle covers at that time, supporting the results depicted in Table 3. However, 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, often well below 20%.[25]

[22] Since 2014, some nacelles could be imported under a different trade category that is not exclusive to wind equipment, and so are not reported in the figure. As such, trends in imports of wind-powered generating sets before 2014 might be expected to differ from those shown in 2014 and after.
[23] In 2016, the Department of Commerce decided to reduce the anti-dumping duties to zero for a single company, which led to an increase in tower imports from Vietnam.
[24] 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.
[25] The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab.

The project finance environment remained strong in 2018

Initial concerns over the potential negative impact of the Tax Cuts and Jobs Act (which became law in late-December 2017) on wind project finance in the United States have proven to be largely unfounded. In particular, an anticipated reduction in the supply of tax equity due to the lower corporate tax rate (which reduces the tax liability of tax equity investors)[26] failed to materialize, as larger profits generally outweighed the lower tax rate, leaving overall tax capacity largely unchanged (Norton Rose Fulbright 2019). As a result, the market remained active in 2018, continuing to finance the backlog of 100% PTC-qualified equipment.

For example, roughly \$6–\$7 billion in third-party tax equity was committed in 2018 to finance new wind projects and partial repowerings—this dollar amount is roughly on par with the amount of tax equity raised in each of the previous four years. Partnership flip structures[27] remained the dominant tax equity vehicle, with indicative tax equity yields closing out the year around 7% on an after-tax unlevered basis (Figure 17).



Sources: Intercontinental Exchange Benchmark Administration (https://www.theice.com/iba), BNEF (2017), Norton Rose Fulbright (2019)

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

On the debt side, banks continued to focus more on shorter-duration loans (7–10 year mini-perms remained the norm[28]), though a number of banks are reportedly willing to lend for as long as 15 or even 18 years in some

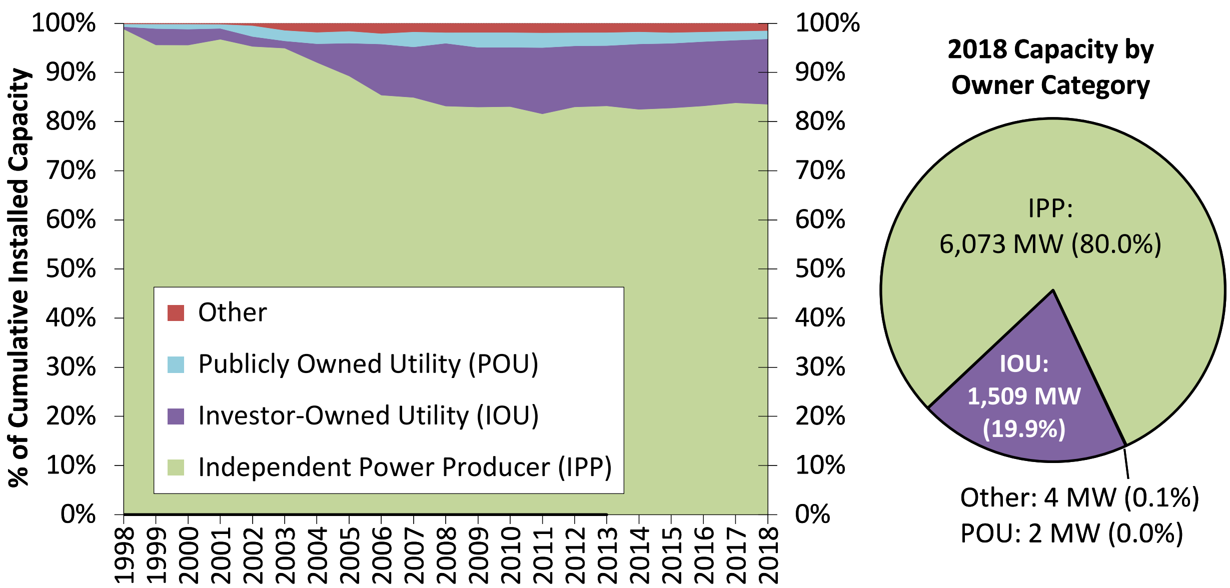
[26] The lower corporate tax rate also reduces the value of depreciation (or expensing) and interest deductions (and under the new law, interest deductions may be further limited if a company's net interest expense exceeds 30% of its adjusted taxable income).
[27] A "partnership flip" is a project finance structure in which the developer or project sponsor partners with a third-party tax equity investor to jointly invest in and own part of 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 toward the project sponsor to the extent possible, in order to support back leverage or dividend payments to YieldCo investors.
[28] 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 ten-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 ten 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).

cases (Norton Rose Fulbright 2019). As shown in Figure 17, all-in interest rates on benchmark 15-year debt moved higher through much of 2018, but then dropped back down to near 4% toward the end of 2018 as the Federal Reserve paused its multi-year string of 25 basis point rate hikes and shifted to more of a neutral stance, causing both the base rate and swap rates to decline (in concert with bank margins).

With two more years (2019 and 2020) in which to finance and build 100% PTC safe-harbored projects, the market should remain active in the near-term. Post-2020, roughly 10 GW of projects have reportedly qualified for 80% of the PTC's nominal value, while at least 6.6 GW have reportedly qualified for 60% of the PTC's nominal value by starting construction by the end of 2018 (Froese 2019). Given the four-year safe harbor window in which to bring PTC-qualified projects online, these 80%- and 60%-PTC projects might be expected to be online by the end of 2021 and 2022, respectively (see Table 4, later, for details on the PTC phase-out).

Independent power producers own the majority of wind assets built in 2018

Independent power producers (IPPs) own 6,073 MW or 80% of the 7,588 MW of new wind capacity installed in the United States in 2018 (Figure 18, right pie chart). Investor-owned utilities (IOUs)—namely MidAmerican (817 MW) and Public Service Company of Colorado (600 MW)—installed a total of 1,509 MW (20%). Publicly owned utilities (POUs) own just 2 MW of the new wind power capacity brought online in 2018. Finally, 4 MW of capacity falls into the "other" category of projects owned by neither IPPs nor utilities (e.g., owned by towns, schools, businesses, farmers).[29] Of the cumulative installed wind power capacity at the end of 2018 (Figure 18, left chart), IPPs own 83% and utilities own 15% (13% IOU and 2% POU), with the remaining 2% falling into the "other" category.



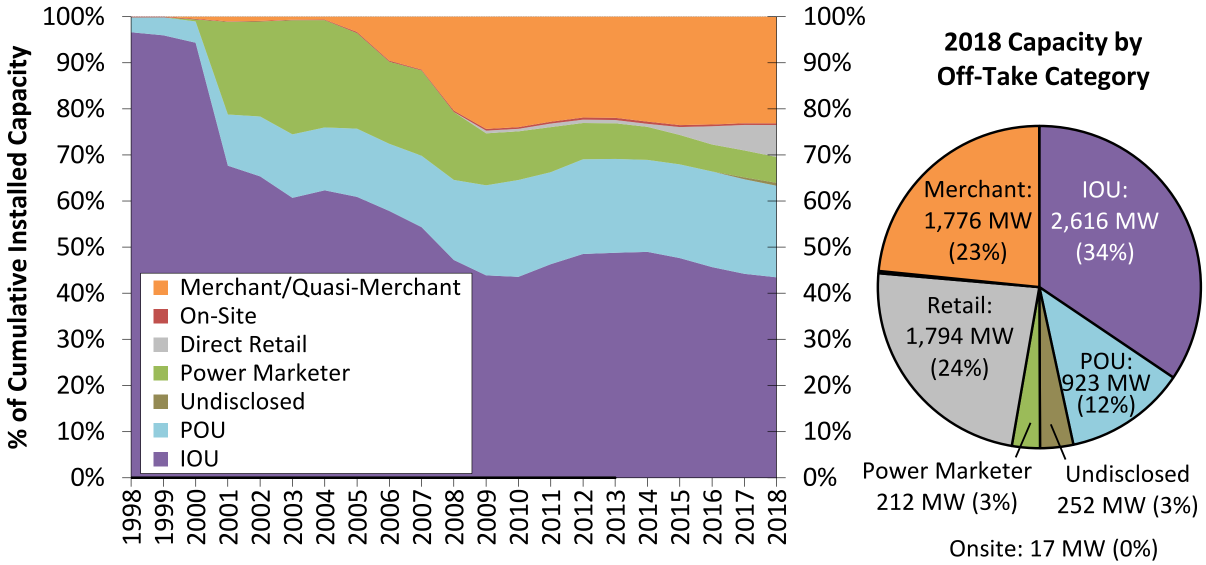
Source: Berkeley Lab estimates based on AWEA WindIQ

Figure 18. Cumulative and annual (2018) wind power capacity categorized by owner type

[29] 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 (2019a), 65 MW (2%) of 2018 wind capacity additions qualified as community wind projects.

Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales and merchant off-take arrangements were both significant

Electric utilities continued to be the largest off-takers of wind power in 2018 (i.e., 'users' of wind to serve load) (Figure 19, right pie chart), either owning wind projects (20%) or buying the electricity from wind projects (27%) that, in total, represent 47% of the new capacity installed last year (with the 47% split between 34% IOU and 12% POU). On a cumulative basis, utilities own (15%) or buy (48%) power from 63% of all wind power capacity installed in the United States (with the 63% split between 43% IOU and 20% POU, with the POU category including community choice aggregators (CCAs)).



Source: Berkeley Lab estimates based on AWEA WindIQ

Figure 19. Cumulative and annual (2018) wind power capacity categorized by power off-take arrangement

Merchant/quasi-merchant projects accounted for 23% of all new 2018 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[30]) rather than being locked in through a long-term PPA. Most of these projects are located within ERCOT in Texas, though there are some merchant/quasi-merchant projects within other markets, including PJM, MISO, SPP, and NYISO.

Direct retail purchasers of wind power, including a diverse and growing set of corporate and non-corporate off-takers, are supporting 1,794 MW or 24% of the new wind power capacity installed in the United States in 2018 (up from 10% of new capacity installed in 2015, but the same share as in both 2016 and 2017). Direct retail sales should continue to represent a sizable market in coming years, based on AWEA (2019a) estimates that 49% of all wind PPAs that were *executed* in 2018 were with non-utility purchasers (compared to 40% in 2017, 39% in 2016, 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 3% of 2018 and 6% of cumulative wind power capacity in the United States sells to power marketers, down from more than 20%

[30] 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.

(cumulative) 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.[31]

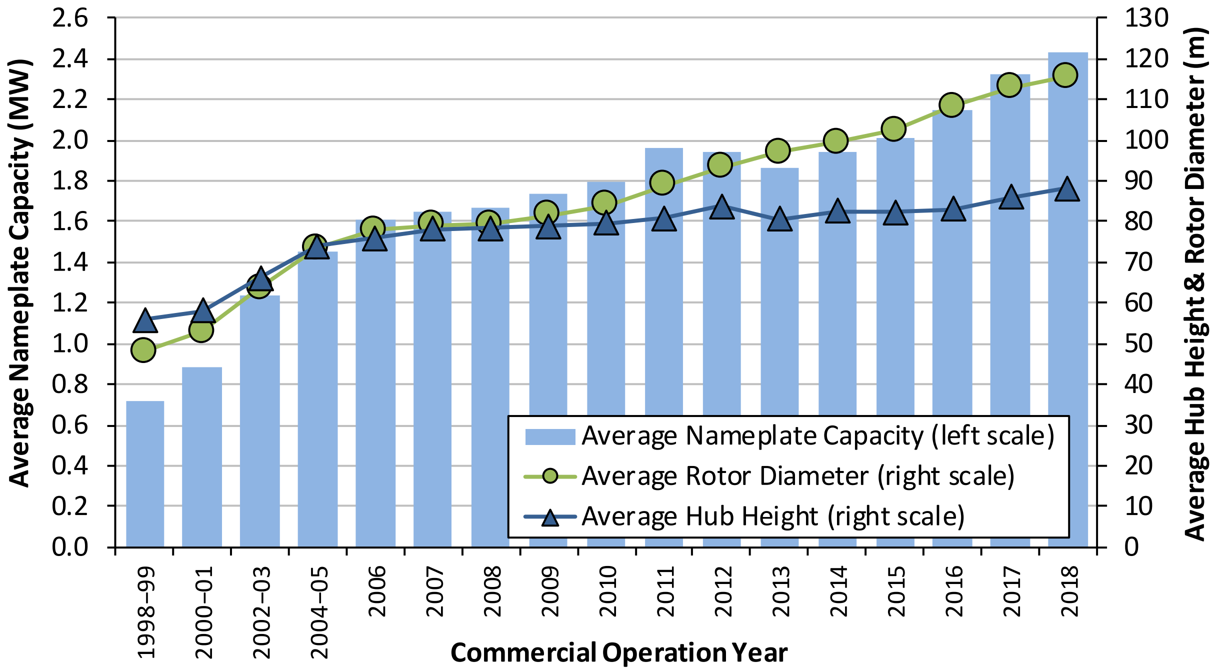
Finally, just 17 MW of the wind power additions in 2018 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.[32]

[31] These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.
[32] For more information on distributed wind, see the U.S. Department of Energy's 2018 Distributed Wind Market Report: https://energy.gov/eere/wind/downloads/2018-distributed-wind-market-report

4 Technology Trends

Average turbine capacity, rotor diameter, and hub height increased in 2018, continuing the long-term trend

The average nameplate capacity of the newly installed wind turbines in the United States in 2018 was 2.43 MW, up by 239% since 1998–1999 and by 5% over 2017 (Figure 20).[33] The average hub height of turbines installed in 2018 was 88.1 meters, up 57% since 1998–1999 and 2.4% over the previous year. Average rotor diameters have increased at a more rapid pace than hub heights over the long term. The average rotor diameter of wind turbines installed in 2018 was 115.6 meters, up 141% since 1998–1999, and 2.3% over the previous year; this translates to a 479% growth in rotor swept area relative to 1998–1999. Trends in hub height and rotor scaling are two of several factors impacting the project-level capacity factors highlighted later in this report.



Sources: AWEA WindIQ, USWTDB

Figure 20. Average turbine nameplate capacity, rotor diameter, and hub height for land-based wind projects[34]

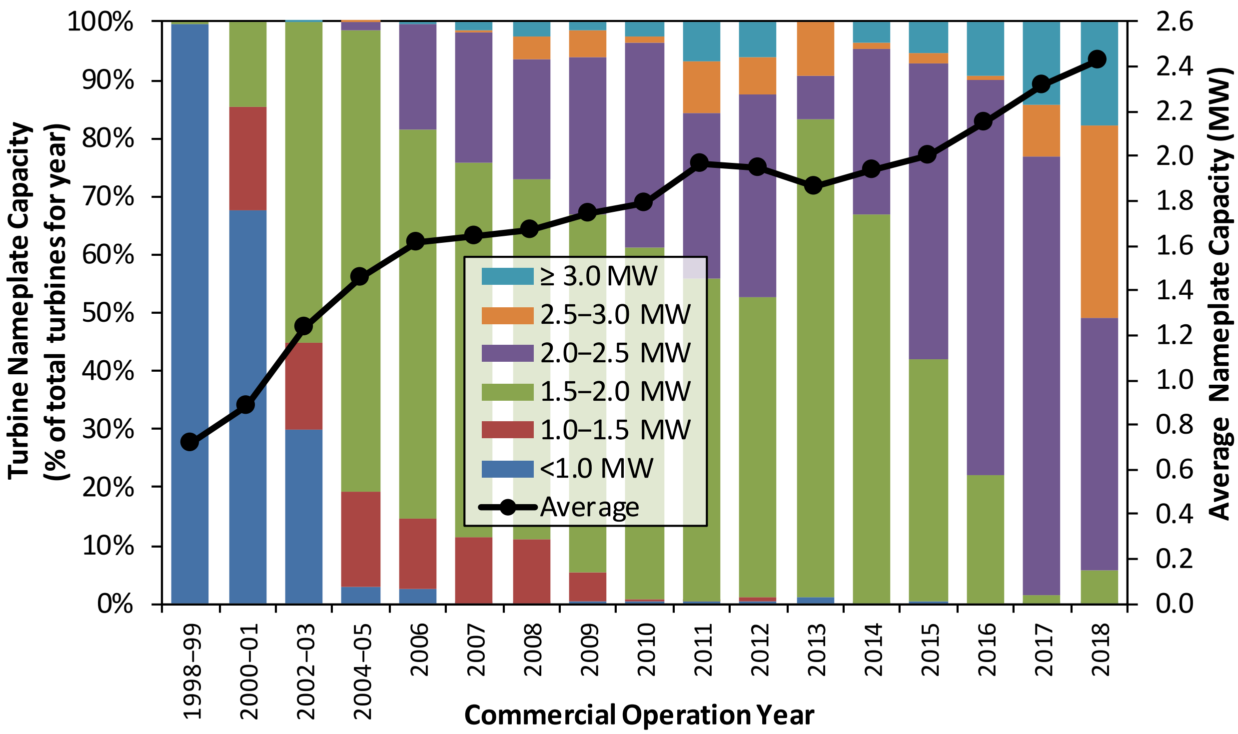
Growth in average rotor diameter and turbine nameplate capacity have outpaced growth in average hub height over the last two decades

As indicated in Figure 20, and as detailed in Figure 21 through Figure 23, increases in nameplate capacity and rotor diameter have outpaced growth in average hub height over the last two decades. That said, there is evidence over the last two years of some increased emphasis on hub height scaling.

[33] Figure 20, as well as a number of the other figures and tables included in this report, combines data into both one and two-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.

[34] The data and trends reported in this Chapter as well as in Chapters 5, 6 and 7 are focused on land-based wind installations. The single, 30 MW offshore wind project in the U.S. is not captured in these chapters.

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 from 2011 through 2015, but has since grown. 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 2018, 2.0–2.5 MW turbines were the largest share (43% market share), but the shares of 2.5–3 MW and 3+ MW turbines grew significantly (to 33% and 18% in 2018, respectively, versus 9% and 14% in 2017).

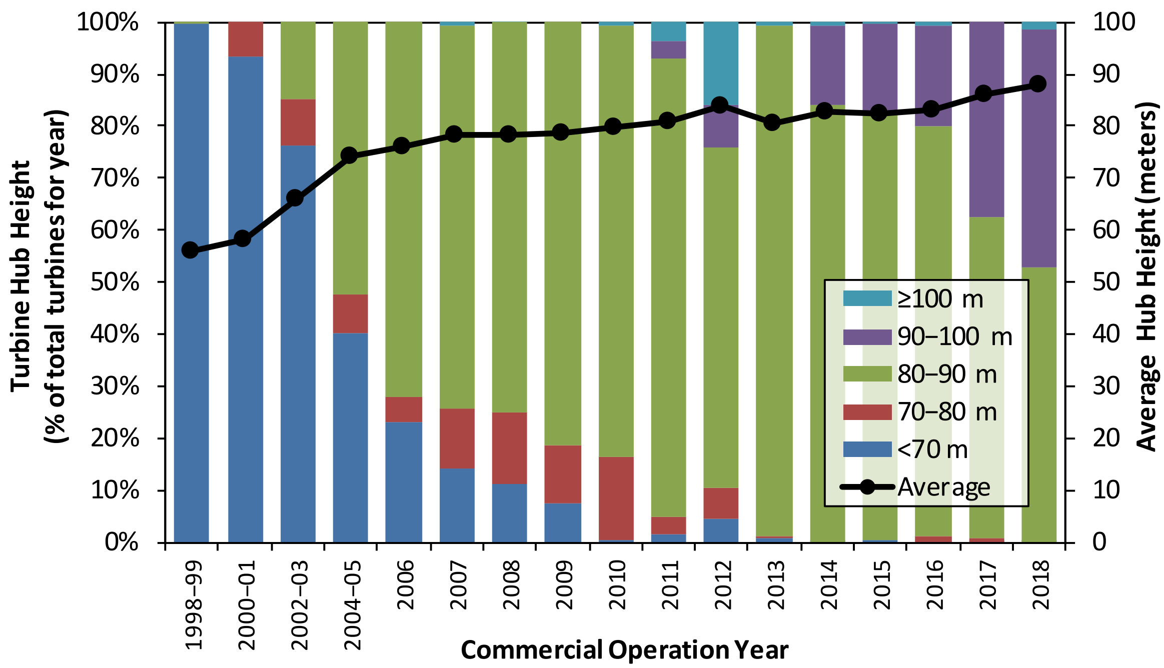


Sources: AWEA WindIQ, USWTDB

Figure 21. Trends in turbine nameplate capacity

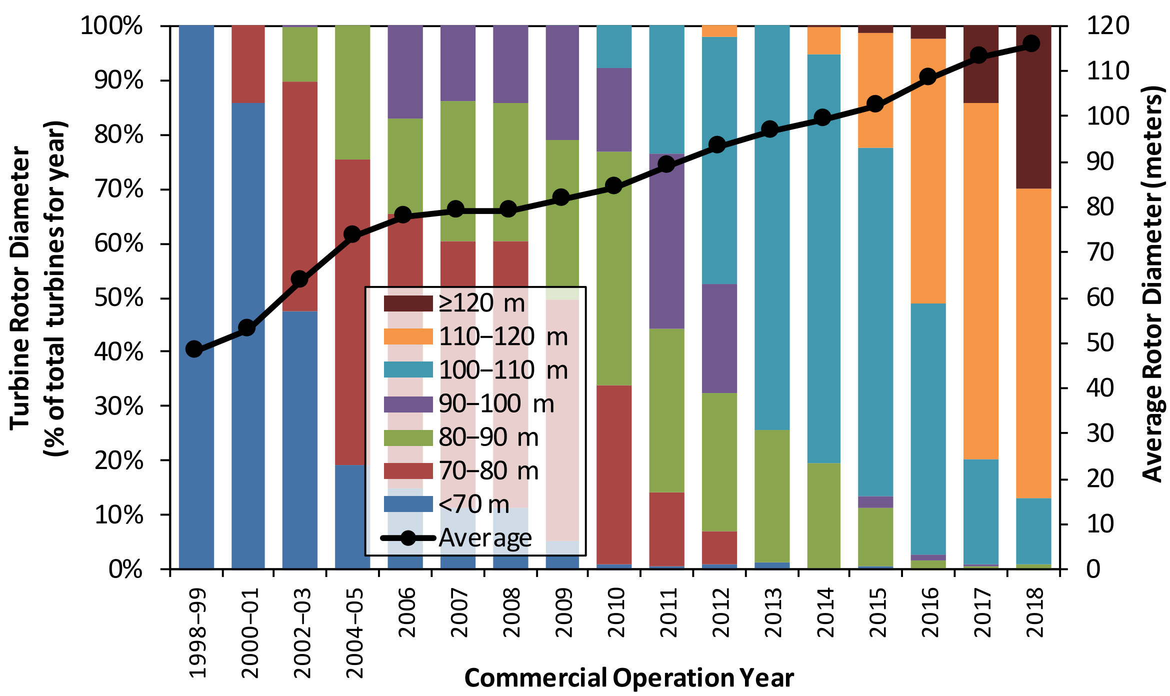
The average hub height of wind turbines had held roughly constant from 2011 through 2016, but saw increases in 2017 and 2018 (Figure 22). 80-meter towers have dominated the market since 2006. However, 90+ meter towers started to penetrate the market in 2011, and in 2018 had a 47% market share. Although we saw the emergence of towers taller than 100 meters as early as 2007, that segment peaked (at least temporarily) in 2012 when 16% of newly installed turbines were taller than 100 meters. From 2012 through 2017, only 1% or less of newly installed turbines in each year featured towers that tall, but 2018 saw a slight increase to 2%. 90-100 meter towers, though, have seen nearly continuous market share gains since their first appearance in 2011. In 2018, 45% of the market used 90–100 meter towers, up from 37% in 2017. The locations and wind resource conditions of these and other tall-tower installations are shown in more detail in Figure 28 and Figure 29.

The movement toward 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 growth in 2018. In 2009, no turbines employed rotors that were 100 meters in diameter or larger, while in 2018 99% of newly installed turbines featured such rotors. Rotor diameters of 110 meters or larger started penetrating the market in 2012; in 2018, they had an 87% market share. Turbines with rotor diameters over 120 meters continued their recent growth, reaching 30% market share in 2018.



Sources: AWEA WindIQ, USWTDB

Figure 22: Trends in turbine hub height



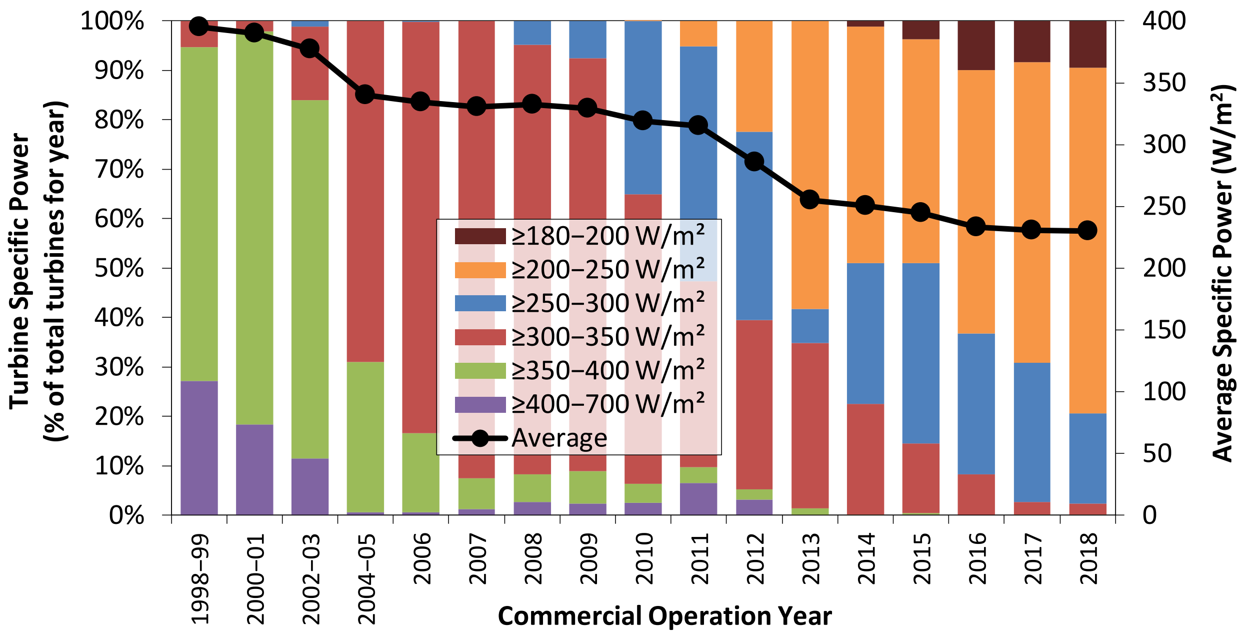
Sources: AWEA WindIQ, USWTDB

Figure 23: Trends in rotor diameter

Turbines originally designed for lower wind speed sites dominate the market, and are being deployed in a range of wind resource conditions

The growth in the average swept area (in m^2) of rotors has been especially rapid over the last two decades, outpacing growth in average nameplate capacity (in W). This has resulted in a decline in the average "specific power" (in W/m^2) among the U.S. turbine fleet over time, from 395 W/m^2 among projects installed in 1998–1999 to 230 W/m^2 among projects installed in 2018 (Figure 24). The trend toward lower specific power machines slowed in 2018, however, due in part to increased use of IEC Class 2/3 over Class 3 turbines.

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, intended to maximize energy capture in areas 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 relatively high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.

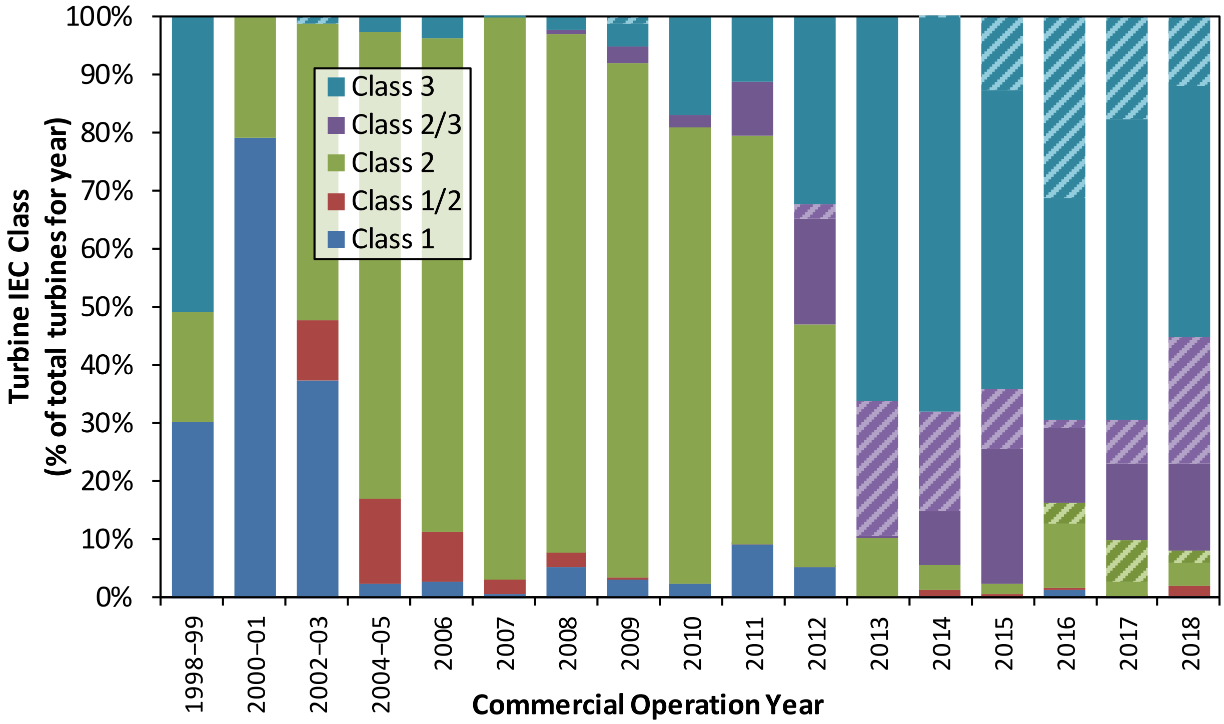


Sources: AWEA WindIQ, USWTDB

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 recent years have been 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 Figure 25).[35]

The U.S. wind market has recently been dominated by IEC Class 3 turbines, though 2018 witnessed a modest reemergence of Class 2/3 turbines. Since 2013, Class 1, 1/2 and 2 turbines have made up less than 20% of the market and, in 2018, these three classes summed to only 8% of new installations.



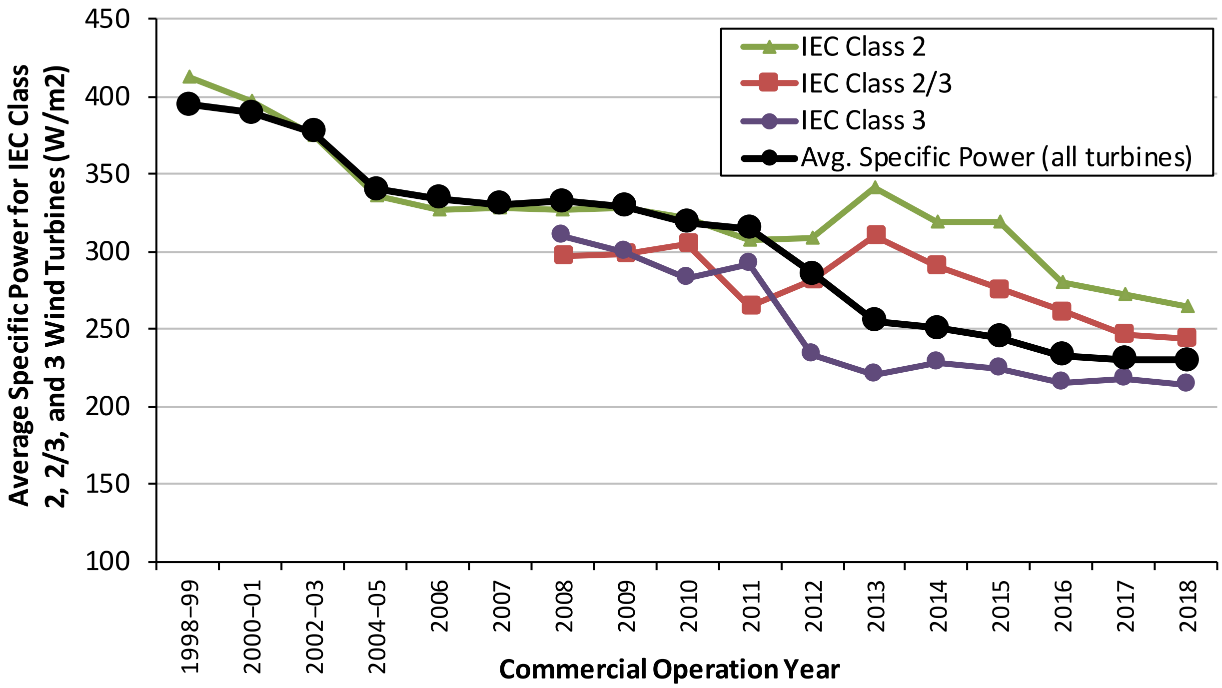
Note: Class S-2, S-2-3, and S-3 turbines are shown with hash marks in their respective bins

Sources: AWEA WindIQ, Berkeley Lab

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 specific power 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. In 2018, all three classes saw modest but multi-point decreases in specific power from 2017 levels (Class 3: 217 to 213 W/m^2; Class 2/3: 247 to 244 W/m^2; and Class 2: 273 to 264 W/m^2), though fleet-wide the decrease was just one point, 231 to 230 W/m^2. This difference is explained by the increase in penetration of Class 2/3 turbines in 2018 (see Figure 25), which have a higher average specific power than Class 3 machines.

[35] 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. Similarly, it rates its 2.0-116 and 2.3-116 models as Class S-3. Others include GE 1.85-87 and GE 2.5-116 (S-2/3), and GE 2.4-107 (S-2). All of the "S" turbines are included in the reported IEC class using their closest class.



Notes: Specific power averages are shown only for years where there were at least 40 new turbines installed with the respective IEC Class. Class S turbines are included in the figure in their corresponding class.

Sources: AWEA WindIQ, USWTDB, Berkeley Lab

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

Wind turbines continued to be deployed in somewhat lower wind-speed sites

Figure 27 shows the long-term average wind resource for wind turbine installations by year. The figure depicts both the long-term site-average wind speed (in meters per second) at 80 meters for turbines installed that year (right scale) and an index of wind resource quality also at 80 meters (left scale).[36]

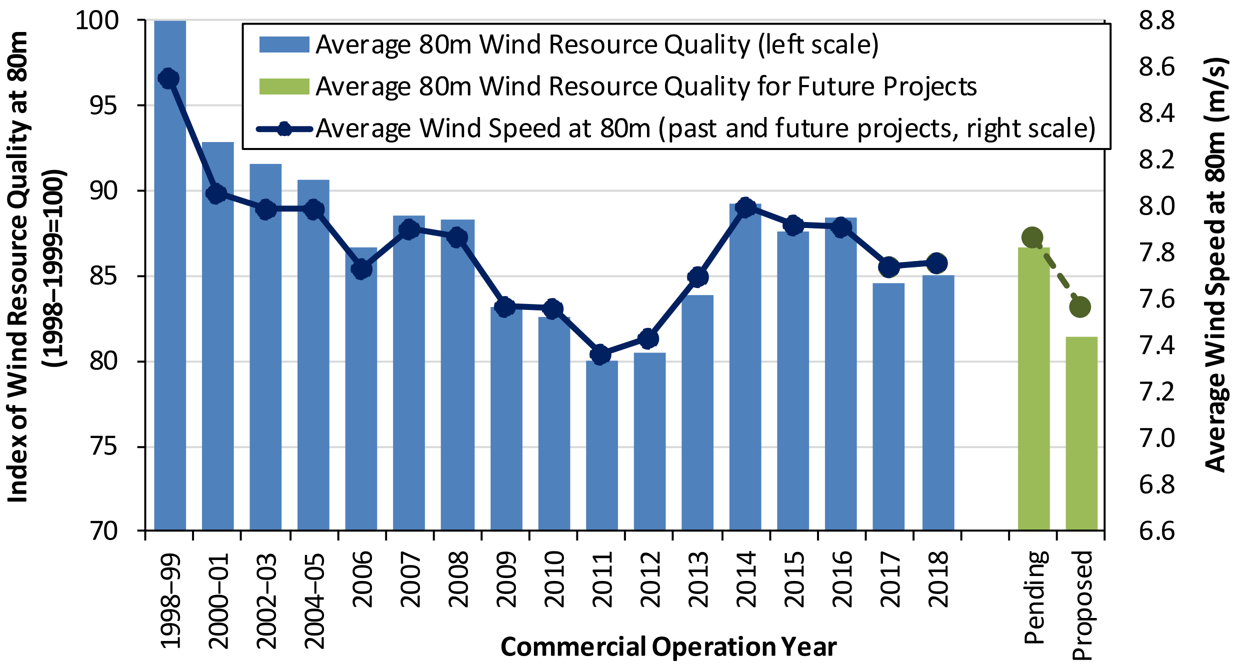
Wind turbines installed in 2018 are located—on average—in sites with an estimated long-term average 80-meter wind speed of 7.8 meters per second (m/s). This represents a slightly higher average wind speed than the previous year, but lower than for those turbines installed from 2014 to 2016. Federal Aviation Administration (FAA) data on not-yet-built "pending" and "proposed" turbines suggest that projects installed in the near future will likely have average wind speeds similar to those of recently installed projects.[37] Trends in the wind resource quality index—which represents estimates of the gross capacity factor for each turbine location, indexed to the 1998–1999 installations—are similar. They show a general decline in resource quality for turbines installed through 2011, an increase from 2012 to 2014, and then a decline since then.

Several factors could have driven these observed trends in average site quality. 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 over time. Second, transmission constraints (or other siting

[36] The wind resource quality index is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. A single, common wind-turbine power curve is used across all sites and timeframes, and no losses are assumed. We index the values to those projects built in 1998–1999. Further details are found in the Appendix.

[37] "Pending" turbines are those that have received a "No Hazard" determination by the FAA and are not set to expire for another 18 months, while "proposed" turbines will also not expire in 18 months but have not yet received any determination. Pending and proposed turbines may not all ultimately be built. However, analysis of past data suggests that FAA pending and proposed turbines offer a reasonable proxy for turbines built in subsequent years.

constraints, or even just regionally differentiated wholesale electricity prices) may have, over time, increasingly focused developer attention on those projects in their pipeline that have access to transmission (or higher-priced markets, or readily available sites without long permitting times) even if located in somewhat lower wind resource sites. The build-out of new transmission (the completion of major transmission additions in West Texas in 2013, for example), however, may at times have offered the chance to install new projects in more energetic sites. Other forms of federal and/or state policy could also play a role. For example, wind projects built in the four-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC. Many projects availed themselves of this opportunity and, because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that developers also seized this limited opportunity to build out the less-energetic sites in their development pipelines. Finally, state policies sometimes motivate in-state or in-region wind development in lower wind resource regimes. As RPS policies have become a less-dominant driver of incremental wind additions in recent years (Barbose 2018), however, economic forces have focused new capacity additions in the Interior region of the country.



Sources: AWEA WindIQ, USWTDB, AWS Truepower, Berkeley Lab

Figure 27. Wind resource quality by year of installation at 80 meters

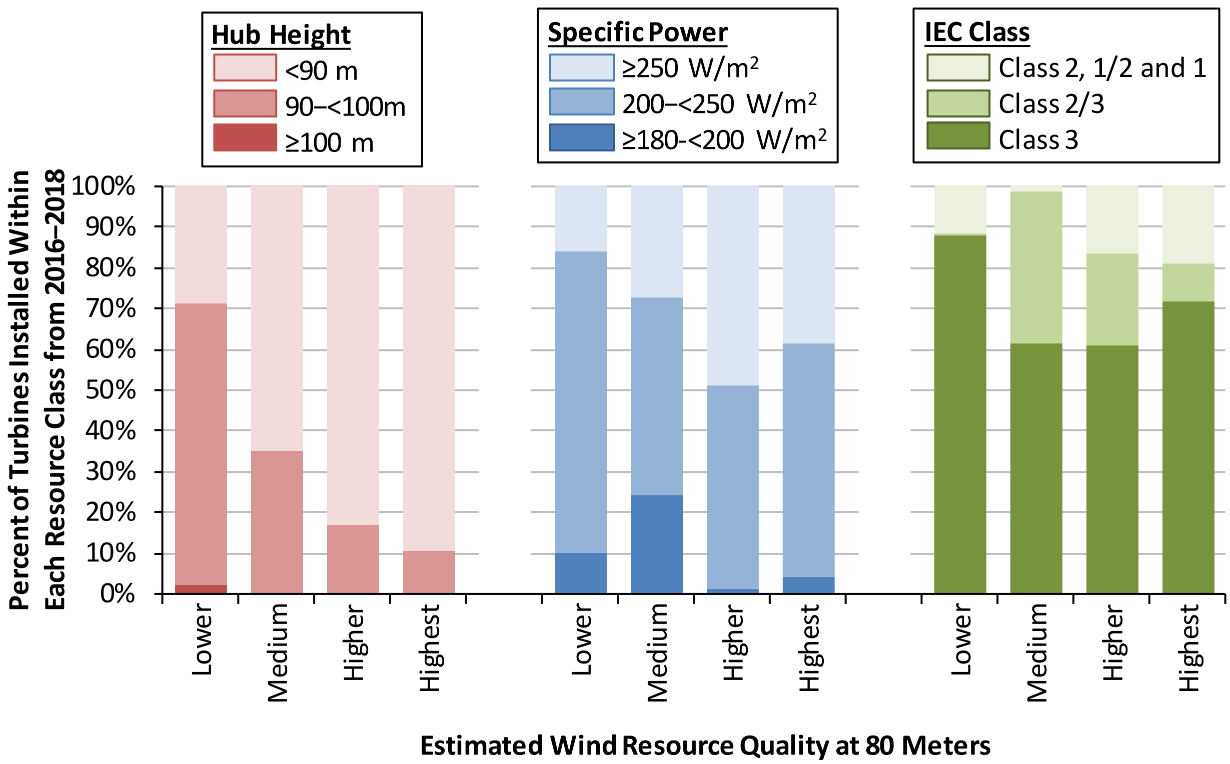
Low specific power turbines continue to be deployed in both lower and higher wind speed sites; taller towers are more commonly found in the Great Lakes and Northeast

One might expect that the increasing market share of turbines designed for lower wind speeds would be due to a movement by developers to deploy turbines in lower wind speed sites. There is some evidence of this movement historically (see Figure 27), but it is clear in Figure 28 and Figure 30 that turbines originally designed for lower wind speeds have been deployed in all regions of the United States, in both lower and higher wind speed sites.

Figure 28 presents the percentage of turbines installed in four wind resource quality groups 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 2016–2018 time period.

Taller towers (i.e., 90 meters and above) saw higher market share during the 2016–2018 period in sites with lower wind speeds. This is likely largely due to the fact that such towers are most economical when deployed at sites with higher-than-average wind shear (i.e., greater increases in wind speed with height); such sites are prevalent in the Great Lakes and Northeast as shown in Figure 29. That notwithstanding, all regions are seeing increasing tall tower usage.

Lower specific power machines (i.e., under 250 W/m^2) installed over this three-year period have been regularly deployed in all resource regimes including at sites with very high wind speeds, though there is some drop-off in the deployment of lower specific power turbines as wind speed increases. Figure 30 shows the prevalence for these low specific power machines in all regions of the country though with higher incidence in the Great Lakes and Interior regions. Turning to IEC Class, we see a somewhat similar story. Specifically, Class 3 and Class 2/3 machines are well-distributed across all wind regimes.

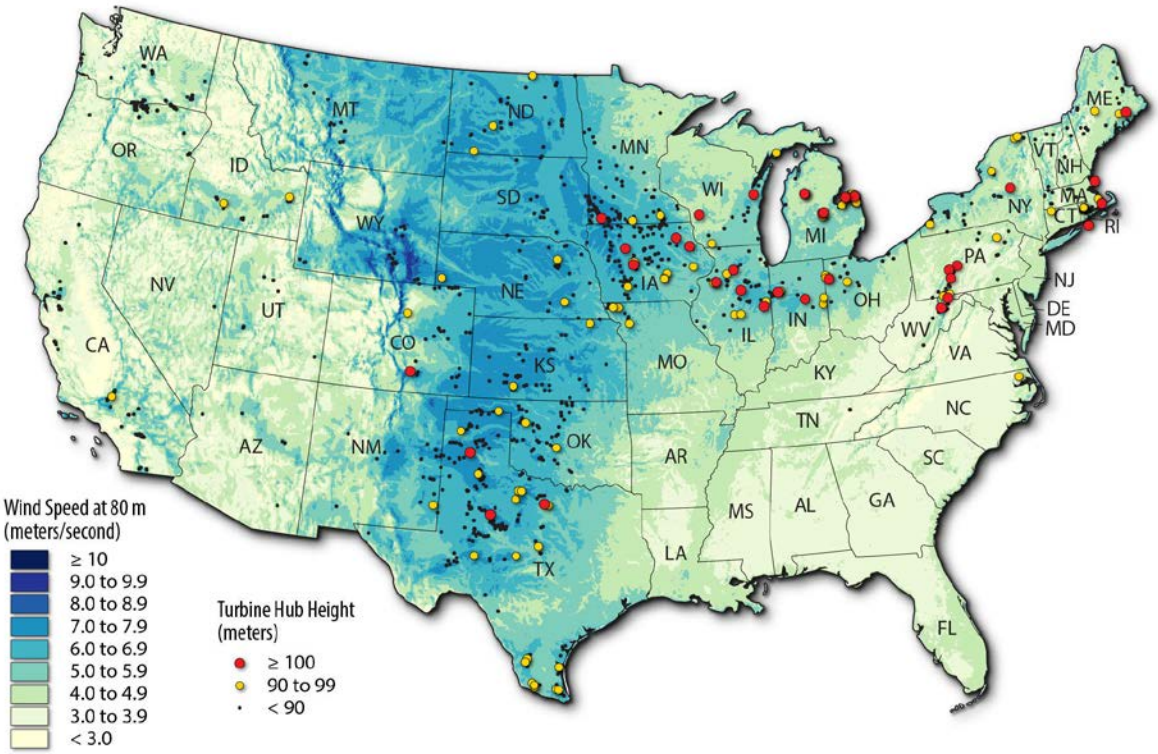


Note: See the Appendix for details on how wind resource quality at each individual project site is estimated.

Sources: AWEA WindIQ, USWTDB, AWS Truepower, Berkeley Lab

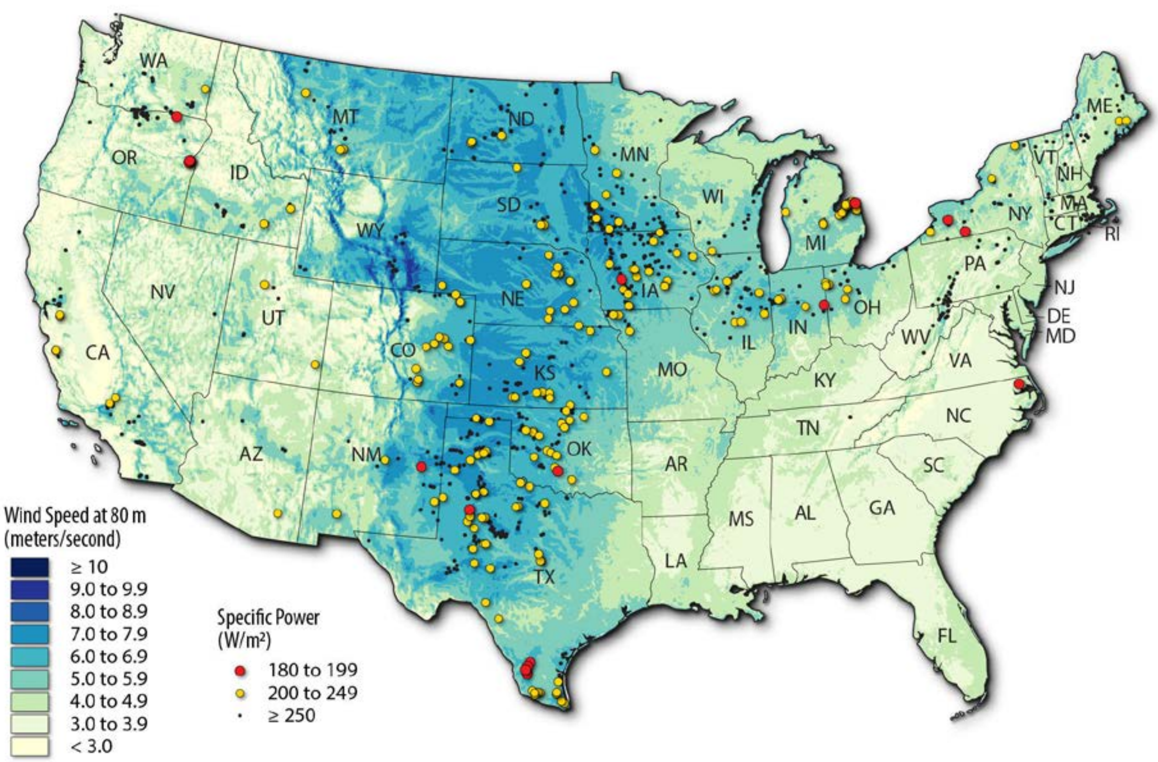
Figure 28. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality

The specific locations of tall tower and low specific power installations, as shown in Figure 29 and Figure 30, rarely overlap. In fact, no U.S. wind projects yet feature both very tall towers (>100m) and very low specific power (<200 W/m^2), and only 27% of installations with either very tall towers or very low specific power have, respective, "relatively" low specific power (200 to 250 W/m^2) or "relatively" tall towers (90 to 100 m). It therefore appears that—thus far—wind developers have tended to trade-off between the two options. It may be that tall towers and low specific power turbines are viewed as, in part, substitutes for increased capacity factors, with diminishing returns in pursuing both simultaneously. Additionally, there may be concerns about the loading on longer blades that occur at the higher wind speeds common with taller towers, or a general desire to stay under the FAA 500 foot 'soft cap' highlighted later. Finally, transportation limitations may, in some cases, preclude the longer blades that might otherwise be used in these installations.



Sources: AWEA WindIQ, USWTDB, AWS Truepower, National Renewable Energy Laboratory (NREL)

Figure 29: U.S. map of cumulative tall tower installations



Sources: AWEA WindIQ, USWTDB, AWS Truepower, National Renewable Energy Laboratory (NREL)

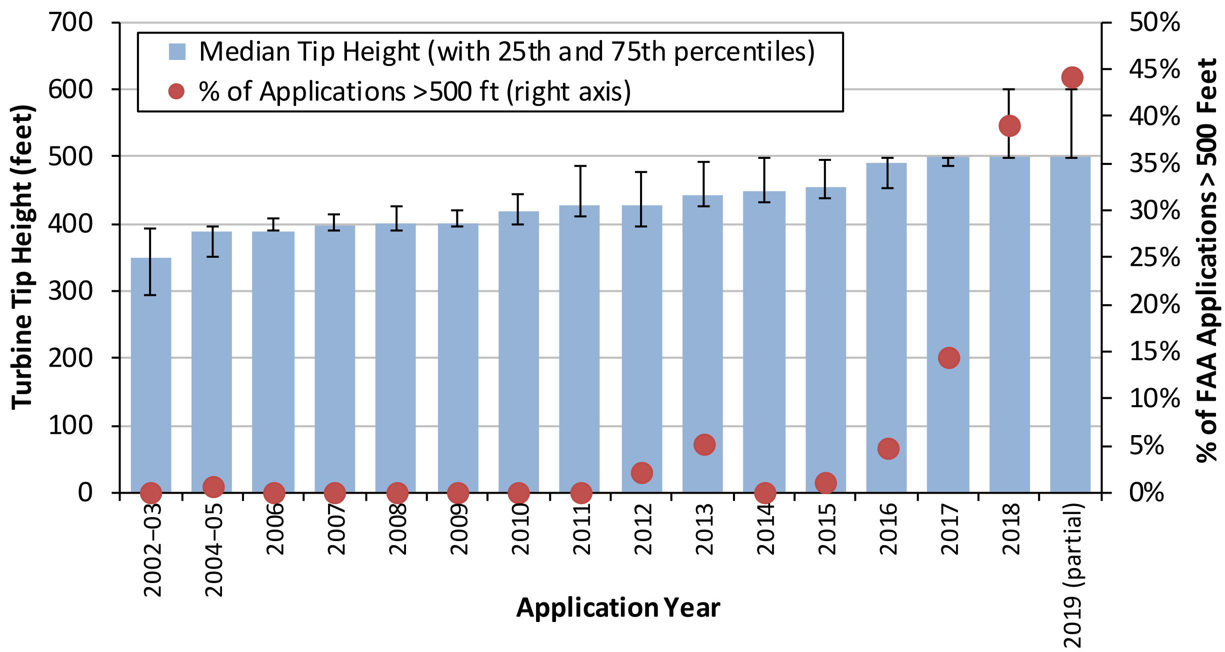
Figure 30: U.S. map of cumulative low specific power installations

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. Taller towers, meanwhile, are increasingly being deployed across a wider diversity of sites, though still with a tendency toward lower wind-speed areas in the Great Lakes and Northeast regions. Thus far, wind developers have not tended to deploy lower specific power and tall tower machines simultaneously.

Wind projects planned for the near future continue the trend of ever-taller turbines

FAA data on total proposed turbine heights (from ground to blade tip extended directly overhead) in permit applications are reported in Figure 31. The median tip height is shown, along with the 25th and 75th percentiles and the percentage of applications involving turbines over 500 feet (approximately 152 meters) at tip height.

From 2002 through 2016, less than 5% of permit applications included turbines with a total height over 500 feet, growing to 14% for applications in 2017, 39% in 2018, and 44% in 2019 (through late-May 2019). Similarly, although the medians approach 500 feet through 2019, the 75th percentile of 2018 and 2019 applications-to-date are 600 feet tall (183 meters). Note that these data represent total turbine height, not hub height, and therefore include the combined effect of both tower and rotor size. Additionally, turbine heights reported in FAA permit applications can differ from what is ultimately installed.[38]



Source: Federal Aviation Administration

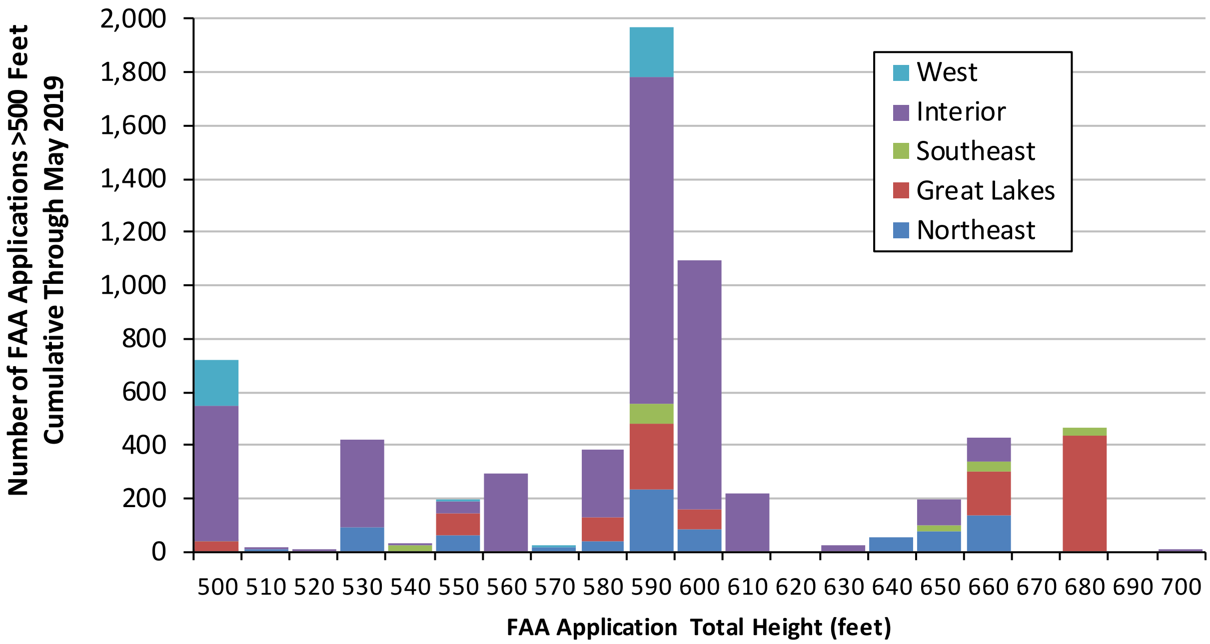
Figure 31. Total turbine heights proposed in FAA applications, over time

The move toward turbines with total heights of over 500 feet is significant. There is anecdotal evidence that developers may have historically perceived a “soft cap” at 500 feet. Although the FAA may require a public comment period for any turbine proposed for higher than 499 feet, perhaps causing some developers to want to stay under that tip height, there are otherwise no height limitations imposed by the FAA.[39] The recent growth

[38] Historically, the FAA permit datasets have strongly conformed to subsequent actual installations on average, providing some confidence that the projected trends shown in the FAA permit data will come to pass.
[39] See Title14, Chapter I, Subchapter E, Part 77 of the Code of Federal Regulations, as well as “frequently asked question” #27 at https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=showWindTurbineFAQs

in applications with turbines above 500 feet suggests that developers anticipate continued scaling in hub heights and rotor diameters, breaking through this earlier perceived "soft cap."

As shown in Figure 32, the height of the greater than 500 feet turbines is not distributed normally, and nor are those turbines distributed evenly across regions. The majority of the proposed tall turbines fall between 590 and 610 feet (~183 meters), but other accumulations exist at 500 feet (~152 meters), 660 feet (~201 meters), and 680 feet (~207 meters). These figures compare to an average total height for turbines installed in 2018 of 479 feet (146 meters). Most of the proposed tall turbines are intended for the Interior region, where the majority of all wind project installations reside. The tallest of these proposed tall turbines, however, would be located in the Great Lakes region, consistent with past tall-tower data reported earlier in Figure 29.



Note: Categories include turbines up to and including the height shown (e.g., 530 are turbines >520 and <=530 feet).

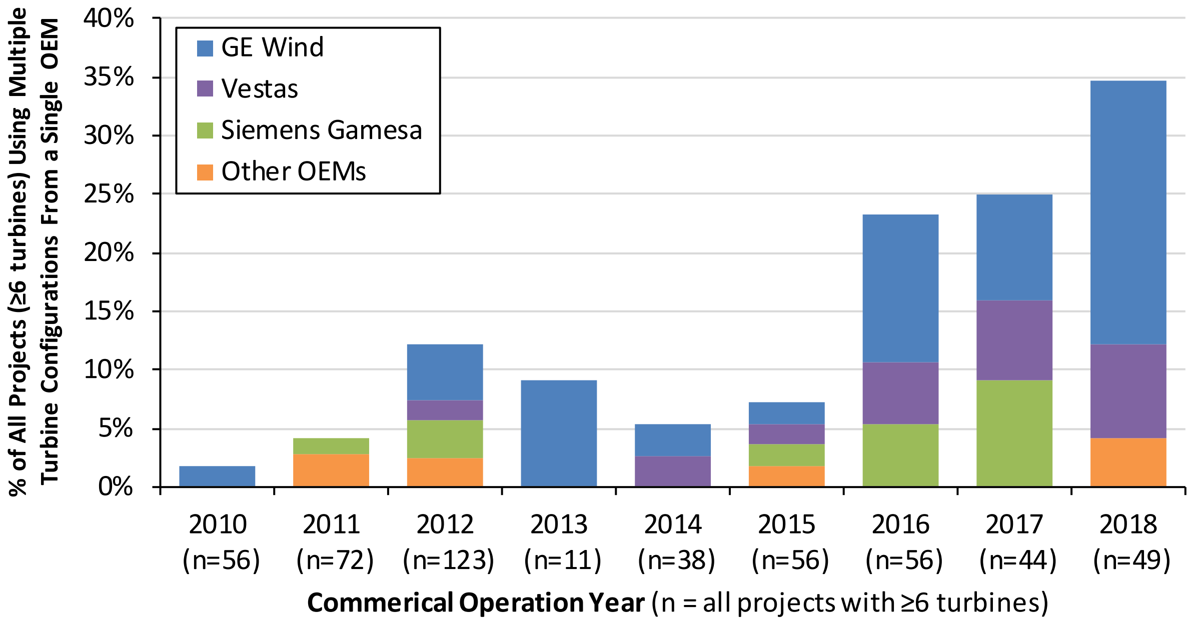
Source: Federal Aviation Administration

Figure 32. Histogram of cumulative FAA applications through May 2019 greater than 500 feet

The number of wind power projects that employed multiple turbine configurations from a single turbine supplier continued to increase

Among those wind projects built in 2018 that contained at least six turbines, 35% used multiple turbines with different hub heights, rotor diameters and/or capacities—all supplied by the same OEM—continuing a trend started in 2016. As shown in Figure 33, this relatively high degree of intra-OEM turbine specialization within individual projects had not previously been prevalent in the U.S. market before 2016, with 2012 being the next highest year at 13%. Most of these turbines, in the 2016–2018 period, differed by all three of the major characteristics: hub height, rotor diameter, and capacity rating.

While there are multiple possible explanations for this recent trend, the most likely involves how developers commonly qualify projects for the PTC—e.g., by ordering a modest subset of the required number of turbines prior to the applicable construction-start deadline (in order to incur at least 5% of total project costs, per IRS guidance), and then months later ordering the balance of required turbines, which by then might feature different characteristics. Related, some of this trend may simply reflect unused, leftover turbines from earlier procurements being deployed in current projects. A final possibility is that there could be increasing sophistication with respect to intra-project turbine siting and wake effects optimization, coupled with an increasing willingness among OEMs to provide multiple turbine configurations.



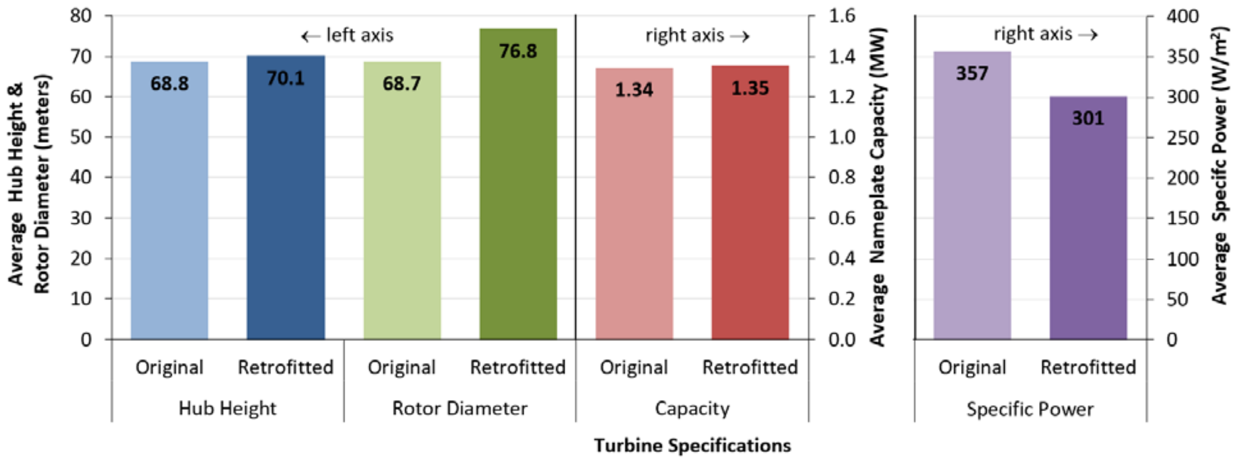
Sources: AWEA WindIQ, USWTDB

Figure 33. Percent of larger projects employing multiple turbine configurations from a single OEM

Through 2018, twenty-three wind projects have been partially repowered, most of which now feature significantly larger rotors and lower specific power ratings

The trend of partial wind project repowering that largely began in 2017 continued through 2018, and involved replacing major components of turbines to increase energy production with more-advanced turbine technology, extend project life, and access favorable tax incentives. In 2017 and 2018, 23 projects were partially repowered (13 in 2017; 10 in 2018), encompassing 2,425 turbines (1,319 in 2017; 1,106 in 2018) and totaling 3,445 MW (before the partial repowering; 2,133 MW in 2017; 1,312 MW in 2018). Most of the 2017 retrofitted turbines were GE (85%), with the GE share dropping to 47% in 2018. The remainder were SGRE turbines (15% in 2017; 48% in 2018) and, in 2018, Vestas (2%) and Bonus (4%). Retrofitting occurred in Texas and Iowa in 2017, and expanded to five states in 2018: Iowa, North Dakota, New Mexico, Oklahoma, and Texas. Retrofitted projects ranged in age from 8 to 17 years old; the median age was 12 years.

Installing longer blades has been common among these retrofits: 100% of the 2017 turbines and 48% of 2018 turbines involved longer blades, with a mean increase in rotor diameter of 8.1 meters over the two years, as shown in Figure 34. A much smaller number of retrofits included changes to hub height (0% in 2017; 12% in 2018) or nameplate capacity (8% in 2017; 9% in 2018), resulting in an average increase in hub height of just 1.3 meters and in nameplate capacity of just 0.01 MW. With the relatively small change in capacity but the larger change in rotor diameter, these retrofits drove a 16% decrease in average specific power, from 357 W/m2 to 301 W/m^2. Interestingly, in 2018, 423 retrofitted turbines (38%) totaling 320 MW of capacity (24%) saw no change to hub height, rotor diameter, or nameplate capacity. Also unique in 2018, 529 turbines saw a change in manufacturer: 167 Bonus and 362 Vestas turbines were re-labeled SGRE turbines, after the retrofit.



Sources: AWEA WindIQ, USWTDB

Figure 34. Change in average physical specifications of turbines that were partially repowered in 2017 and 2018

Finally, in 2018, portions of two projects (38 turbines totaling 67.8 MW in Texas) were decommissioned and replaced with new towers, blades, and nacelles—'full' repowering as opposed to 'partial.' This full repowering is expected to accelerate in the coming years, as turbines installed in the late 1990s and early 2000s age.

5 Performance Trends

Following the previous discussion of technology trends, this chapter presents data from a compilation of project-level capacity factors.[40] The full data sample consists of 965 wind projects built between 1998 and 2017 totaling 86,217 MW (97% of nationwide installed wind capacity at the end of 2017).[41] Excluded from this assessment are older projects installed prior to 1998. In addition, fourteen projects totaling more than 1.4 GW that were either partially or fully repowered in 2018 are excluded from the 2018 capacity factor sample, given that they were at least partly offline during a portion of the year.

The chapter is divided into six subsections: the first presents raw capacity factor data, both by project age and fleet-wide; the second explores variations in capacity factor by region and state; the third focuses on the influence of turbine design and site characteristics; the fourth discusses the impact of wind power curtailment; the fifth examines temporal variations in the wind resource; and the sixth analyzes the possibility of performance degradation over time. A Text Box highlights performance enhancements from projects that were partially repowered in 2017. Unless otherwise noted, all capacity factors in this chapter are reported on an as-observed and unadjusted basis (i.e., after any losses from curtailment, less-than-full availability, wake effects, ice or soil on blades, etc.). In two cases—when looking for performance degradation over time, and when exploring the impact of repowering—we make adjustments for inter-annual variability in the wind resource.

The average capacity factor in 2018 exceeded 40% among wind projects built in recent years, and reached 35% on a fleet-wide basis

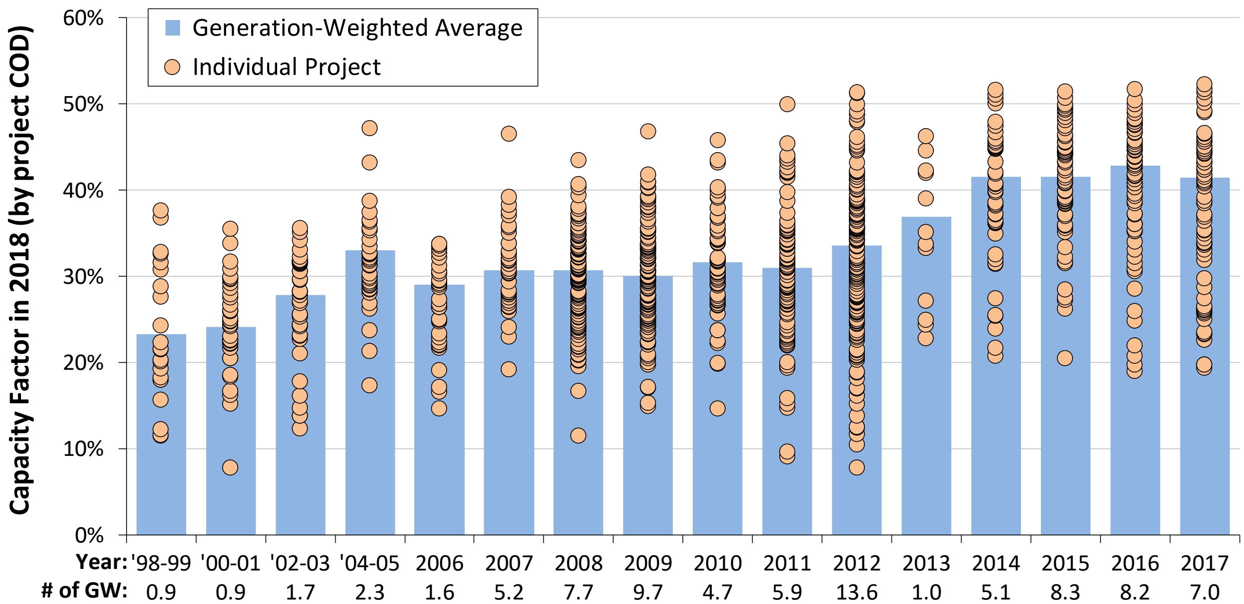
Figure 35 shows both individual project and average capacity factors in 2018, broken out by commercial operation date.[42] Projects built in 2018 are excluded, as full-year performance data are not yet available for those projects. From left to right, Figure 35 shows an increase in weighted-average 2018 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 2018. This pattern of stagnation is broken by projects installed in 2012–2013, and even more so by those that achieved commercial operations in 2014–2017.[43] The average 2018 capacity factor among projects built from 2014 to 2017 was 41.9%, compared to an average of 30.8% among all projects built from 2004 to 2011, and 23.8% among all projects built from 1998 to 2001. This apparent improvement in capacity factor among more-recently built projects is impacted by several factors that are explored later, including project location and the quality of the wind resource at each site, turbine scaling and design, and performance degradation over time.

[40] Capacity factor is a measure of the actual energy generated by a project over a given timeframe (typically annually) relative to the maximum possible amount of energy that could have been generated over that same timeframe if the project had been operating at full capacity the entire time.

[41] Although some performance data for wind power projects installed in 2018 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 2017, often focusing on 2018 capacity factors for those projects.

[42] Focusing on capacity factors in a single year, 2018, controls (at least loosely) for time-varying influences such as the degree of wind power curtailment or inter-annual variability in the strength of the wind resource. But it also means that the *absolute* capacity factors shown in Figure 35 may not be representative over longer terms if 2018 was not a representative year in terms of curtailment or the strength of the wind resource (though as noted later, 2018 was a fairly average wind year overall).

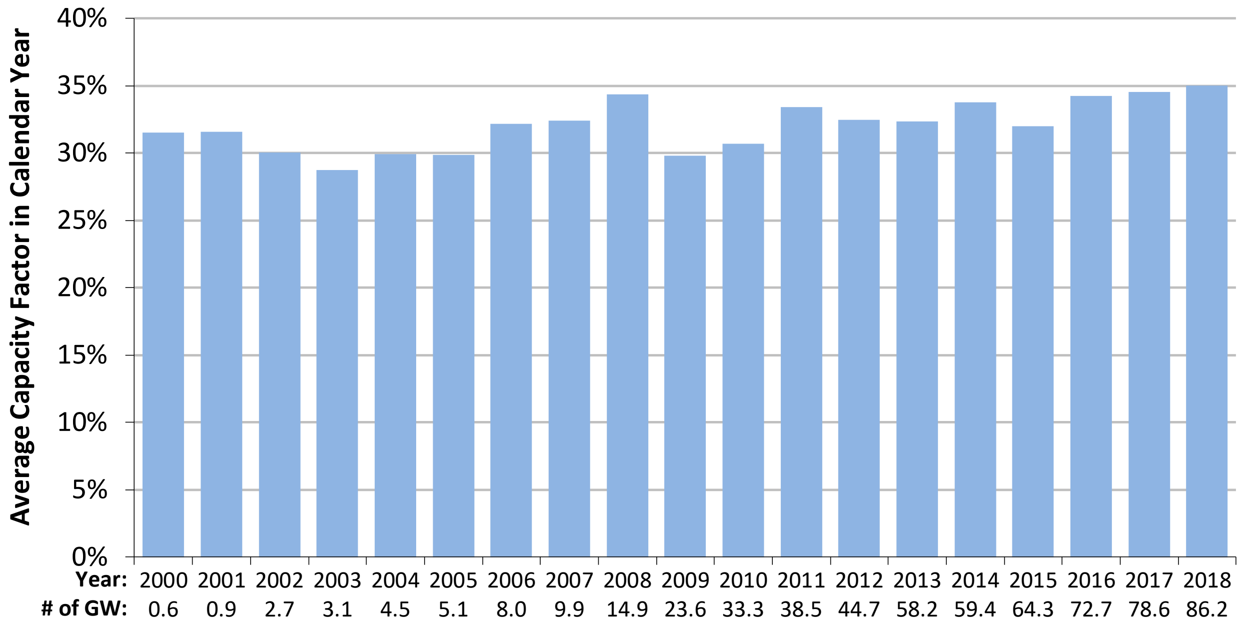
[43] The 2018 capacity factor of projects that were built in 2017 may be biased low, due to possible first-year “teething” issues, as projects may take a few months to achieve normal, steady-state production after first achieving commercial operations.



Source: Berkeley Lab

Figure 35. Calendar year 2018 capacity factors by commercial operation date

Figure 36 presents data on essentially the same sample of projects built from 1998–2017, but organized in a different way: the blue bars show the average sample-wide capacity factor in each calendar year among a progressively larger cumulative sample each year. Viewed this way, we would expect to see a gradual improvement in capacity factor over time, as the advancements in turbine design (e.g., reductions in specific power, increases in tower height) that have driven the dramatic trend seen above in Figure 35 take longer to infiltrate and influence the overall fleet. In general, the data appear to support this trend, with somewhat higher capacity factors in more recent years—reaching 35% for the first time in 2018. But there is also considerable year-to-year variability in the data, driven in part by two factors—wind energy curtailment and inter-year variability in the strength of the wind resource—that are discussed below.

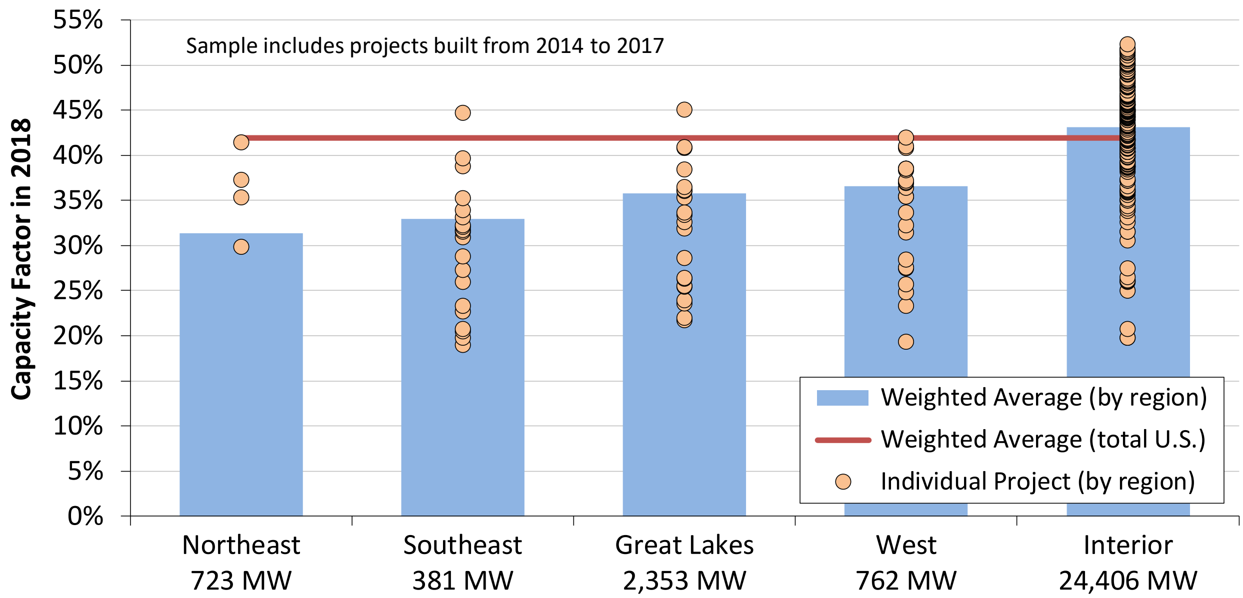


Source: Berkeley Lab

Figure 36. Average sample-wide capacity factors by calendar year

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 35 is enormous, with capacity factors in 2018 ranging from a minimum of 20% to a maximum of 52% among those projects built in 2017. (This spread is even wider for projects built in earlier years.) Some of the spread in project-level capacity factors—for projects built in 2017 and earlier—is attributable to regional variations in average wind resource quality. As such, Figure 37 shows the regional variation in capacity factors in 2018 (using the regional definitions shown in Figure 1, earlier) based on the sample of wind power projects built from 2014 through 2017—a 4-year period that Figure 35 shows to be relatively stable in terms of the nationwide average capacity factors.



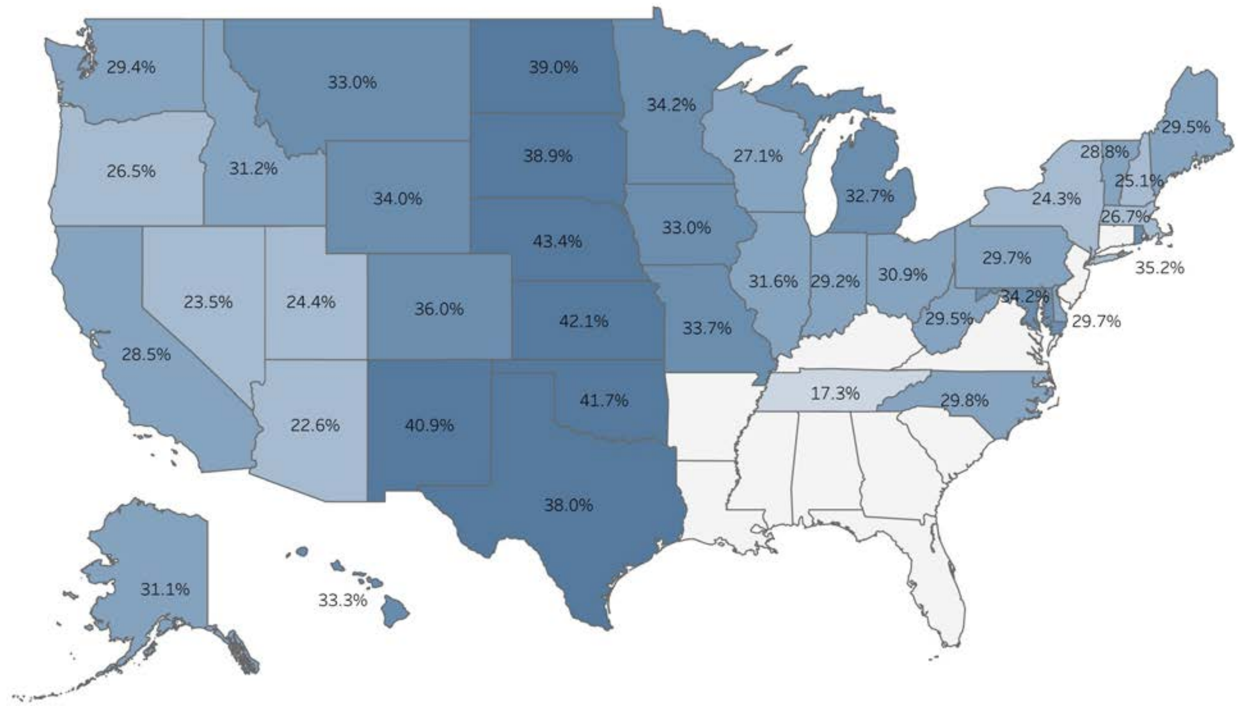
Source: Berkeley Lab

Figure 37. Calendar year 2018 capacity factors by region: 2014–2017 projects only

Four of the five regions have a rather limited sample, due to the fact that 85% of the total capacity installed from 2014 to 2017 was located in the Interior region. Nonetheless, generation-weighted average capacity factors appear to be highest in the Interior region (43.1%) and the lowest in the Northeast (31.3%), with the Southeast (33.0%), Great Lakes (35.8%), and West (36.6%) falling in between.[44] Even within these regions, however, there is still considerable spread.

Figure 38 includes data on the full sample of projects built from 1998 through 2017, but breaks things down further by showing average state-level capacity factors in 2018. The overall range runs from 17%–43%, with a notable amount of variation even among states within the same region.

[44] Care should be taken in extrapolating these results, given the relatively small sample size in some 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 2018.



Source: Berkeley Lab

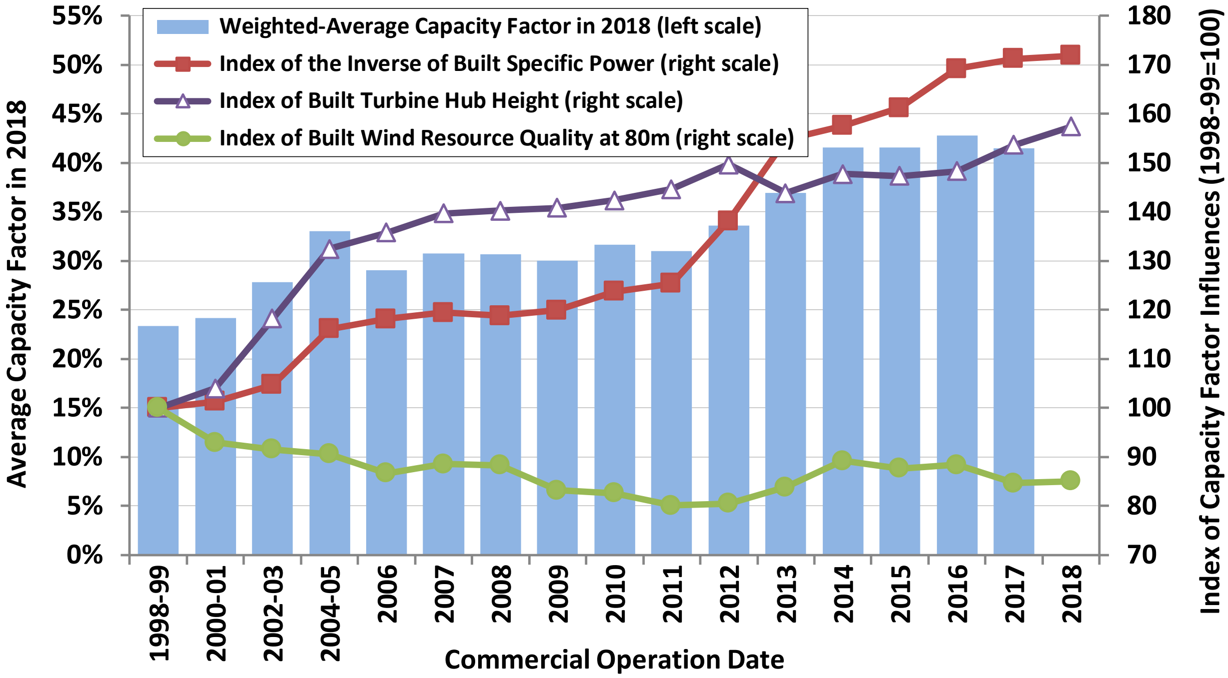
Figure 38. Average 2018 capacity factors by state: 1998–2017 projects

As shown earlier in Chapter 4, the rate of adoption of turbines with taller towers and lower specific power ratings has varied by region. For example, Figure 29 (earlier) shows a greater preponderance of tall towers in the Great Lakes and Northeast regions than elsewhere, while Figure 30 shows lower specific power turbines being most prevalent in the Great Lakes and Interior regions. 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 Figure 37 and Figure 38.

Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor

The trends in average capacity factor by commercial operation date seen in Figure 35 can largely be explained by several underlying influences described in Chapter 4 and shown again in Figure 39. First, there has been a trend toward progressively lower specific power and higher hub heights. Second, there was a progressive build-out of lower-quality wind resource sites through 2012, followed by deployment at more energetic sites thereafter. Finally, as shown later, project age 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 again in Figure 39 in index form, relative to projects built in 1998–1999 (with specific power shown in the inverse, to correlate with capacity factor movements). 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. 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 resource areas,[45] especially among projects installed from 2009 through 2012[46] as shown by the wind resource quality index in Figure 39. This trend reversed course in 2013 and 2014, and has largely held steady since then, though with a dip in 2017 and 2018.



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 39. 2018 capacity factors and various drivers by commercial operation date

In Figure 39, the significant improvement in average 2018 capacity factors from among 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 toward somewhat-lower-quality wind resource sites. The stagnation in average capacity factors 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 after 2011 is driven by a steep reduction in average specific power coupled with a marked improvement in the quality of wind resource sites. (Average hub height increased modestly over this period.) Looking ahead to 2019, projects with commercial operation dates in 2018 could possibly record higher capacity factors on average than those built in 2017, in light of a slight reduction in average specific power coupled with an uptick in average hub height, while average site quality held steady.

[45] As described earlier relating to Figure 27 (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 1998–1999.

[46] The text immediately preceding Figure 27 lists several possible explanations for the buildout of less-energetic sites from 2009 to 2012, including the availability of the Section 1603 grant.

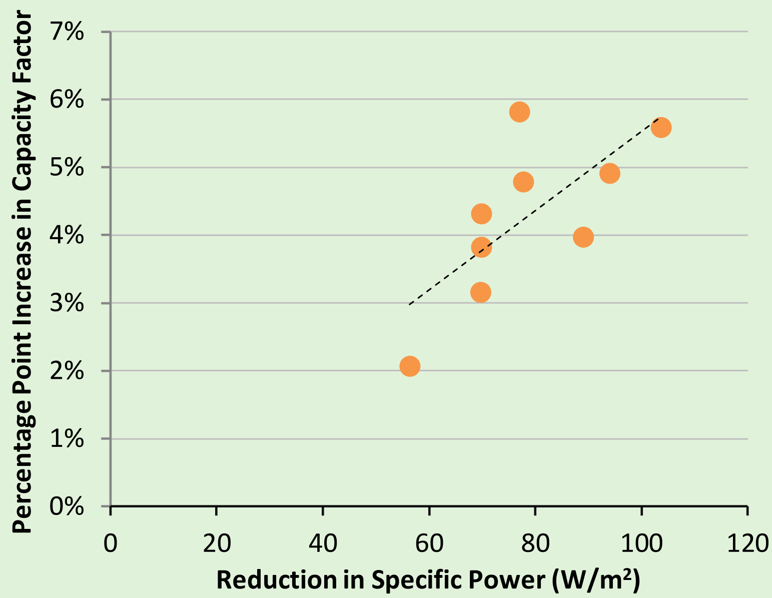
To help disentangle the primary and sometimes competing influences of turbine design evolution and wind resource quality on capacity factor, Figure 40 controls for each. Across the x-axis, projects are grouped into four different categories, depending on the wind resource quality estimated for each site. 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 capacity factors in 2018 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 capacity factors in 2018 than those in a higher specific power range.

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 the side bar on this page, as well as in Figure 41, which again groups projects into the same four different categories of wind resource quality, and then reports average realized 2018 capacity factors by commercial operation date within each category.[47] 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. In other words, the fleet-wide improvement in capacity factors by project vintage shown above in Figure 35 is seen across all four wind resource bins, and is not simply a result of shifting toward more-energetic sites over time (in fact, Figure 27 and Figure 39 above show the opposite—i.e., that the wind industry has generally built out less-energetic sites over time).

First wave of partial repowering demonstrates higher capacity factors from lower specific power

Nine projects totaling 2.2 GW partially repowered their turbines in 2017, increasing rotor size in all nine cases and boosting turbine capacity in two of the nine cases (all nine projects re-used the existing towers, resulting in no change to hub height).

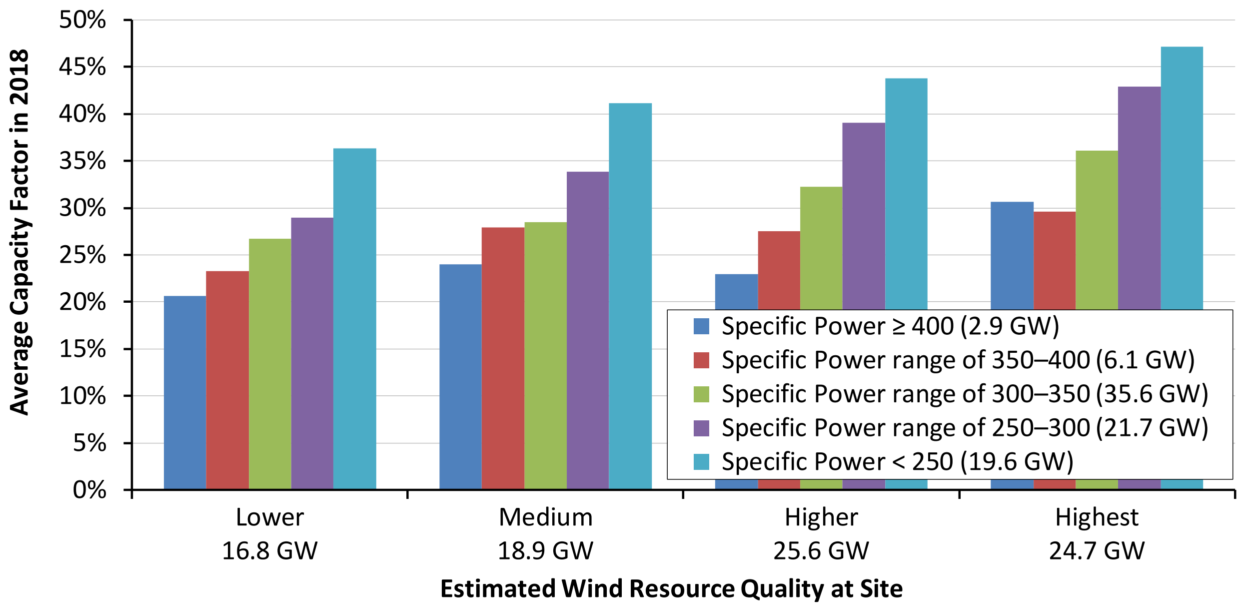
For each of these projects, the figure below shows the increase in capacity factor in 2018 (relative to the 4-year average from 2013 to 2016; 2017 is omitted) as a function of the reduction in average specific power (itself a reflection of increased blade length). Not surprisingly, those projects that reduced specific power the most generally saw the largest boost in capacity factor.



Note: All capacity factor data used in this graph are corrected for inter-annual variability in the wind resource (see Appendix for normalization methodology).

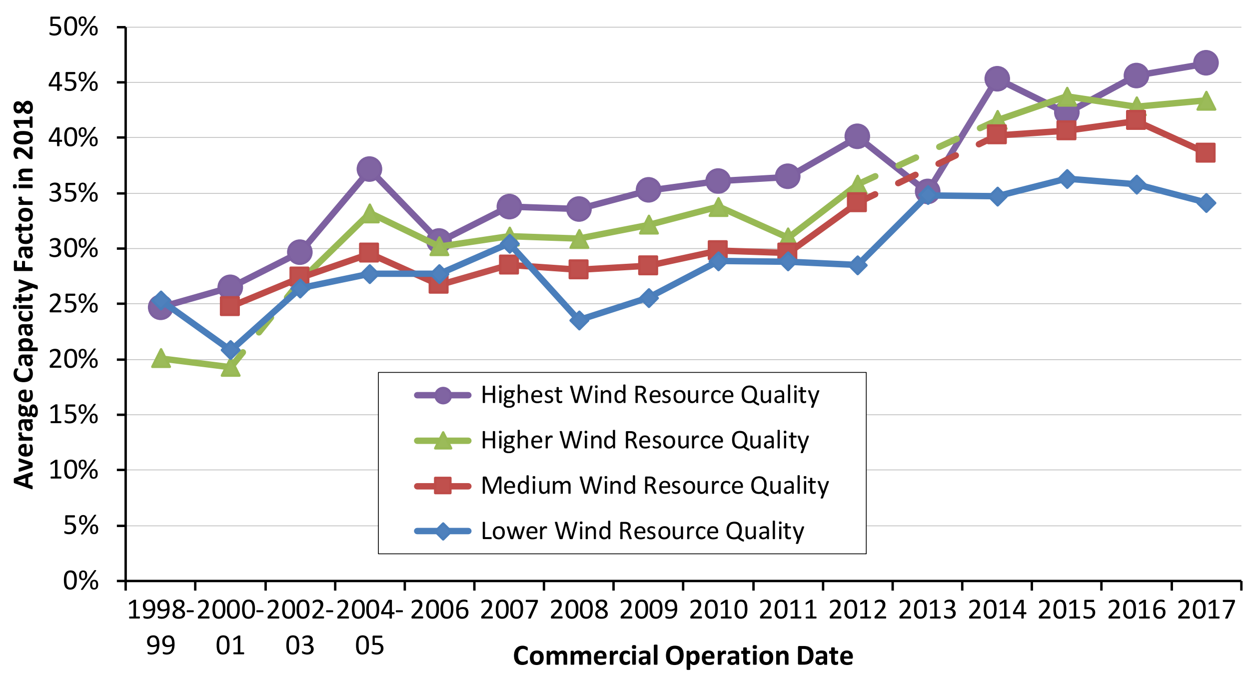
Within this chapter, these nine projects are omitted from all graphs in 2017 (the year in which the partial repowering occurred) as well as from most graphs in 2018 (due to difficulties in appropriately characterizing their vintage), with the exception of both Figure 36 and Figure 40, where vintage is not a consideration.

[47] The figure only includes those data points representing at least three projects in any single resource-year pair. In years where insufficient sample size prohibits the inclusion of a data point (e.g., in 2013), dashed lines are used to interpolate from the prior year to the subsequent year.



Note: See the Appendix for details on how the wind resource quality at each individual project site is estimated.
Source: Berkeley Lab

Figure 40. Calendar year 2018 capacity factors by wind resource quality and specific power: 1998-2017 projects



Source: Berkeley Lab

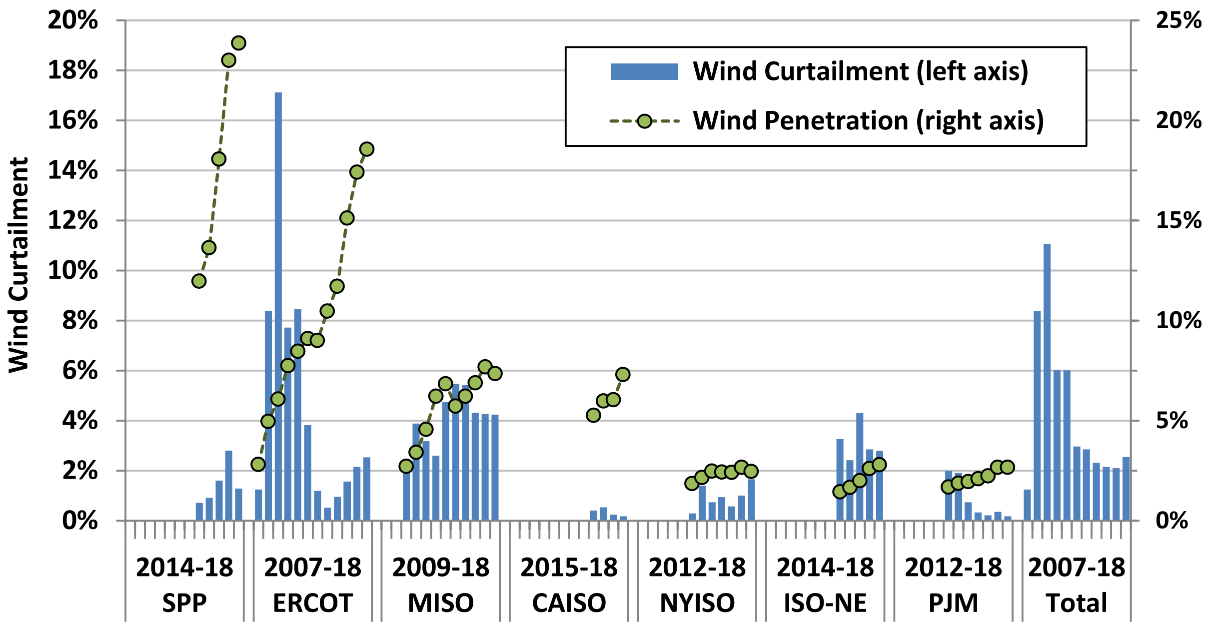
Figure 41. Calendar year 2018 capacity factors by commercial operation date and wind resource quality

Wind curtailment can differentially impact project performance across sites and regions

Curtailment of wind project output results from 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.

Curtailment might be expected to increase as wind energy penetrations rise, though as shown in Figure 42, this has not always been the case. For example, the Southwest Power Pool (SPP) has the highest wind penetration rate of any of the ISOs shown in Figure 42, yet just 1.3% of potential wind energy generation within the SPP region was curtailed in 2018—down from 2.8% in 2017, and below the curtailment levels in several other ISOs with much lower wind penetration rates.

Moreover, in areas where curtailment has been particularly acute in the past—principally in Texas—steps taken to address the issue have significantly reduced curtailment, even as wind penetration has increased. For example, Figure 42 shows that just 0.5% of potential wind energy generation within the main Texas grid (ERCOT) was curtailed in 2014, down sharply from 17% in 2009, roughly 8% in both 2010 and 2011, and nearly 4% in 2012. This decline in curtailment corresponds to the significant build-out of new transmission serving West Texas (collectively referred to as the Competitive Renewable Energy Zone upgrades), most of which were completed by the end of 2013. Since 2014, however, wind penetration has continued to increase in ERCOT, and so too has wind curtailment, rising to an average of 2.5% in 2018.[48]



Notes: All curtailment percentages shown in the figure represent both forced and economic curtailment. PJM's 2012 curtailment estimate is for June through December only. For each year, the total reflects only those ISOs for which we have curtailment data.

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

Figure 42. Wind curtailment and penetration rates by ISO

Though SPP and ERCOT have by far the highest wind penetration rates, other ISOs are also experiencing wind curtailment to varying degrees. The California Independent System Operator (CAISO) and PJM both

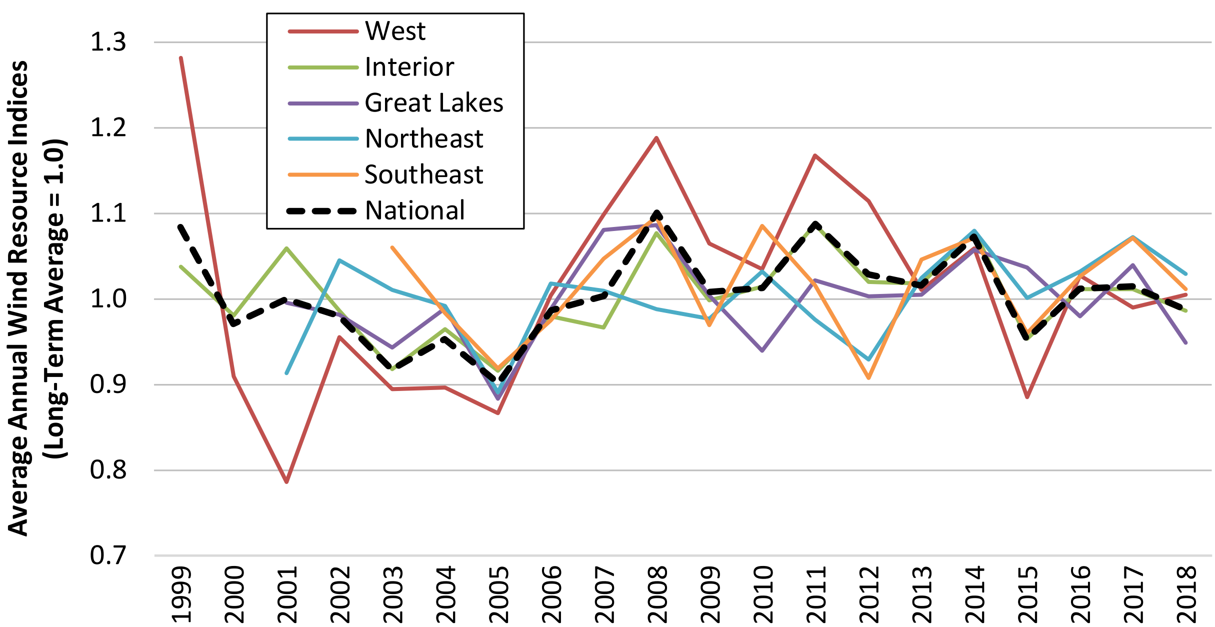
[48] This 2.5% ERCOT-wide average masks a long tail on the distribution of individual project-level curtailment, with 11 projects (totaling nearly 1.4 GW) curtailed more than 10% and four of those projects (totaling nearly 600 MW) curtailed 18%–25% in 2018.

experienced only negligible wind curtailment in 2018, but curtailment was more significant within the Midcontinent Independent System Operator (MISO), ISO New England (ISO-NE) and the New York Independent System Operator (NYISO) at 4.2%, 2.8% and 1.7%, respectively. The overall wind power curtailment rate in 2018 across all seven regions shown in Figure 42 was 2.2%. Curtailment rates for all regions 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.

Obviously, wind power curtailment reduces capacity factors. Sample-wide capacity factors in 2018 would have been on the order of 0.7 percentage points higher nationwide absent curtailment in just these seven ISOs.[49]

Temporal variations in wind speed also impact performance

The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation, in turn, impacts project performance from year to year. Figure 43 shows national and regional indices of the historical inter-annual variability in the wind resource among the U.S. fleet over time.[50] Though inter-annual variation has, at times, exceeded +/-20% at the regional level, geographical averaging has enabled nationwide variation to remain within +/-10%. More recently, for the third year in a row, wind speeds across the continental United States in 2018 were generally close to their long-term averages, both within each region and on average across all regions (separate data presented by AWS Truepower (2019) tells a similar story).



Source: Berkeley Lab; methodology behind the index of inter-annual variability is explained in the Appendix

Figure 43. Inter-annual variability in the wind resource by region and nationally

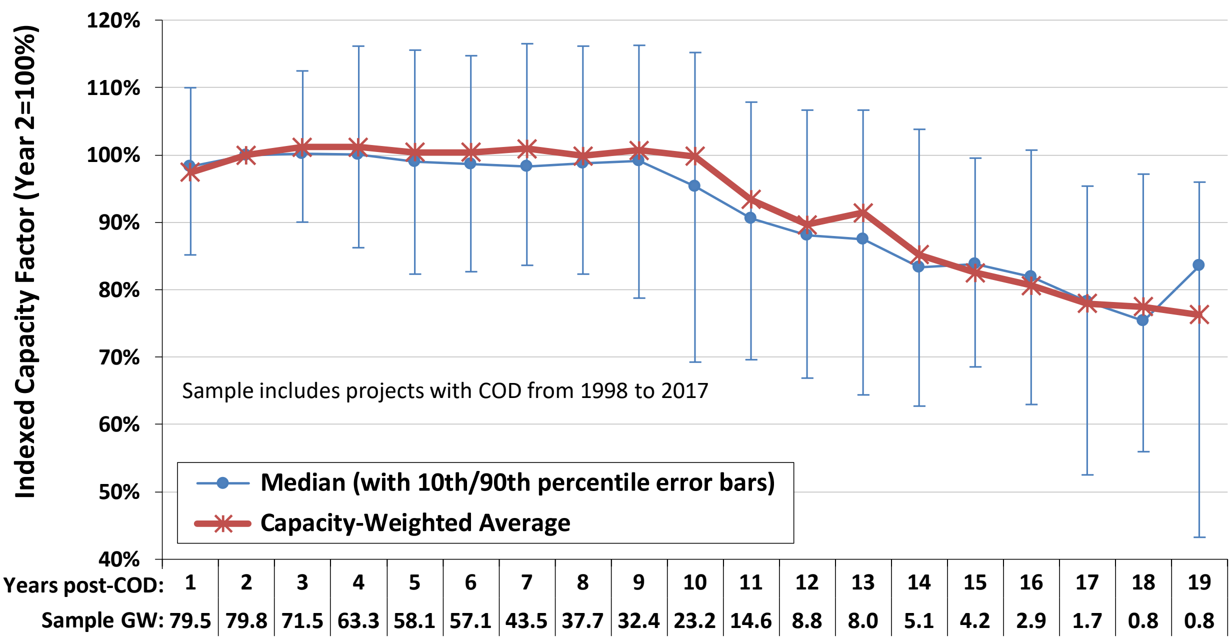
[49] The seven ISOs included in Figure 42 collectively contributed 84% of total U.S. wind generation in 2018. The estimated pre-curtailment sample-wide capacity factor would have been even higher if comprehensive curtailment data were available for all areas of the country.

[50] These indices estimate changes in the strength of the average region- or fleet-wide wind resource from year to year and are constructed from ERA5 reanalysis wind speed data for individual project locations by applying applicable wind turbine power curves and then aggregating up to the region or fleet level (see the Appendix for more details). Note that these indices of inter-annual variability differ from the AWS Truepower wind resource quality data presented elsewhere, in that the former show variability from year to year across the entire region or fleet, while the latter focuses on the multi-year long-term average wind resource at specific wind project sites.

Wind project performance degradation may also explain why older projects did not perform as well in 2018

One final variable that could be influencing the apparent improvement in capacity factors in 2018 among more recent projects 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 in 2018 than more recent projects simply due to their relative age. Figure 44 explores this question by graphing both median (with 10th and 90th percentile bars) and capacity-weighted average "weather-normalized" (i.e., to correct for inter-annual variability in the strength of the wind resource) capacity factors over time. Here, time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and each project's capacity factor is indexed to 100% in year two in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values. Year two is chosen as the index base, rather than year 1, to 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.

Figure 44 suggests some amount of performance degradation, though perhaps only once projects age beyond 9 or 10 years. Potential drivers of any such degradation might include a change in how projects are operated once they age beyond the 10-year PTC window, less-rigorous maintenance protocols following the expiration of warranties and initial service agreements, and/or more frequent component failures and downtime as equipment ages. All of these potential drivers are, in turn, affected by the terms and conditions embedded within power purchase agreements (PPAs)—e.g., whether the PPA includes an availability and/or performance guarantee. Whatever the cause, the decline in capacity factors as projects age could partially explain why, for example, in Figure 36 the sample-wide capacity factors in 2000 and 2001 exceeded 31.5%, while in Figure 35 the projects built in 2000–2001 posted average capacity factors of just 24% in 2018.



Source: Berkeley Lab

Figure 44. Post-COD changes in capacity factors over time suggest performance degradation

Although these suppositions surrounding Figure 44 are intriguing and worthy of further study, a number of caveats are in order. First, 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. Second, 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 44, shows the performance of those turbines that are operating in each period, rather than relative to the original nameplate capacity of the overall project. Similarly, repowered projects are considered to be new projects in the year in which the repowered capacity comes online.

Taken together, Figure 35 through Figure 44 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.

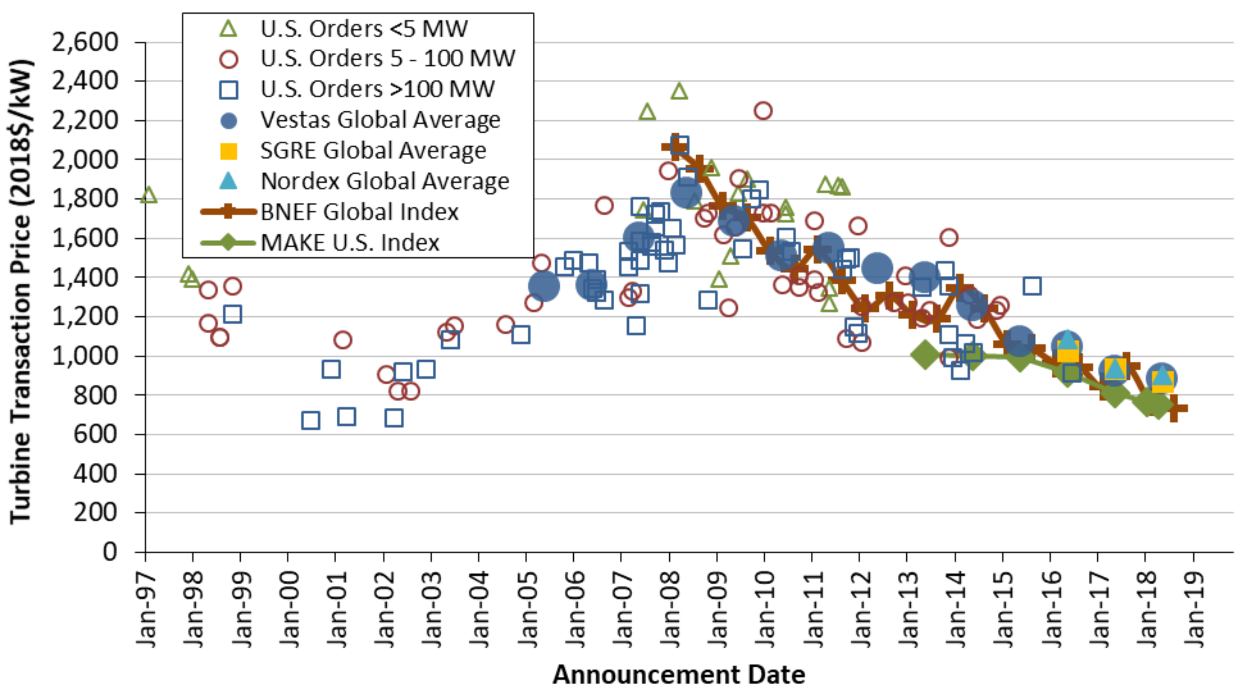
6 Cost Trends

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 cost decreases occurred in 2018, with wind turbines sold at price points similar to the early 2000s.

Figure 45 depicts wind turbine transaction prices from a variety of sources: (1) Vestas, SGRE, and Nordex, on those companies' global average turbine pricing, as reported in corporate financial reports; (2) BNEF (2018a) and MAKE (2018), on those companies' turbine price indices by contract signing date; and (3) 122 U.S. wind turbine transactions totaling 30,780 MW announced from 1997 through 2018, as previously collected by Berkeley Lab.[51] Wind turbine transactions can differ in the services included (e.g., whether towers 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. Most of the prices and transactions reported in the figure are inclusive of towers, and delivery to the site.



Sources: Berkeley Lab, Vestas, SGRE, BNEF, MAKE

Figure 45. Reported wind turbine transaction prices over time

[51] Sources of turbine price data for these 122 transactions vary, and include financial and regulatory filings, as well as press releases and news reports. Most of the transactions include turbines, towers, delivery to site, and limited warranty and service agreements, but the precise content of many of the individual transactions is not known.

After hitting a low of roughly $800/kW from 2000 to 2002, average wind turbine prices increased by more than $800/kW through 2008, rising to an average of greater than $1,600/kW. This increase in turbine prices 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 steeply declined, 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 45, data signal average pricing in the range of $700/kW to $900/kW.

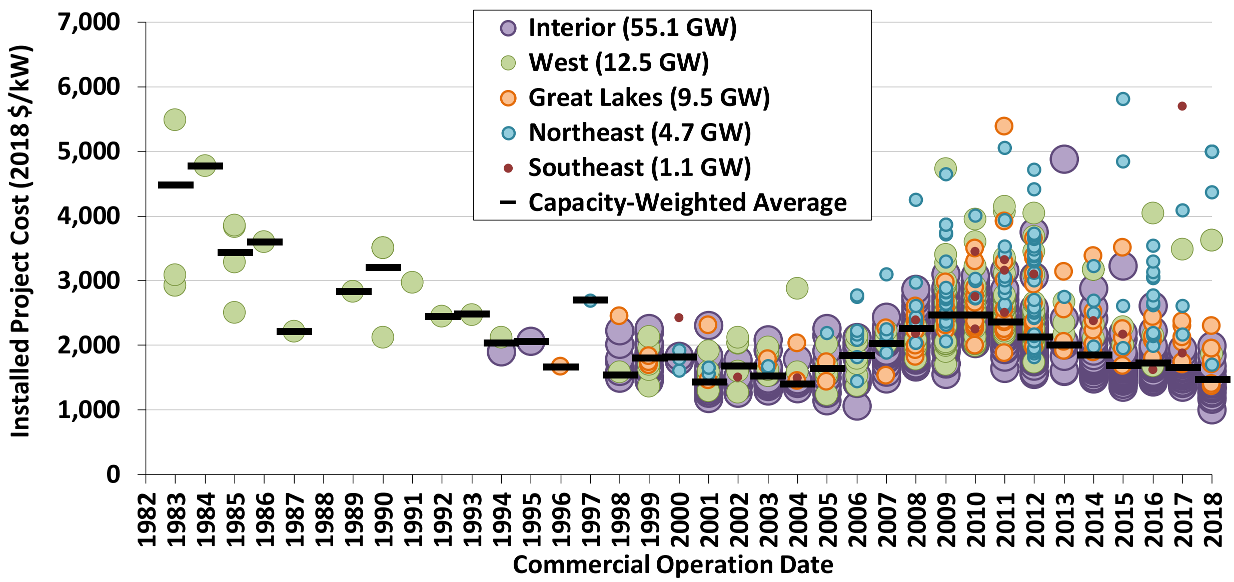
Overall, these figures suggest price declines of roughly 50% since 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., the recent growth in average hub heights and rotor diameters shown in Chapter 4) and, in some cases, more favorable terms for turbine purchasers (e.g., 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 this downward trend is compared to a 2008 peak in the market in terms of turbine pricing, and that looking back farther in time, turbine prices have only recently fallen back to where they were 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 projects in the United States, including data on 44 projects completed in 2018 totaling 5,676 MW, or 75% of the wind power capacity installed in that year. In aggregate, the dataset (through 2018) includes 975 completed wind power projects in the continental United States totaling 82,975 MW and equaling roughly 86% of all wind power capacity installed at the end of 2018. 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.

As shown in Figure 46, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s,[52] 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 peaked in 2009/2010, with declines since that time. It is not surprising that changes in average installed project costs would lag behind changes in average turbine prices, as this reflects the normal passage of time between when a turbine supply agreement is signed (the announcement date in Figure 45) and when those turbines are actually installed and commissioned (the commercial operations date in Figure 46).

[52] 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 consistent with average cost data for a subset of those years reported by the California Energy Commission (1988) and Gipe (1995).



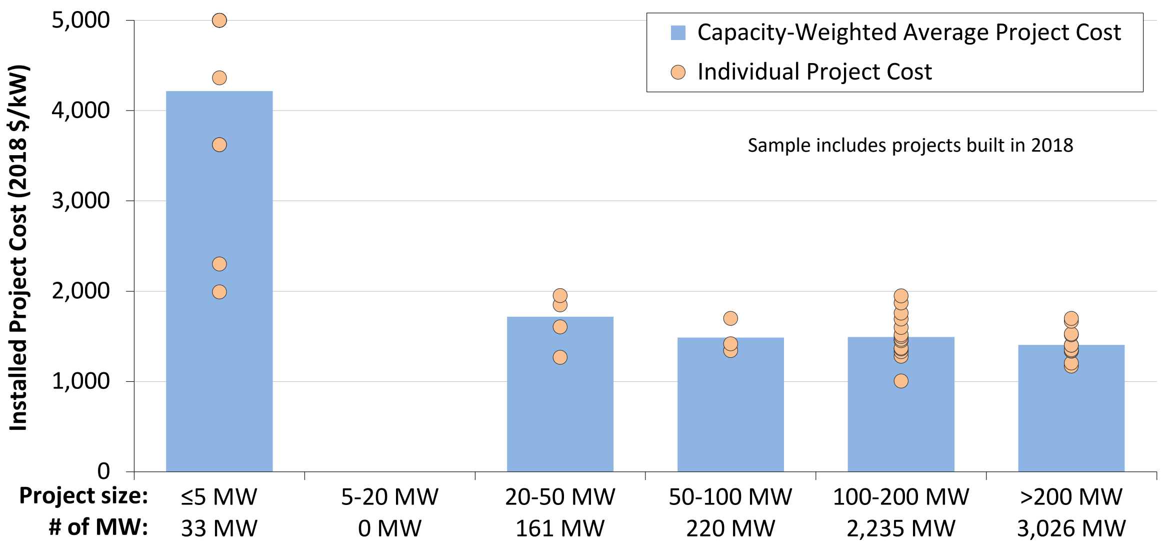
Sources: Berkeley Lab (some data points suppressed to protect confidentiality), Energy Information Administration

Figure 46. Installed wind power project costs over time

In 2018, the capacity-weighted average installed project cost within our sample stood at roughly $1,470/kW. This is down nearly $1,000/kW or 40% from the average reported costs in 2009 and 2010, but is roughly on par with 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 and where average costs have fallen by more than $1,000/kW since 2010. Early indications from a limited sample of 14 projects (totaling 2.9 GW) currently under construction and anticipating completion in 2019 suggest that capacity-weighted average installed costs in 2019 will be slightly lower than in 2018, with some developers reporting costs in the $1,100–$1,250/kW range.

Installed costs differed by project size and turbine size

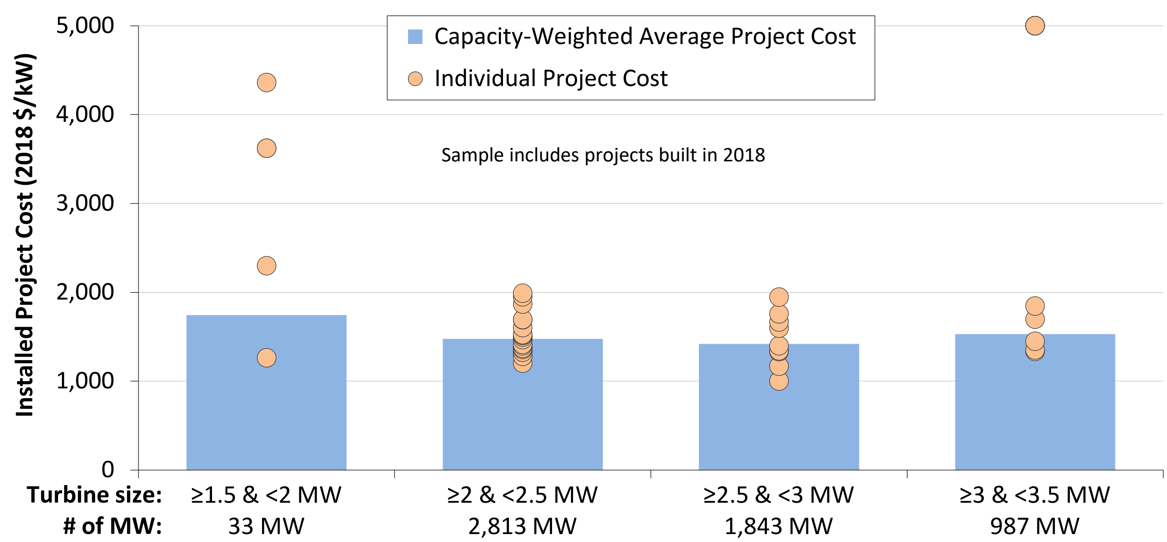
Installed costs exhibit economies of scale, which are especially evident when moving from small- to medium-sized projects. Figure 47 shows that among the sample of projects installed in 2018, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects 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 47. Installed wind power project costs by project size: 2018 projects

Another way to look for economies of scale is by turbine size, on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines. Figure 48 explores this relationship and finds mixed results. On a $/kW basis, projects using larger turbines (in the 2–2.5 MW and 2.5–3 MW bins) do appear to be progressively less-expensive on average than projects using smaller turbines (of between 1.5 and 2 MW). But, the trend ends with projects using turbines of 3 MW or larger—partly due to a number of single-turbine projects using 3 MW turbines installed in 2018 at the same $5,000/kW cost.[53]



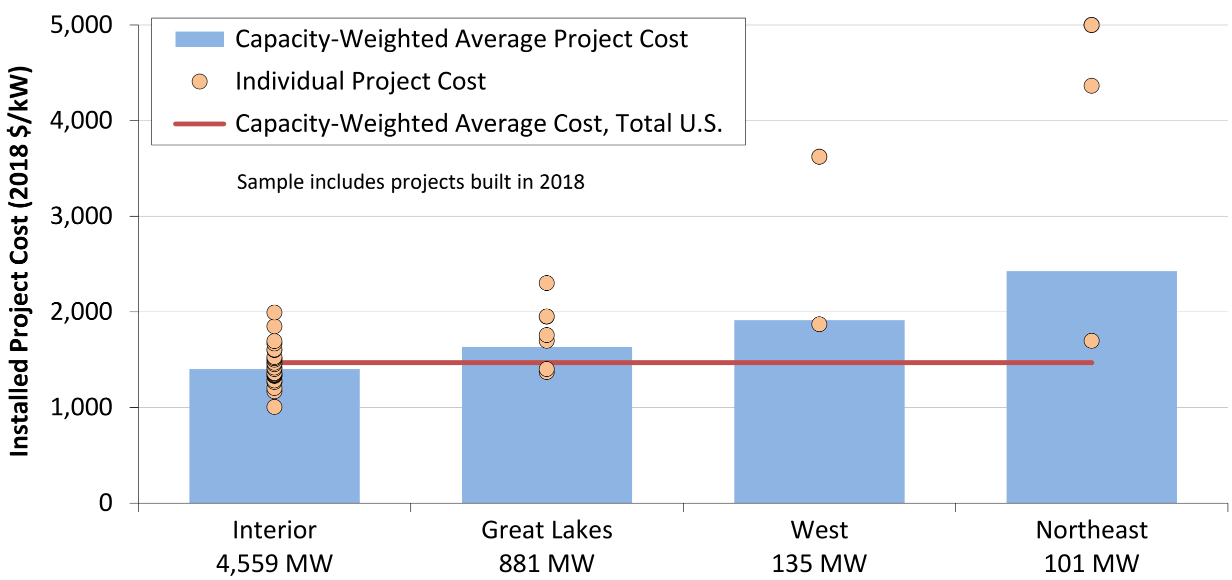
Source: Berkeley Lab

Figure 48. Installed wind power project costs by turbine size: 2018 projects

[53] Notwithstanding these small, single-turbine projects using large turbines, in general there is likely to be some correlation between turbine size and project size, at least at the low end of the range of each. As such, Figure 47 and Figure 48 could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size. The same challenges exist when considering regional differences in costs, as the largest projects tend to be built in the lowest-cost Interior of the country—making it difficult to discern the degree to which cost differences are determined by project size or region.

Installed costs differed by region

As intimated earlier in Figure 46, regional differences in average project costs are also apparent and may occur due to variations in labor costs, 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 2018, Figure 49 breaks out project costs among four of the five regions defined in Figure 1.[54] The Interior region—which tends to feature larger projects on flatter terrain—was the lowest-cost region on average, with an average cost of $1,400/kW, while the Northeast—which tends to feature smaller projects on complex terrain—was the highest-cost region in 2018.[55] Two of the four regions have very limited sample size, so extrapolations based on these data should be treated with care. Nonetheless, outside of the Interior region, the average cost in 2018 was $1,740/kW.



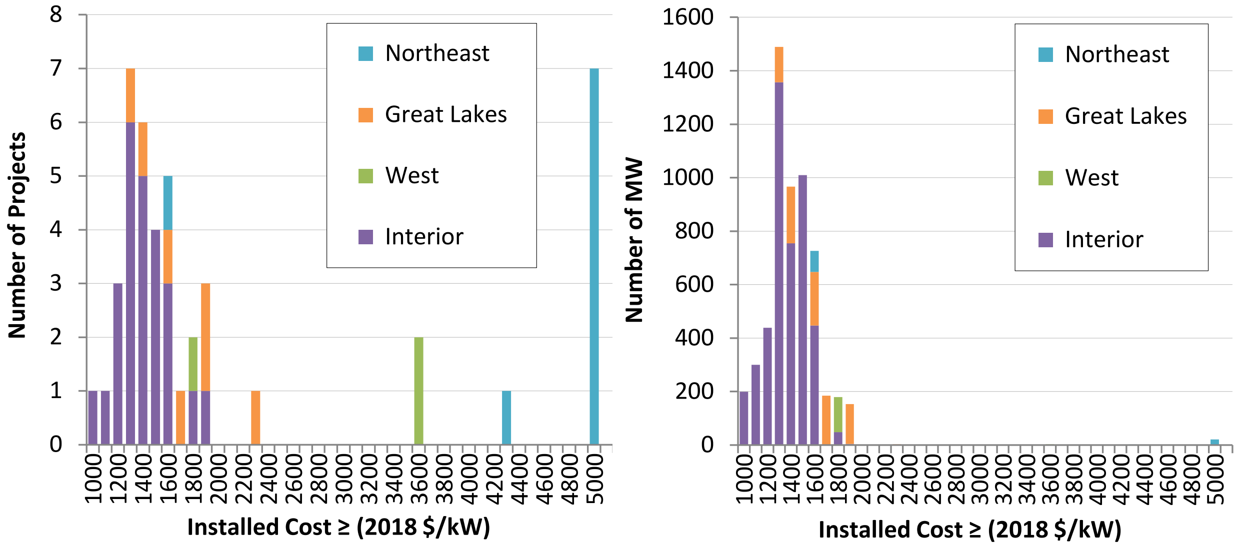
Source: Berkeley Lab

Figure 49. Installed wind power project costs by region: 2018 projects

Figure 50 shows two histograms that present the distribution of installed project costs among 2018 projects, in terms of both number of projects and capacity. Most of the projects—and most of the low-cost projects—are located in the Interior region, where the distribution is centered on the $1,300–$1,400/kW bins. Projects in other regions generally have higher costs (a number of the high-cost projects shown in the left half of the figure are not visible in the right half because their capacity is very small).

[54] For reference, the 96,433 MW of wind installed in the United States at the end of 2018 is apportioned among the five regions shown in Figure 1 as follows: Interior (68%), West (15%), Great Lakes (11%), Northeast (5%), 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.

[55] 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 49.



Source: Berkeley Lab

Figure 50. Histogram of installed costs by projects and MW: 2018 projects

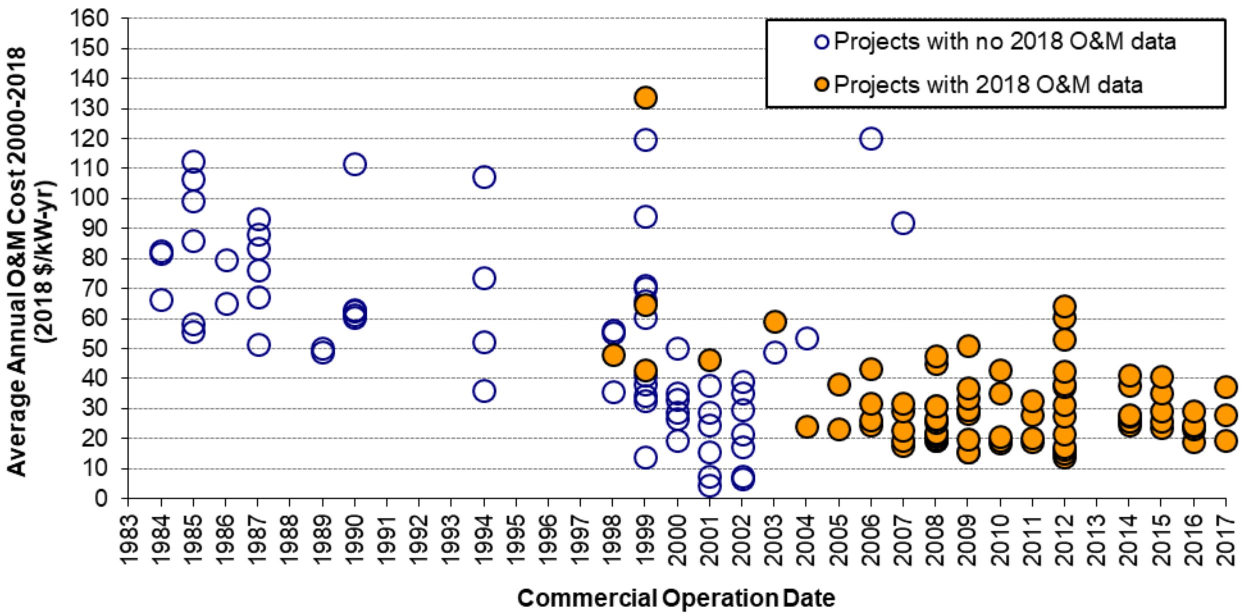
Operations and maintenance costs varied by project age and commercial operations date

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 time (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 168 installed wind power projects in the United States, totaling 14,709 MW and with commercial operation dates of 1982 through 2017. These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects and so may not be broadly representative. 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.[56] Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance, are generally not included. As such, Figure 51 and Figure 52 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 only 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; expressing O&M costs in units of $/MWh yields qualitatively similar results to those presented in this section.

[56] 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.

Figure 51 shows project-level O&M costs by commercial operation date.[57] Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2018, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2017, only year 2018 data are available, and that is what is shown.[58] Many other projects only have data for a subset of years during the 2000–2018 timeframe, so each data point in the chart may represent a different averaging period within the overall 2000–2018 timeframe. The chart highlights the 83 projects, totaling 11,062 MW, for which 2018 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.



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

Figure 51. Average O&M costs for available data years from 2000 to 2018, by COD

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 51 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 2000–2018 O&M costs for the 24 projects in the sample constructed in the 1980s equal $72/kW-year, dropping to $60/kW-year for the 37 projects installed in the 1990s, to $29/kW-year for the 65 projects installed in the 2000s, and staying at $29/kW-year for the 42 projects installed since 2010.[59,60] This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs

[57] For projects installed in multiple phases, the commercial operation date of the largest phase is used. For repowered projects, the date at which repowering was completed is used.

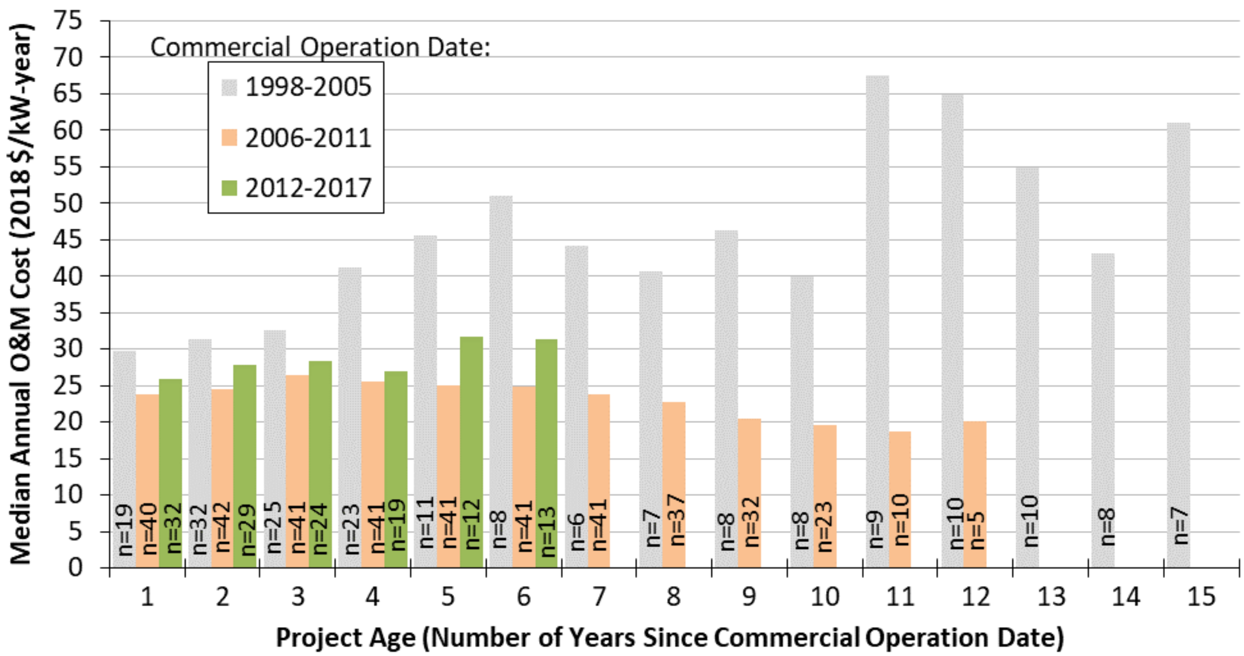
[58] Projects installed in 2018 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2018 would be year 2019.

[59] Operational expenditure data collected via an industry survey and reported in Wiser et al. (2019) are generally consistent with these cost ranges and trends. Also somewhat consistent with these observed O&M cost magnitudes (if not necessarily time trends), BNEF (2018b) reports that, globally, the average cost from a sample of initial full-service O&M contracts was $26.4/kW-year for those agreements signed in 2016, $20.5/kW-year in 2017, and $18.1/kW-year in 2018. North American contracts in 2018, meanwhile, had a reported average of just $15.4/kW-yr.

[60] If the data were expressed instead in terms of $/MWh, capacity-weighted average 2000–2018 O&M costs were $37/MWh for projects in the sample constructed in the 1980s, dropping to $25/MWh for projects constructed in the 1990s, to $11/MWh for projects constructed in the 2000s, and to $9/MWh for projects constructed since 2010.

generally increase as turbines age, component failures become more common, and manufacturer warranties expire;[61] and (2) projects installed more recently, with larger turbines, more sophisticated designs and servicing, and more-mature technology may experience lower overall O&M costs on a $/kW-year basis.

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 52 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. 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 2018b, Wiser et al. 2019). 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 52. Median annual O&M costs by project age and commercial operation date

With these limitations in mind, Figure 52 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 relatively limited for these earliest projects. Projects built in 2006 or after, on the other hand, do not show a consistent trend in costs with project age. Figure 52 also shows that projects installed more recently have had, in general, lower O&M costs than those installed in earlier years (1998–2005), at least for the first 12 years of operation, with little difference in observed costs between the sample of projects built from 2006 to 2011 and those built from 2012 to 2017.

As indicated previously, the data presented in Figure 51 and Figure 52 include only a subset of total operating expenses. In comparison, the financial statements of EDP Renováveis (EDPR), a company that owned more than 5.2 GW of U.S. wind project assets at the end of 2018 (all of which have been installed since 2000), indicate markedly higher total operating costs. Specifically, EDPR (2019) reported total operating expenses of

[61] Some of the projects installed most recently may still be within their turbine manufacturer warranty period, and/or may have partially capitalized O&M service contracts within their turbine supply agreement. In either case, reported O&M costs would be artificially low.

$59/kW-year for its North American portfolio in 2018[62]—twice the ~$29/kW-year average O&M cost reported above for the 107 projects in the Berkeley Lab data sample installed since 2000. Similarly, a U.S. wind industry survey of total operating costs shows that these expenses for recently installed projects are anticipated to average between $33/kW-year and $59/kW-year, with a mid-point of ~$44/kW-year (Wiser et al. 2019).

The disparity between total operating costs and those costs reported in 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 2018 ($59/kW-year) into three categories: supplies and services, which "includes O&M costs" ($34/kW-year); personnel costs ($12/kW-year); and other operating costs, which "mainly includes operating taxes, leases, and rents" ($12/kW-year). Among these three categories, the $34/kW-year for supplies and services is probably closest in scope to the Berkeley Lab data. The recent wind industry survey noted, meanwhile, demonstrates that turbine O&M is expected to constitute less than half of total operating costs (Wiser et al. 2019).

[62] Though not entirely clear, EDPR's reported operating expenses may exclude any repair or replacement costs that have been capitalized rather than expensed. Also, at the end of 2018, EDPR's North American portfolio consisted of 5,242 MW of wind and 90 MW of PV in the United States, along with 30 MW of wind in Canada and 200 MW of wind in Mexico. Hence, reported North American operating costs are neither entirely U.S.-based nor entirely for wind.

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, resulting in a dataset that currently consists of 448 PPAs totaling 42,018 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation later in 2019 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.[63]

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 2018 dollars.[64] Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.[65] 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[66]) 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 later text box.

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to solar PPA prices and future natural gas prices, and compared to past wholesale energy and capacity market value. In addition, REC prices are presented in a subsequent text box.

[63] 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 historically, this distinction could limit our sample more severely in the future if corporate off-take agreements remain popular.

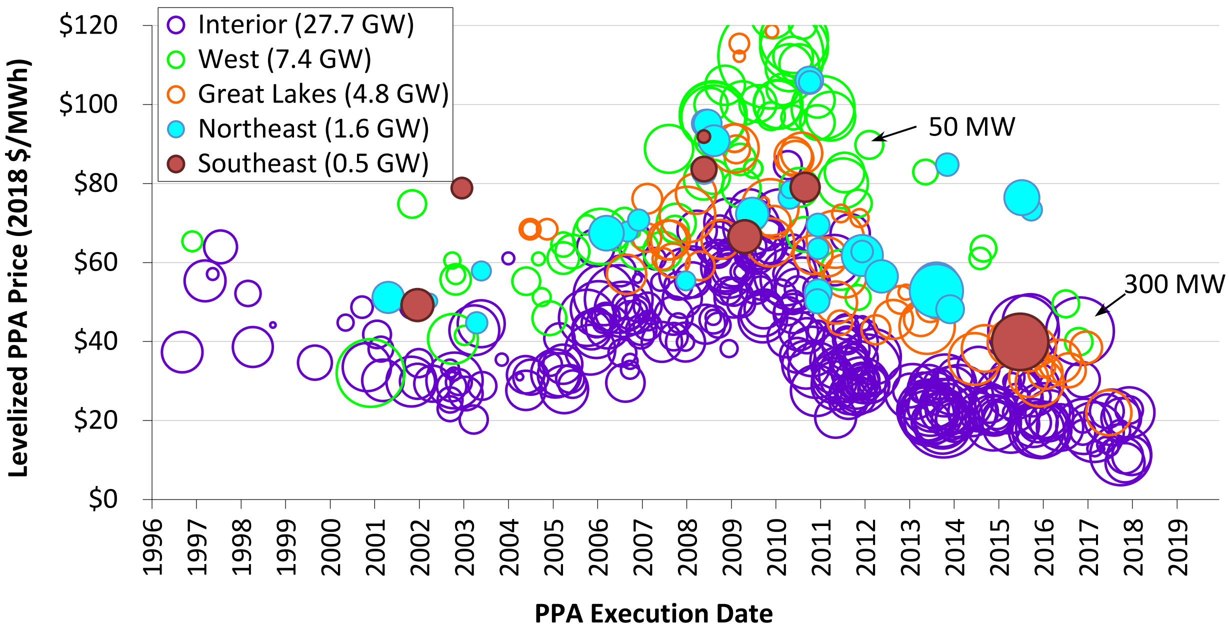
[64] Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing 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 56% 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.

[65] 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).

[66] The estimated levelized PPA price impact of $15+/MWh is different from the PTC's 2018 face value of $24/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)).

Wind power purchase agreement prices are at historical lows

Figure 53 plots contract-level levelized wind power purchase agreement (PPA) prices by contract execution date, showing a clear decline in PPA prices since 2009–2010, both overall and by region.[67] This trend is particularly evident in the Interior region, which tends to dominate the overall sample, particularly in recent years. As a result of its low average project costs and high average capacity factors shown earlier in this report, the Interior region also tends to be the lowest-priced region over time.[68]



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

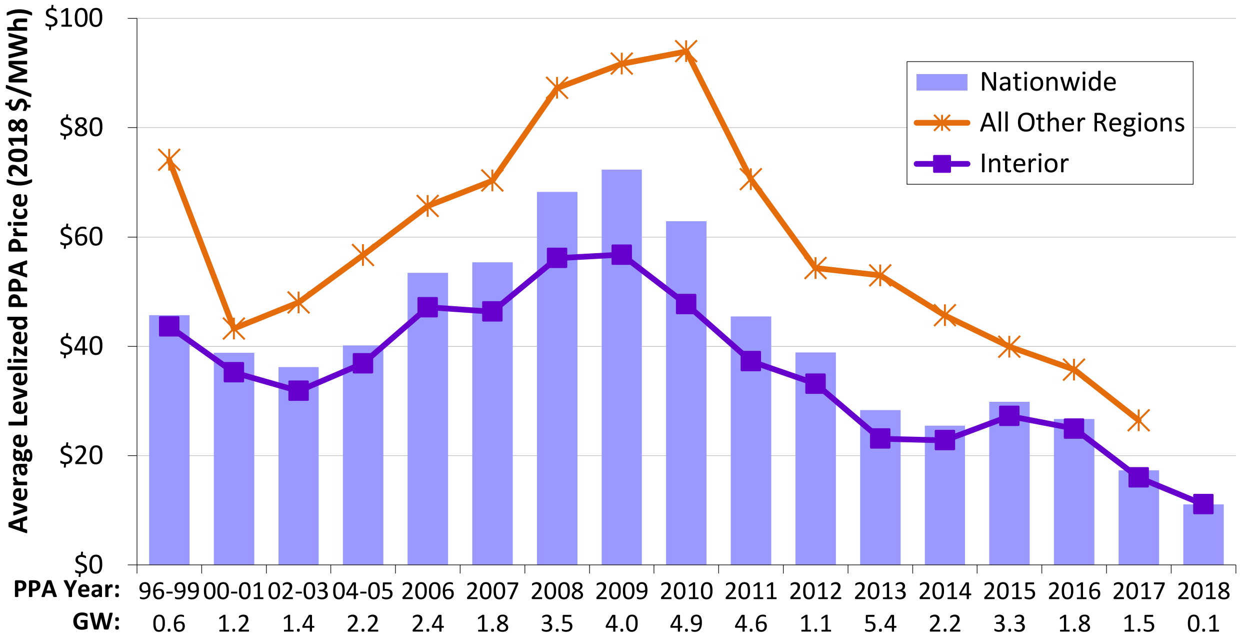
Source: Berkeley Lab

Figure 53. Levelized wind PPA prices by PPA execution date and region (full sample)

Figure 54 provides a smoother look at the time trend nationwide and regionally (for just the Interior region and all other regions combined) by averaging the individual levelized PPA prices shown in Figure 53 by year. After topping out above $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to below $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 remains substantial, from an average of $57/MWh among contracts executed in 2009 to below $20/MWh in 2017 and 2018. Across all other regions, average PPA prices have been higher.

[67] 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.

[68] 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.



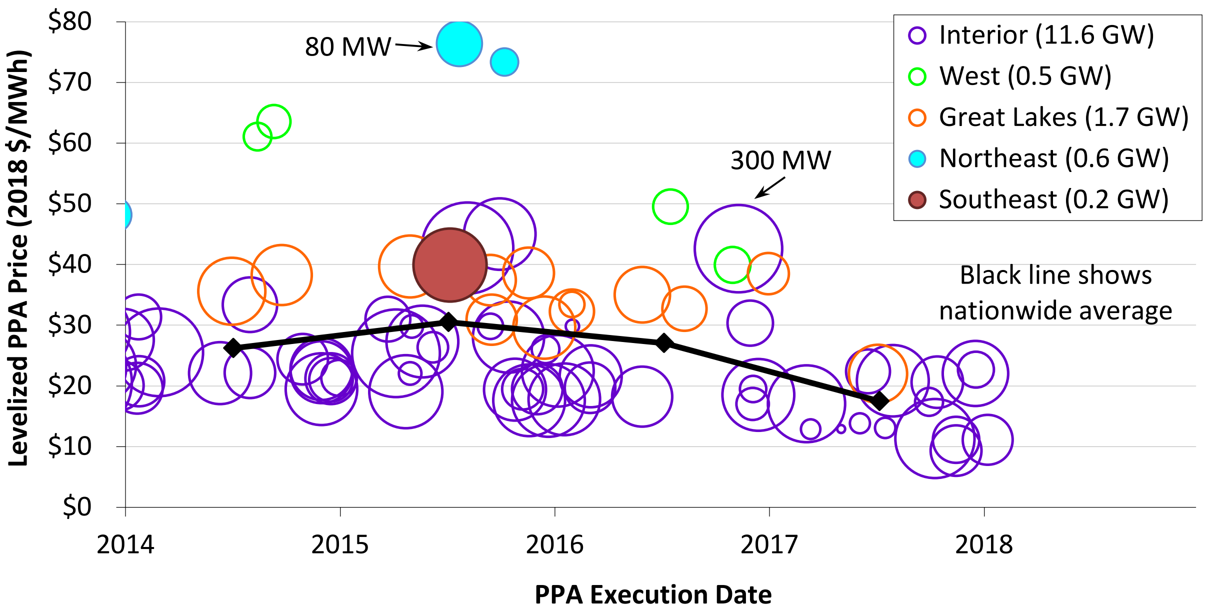
Source: Berkeley Lab

Figure 54. 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 projects, as documented in Chapter 5. Scaling has also enabled reductions in operating costs, as described in Chapter 6. This combination of declining CapEx and OpEx and improved performance—along with historically low interest rates (as shown earlier in Figure 17)—has driven wind PPA prices to today's record-low levels.

Recent wind power purchase agreements are priced in the mid-teens in some cases

Other sources (e.g., LevelTen Energy 2019) have noted recently signed or offered wind PPAs that are priced significantly below $20/MWh—in some cases in the low-to-mid teens per MWh. Although we have yet to see data on many of these contracts, within our full current sample there are 16 projects (all in the Interior region) totaling 2,468 MW that sell their output through 22 different PPAs signed since early 2015, all with levelized pricing below $20/MWh. Figure 55 focuses only on wind PPA prices signed since 2014, to more-readily show these sub-$20/MWh PPAs. The levelized prices of these 22 PPAs range from $9.3/MWh to $19.7/MWh. Contract terms range from 15–35 years, with an average of 23.5 years.



Source: Berkeley Lab

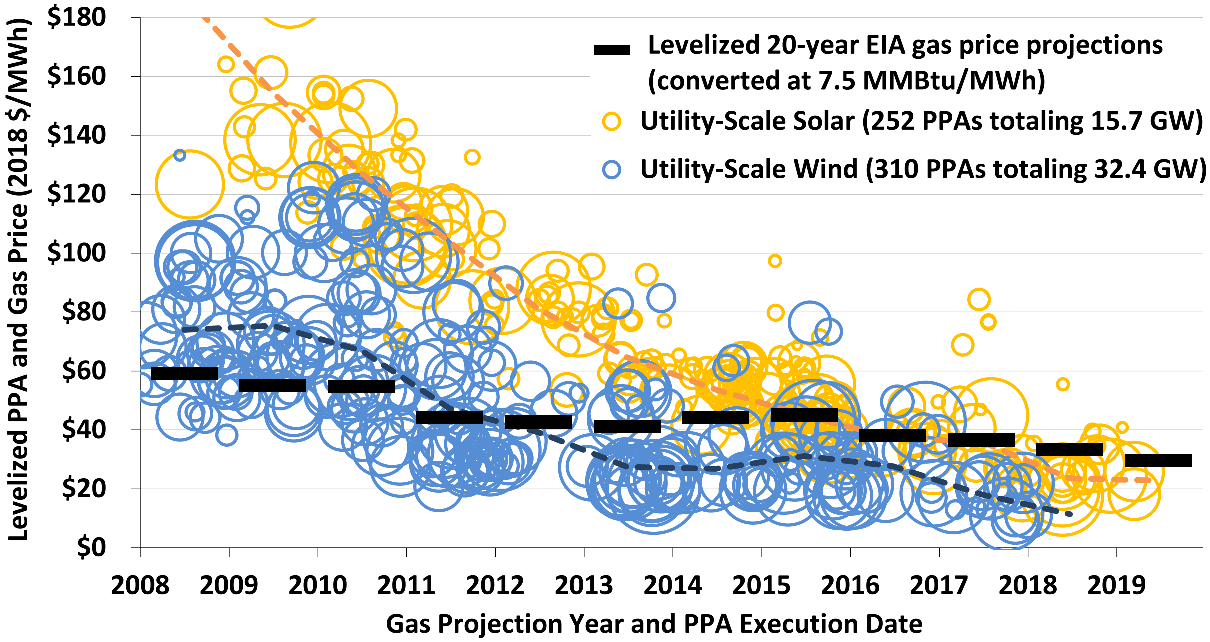
Figure 55. Levelized wind PPA prices by PPA execution date and region (recent sample)

Despite ultra-low PPA prices, wind faces stiff competition from solar and gas

Figure 56 plots wind PPA prices against utility-scale solar PPA prices on a levelized basis since 2008 (the dashed blue and gold lines show the generation-weighted average wind and solar PPA prices in each year, respectively). Although the gap between wind and solar PPA prices was quite wide a decade ago, that gap has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices.[69]

The figure also shows that wind PPA prices—and, more recently, utility-scale solar PPA prices—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 generators.[70] Supported by federal tax incentives, the generation-weighted average levelized wind and solar PPA prices within our contract sample have, for several years now, been below the projected levelized cost of burning natural gas in existing gas-fired combined cycle units.

[69] The solar PPA prices are sourced from Berkeley Lab's "Utility-Scale Solar" report series (utilityscalesolar.lbl.gov).
[70] For example, the black dash marker in 2008 shows the 20-year levelized gas price projection from Annual Energy Outlook 2008, while the black dash in 2019 shows the same from Annual Energy Outlook 2019 (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh). The assumed heat rate is intended to reflect an average among the existing fleet of combined cycle generators, rather than the current best-in-class, which might be closer to 6.0-6.5 MMBtu/MWh. Price expectations reflected in NYMEX natural gas futures contracts might differ from the EIA projections used here, but the NYMEX futures strip extends only 12-13 years, compared to the 20-year term used in the figure.

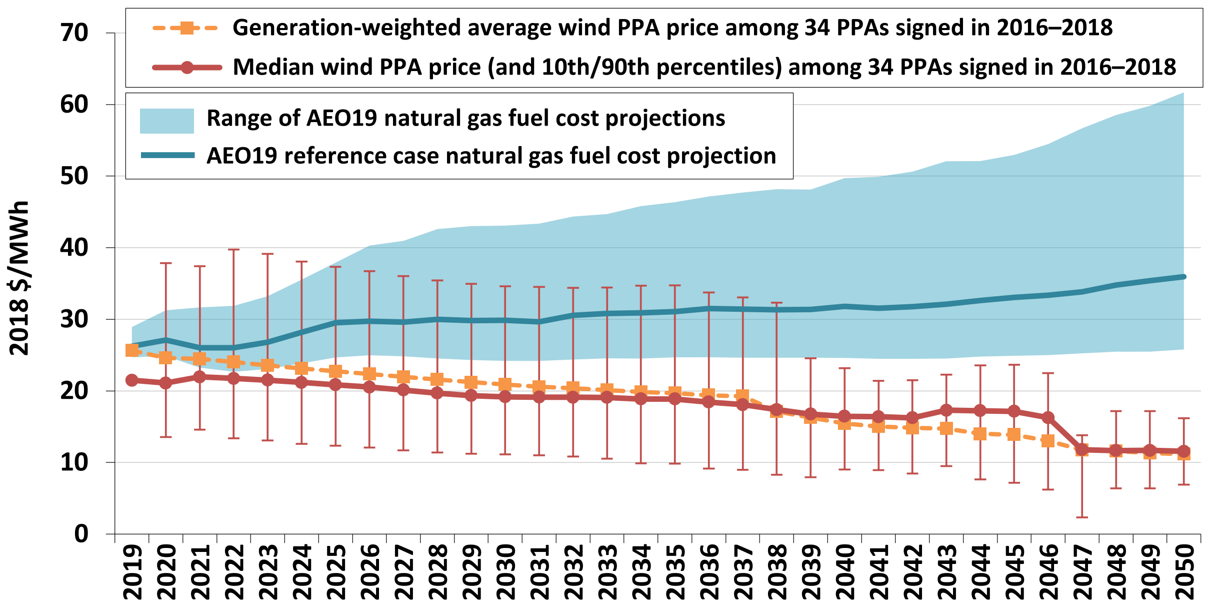


Sources: Berkeley Lab, Energy Information Administration

Figure 56. Levelized wind and solar PPA prices and levelized gas price projections

Rather than levelizing the wind PPA prices and gas price projections, Figure 57 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 2016–2018 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[71] As shown, the median and generation-weighted average wind PPA prices from contracts executed in the past three years are consistently below the low end of the projected natural gas fuel cost range, 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 2025.

[71] The fuel cost projections come from the EIA's *Annual Energy Outlook 2019* publication, and increase from around $3.27/MMBtu in 2019 to $5.34/MMBtu (both in 2018 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 8.0 MMBtu/MWh in 2019 and gradually decline to roughly 6.7 MMBtu/MWh by 2050).



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration

Figure 57. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Figure 57 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.

The economic competitiveness of wind energy is in part dictated by its grid-system value in wholesale power markets

In many regions of the country, wind energy participates in organized wholesale electricity markets for energy and, where available, capacity. In some cases, wind projects directly bid into those markets, and earn the prevailing market price. In other cases—especially when a PPA is in place—the wind energy purchaser will schedule the wind energy into the market, paying the wind project owner the pre-negotiated PPA price but earning revenue from the prevailing wholesale market price.

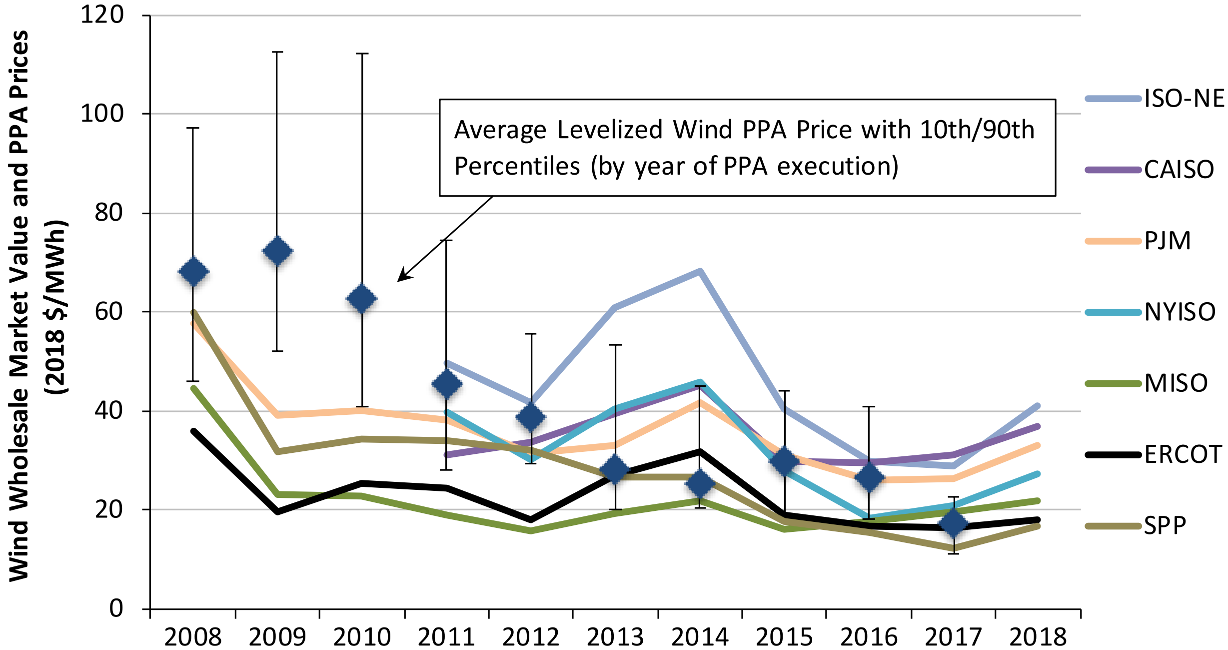
In either instance, the revenue earned (or that could have been earned) from the sale of wind into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system. In the case of merchant wind projects, the link is direct and affects the revenue of the plant. In the case of wind projects sold under a PPA, on the other hand, the pre-negotiated PPA price establishes plant revenue and, depending of the specifics of the PPA, pricing may or may not be linked to wholesale market prices. In this latter case, however, the revenue earned or that would have been earned by the sale of wind in the wholesale market still reflects the underlying market value of that wind—but in this case, for the purchaser, in the form of an avoided cost. This is because wholesale electricity prices reflect the timing of when energy is cheap or expensive and embed the cost of transmission congestion and losses. A purchaser could, in theory, obtain power from the wholesale market instead of from a wind project. A wind project's estimated revenue were it participating in the wholesale market therefore reflects costs avoided by the purchaser of wind under a PPA. This (potential) revenue—or value—can be segmented into "energy" market value and, where capacity markets or requirements exist, "capacity" value.

Wholesale energy prices vary over time, and by location. Overall, these prices have fallen over the last decade, in large measure due to the decline in the price of natural gas (Wiser et al. 2017), though gas prices rebounded somewhat in both 2017 and 2018. Moreover, because wind power deployment is sometimes concentrated in areas with limited transmission capacity, wholesale energy prices at the local pricing nodes to which wind plants interconnect are often suppressed. Even absent transmission constraints, wind plants push local wholesale energy prices lower when wind output is high. More generally, the temporal profile of wind output is not always well aligned with system needs, potentially further reducing the energy market value of wind generation. Some of these tendencies apply equally well to wind's capacity value, which is impacted by the cost of capacity but also by regional rules that define the credit that wind receives for providing capacity. In sum, these trends suggest that the wholesale energy and capacity value of wind may have declined over time, and may in general be somewhat lower than the energy and capacity market value of other generation sources.

Figure 58 estimates the historical wholesale energy and capacity market value of wind across a number of different regions of the country. Specifically, we estimate the energy market value of wind using plant-level hourly wind output profiles and real-time hourly wholesale energy pricing patterns at the nearest pricing node (i.e., locational marginal prices, LMPs). Plant-level capacity values are estimated based on the relevant capacity price or cost for the region in question, and local rules for wind's capacity credit.[72] Energy and capacity are summed for each plant, and plant-level total value estimates are then averaged to estimate regional values. As a result, the analysis considers the output profile of wind, the location of wind, and how those characteristics interact with local wholesale energy and capacity prices and rules, ultimately yielding an estimate of the revenue that would have been earned had wind sold its output at the hourly LMP and also considering any available capacity-based revenue. The figure then contrasts those wholesale market value estimates for wind with nationwide generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) based on the years in which the PPAs were executed. The comparison between market value estimates and PPA prices is relevant in as much as PPA prices reflect the cost of wind, whereas wholesale energy market value reflects a portion of the value of that wind generation.

These estimates show that the wholesale market value of wind has generally declined over the last decade and varies by region, but that there has been a modest rebound in value over the last two years as gas prices have trended upward. With the sharp drop in wholesale electricity prices and therefore market value of wind in 2009, average wind PPA prices tended to well-exceed the wholesale market value of wind from 2009 to 2012. With continued declines in wind PPA prices, however, those prices reconnected with the market value of wind in 2013 and have remained generally in competitive territory in subsequent years. This suggests that—with the help of the PTC, which reduces PPA prices—wind power developers and off-takers are successfully contracting at levels that are generally comparable in terms of both cost and value, with a number of recent wind PPAs coming in at a discount relative to wholesale market value estimates.

[72] The Appendix provides additional details on the methods used to estimate the wholesale energy and capacity value of wind.

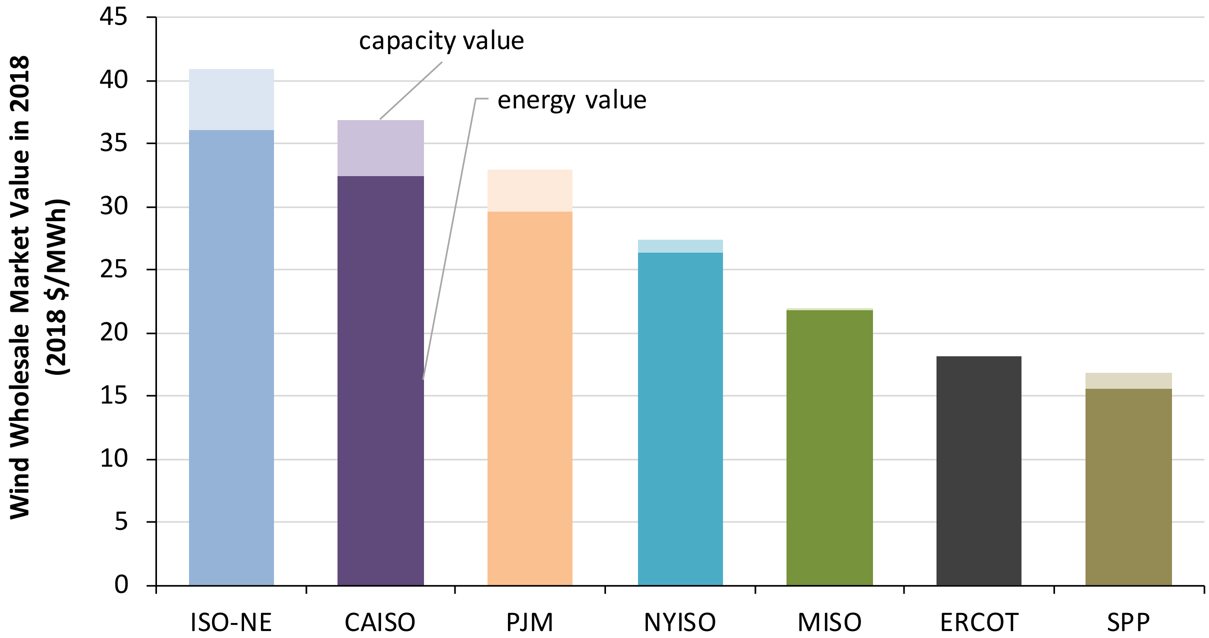


Note: Hourly wind output profiles and wholesale prices are not available for all historical years for all regions; as such, estimates of the wholesale value of wind are not available for all years for all regions.

Sources: Berkeley Lab, ABB, ISOs

Figure 58. Regional wholesale market value of wind and average levelized long-term wind PPA prices over time

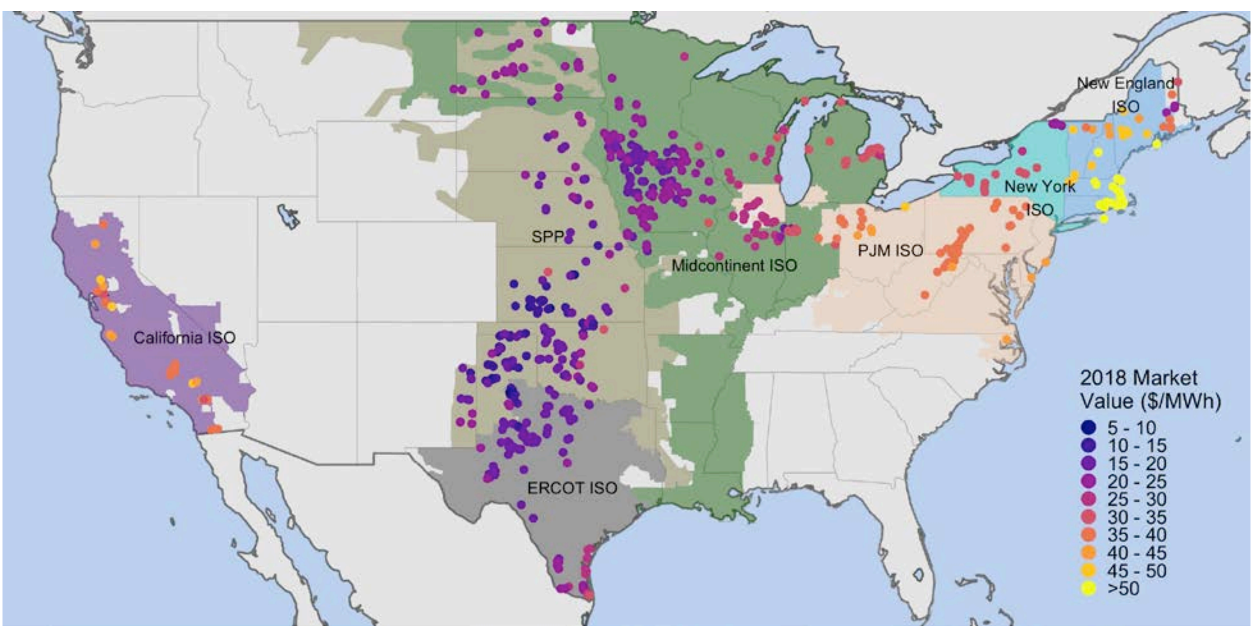
Because many of the regional wholesale market value estimates are in a similar range, it is difficult to discern individual regional data points in Figure 58. Accordingly, Figure 59 presents these estimates of wind's wholesale market value, by region, but only for the latest year—2018. The figure also disaggregates the market value estimates into their constituent parts: energy and capacity. The average market value of wind in 2018 was the lowest in SPP ($17/MWh), ERCOT ($18/MWh) and MISO ($22/MWh), whereas the highest-value market was ISO-NE ($41/MWh). Energy value represented the largest share of the total, with capacity value varying widely regionally and being considerably lower in absolute magnitude.



Sources: Berkeley Lab, ABB, ISOs

Figure 59. Regional wholesale market value of wind in 2018, by region

Finally, Figure 60 presents the 2018 market value estimates at a project level. These estimates span a wide range, from a low of $6/MWh to a high of $73/MWh, with a weighted average of $22/MWh. The figure also illustrates the variability that exists in market value within each region, with areas facing transmission congestion and high wind penetrations experiencing lower market value. Higher market value estimates are found in uncongested areas, areas with higher average wholesale prices, and areas where wind output profiles are more-correlated with electricity demand.



Sources: Berkeley Lab, ABB, ISOs

Figure 60. Project-level wholesale market value of wind in 2018

Important Note: Notwithstanding the above comparisons, neither the wind prices nor wholesale market value estimates (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind (and solar) PPA prices with wholesale value and natural-gas cost estimates in this manner are the following:

- Wind (and solar) 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 thermal generation and its fuel production. Wholesale electricity prices may also not fully account for the health and environmental costs of various generation technologies, and for other societal concerns such as fuel diversity, fuel security, and resilience.
- Wind (and solar) 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 and solar PPA prices—once established—are fixed and known. The estimated wholesale market value of wind represents historical values, whereas future natural gas prices are uncertain. Said another way, levelized wind (and solar) 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 value estimates are pertinent to just the specific historical years evaluated, and future natural gas prices reflect uncertain forecasts.

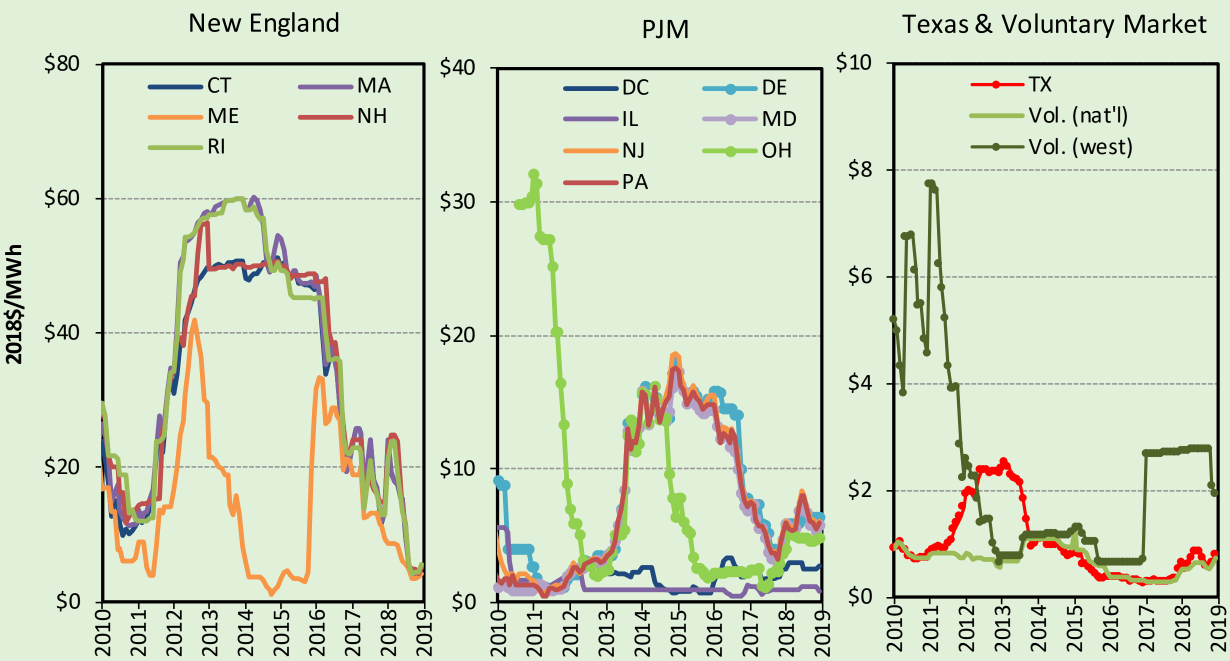
In short, comparing levelized long-term wind PPA prices with either yearly estimates of the wholesale market value of wind or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to other generation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

REC prices in RPS compliance markets remained low in 2018

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 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.

REC prices in most compliance markets remained relatively low in 2018, reflecting an over-supply relative to current RPS demand. In New England, REC prices continued their slide of the past several years, falling from roughly \$15/MWh at the end of 2017 to \$5/MWh by year-end 2018. In PJM, REC prices in most states (DE, MD, NJ, PA, OH) rebounded slightly from the prior year, but still remained well below the pricing levels seen in 2014–2015, varying within a range of roughly \$5/MWh to \$8/MWh over the course of 2018. The two other PJM states shown (DC and IL) have less restrictive eligibility rules than other states in the region, and thus saw even lower REC prices, ranging from \$1/MWh to \$3/MWh in 2018. Prices for RECs offered in the national voluntary market and for RPS compliance in Texas remained below \$1/MWh throughout the year, reflecting sustained over-supply, while prices for voluntary RECs sourced from the Western United States remained at just under \$3/MWh over the course of the year.



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.

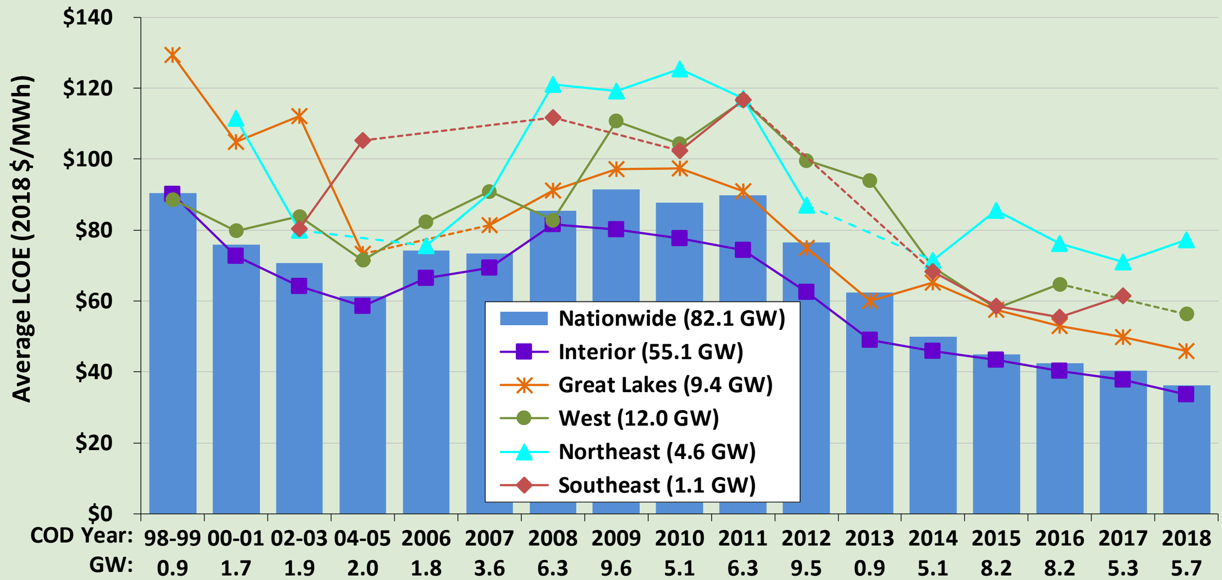
Source: Marex Spectron.

PPA price trends reflect the levelized cost of wind energy

In a competitive market, bundled long-term PPA prices can be thought of as reflecting the levelized cost of energy (LCOE) reduced by the levelized value of any incentives received (e.g., the PTC). Hence, as a first-order approximation, LCOE can be estimated simply by adding the levelized value of incentives received to the levelized PPA prices. LCOE can also be estimated more directly from its components, however, and Berkeley Lab has data on both the installed cost and capacity factor of 76.5 GW of wind power projects installed from 1998 through 2017, representing 86% of all capacity built over that period. Here we use those data, in conjunction with time-varying estimates of both operational and financing costs (the latter assuming no PTC), to estimate the LCOE of wind energy over time and by region, in real 2018 dollars. One benefit of this "bottom up" 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.

Based on a variety of data sources (including discussions with industry experts), total operational expenses are assumed to fall from a levelized cost of $82/kW-year in 1998 to $61/kW-year by 2003, $52/kW-year by 2010, and $43/kW-year by 2018 (and are interpolated linearly between these years). The weighted average cost of capital assumes a 65%:35% debt-to-equity ratio (possible in the absence of the PTC), with the cost of debt varying over time based on historical changes in the 20-year swap rate and bank spread, while the cost of equity holds steady at 10%. We assume that project life increases linearly from 20 years for all projects built before 2013 to 25 years for all projects built after 2016. We assume standardized tax rates (a combined federal and state tax rate of 40% for all projects built prior to 2018's reduction in the corporate federal tax rate, and 27% thereafter), 5-year accelerated depreciation, and 2% annual inflation. For capacity factors, we use an average of available project-level data; as such, projects installed in 1998 may have 20 years of data to average, whereas projects installed in 2017 will have just one year. For 5.7 GW of projects built in 2018 (that have not yet been operating for a full year) for which we have installed cost estimates, we assume that capacity factors match the average capacity factor of projects built in the same region from 2015 to 2017.

The figure depicts the resulting generation-weighted average LCOE values over time, nationwide and by region (regional results are only shown for years in which there is at least 20 MW of project sample). Regional LCOE values span a wide range, but regional and nationwide trends closely follow the PPA price trends shown earlier—i.e., generally decreasing from 1998 to 2005, rising through 2009, and then declining through 2018. The lowest LCOEs are found in the Interior region, with a 2018 average of $34/MWh and with some projects as low as $27/MWh; looking back in time, these are the lowest wind LCOEs on record. On a nationwide basis, the average LCOE for projects built in 2018 is at an all-time low—$36/MWh.



8 Policy and Market Drivers

The federal production tax credit remains one of the core motivators 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 (via the Energy Policy Act of 1992—see Table 4), the PTC provides a 10-year, inflation-adjusted credit that stood at $24/MWh in 2018. The historical impact of the PTC on the wind industry is illustrated by the pronounced lulls in wind additions in the years (2000, 2002, 2004, 2013) during which the PTC lapsed, as well as by the increased activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 2).

In December 2015, via the Consolidated Appropriations Act of 2016 (see Table 4), Congress passed a five-year extension of the PTC (as well as the ITC, which wind projects can elect to receive in lieu of the PTC). To qualify, projects must begin construction before January 1, 2020. Moreover, in 2016 the IRS issued Notice 2016-31, which allows four years for project completion after the start of construction, without the burden of proving continuous construction. This guidance lengthened the "safe harbor" completion period from the previous term of two years.

In extending the PTC, Congress established a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC phases 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 PTC.

Developers 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 (2017) reported two such estimates of PTC-qualified capacity—30–58 GW and 40–70 GW—while consultant MAKE pegged the number at 45 GW (Recharge 2017). Notwithstanding this large volume of turbines that will be deployed through 2020 (within the four-year safe harbor window), an additional 10 GW of wind capacity was reportedly qualified for 80% of the PTC by the end of 2017, with yet another 6.6 GW qualified in 2018 for the 60% PTC (Froese 2019).

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 five- to six-year period for tax purposes. Even shorter "bonus depreciation" schedules have been periodically available, since 2008, and the December 2017 tax reform legislation allows both new and used equipment to be fully expensed (i.e., equivalent to 100% bonus depreciation) in the year of purchase; historically, however, the wind industry has not opted to fully utilize such bonus depreciation measures.

The continued near-term availability of federal tax incentives underpins recent low-priced power purchase agreements for wind energy, and is a significant contributor to the ongoing surge in wind capacity additions. As discussed earlier, the tax reform legislation passed in December 2017 seems unlikely to substantially impact wind development during the current PTC cycle. The PTC phase-out, on the other hand, imposes risks to the industry's competitiveness in the mid- to long-term.

Table 4. History of Production Tax Credit Extensions

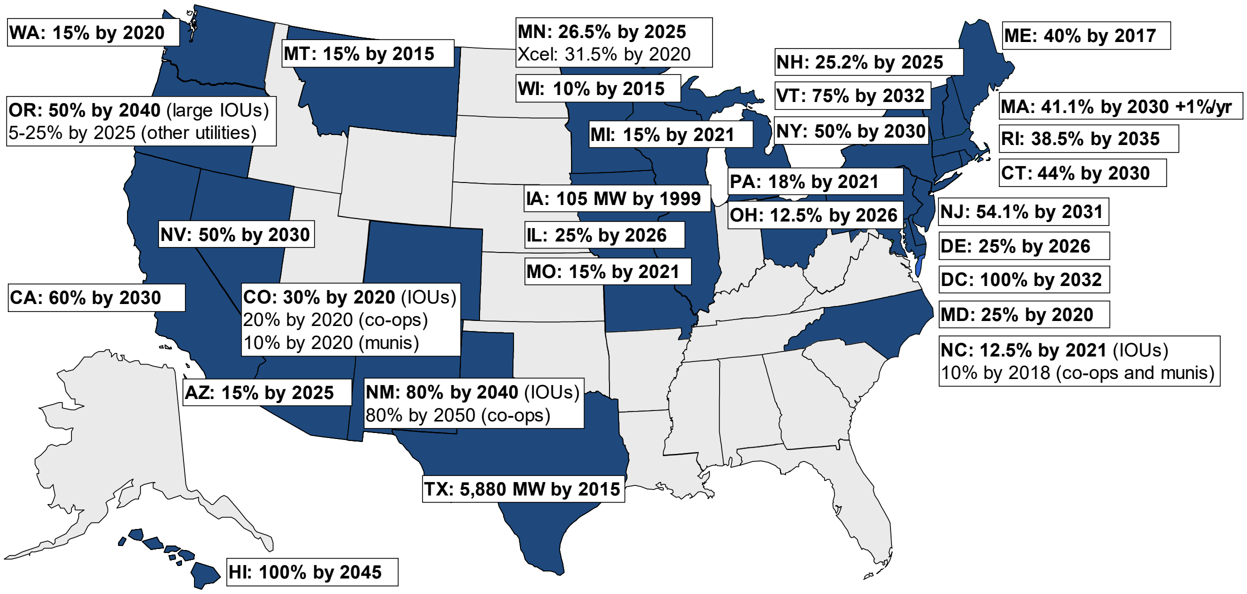
Legislation	Date Enacted	Start of PTC Window	End of PTC Window	Effective PTC Planning Window (considering lapses and early extensions)
Energy Policy Act of 1992	10/24/1992	1/1/1994	6/30/1999	80 months
>5-month lapse before expired PTC was extended				
Ticket to Work and Work Incentives Improvement Act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

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. While it is rarely used, this ITC option has been included in all subsequent PTC extensions (and will follow the same phase-out 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. 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 wind power growth is outpacing state targets

As of May 2019, mandatory RPS programs existed in 29 states and Washington, D.C. (Figure 61).[73,74] In recent years, a sizeable contingent of states have increased their RPS targets, in many cases to levels ranging from 50% to 100% of retail electricity sales. Since the beginning of 2018 and through May 2019, six states (California, Connecticut, Massachusetts, New Jersey, New Mexico, and Nevada) and Washington, D.C. have enacted legislation increasing their RPS targets. In addition to the RPS policies shown in Figure 61, several states—including California, New Mexico, and Washington—have also adopted 100% zero-carbon electricity standards or goals.



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 61. State RPS policies as of May 2019

Of all wind power capacity built in the United States from 2000 through 2018, Berkeley Lab estimates that roughly 47% is delivering RECs to load-serving entities 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; 19% of U.S. wind capacity additions in 2018 is estimated to serve RPS requirements. Outside of the wind-rich Interior region, however, RPS requirements continue to form a strong driver for wind growth, with 63% of 2018 wind capacity additions in those regions serving RPS demand.

In aggregate, existing state RPS policies will require 570 terawatt-hours of RPS-eligible electricity by 2030, at which point RPS requirements in most states 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

[73] The data and analysis reported in this section largely derives from Barbose (2018), with some updates to include 2019 data.
[74] Although not shown in Figure 55, 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.

total of around 167 GW of RPS-eligible generation capacity needed to meet RPS demand in 2030.[75] Of that total, Berkeley Lab estimates that existing state RPS programs will require roughly 60 GW of renewable capacity additions by 2030, relative to the installed base at year-end 2018.[76] This equates to an average annual build-rate of roughly 5.0 GW per year, only a portion of which will be wind. By comparison, over the past decade, U.S. wind power capacity additions averaged 7.2 GW per year, and total U.S. renewable capacity additions averaged 13.1 GW per year.

In addition to state RPS policies, utility resource planning requirements—principally in Western and Midwestern states—have motivated wind power additions in recent years.[77] So has voluntary customer demand for "green" power (O'Shaughnessy et al. 2018). 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.[78] Finally, some states and regions have enacted carbon reduction policies that may help to support wind power development. For example, the Northeast's Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy has been operational for a number of years,[79] and California's greenhouse gas cap-and-trade program commenced operation in 2012,[80] although carbon pricing in these programs has generally been too low to drive significant wind energy growth.

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

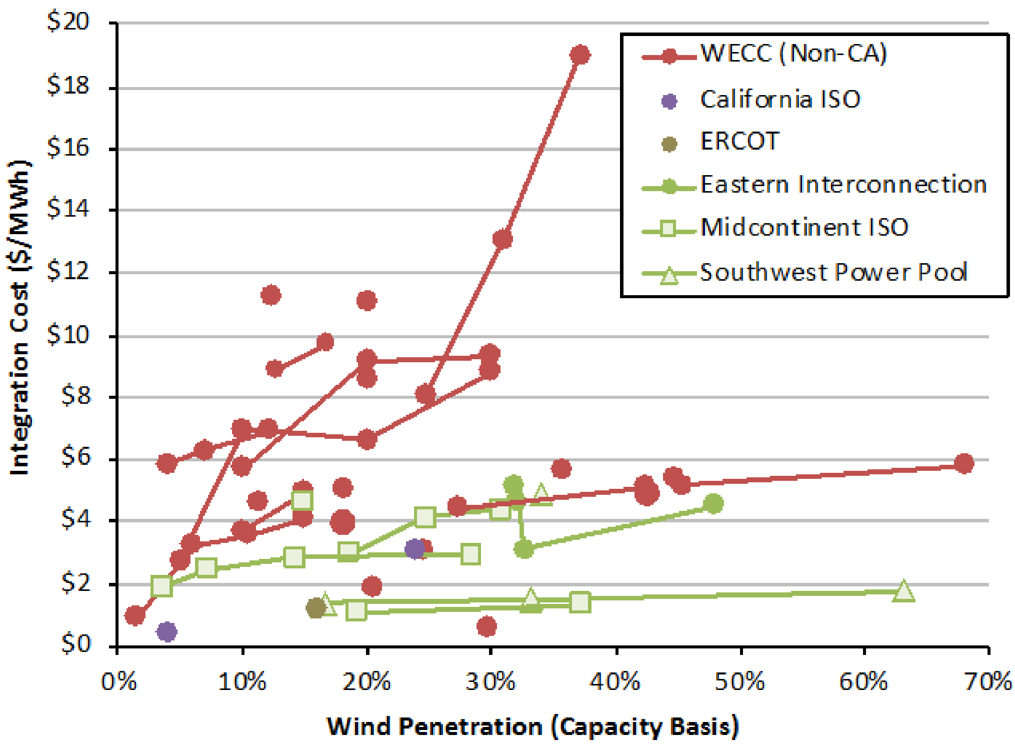
Wind energy output is variable and often the areas with the greatest wind speeds are distant from electricity load centers. As a result, integration with the power system and provision of adequate transmission capacity are particularly important for wind energy. Concerns about, and solutions to, these issues impact the pace of wind power deployment. Worldwide experience in operating power systems with wind energy highlights the critical role of power system flexibility, defined as the characteristics of a power system that facilitate effective management of variability and uncertainty (IEA 2019).

Figure 62 provides a selective listing of estimated wind integration costs at various levels of wind capacity penetration, from studies completed from 2003 through 2018, and grouped by region of the United States. While studies differ in how they define integration costs, the impacts assessed typically include any additional balancing costs associated with managing increased forecast errors and balancing reserves. These integration costs were not included in the earlier analysis of the market value of wind, which only accounted for the time-varying generation profile and the location of wind in the system. Some of the integration cost studies reported in Figure 62 also include an estimate of the difference in the value of wind with a time-varying profile compared to a more conventional dispatch profile, thereby potentially overlapping with the market value

[75] 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.
[76] 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 2018. 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 load-serving entities 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).
[77] See, e.g., https://resourceplanning.lbl.gov/login.php
[78] See, e.g., https://www.dsireusa.org/
[79] See, e.g., https://www.rggi.org/
[80] See, e.g., https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm

results presented earlier. The wind integration costs in these studies do not, however, include any costs associated with incremental transmission or the lower capacity contribution of wind, costs that are sometimes included in other integration cost estimates and that are partially captured in the market value estimates presented earlier (e.g., Heptonstall et al. 2017, BP 2018).

Integration costs estimated by the studies reviewed are near or below $5/MWh in all of the regions shown, except the non-California portion of the Western Electricity Coordinating Council (WECC), for wind power capacity penetrations up to and even exceeding 40% of the peak load of the system in which the power is delivered. Studies in the non-California portion of WECC are all focused on individual utilities that also act as balancing authorities, with responsibility to maintain a balance between supply and demand at all times. These studies tend to find higher integration costs, though, with limited exceptions, integration costs estimated by the studies reviewed are still below $10/MWh. Even in the non-California portion of WECC, however, some recent studies find relatively low integration costs. Overall, the results of these studies show that costs tend to increase with wind penetration levels, and tend in general to be lower when balancing areas are larger. 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.



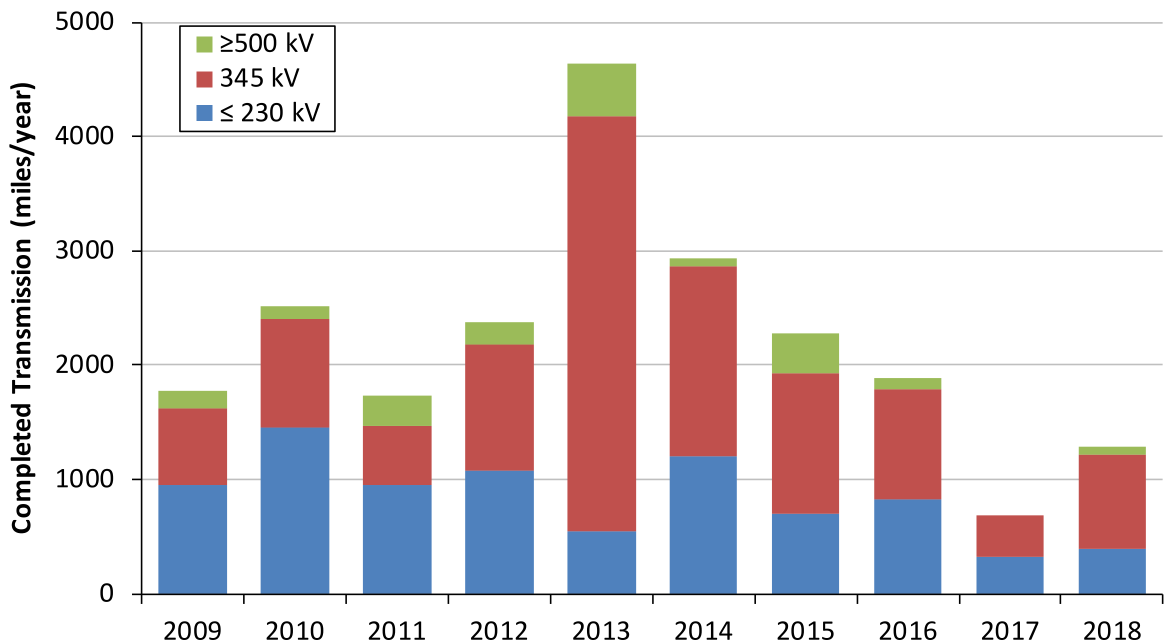
Notes: All studies categorized as WECC (Non-CA) are from individual utilities within WECC. Studies in California and ERCOT are all regional. Many of the studies in the Eastern Interconnect (inclusive of those in MISO and SPP) are regional, but some are from individual utilities. Studies that assessed multiple wind energy penetrations using a common methodology are depicted with connecting lines.

Sources: Additional details on the studies included in this review, and therefore represented in the figure, can be found in the data file associated with this report, downloadable from: https://emp.lbl.gov/wind-technologies-market-report

Figure 62. Integration costs at various levels of wind power capacity penetration

Beyond these studies, system operators and planners continue to make progress integrating wind into the power system with new records for instantaneous wind penetration hit each year, including SPP reaching an instantaneous wind penetration of over 70% in April 2019. SPP is developing products to better manage uncertainty in order to minimize manual adjustments by system operators, focusing on uncertainty in the 30-minutes to 3-hour period (SPP 2019). MISO has found that incorporating the ability to dispatch wind resources in the MISO markets improves congestion management, almost entirely eliminating manual curtailment of wind (Potomac Economics 2018). MISO also found that it needed to better incorporate the technical characteristics of wind turbines into wind energy forecasts, however, as a severe cold snap demonstrated that wind turbines often shut down in especially low temperatures (Potomac Economics 2019a). Finally, system operators continue to examine issues arising from wind generators not naturally contributing inertia to the system and displacing synchronous generators that do (e.g., Matevosyan 2018). An increase in ancillary service requirements in ERCOT in 2018 was primarily due to the need to ensure adequate online inertia (Potomac Economics 2019b).

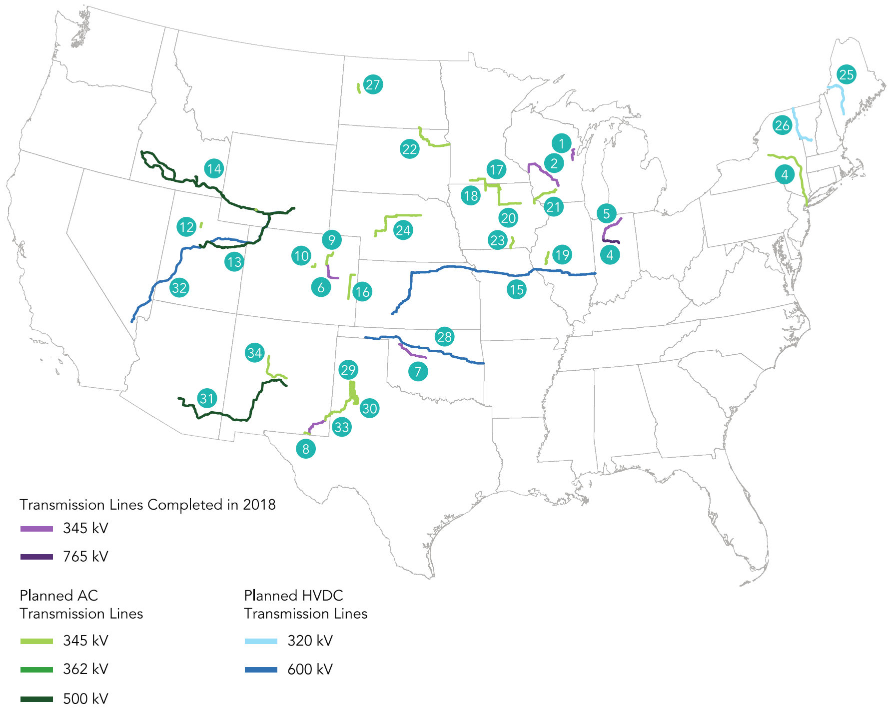
The best wind resources are often located far from load centers, and so transmission is also particularly important for wind power. Transmission additions were limited in 2018, with approximately 1,300 miles of transmission lines coming online (see Figure 63). The decline since the peak in 2013 is, in part, due to the completion of the Texas CREZ lines in 2013. As of March 2019, FERC (2019b) finds that another 6,300 miles of new transmission (or upgrades) are proposed to come online by April 2021, with 2,200 miles of those lines having a higher probability of completion.



Source: FERC monthly infrastructure reports

Figure 63. Miles of transmission projects completed, by year and voltage

Eight transmission projects that may support wind energy were completed in 2018. In addition, AWEA (2019a) has identified a large number additional near-term transmission projects that, if completed, could support considerable amounts of wind capacity (see Figure 64).



	Project Name	In-Service Date
1	**Bay Lake (North Appleton to Morgan)**	**2018**
2	**MVP 5**	**2018**
3	**Hobbs-China Draw**	**2018**
4	**MVP 14**	**2018**
5	**MVP 12**	**2018**
6	**Rush Creek**	**2018**
7	**Windspeed II**	**2018**
8	China Draw-Phantom-Roadrunner	2021
9	Daniels Park - Missile to Pawnee	2019
10	Daniels Park - Smoky Hill to Daniels Park	2019
11	Empire State Connector	2023
12	Gateway Central	2022
13	Gateway South	2021
14	Gateway West	2020 - 2024
15	Grain Belt Express	2023
16	Lamar - Front Range	2023
17	Ledyard-Colby	-
18	Minnesota-Iowa	2019
19	MVP 11	2019
20	MVP 4	2019
21	MVP 5	2023
22	MVP 6	2019
23	MVP 7	-
24	Nebraska Transmission Line	2021
25	New England Clean Energy Connect	2022
26	New England Clean Power Link	2022
27	North Killdeer Loop	2019
28	Plains & Eastern	2020
29	South Plains - Ogallala to Abernathy	2021
30	South Plains Abernathy to Wadsworth	2021
31	SunZia Southwest	2020
32	TransWest Express	2023
33	Tuco-Yoakum-Hobbs	2020
34	Western Spirit	2020

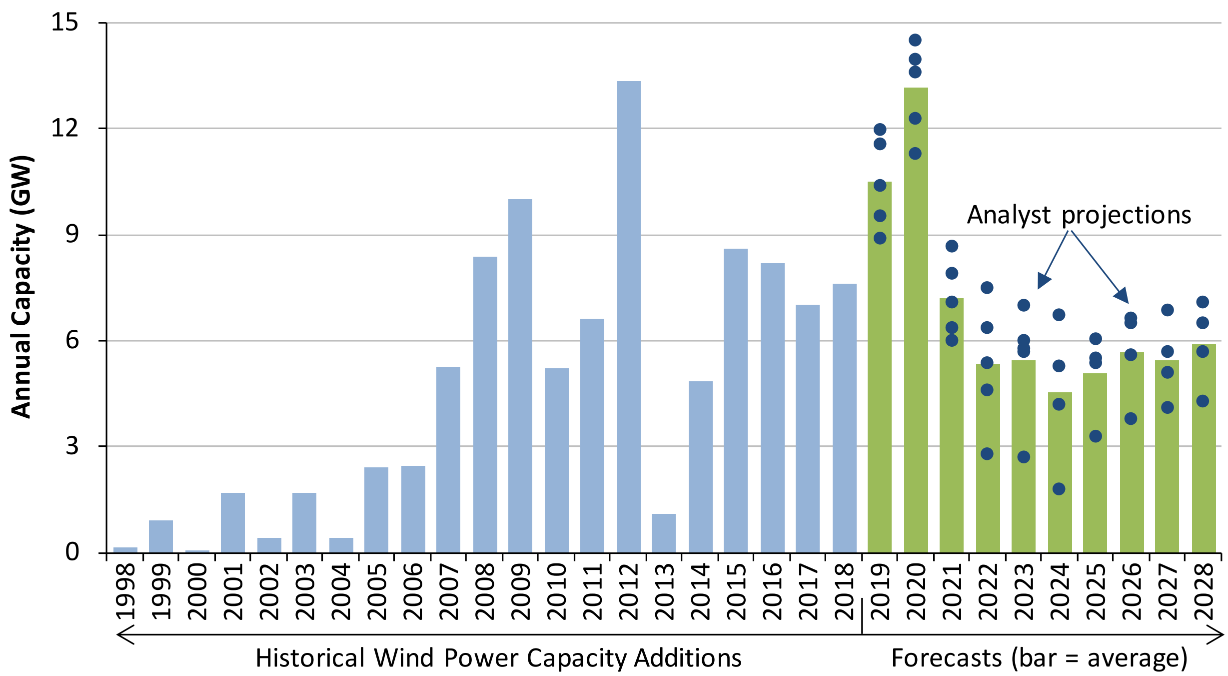
Source: AWEA (2019a)

Figure 64. Transmission line activity: completed in 2018, and planned for near future

9 Future Outlook

Energy analysts project that annual wind power capacity additions will continue at a rapid clip for the next couple years, before declining, driven by the five-year extension of the PTC 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. Factors impacting wind energy demand also include corporate wind energy purchases and state-level renewable energy policies.

Among the forecasts for the domestic market presented in Figure 65, expected capacity additions increase from 9–12 GW in 2019 to 11–15 GW in 2020 (BNEF 2019, Wood Mackenzie 2019, Navigant 2019, IHS 2019, GWEC 2019). Forecasts for 2021 to 2028, on the other hand, show a downturn in additions in part due to the PTC phase-out. Expectations for continued low natural gas prices and modest growth in electricity demand also put a damper on growth expectations, as do limited transmission infrastructure and competition from other resources (natural gas and—increasingly—solar, in particular) in certain regions of the country. At the same time, declines in the price of wind energy over the last decade have been substantial, helping to improve the economic position of wind even in the face of challenging competition. The potential for continued advancements and cost reductions enhances the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and continued state policies supportive of wind energy. 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 power additions, especially after 2021, remain uncertain.



Sources: AWEA WindIQ (historical additions), BNEF (2019), IHS (2019), GWEC (2019), Navigant (2019), Wood Mackenzie (2019)

Figure 65. 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 (60 GW, in total) are greater than the pathway envisioned in the DOE report (54 GW). Projected growth from 2021 through 2028 (45 GW), however, is well below the *Wind Vision* pathway (90 GW). As discussed in the DOE *Wind Vision* (2015), and as further suggested by these comparisons, achieving 20% wind energy by 2030 and 35% by 2050 would likely 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 and repowering in the United States (as well as certain details on the underlying wind power projects) are sourced largely from AWEA (2019a). Annual wind power capital investment estimates derive from multiplying 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 Wood Mackenzie Power & Renewables.

Global cumulative (and 2018 annual) wind power capacity data are sourced from GWEC (2019) but are revised, as necessary, to include the U.S. wind power capacity used in the present report. Wind energy penetration is compiled by AWEA (2019a).

The wind project installation map was created by NREL, based (in part) on AWEA's WindIQ project database. Wind energy as a percentage contribution to statewide electricity generation and consumption is based on EIA data for wind generation divided by in-state total electricity generation or consumption in 2018.

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

Industry Trends

Turbine manufacturer market share data are derived from the AWEA WindIQ 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 (2019a), 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 of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. Census Bureau, and obtained from the U.S. Census's USA Trade Online data tool (https://usatrade.census.gov/). The analysis of the 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	2005–2018	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	2011–2018	mostly 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	2012–2018	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	2012–2018	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	2012–2018	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014–2018	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[81]

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 and other wind equipment shipped under 8503.00.9560—a range of ±50% of the total estimated wind import value is applied for HTS code 8503.00.9560.

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from the Intercontinenatal Exchange, BNEF, and Norton Rose Fulbright. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of AWEA's WindIQ project database.

Wind Turbine Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, specific power, and IEC Class was compiled by Berkeley Lab within the United States Wind Turbine Database (USWTDB) based on information provided by AWEA, turbine manufacturers, standard turbine specifications, the 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 2018. Some turbines 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

[81] 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 blades—which are essential to wind-powered generating sets as defined in the HTS.

numerical class for purposes of analysis but are also reported separately 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 March 31, 2019 and September 30, 2020 were categorized as either "pending" turbines (for those that already had received an evaluation of "no hazard") or "proposed" turbines (for those that were still being evaluated). For Figure 32, no distinction regarding either expiration dates or hazard evaluations was made—instead, all permit applications in the OE/AAA file were used and were binned based on their submission year.

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, MISO, PJM, NYISO, SPP, ISO-New England, and CAISO.

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, within the USWTDB, 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 WindIQ 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 the 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 52,115 turbines of the 52,830 installed from 1998 through 2018 in the continental United States (i.e., nearly 99%). Roughly 80% of the 715 turbines that are *not* mapped are more than twelve years old.

The relative strength of the average "fleet-wide" wind resource from year to year is estimated based on weighting each operational project-level wind resource (or "wind index") by its share of the total operational fleet-wide capacity for the particular year. For each individual wind plant, an annual wind index is calculated as the ratio of a particular year's predicted capacity factor to the long-term average predicted capacity factor (with the long-term average calculated from 1998-2018). Site-level available wind resources are calculated for each hour of each year based on ERA5 reanalysis wind speed data for each plant's location. ERA5 has a horizontal resolution of ~30 km × 30 km. Site-specific estimated wind speeds (with the geographic resolution previously noted) are interpolated between ERA5 model heights to the corresponding representative hub-height for each wind project. Hourly wind speeds at each project are then converted to wind power by applying project-specific power curves. Power curves are based on the set of turbine-specific power curves reported by *thewindpower.net*, which provides power curves for more than 750 separate turbines. Although many projects contain only a single type of turbine, some projects contain multiple turbine types. For the latter projects, a turbine power curve is selected that most closely matches the average turbine capacity, rotor diameter, and specific power across the project. The wind indices are calculated without accounting for wake, electrical, or other losses, or curtailment, and are based only on the ERA5 wind speeds. These indices are used to represent changes in the wind resource from one year to the next, and reflect the ERA5-based strength of the total potential wind resource given the types of turbines that are deployed at each site. Note that these data and indices are used to characterize year-to-year variations in the strength of the wind resource, whereas AWS Truepower estimates are used to characterize the strength of the site-specific long-term annual average wind resource. We use AWS Truepower estimates for the latter need due to their higher geographic resolution.

Historical U.S. wind turbine transaction prices were, in part, 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. Additional data come from Vestas, SGRE and Nordex corporate reports, BNEF, and MAKE Consulting.

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 2016, EIA Form 860 data are used extensively. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not all equally credible, less emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer greater 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.

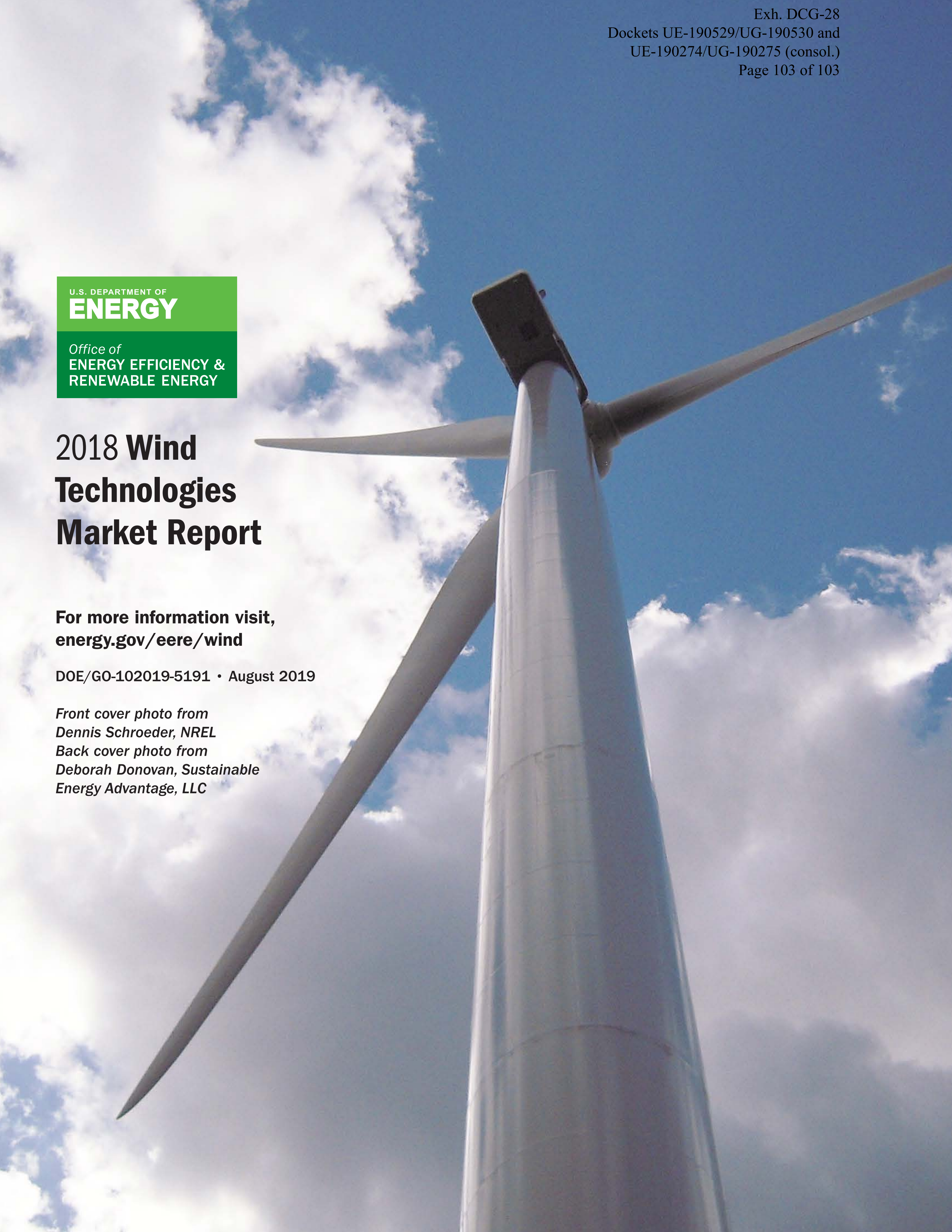
Wind PPA price data are based on multiple sources, including prices reported in FERC's *Electronic Quarterly Reports*, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs.

To calculate the historical wholesale energy market value of wind we match estimated hourly wind generation profiles to hourly nodal real-time wholesale prices. As described in more detail below, we also calculate the capacity value at each plant, based on the modeled wind profiles and ISO-specific rules for wind's capacity credit and ISO-zone-specific capacity prices. We calculate the average $/MWh energy and capacity value for each plant and year. We estimate the ISO-level average value by weighting plant-level value estimates by plant capacity. To calculate the average energy and capacity $/MWh value, we calculate the numerator based on actual hourly generation after curtailment but calculate the denominator based on the total generation without curtailment. We account for curtailment only in the numerator so that increased levels of curtailment will reduce the average $/MWh value. The MWh, in this case, reflect potential wind generation before curtailment. Note that public data do not broadly exist for hourly wind output profiles at the plant level. Consequently, we leverage the ERA5-based modeled wind generation estimates described earlier. However, when developing energy value estimates we adjust plant-level ERA5-based generation estimates for curtailment and apply a bias correction process. The resulting generation estimates incorporate publicly available information on actual generation as well as site-specific ERA5 modeled wind speeds. One exception to this process is for plants located in ERCOT. ERCOT provided high time resolution records of plant level generation and curtailment going back to 2013, and, where available, we use these reported values over the modeled values.

Details on the processes related to curtailment and bias correction follow: Total curtailment is reported by each ISO for either each hour or each month. CAISO, ERCOT, and SPP report hourly curtailment; MISO, NYISO, ISO-NE, and PJM report monthly curtailment. We distributed total reported hourly curtailment evenly across all plants within a particular ISO that face local prices below zero for that hour (i.e., generation from plants with negative prices is reduced by an equal percentage so that the total proportion of generation curtailed across all plants in the ISO matches the proportion of generation curtailed as reported by the ISO). If, in a particular hour, there is not enough modeled curtailment among plants with prices below zero, the price cutoff point is incrementally raised until the curtailment proportion matches the reported total. A similar process is used to distribute monthly curtailment ISO totals to individual plants and hours. The bias correction involves an iterative linear scaling approach so that each plant's total modeled generation matches its reported generation (from EIA or FERC, typically at the monthly or quarterly level) and the sum of estimated hourly generation across all plants within each ISO matches the hourly total wind generation reported by each ISO. Because we do not necessarily include the same exact set of plants that each ISO includes when reporting its total hourly wind production, we scale the ISO-level total generation to match the total estimated generation within our set of plants, and effectively match the relative hourly shape at the ISO-level. For our value estimates we exclude plants that fall outside the ISO regions because we cannot include curtailment or bias correction for those plants. Also, depending on the ISO, curtailment data may not be available for all historical years. When curtailment data are not available, we continue to employee the bias correction process but do not pre-process the generation estimates for curtailment.

Our data source for hourly nodal real-time wholesale electricity prices and for hourly regional wind output profiles is ABB's Velocity Suite database (which, in many cases, derives data from ISOs). Curtailment data are downloaded directly from each ISO, or in some cases, from ABB's Velocity Suite database. For each wind power plant, we identify the nearest or most-representative pricing node (in most cases within 10 km of the plant), which allows us to match representative prices to each plant. For some regions, hourly wind output profiles are only available for a subset of the relevant years of our analysis; as such, estimates of the wholesale energy value of wind are not available for all years for all regions. Finally, as indicated earlier, capacity value is estimated for each plant based on modeled wind profiles and ISO and ISO-zone specific capacity prices or costs, as well as relevant regional rules for wind's capacity credit. No capacity value is calculated for ERCOT because ERCOT runs an energy-only market that does not require load serving entities to meet a resource adequacy obligation. As for capacity prices and costs, many regions have organized capacity markets, in which case we use market-clearing prices from those auctions in concert with ISO-rules or estimates for the capacity credit of wind plants. For regions where load serving entities have a resource adequacy obligation but lack organized capacity markets, on the other hand, we use available data from regulatory bodies to approximate capacity costs and combine those data with regional estimates or rules for wind's capacity credit.

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 2019* 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.



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