U.S. DEPARTMENT OF ENERGY

Office of ENERGY EFFICIENCY & RENEWABLE ENERGY

Land-Based Wind Market Report: 2022 Edition

This report is being disseminated by the U.S. Department of Energy (DOE). As such, this document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for fiscal year 2001 (public law 106-554) and information quality guidelines issued by DOE. Though this report does not constitute "influential" information, as that term is defined in DOE's information quality guidelines or the Office of Management and Budget's Information Quality Bulletin for Peer Review, the study was reviewed both internally and externally prior to publication. For purposes of review, the study benefited from the advice and comments of eleven industry stakeholders, U.S. Government employees, and national laboratory staff.

Available electronically at SciTech Connect: http://www.osti.gov/scitech

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
OSTI: http://www.osti.gov
Phone: 865.576.8401
Fax: 865.576.5728
Email: reports@osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Road
Alexandria, VA 22312
NTIS: http://www.ntis.gov
Phone: 800.553.6847 or 703.605.6000
Fax: 703.605.6900
Email: orders@ntis.gov

Preparation and Authorship

This report was prepared by Lawrence Berkeley National Laboratory for the Wind Energy Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy.

Corresponding authors of the report are: Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory. The full author list includes: Ryan Wiser, Mark Bolinger, Ben Hoen, Dev Millstein, Joe Rand, Galen Barbose, Naïm Darghouth, Will Gorman, Seongeun Jeong, and Ben Paulos.

Acknowledgments

For their support of this ongoing report series, the authors thank the entire U.S. Department of Energy (DOE) Wind Energy Technologies Office team. In particular, we acknowledge Gage Reber and Patrick Gilman. For reviewing elements of this report or providing key input, we also thank: Manussawee Sukunta (U.S. Energy Information Administration); Andrew David (Silverado Policy Accelerator); Charlie Smith (Energy Systems Integration Group); Feng Zhao (Global Wind Energy Council); David Milborrow (consultant); John Hensley (American Clean Power Association); Mattox Hall (Vestas); Aaron Barr (Wood Mackenzie); and Patrick Gilman, Gage Reber, and Liz Hartman (DOE). For providing data that underlie aspects of the report, we thank the U.S. Energy Information Administration, BloombergNEF, Wood Mackenzie, Global Wind Energy Council, and the American Clean Power Association. Thanks also to Donna Heimiller (NREL) for assistance in mapping wind resource quality; and to Amy Howerton, Carol Laurie and Alexsandra Lemke (NREL), and Liz Hartman and Heather Doty (DOE) for assistance with layout, formatting, production, and communications. Lawrence Berkeley National Laboratory's contributions to this report were funded by the Wind Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the DOE under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

List of Acronyms

ACP	American Clean Power Association
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COD	commercial operation date
CCA	community choice aggregator
DOE	U.S. Department of Energy
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
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

RPS	renewables portfolio standard
RTO	regional transmission organization
SGRE	Siemens Gamesa Renewable Energy
SPP	Southwest Power Pool
W	watt
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

Wind power additions in the United States totaled 13.4 gigawatts (GW) in 2021. Recent growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind capacity additions, even as supply chain constraints due to increased commodity and transportation costs and COVID-19 restrictions push costs higher.

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

Installation Trends

- **U.S. wind power capacity grew at a strong pace in 2021, with 13.4 GW of new capacity added and $20 billion invested.** Cumulative wind capacity grew to nearly 136 gigawatts (GW) by the end of 2021. In addition, 1.6 GW of existing wind plants were partially repowered in 2021, mostly by upgrading rotors and nacelle components.
- **Wind power represented the second largest source of U.S. electric-power capacity additions in 2021, at 32%, behind solar's 45%.** Wind power constituted 32% of all generation and storage capacity additions in 2021. Over the last decade, wind represented 30% of total capacity additions, and a larger fraction of new capacity in SPP (83%), ERCOT (52%), MISO (52%), and the non-ISO West (33%).[1]
- **Globally, the United States again ranked second in annual wind capacity, but remained well behind the market leaders in wind energy penetration**. Global grid-connected wind additions totaled 94 GW in 2021, yielding a cumulative 839 GW. The United States remained the second-leading market in terms of annual and cumulative capacity, behind China. A number of countries have achieved high levels of wind penetration, with wind supplying 44% of Denmark's total electricity generation in 2021, and over 20% in Ireland, Portugal, Spain, Germany, and the U.K. In the United States, wind supplied 9.1%.
- **Texas installed the most wind capacity in 2021 with 3,343 MW, followed by Oklahoma, New Mexico and Kansas; eleven states exceeded 20% wind energy penetration.** Texas also remained the leader on a cumulative basis, with nearly 36 GW of capacity. Notably, the wind capacity installed in Iowa supplied 55% of all in-state electricity generation in 2021, while South Dakota (52%), Kansas (45%), Oklahoma (41%), and North Dakota (34%) were all above 30%. Within independent system operators (ISOs), wind penetration (expressed as a percentage of load) was 34.8% in SPP, 24.2% in ERCOT, 12.0% in MISO, 8.4% in CAISO, 3.5% in PJM, 3.0% in ISO-NE, and 2.7% in NYISO.
- **Hybrid wind plants that pair wind with storage and other resources saw limited growth in 2021, with just two new projects completed.** There were 41 hybrid wind power plants in operation at the end of 2021, representing 2.4 GW of wind and 0.9 GW of co-located assets. The most common wind hybrid project combines wind and storage technology, where 1.4 GW of wind has been paired with 0.2 GW of battery storage. The average storage duration of these projects is 0.6 hours, suggesting a focus on ancillary services and limited capacity to shift large amounts of energy across time. While only two new wind hybrids were commissioned in 2021, solar hybrids expanded rapidly with 67 new PV+storage projects coming online in 2021.

[1] The nine regions most commonly used in this report are the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO), and the non-ISO West and Southeast.

- **A record-high 247 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace.** At the end of 2021, there were 247 GW of wind capacity seeking transmission interconnection, including 77 GW of offshore wind and 19 GW of hybrid wind projects (in the latter case, mostly wind paired with storage). In 2021, 73 GW of wind capacity entered interconnection queues. Energy storage interconnection requests have increased rapidly in recent years, both for stand-alone and hybrid plants, most-often pairing solar with storage. The West (non-ISO), SPP, and NYISO regions had the greatest quantity of wind in their queues at the end of 2021. Roughly one-third of all wind capacity added to queues in 2021 was for offshore wind plants.

Industry Trends

- **Just four turbine manufacturers, led by GE, supplied all of the U.S. wind power capacity installed in 2021.** In 2021, GE captured 47% of the U.S. market for turbine installations, followed by Vestas at 26% and Siemens-Gamesa Renewable Energy (SGRE) and Nordex, both at 13%.[2]
- **The domestic wind industry supply chain contracted in 2021, with a 50% decline in blade manufacturing capability.** Domestic nacelle assembly and tower manufacturing capability declined modestly in 2021, to an equivalent 12.3 GW and 9.2 GW per year, respectively. Blade manufacturing capability plummeted by 50%, however, as three domestic manufacturing facilities closed or idled, and stood at 4.6 GW per year. More broadly, fierce competition and supply-chain constraints resulted in low profit margins for turbine manufacturers. Nonetheless, wind-related job totals in the United States increased in 2021, to 120,164.
- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports, which totaled $3.1 billion in 2021.** The United States imports wind equipment from many countries, including most prominently in 2021: Mexico, Spain, and India. Domestic content is highest for nacelle assembly (>85%) and towers (55%–70%). For blades, it declined precipitously to just 15–25% in 2021 as competitive pressures made blade imports more economical than domestically produced blades.
- **Independent power producers own the majority of wind assets built in 2021, following historical trends.** Independent power producers (IPPs) own 75% of the new wind capacity installed in the United States in 2021, with the remaining assets (25%) owned by investor-owned utilities.
- **Direct retail sales and merchant offtake arrangements for wind, in combination, matched or surpassed long-term contracted wind sales to utilities in 2021.** Electric utilities either own (25%) or buy electricity (19%) from wind projects that, in total, represent 44% of the new wind capacity installed in 2021. But direct retail purchasers of wind—including corporate offtakers—account for at least 35%, while merchant/quasi-merchant projects and power marketers make up at least another 7% and 2%, respectively. The remainder (11%) is presently undisclosed.

Technology Trends

- **Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term.** To optimize project cost and performance, and thus minimize overall cost of energy, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed wind turbines in the United States in 2021 was 3.0 MW, up 9% from the previous year and 319% since 1998−1999. The average rotor diameter of newly installed turbines in 2021 was 127.5 meters, a 2% increase over 2020 and 164% over 1998−1999, while the average hub height was 93.9 meters, up 4% from 2020 and 66% since 1998−1999.

[2] Numerical values presented here and elsewhere may not add to 100%, due to rounding.

- **Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has reversed over the last two years.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average "specific power" [3] (in W/m^2), from 393 W/m^2 among projects installed in 1998–1999 to 231 W/m^2 among projects installed in 2021—though specific power has modestly increased over the last two years. Turbines with low specific power were originally designed for lower wind speed sites, but are now being used at many sites as the most attractive technology.

- **Wind turbines were deployed in somewhat lower wind-speed sites in 2021 than in the previous seven years.** Wind turbines installed in 2021 were located in sites with an average estimated long-term wind speed of 8.0 meters per second at a height of 100 meters above the ground—this is the lowest average long-term wind speed among newly built projects in the last eight years. Federal Aviation Administration (FAA) and industry data on projects that are either under construction or in development suggest that the sites likely to be built out over the next few years will, on average, have even lower average wind speeds. Increasing hub heights help to partially offset these trends, enabling turbines to access higher wind speeds.

- **Low-specific-power turbines are deployed on a widespread basis; taller towers are seeing increased use in a wider variety of sites.** Low specific power turbines continue to be deployed in all regions, 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 upper Midwest and Northeastern regions.

- **Wind projects planned for the near future are poised to continue the trend of ever-taller turbines.** The average "tip height" (from ground to blade tip extended directly overhead) among projects that came online in 2021 is 517 feet (158 meters). FAA data suggest that future projects will deploy even taller turbines. Among "proposed" turbines in the FAA permitting process, the average tip height reaches an average of 643 feet (196 meters).

- **In 2021, twelve wind projects were partially repowered, most of which now feature significantly larger rotors and lower specific power ratings.** Partially repowered projects in 2021 totaled 1.6 GW prior to repowering, a decline from the roughly 3 GW of projects partially repowered in each of the previous two years. Of the changes made to the turbines, larger rotors dominated, reducing specific power from 312 to 223 W/m^2. The primary motivations for partial repowering have been to re-qualify for the PTC, while at the same time increasing energy production and extending the useful life of the projects.

Performance Trends

- **The average capacity factor in 2021 was 35% on a fleet-wide basis and 39% among wind projects built in recent years**. The average 2021 capacity factor among projects built from 2014 to 2020 was 39%, compared to an average of 26% among projects built from 2004 to 2011, and 19% among projects built from 1998 to 2001. This improvement among more-recently built projects has pushed the cumulative fleet-wide capacity factor higher over time; it was 35% in 2021. The 2021 capacity factor for projects built in 2020 was 38%, somewhat lower than for projects built from 2014 to 2020.

- **State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country.** Based on projects built from 2016 to 2020, average capacity factors in 2021 were highest in central states and lower closer to the coasts. Not surprisingly, the state and regional rankings are roughly consistent with the relative quality of the wind resource in each region.

[3] 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.

- **Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor over the long term**. The decline in specific power has been a major contributor to higher capacity factors, but has been offset in part by a tendency toward building projects at sites with lower annual average wind speeds. As a result, average capacity factors over the last eight years have been reasonable stable, with some evidence of modest declines most recently as specific power has drifted upwards and site quality has modestly decreased.
- **Wind power curtailment in 2021 across seven regions averaged 4.8%, up from a low of 2.1% in 2016.** Across all ISOs, wind energy curtailment in 2021 stood at 4.8%—generally rising over the last five years. This average masks variation across regions and projects. SPP (6.4%), ERCOT (5.2%), and MISO (4.7%) experienced the highest rates of wind curtailment, while the other four ISOs were each at 2% or less.
- **2021 was an average wind resource year across most of the country.** 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 impacts project performance from year to year. In 2021, the national wind index stood at its long-term average, as most regions experienced a fairly average wind year (CAISO and NYISO excepted).
- **Wind project performance degradation also explains why older projects did not perform as well in 2021**. Capacity factor data suggest some amount of performance decline with project age, though perhaps mostly once projects age beyond 10 years. The apparent decline in capacity factors as projects progress into their second decade partially explains why older projects—e.g., those built from 1998 to 2001—did not perform as well as newer projects in 2021. From year 15 to 20, project performance appears to average roughly 75% of early-year performance.

Cost Trends

- **Wind turbine prices increased by an average of 5% to 10% in 2021 given supply chain pressures.** Wind turbine prices declined by 50% between 2008 and 2020. However, recent supply-chain pressures and rising commodity prices led to increased turbine prices in 2021. Data indicate recent pricing generally in the range of $800/kW to $950/kW,[4] roughly 5% to 10% higher than a year prior.
- **Installed project costs in 2021 held steady at an average of $1,500/kW even as turbine prices rose.** The capacity-weighted average installed cost within a sample of 2021 projects stood at $1,500/kW. This is a decrease of more than 40% 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 today. Installed costs have largely held steady over the last four years. Given the time-lag between turbine orders and project commissioning, installed project costs may rise in 2022.
- **Installed costs differed by region, from $1,350/kW to $1,600/kW.** ERCOT and the (non-California) Western states hosted the lowest-cost projects built in 2021, with average costs of $1,350/kW and $1,380/kW respectively. Higher average costs were experienced in other regions for projects installed in 2021; for example, average costs in SPP and MISO were $1,500/kW and $1,600/kW, respectively.
- **Installed costs (per megawatt) generally decline with project size; are lowest for projects over 200 MW.** Installed costs exhibit economies of scale, with costs declining as project capacity increases.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, projects installed over the past 15 years have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first years of operation. The data also suggest that O&M costs tend to increase as projects age, at least for the older projects in the sample.

[4] All cost figures presented in the report are denominated in real 2021 dollars.

Power Sales Price and Levelized Cost Trends

- **Wind power purchase agreement prices have been drifting higher since about 2018, with a recent range from below $20/MWh to more than $30/MWh.** The combination of declining CapEx and OpEx and improved performance drove wind PPA prices to all-time lows through 2018, though prices have since stabilized and even increased somewhat—in part due to supply-chain pressures and perhaps also due to the ongoing phase-down of the PTC. In the Central region of the country, recent pricing is around $20/MWh. In the West and East, prices tend to average above $30/MWh.
- **LevelTen Energy's PPA price indices confirm rising PPA prices, and regional variations.** In contrast to the PPAs summarized above, which principally involve utility purchasers, LevelTen Energy provides an index of wind PPA offers made to large, end-use customers. These data also show that prices have generally risen over the last couple years, and vary by ISO. Among regions reporting data, CAISO features the highest pricing (~$52/MWh once converted to 2021 dollar terms); the lowest prices are found in ERCOT and SPP (~$25/MWh in 2021 dollars). In real dollar terms, LevelTen's reported price trends since 2018 are similar to the real-dollar denominated PPA trends described in the prior section.
- **The (unsubsidized) average levelized cost of wind energy has fallen to around $32/MWh.** Trends in the levelized cost of energy (LCOE) generally follow PPA trends, at least over the long term. Wind's LCOE generally decreased from 1998 to 2005, rose through 2009, and then declined through 2018, with a subsequent plateau over the last several years. The national average LCOE of wind projects built in 2021—excluding the PTC—was $32/MWh. As supply chain pressures continue, LCOE may be expected to rise in the near term.
- **Levelized costs vary by region, with the lowest costs in ERCOT, SPP, and the non-ISO West**. The lowest LCOEs for projects constructed in 2021—only considering regions with a larger sample—are found in ERCOT ($28/MWh), SPP ($30/MWh), and the non-ISO West ($29/MWh).

Cost and Value Comparisons

- **Despite low PPA prices, wind faces 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 gas-fired combined cycle units.
- **The grid-system market value of wind rebounded in 2021 to levels last seen in 2018, and is roughly consistent with recent PPA prices of under $20/MWh to $40/MWh.** 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. In 2021, wind energy value rebounded from the 2020 low associated with the pandemic. The national average market value of wind in 2021 was $26/MWh. With high natural gas and wholesale power prices so far in 2022, wind's average market value may increase again this year.
- **The grid-system market value of wind in 2021 varied by project location, from an average of $16/MWh in MISO to $48/MWh in CAISO.** Regionally, wind market value in 2021 was lowest in MISO and SPP (average of $16/MWh and $19/MWh, respectively) and highest in CAISO and ISO-NE ($48/MWh and $44/MWh). The market value across all wind projects located in ISOs spanned $7/MWh to $48/MWh in 2021 ($10^{th}$–$90^{th}$ percentile range). Within a region, transmission congestion can noticeably reduce the grid-value of wind plants. In some situations, wind patterns are locally differentiated, and can lead to value enhancements or reductions versus plants located elsewhere.

- **The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment.** The regions with the highest wind penetrations (SPP at 35%, ERCOT at 24%, and MISO at 12%) have generally experienced the largest reduction in wind's value relative to average wholesale prices. In 2021, wind's value was roughly 40%, 50%, 60%, and 80%, lower than average wholesale prices in NYISO, MISO, SPP, and ERCOT, respectively; but was only roughly 10% lower in ISO-NE and CAISO, and ~20% lower in PJM. These value reductions were primarily caused by a combination of transmission congestion and wind generation profiles that were negatively correlated with wholesale prices. Curtailment had only a minimal impact.
- **The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind.** Wind reduces emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide, providing public health and climate benefits. Nationally and considering all wind plants, these benefits can be quantified in monetary terms, averaging $80/MWh-wind in 2021. Benefits were largest, ranging from $83/MWh to $125/MWh, in the Central, Midwest, and Mid-Atlantic regions. Values were lowest in New York ($32/MWh) and New England ($28/MWh). Focusing only on the set of wind plants built in 2021, the average climate, health, and grid-system value sums to almost four times the average LCOE. Climate, health, and grid value averaged $53/MWh, $39/MWh and $24/MWh, respectively, compared to an average LCOE of $32/MWh.

Future Outlook

- **Energy analysts project that total annual wind additions will generally decline through 2023 before rebounding.** Specifically, expected additions drop to an average of 7 GW in 2023 before increasing to as much as 13 GW in 2025. These projected trends are driven in part by expectations about the expiration of the federal PTC, and by anticipated growth in offshore wind in the mid-2020s. Near-term additions are also influenced by the cost and performance of wind technologies, corporate wind energy purchases, and state-level renewable energy policies. Limited transmission infrastructure and competition from solar dampen growth expectations, while continuing supply chain pressures also impact deployment levels.
- **Longer term, the prospects for wind energy will be influenced by the sector's ability to continue to improve its economic position even in the face of challenging competition and near-term supply chain constraints.** Corporate demand for clean energy and state-level policies will also continue to impact wind deployment, as will the buildout of transmission infrastructure and uncertain future natural gas prices. Finally, there have been recent legislative proposals for a long-term extension of the PTC and other national policies to support a clean energy transition. The fate of these proposals will impact the sector's upside potential to exceed the projections shown above.

Table of Contents

List of Figures

List of Tables

1 Introduction

Wind power capacity additions in the United States totaled 13.4 gigawatts (GW) in 2021. Recent growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind capacity additions, yielding low-priced wind energy for utility, corporate, and other power purchasers even as supply chain constraints due to increased commodity and transportation costs and COVID-19 restrictions begin to push costs higher.

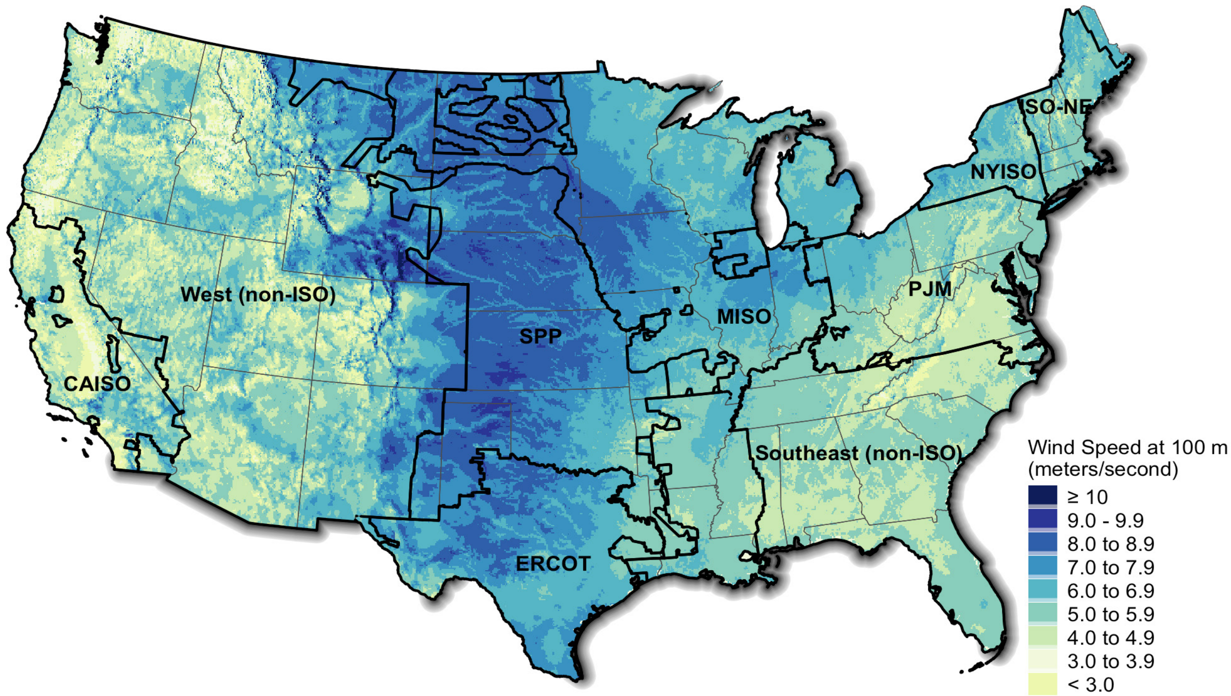
This annual report—now in its sixteenth year—provides an overview of trends in the U.S. wind power market, with a particular focus on the year 2021. The report begins with an overview of installation-related trends: U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual U.S. states; hybridization with storage and other sources of generation; and the quantity of proposed wind power capacity in 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 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 capacity, hub height, rotor diameter, and specific power, as well as changes in site-average wind speed and recent repowering activity. After that, the report discusses wind performance, cost, and pricing. In doing so, it describes trends in capacity factors, wind turbine prices, installed project costs, and operations and maintenance (O&M) expenses. Levelized costs are calculated based on these input parameters. The report 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, forecasts of future natural gas prices, and sales prices for solar power. An additional comparison assesses the levelized cost of wind energy relative to its societal value, defined somewhat narrowly here to include the grid-system value of wind along with its health and climate benefits. Finally, the report concludes with a preview of possible near-term market developments based on the findings of other 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 nine regions, seven of which align with organized wholesale power markets (i.e., independent system operators)[5], on a map of average annual U.S. wind speed at 100 meters above the ground. These nine regions will be referenced on many occasions throughout this report.

This edition of the annual report updates data presented in previous editions while highlighting recent trends and new developments. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[6] The U.S. wind power sector is multifaceted, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Further information on *distributed wind power*, which includes smaller wind turbines as well as the use of larger turbines in distributed applications, is available through a separate annual report funded by the U.S. Department of Energy (DOE)—the Distributed Wind Market Report. In Chapters 2, 3, and 9—where it is sometimes difficult to separate offshore and land-based wind—this report emphasizes land-based and offshore wind, in combination. Other chapters exclusively focus on land-based wind. A companion study funded by DOE that focuses exclusively on *offshore wind power* is also available—the Offshore Wind Market Report.

[5] The seven independent system operators (ISOs) include the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO).

[6] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match the American Clean Power 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 ACP's reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.



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

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 100 meters

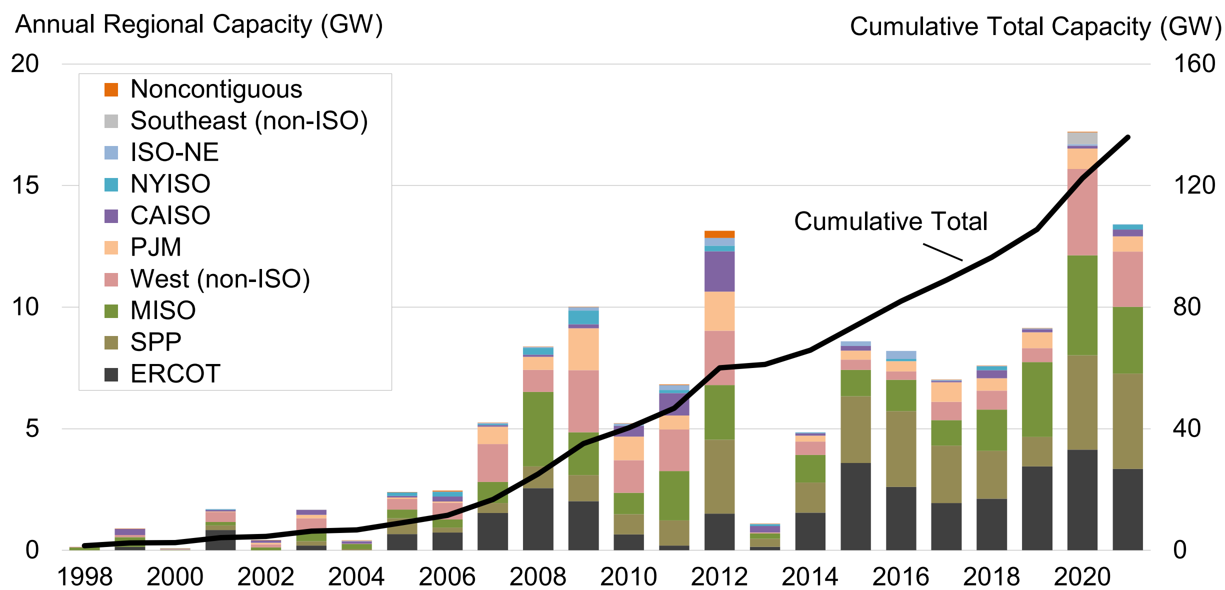
Much of the data included in this report were compiled by DOE's Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the U.S. Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the American Clean Power Association (ACP—along with its predecessor, the American Wind Energy Association). 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.

2 Installation Trends

U.S. wind power capacity grew at a strong pace in 2021, with 13.4 GW of new capacity added and $20 billion invested

U.S. wind capacity additions equaled 13.4 GW in 2021, bringing the cumulative total to nearly 136 GW at the end of the year (Figure 2).[7] This growth represented $20 billion of investment in new wind power project installations in 2021, for a cumulative investment total of roughly $270 billion since the beginning of the 1980s.[8,9] Nearly 75% of the new wind capacity installed in 2021 is located in ERCOT, MISO and SPP.

A relatively new trend is that of partial wind project repowering, in which major components of turbines are replaced. Such efforts provide access to favorable tax incentives, increase energy production with more-advanced turbine technology, and extend project life. As detailed further in Chapter 4, in addition to the newly installed capacity reported above, 1.6 GW of existing wind plants were partially repowered in 2021, mostly in the form of increased rotor diameters and the replacement of major nacelle components; this is a decline from the previous two years, when roughly 3 GW were retrofitted each year.[10]



Source: ACP

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

[7] The nearly 136 GW of cumulative capacity includes the 30 MW Block Island offshore wind plant and the 12 MW Coastal Virginia Offshore Wind pilot project. When reporting annual capacity additions, this report focuses on *gross* 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. Cumulative capacity ('Total' in Figure 2) includes both decommissioning and repowering.

[8] All cost and price data are reported in real 2021 dollars.

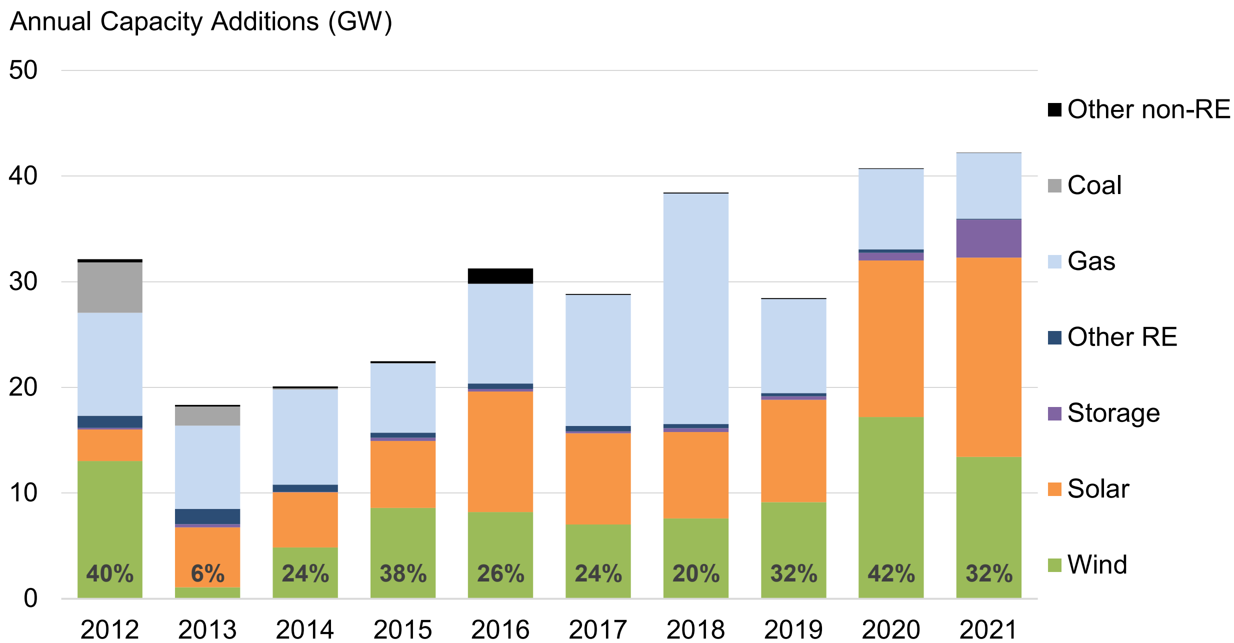
[9] These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

[10] The 1.6 GW of partially repowered capacity reflects 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.

As in previous years, growth was driven in part by long-term improvements in the cost and performance of wind power technologies. The federal PTC, state renewables portfolio standards (RPS), and corporate demand for renewable energy also played important roles. Meanwhile, the ability of partially repowered wind projects to access the PTC has been the primary motivator for the growth in partial repowering in recent years. The industry also contended with headwinds in 2021, however, related to supply chain pressures, policy uncertainty, and interconnection delays, which together reportedly caused 5 GW of wind projects previously planned for completion in 2021to slip to later years (ACP 2022).

Wind power represented the second largest source of U.S. electric-power capacity additions in 2021, at 32%, behind solar's 45%

Wind power has comprised a sizable share of capacity additions in recent years. In 2021, it constituted 32% of all U.S. generation and storage capacity additions, second only to solar power at 45% (Figure 3).[11] Natural gas and other non-renewable capacity additions continued their recent decline, falling to their lowest level in more than 20 years.

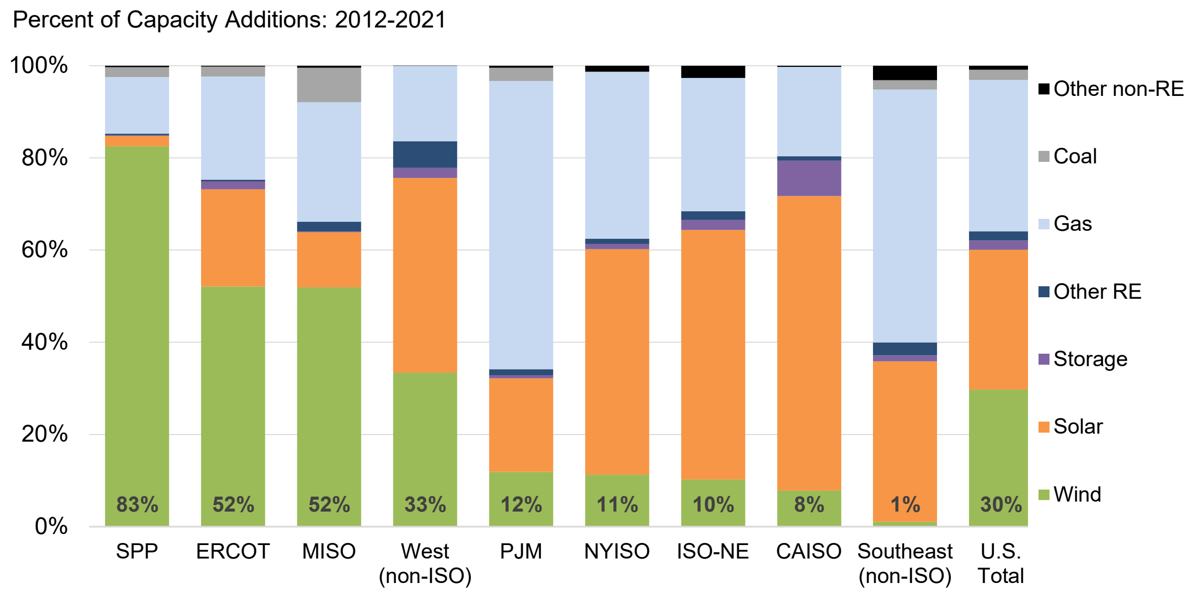


Sources: Hitachi, ACP, EIA, Berkeley Lab

Figure 3. Relative contribution of generation types and storage to U.S. annual capacity additions

Over the last decade, wind power represented 30% of total U.S. generation and storage capacity additions, and an even larger fraction of new capacity in SPP (83%), ERCOT (52%), MISO (52%), and the non-ISO West (33%) (Figure 4; see Figure 1 for regional definitions). Wind power's contribution to capacity growth over the last decade is somewhat smaller—but still significant—in PJM (12%), NYISO (11%), ISO-NE (10%), and CAISO (8%), and considerably less in the Southeast (1%).

[11] Data presented here are based on gross capacity additions, not considering retirements or partial repowering. For solar, both utility-scale and distributed applications are included. Data include only the 50 U.S. states, not U.S. territories.



**U.S. Total also includes AK and HI, in addition to the regions listed*

Sources: Hitachi, ACP, EIA, Berkeley Lab

Figure 4. Generation and storage capacity additions by region over last ten years

Globally, the United States again ranked second in annual wind capacity, but remained well behind the market leaders in wind energy penetration

Global wind additions totaled 94 GW in 2021 (including both land-based and offshore wind, and focusing on capacity that was been connected to the grid). With its 13.4 GW representing 14% of new global installed capacity in 2021, the United States continued to maintain its second-place position behind China (Table 1). Cumulative global wind capacity totaled 839 GW at the end of the year (GWEC 2022),[12] with the United States accounting for 16%—also a distant second to China.

Table 1. International Rankings of Total Wind Power Capacity

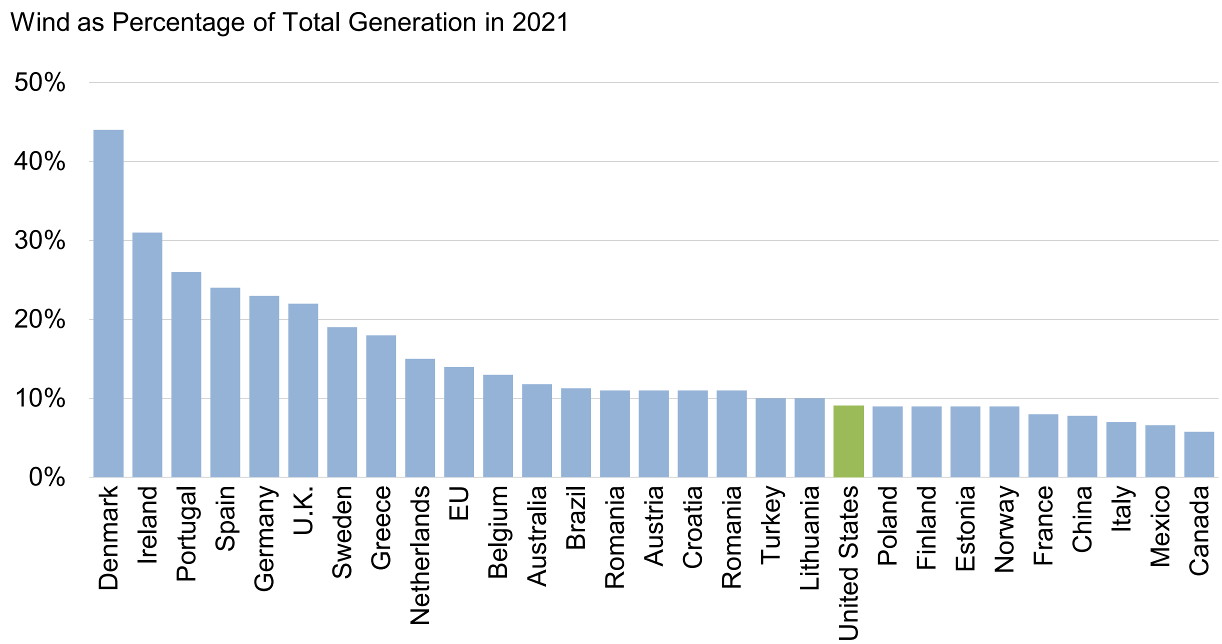
Annual Capacity (2021, GW)	
China	47.6
United States	**13.4**
Brazil	3.8
Vietnam	3.5
United Kingdom	2.6
Sweden	2.1
Germany	1.9
Australia	1.7
India	1.5
Turkey	1.4
Rest of World	14.7
TOTAL	**94.3**

Cumulative Capacity (end of 2021, GW)	
China	338.3
United States	**135.9**
Germany	64.5
India	40.1
Spain	28.3
United Kingdom	26.6
Brazil	21.6
France	19.1
Canada	14.3
Sweden	12.1
Rest of World	138.1
TOTAL	**838.9**

Sources: GWEC (2022); ACP for U.S.

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 (2022) but are updated, where necessary, with the U.S. data presented here.

A number of countries have achieved relatively high levels of wind energy penetration (i.e., wind generation as a percentage of total generation) in their electricity grids. Figure 5 presents data on a subset of countries. Wind penetration was 44% in Denmark in 2021, and was between 22% and 31% in Ireland, Portugal, Spain, Germany, and the U.K. In the United States, wind supplied 9.1% of total electricity generation in 2021 (see Table 2 for additional details).



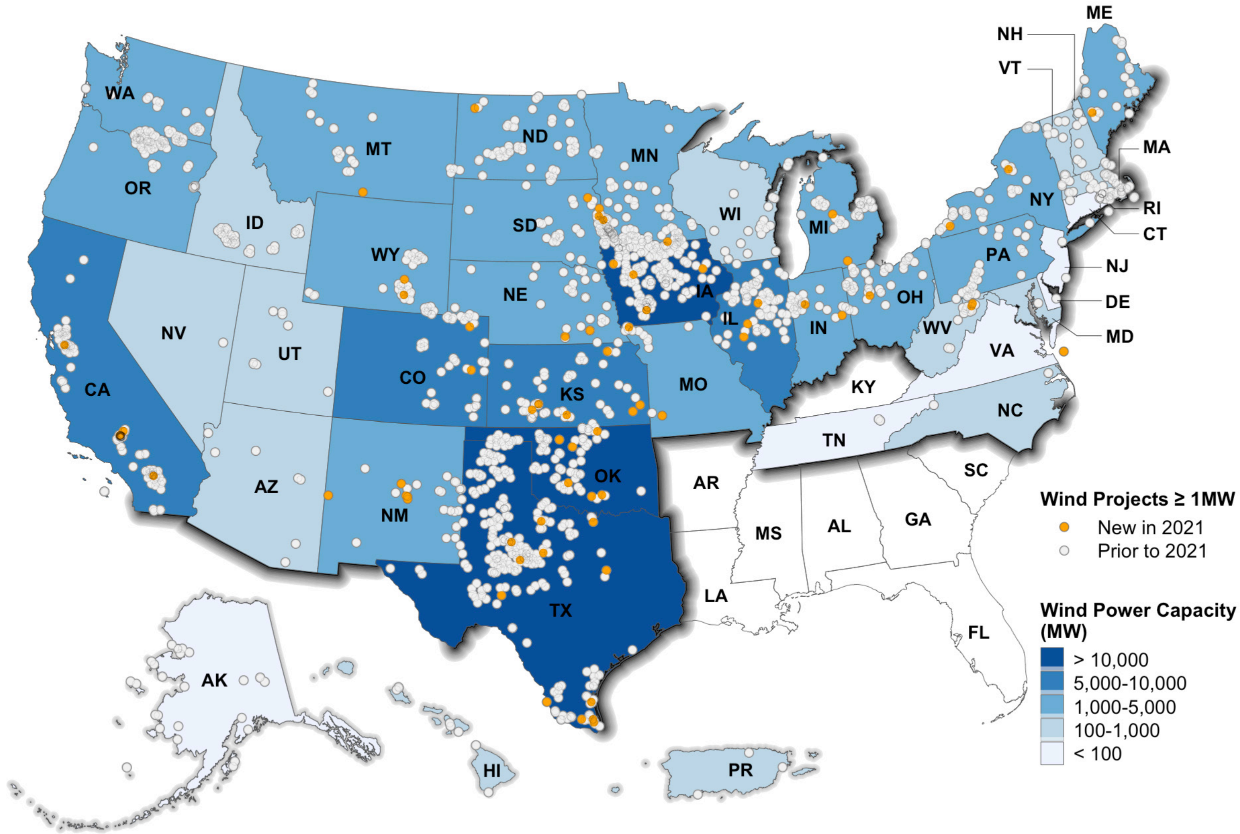
Source: ACP

Figure 5. Wind energy penetration in subset of top global wind markets

Texas installed the most wind capacity in 2021 with 3,343 MW, followed by Oklahoma, New Mexico and Kansas; eleven states exceeded 20% wind energy penetration

New utility-scale wind turbines were installed in 22 states in 2021 (including a 12 MW pilot offshore wind project in Virginia). Texas once again installed the most new wind capacity of any state, adding 3,343 MW. As shown in Figure 6 and in Table 2, other leading states—in terms of new capacity—included Oklahoma, New Mexico, and Kansas, all of which added more than 1,000 MW (i.e., 1 GW) of new wind in 2021.

On a cumulative basis, Texas remained the clear leader, with 36 GW installed at the end of 2021—almost three times as much as the next-highest state (Iowa). In fact, Texas has more wind capacity than all but four countries (Table 1). States distantly following Texas in cumulative installed capacity include Iowa (>12 GW), Oklahoma (~11 GW), Kansas (>8 GW), Illinois (~7 GW), and California (>6 GW). Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2021, with 23 of these above 1 GW, 19 above 2 GW, and 15 above 3 GW.



Sources: ACP, Berkeley Lab

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 2021 divided by total in-state electricity generation and by in-state electricity sales in 2021. 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, Iowa leads the list, with 55% of electricity generated in the state coming from wind, followed by South Dakota, Kansas, Oklahoma, and North Dakota. As a fraction of in-state sales, South Dakota is the leading state, with nearly 72% of the electricity sold in the state being met by wind, followed by Iowa, North Dakota, and Kansas (all over 60%), and then Wyoming and Oklahoma (both over 50%). Eleven states have achieved wind penetration levels of 20% or higher when expressed either as a percentage of generation or as a percentage of sales.

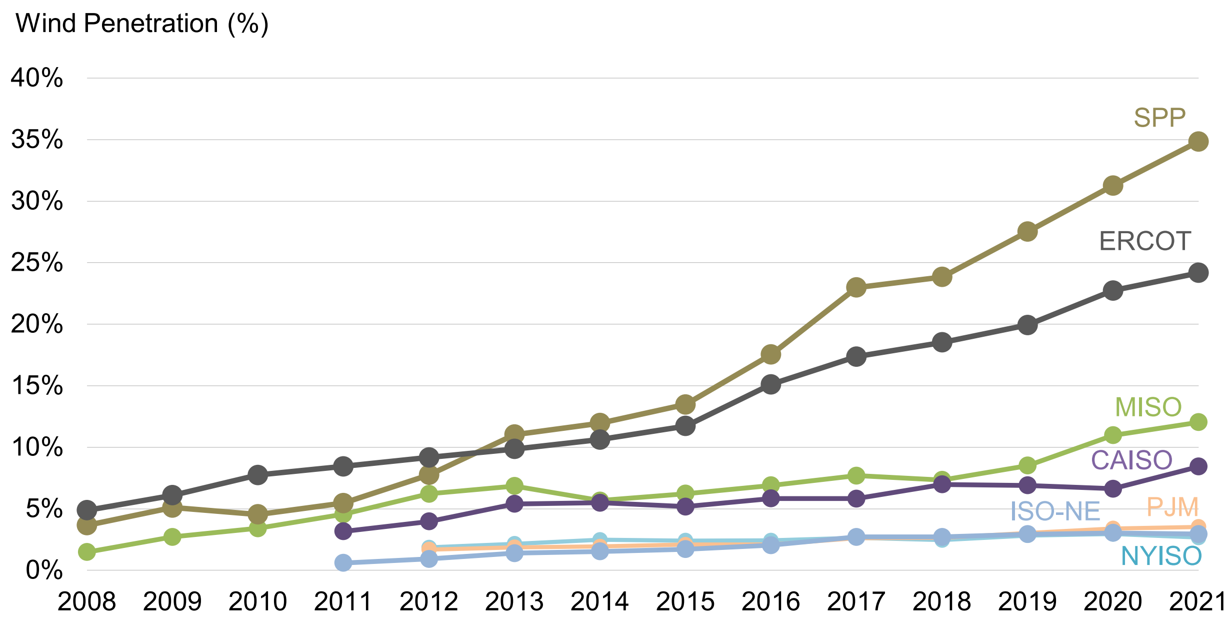
Table 2. U.S. Wind Power Rankings: The Top 20 States

Installed Capacity (MW)				2021 Wind Generation as a Percentage of:			
Annual (2021)		Cumulative (end of 2021)		In-State Generation		In-State Sales	
Texas	3,343	Texas	35,969	Iowa	55.1%	South Dakota	71.6%
Oklahoma	1,403	Iowa	12,219	South Dakota	52.3%	Iowa	69.1%
New Mexico	1,368	Oklahoma	10,994	Kansas	45.1%	North Dakota	63.3%
Kansas	1,228	Kansas	8,245	Oklahoma	41.4%	Kansas	63.0%
South Dakota	610	Illinois	6,997	North Dakota	34.0%	Wyoming	53.3%
Iowa	600	California	6,142	New Mexico	29.8%	Oklahoma	51.5%
Illinois	580	Colorado	5,035	Colorado	26.0%	New Mexico	41.4%
Michigan	550	Minnesota	4,591	Nebraska	25.1%	Nebraska	30.5%
Indiana	500	North Dakota	4,302	Maine	23.0%	Colorado	26.4%
Missouri	448	New Mexico	4,001	Minnesota	21.6%	Texas	23.5%
Nebraska	388	Oregon	3,842	Texas	20.6%	Maine	22.2%
Wyoming	349	Indiana	3,468	Wyoming	19.3%	Minnesota	19.6%
Colorado	305	Washington	3,396	Oregon	15.6%	Montana	18.9%
North Dakota	299	Wyoming	3,178	Idaho	15.6%	Oregon	18.5%
California	288	Michigan	3,159	Vermont	14.5%	Illinois	13.8%
Minnesota	266	Nebraska	2,942	Montana	11.5%	Washington	10.8%
Ohio	247	South Dakota	2,915	Illinois	10.2%	Idaho	10.5%
Montana	240	Missouri	2,435	Washington	8.7%	Missouri	8.4%
New York	205	New York	2,191	Missouri	8.4%	Indiana	7.9%
West Virginia	169	Pennsylvania	1,459	Indiana	8.3%	Michigan	7.9%
Rest of U.S.	*27*	*Rest of U.S.*	*8,405*	*Rest of U.S.*	*1.6%*	*Rest of U.S.*	*1.5%*
TOTAL	**13,413**	**TOTAL**	**135,886**	**TOTAL**	**9.1%**	**TOTAL**	**10.0%**

Note: Based on 2021 wind and total generation and retail sales by state from EIA's Electric Power Monthly.

Sources: ACP, 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 2021, wind penetration (expressed as a percentage of load) was 34.8% in SPP, 24.2% in ERCOT, 12.0% in MISO, 8.4% in CAISO, 3.5% in PJM, 3.0% in ISO-NE, and 2.7% in NYISO (Figure 7).



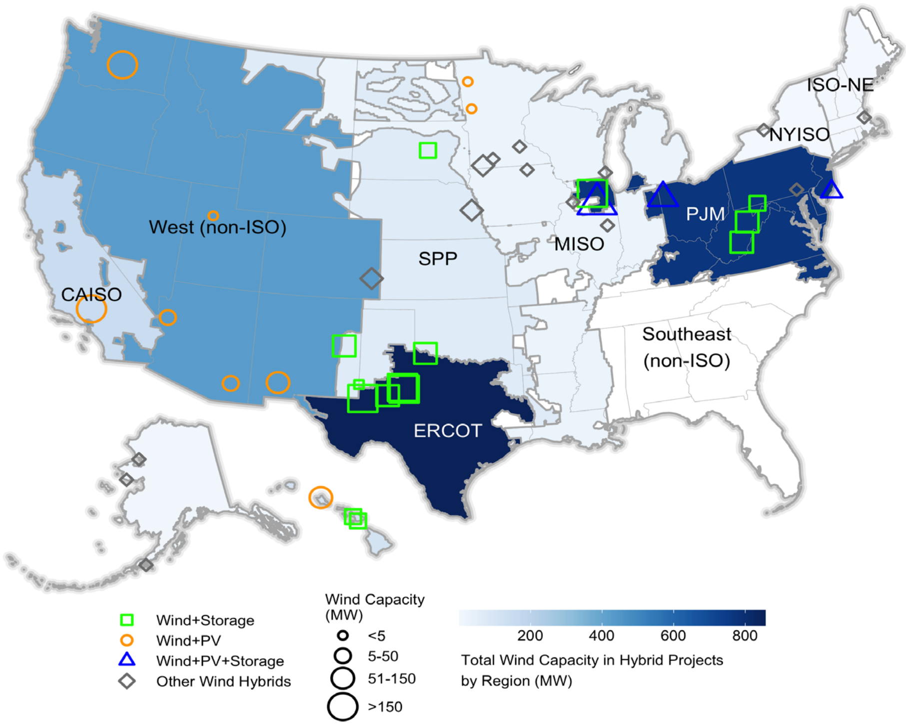
Sources: SPP, ERCOT, MISO, CAISO, PJM, ISO-NE, NYISO

Figure 7. Wind penetration as a proportion of load by independent system operator regions

Hybrid wind plants that pair wind with storage and other resources saw limited growth in 2021, with just two new projects completed

Though only two new wind hybrid projects were commissioned in 2021, there were 41 hybrid wind power plants in operation at the end of 2021, representing 2.4 GW of wind and 0.9 GW of co-located assets (storage, PV, or fossil-fueled generators). Some of these represent full hybrids where, for example, wind and storage are co-located and the design, configuration, and operation of the constituent technologies are fully integrated. In other cases, plants are co-located, sharing a point of interconnection, but are designed, configured, and operated more independently (e.g., hybrids that pair wind and gas plants).

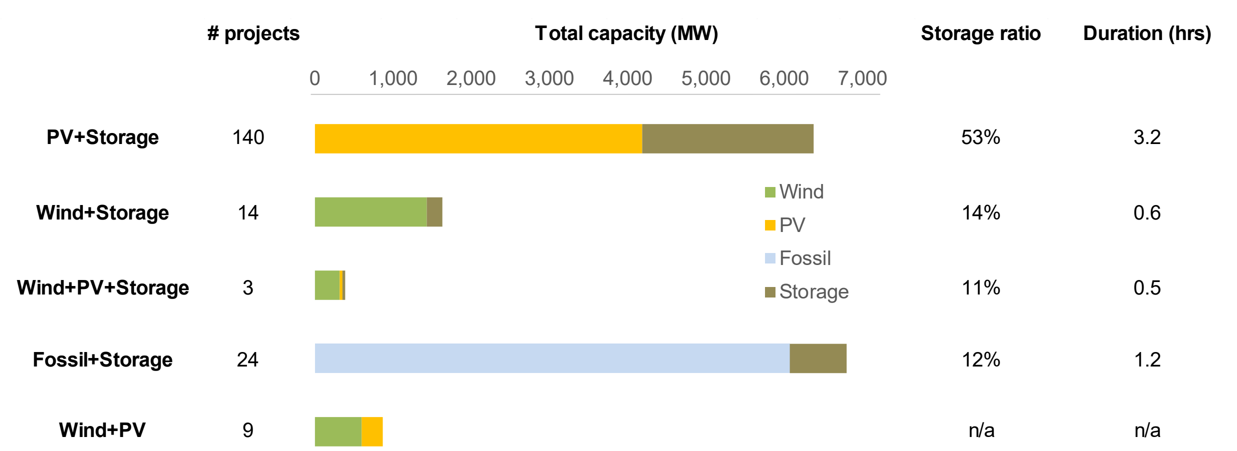
The most common type of wind hybrid project combines wind and storage technology, where 1.4 GW of wind has been paired with 0.2 GW of battery storage across 14 plants. However, no new projects of this type were installed in 2021. Other combinations include wind and PV; wind, PV, and storage; wind and gas; and more (Figure 8). The ERCOT region hosts the largest amount of wind capacity in hybrid plants (0.86 GW), followed by PJM (0.77 GW) and the non-ISO West (0.43 GW). Wind capacity tends to be largest for wind+storage hybrids than for other hybrid configurations.



Sources: EIA-860 2021 Early Release, Berkeley Lab

Figure 8. Location and capacity of hybrid wind plants in the United States

Figure 9 displays design characteristics for a subset of the more-common hybrid plant configurations, including those that do not incorporate wind. Wind+storage hybrids have a 14% storage-to-generator ratio with an average storage duration of just 0.6 hours, suggesting a focus on providing ancillary services and only limited capacity to shift large amounts of energy across time. Fossil+storage hybrids have similar storage-to-generator ratios (12%) but longer battery durations (1.2 hours). PV+storage hybrids have significantly higher average storage-to-generator ratios (53%) and battery durations (3.2 hours). Based on data from proposed projects, presented in the next section on interconnection queues, there is growing interest in hybridizing with larger storage-to-generator ratios and longer storage durations.



Notes: Not included in the figure are 108 hybrid projects with other configurations. Storage ratio defined as total storage capacity divided by total generator capacity for a given project type.

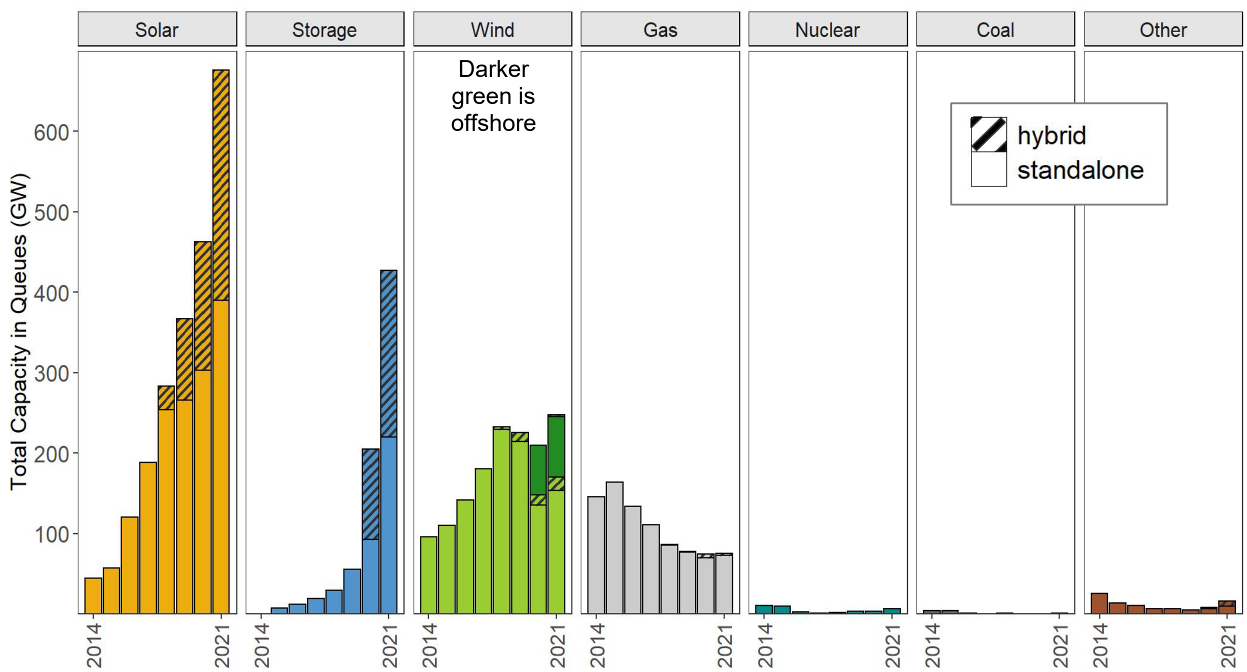
Sources: EIA-860 2021 Early Release, Berkeley Lab

Figure 9. Design characteristics of hybrid power plants operating in the United States, for a subset of configurations

The trend to co-locate wind with other assets has progressed at a slow, steady pace since 2006, with two new wind hybrids commencing operation in 2021: one Wind+PV and the other Wind+PV+Storage. In contrast, commercial interest in solar hybrids has expanded rapidly, with 67 new PV+storage projects coming online in 2021.

A record-high 247 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace

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 10 provides this information over the last eight years for wind power and other resources aggregated across more than 40 different interconnection queues administered by ISOs and utilities.[13] These data should be interpreted with caution: placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built. An analysis of five ISO queues found an overall average completion rate of 23% for projects of all types proposed from 2000 to 2016 (Rand et al. 2022). Some projects are speculative in nature, and duplicate projects also complicate interpretation.



Notes: Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data; storage capacity in hybrids was not estimated for years prior to 2020; offshore wind was not separately identified prior to 2020.

Source: Berkeley Lab review of interconnection queues

Figure 10. Generation capacity in interconnection queues from 2014 to 2021, 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 developer interest. At the end of 2021, there were 247 GW

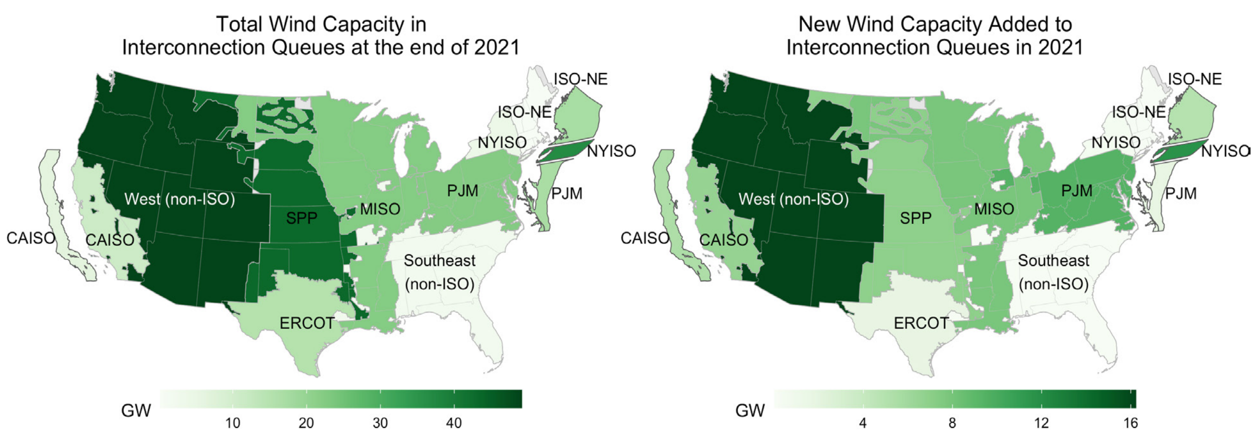
---

[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 85% of the U.S. total. The figures in this section only include projects that were active in the queues at the times specified but that had not yet been built; suspended projects are not included.

of wind capacity in the queues reviewed for this report—a marked increase from the 209 GW in the queues the previous year and supported by continued growth in offshore wind in the queues. In 2021, 73 GW of new wind capacity entered the queues, 12 GW of which were in hybrid configurations and 24 GW of which were for offshore wind. Solar additions to interconnection queues far outpaced wind in 2021, with 265 GW added. Storage additions to the queues have increased much more rapidly than wind in recent years as well, both for standalone plants and hybridized with solar or wind. Overall, wind represented 17% of all capacity in the queues at the end of 2021, compared to 47% for solar, 29% for storage, and just 5% for natural gas.

The total wind capacity in the interconnection queues is spread across the United States, as shown in Figure 11 (left image), with the largest amounts in the West (non-ISO) (20%), SPP (17%), NYISO (16%), and PJM (16%). Smaller amounts are found in MISO (9%), CAISO (7%), ISO-NE (7%), ERCOT (6%), and the Southeast (non-ISO) (1%). A majority (56%) of wind capacity in the queues has requested to come online by the end of 2024, and 16% of wind capacity has a fully executed interconnection agreement.

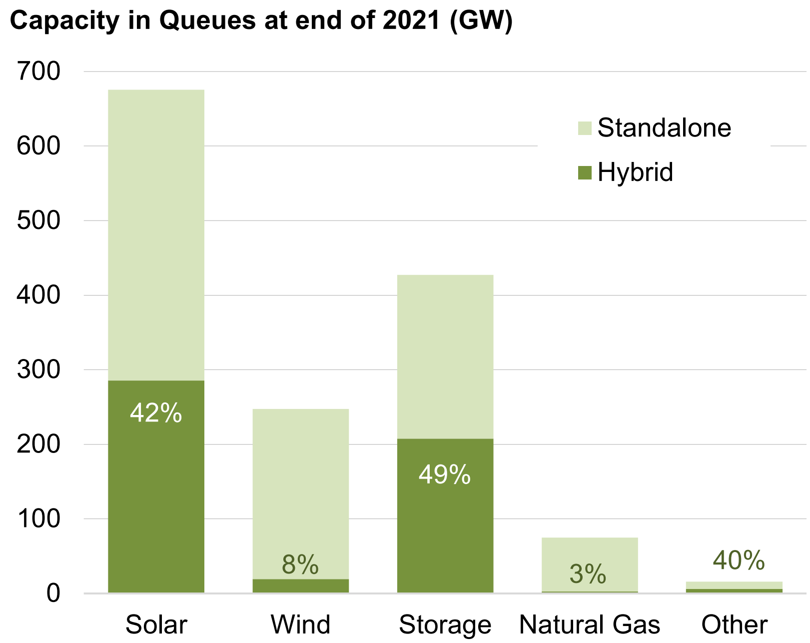
Focusing just on wind power additions to the queues in 2021 (Figure 11, right image), the West (non-ISO), NYISO, CAISO, and PJM experienced especially large annual additions, with NYISO's additions being almost entirely for offshore wind (>11 GW each). Across all queues, 31% (77 GW) of all wind capacity in the queues at the end of 2021 was offshore, and 33% (24 GW) of the wind added to queues in 2021 was offshore. Offshore wind capacity was added on both the East Coast (NYISO, PJM, ISO-NE) and the West Coast (CAISO).



Source: Berkeley Lab review of interconnection queues

Figure 11. Wind power capacity interconnection queues at end of 2021, by region

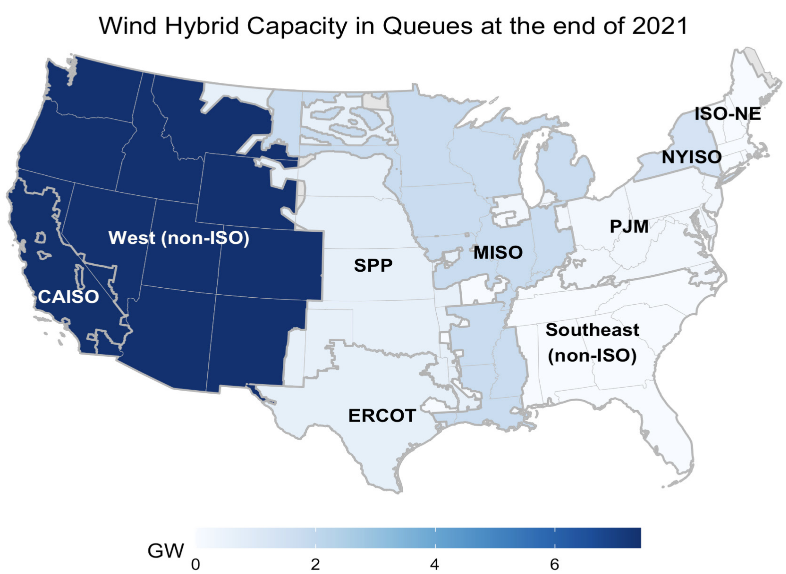
As shown in Figure 12, 42% of the solar capacity in interconnection queues at the end of 2021 has been proposed as hybrid plants, whereas only 8% of the wind capacity is paired with storage or another generation resource. In part this is due to policy design—the investment tax credit for solar can also be used for paired storage, whereas the production tax credit regularly used by wind plants has no such storage allowance. Of the 19 GW of proposed wind capacity in hybrid configurations, the majority (12 GW) is paired with storage, with less paired with solar (4 GW) or both solar and storage (2 GW).



Source: Berkeley Lab review of interconnection queues

Figure 12. Generation capacity in interconnection queues, including hybrid power plants

As shown in Figure 13, commercial interest in wind hybrid plants is highest in California and the West (non-ISO). In fact, 42% of the wind in CAISO's queues is proposed as a hybrid, as is 15% of the wind in the West.



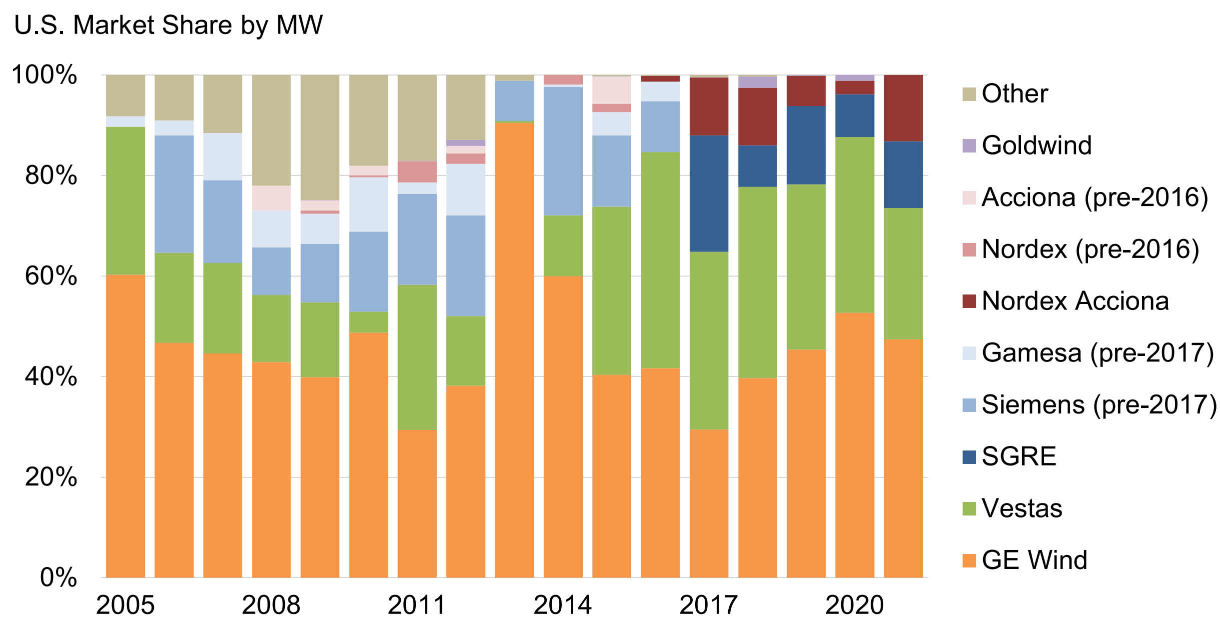
Source: Berkeley Lab review of interconnection queues

Figure 13. Hybrid wind power plants in interconnection queues at the end of 2021

3 Industry Trends

Just four turbine manufacturers, led by GE, supplied all of the U.S. wind power capacity installed in 2021

Of the 13.4 GW of wind installed in the United States in 2021, GE Wind supplied 47%, with Vestas coming in second (26%), followed by Siemens Gamesa Renewable Energy (SGRE, 13%) and Nordex (13%) essentially tied in third (Figure 14).[14] GE and Vestas have dominated the U.S. market for some time, with SGRE and Nordex vying for third.



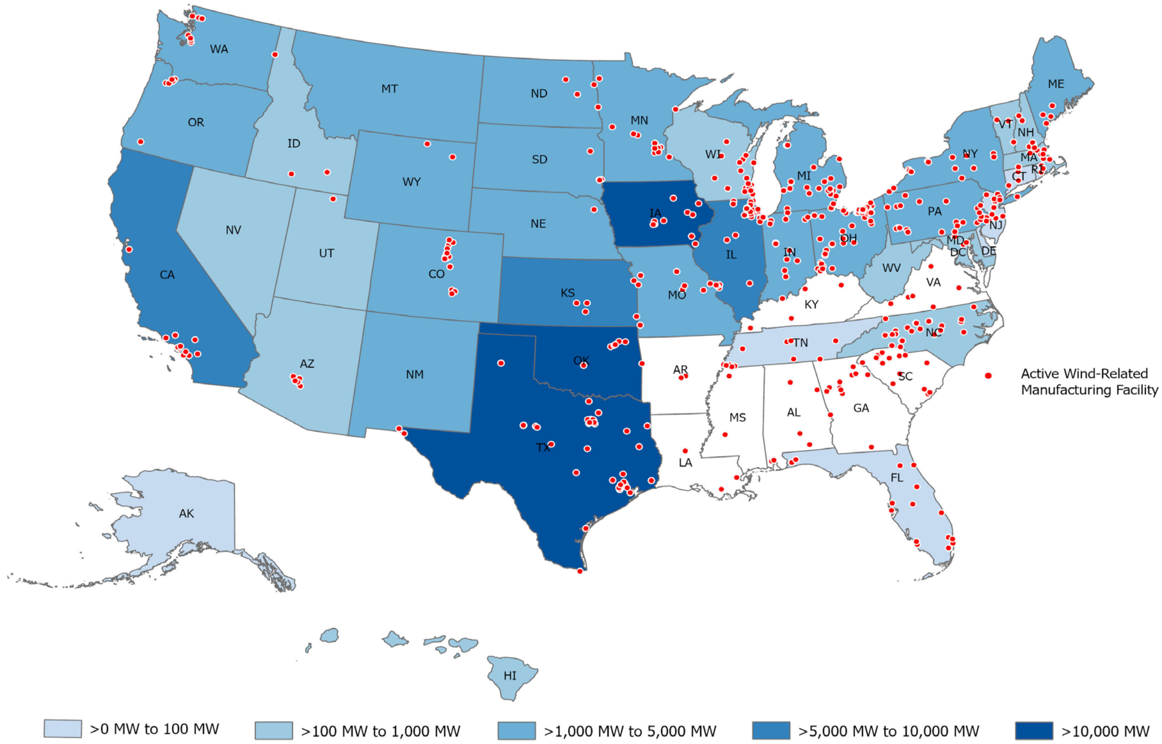
Source: ACP

Figure 14. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2021

The domestic wind industry supply chain contracted in 2021, with a 50% decline in blade manufacturing capability

Figure 15 identifies the many wind turbine component manufacturing, assembly, and other supply chain facilities operating in the United States at the end of 2021. Three of the major turbine OEMs that serve the U.S. wind industry—GE, Vestas, and SGRE—are represented within this total, each having one or more operating manufacturing facility. The figure also highlights the geographic breadth of the domestic supply chain.

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



Source: ACP

Figure 15. Location of turbine and component manufacturing facilities

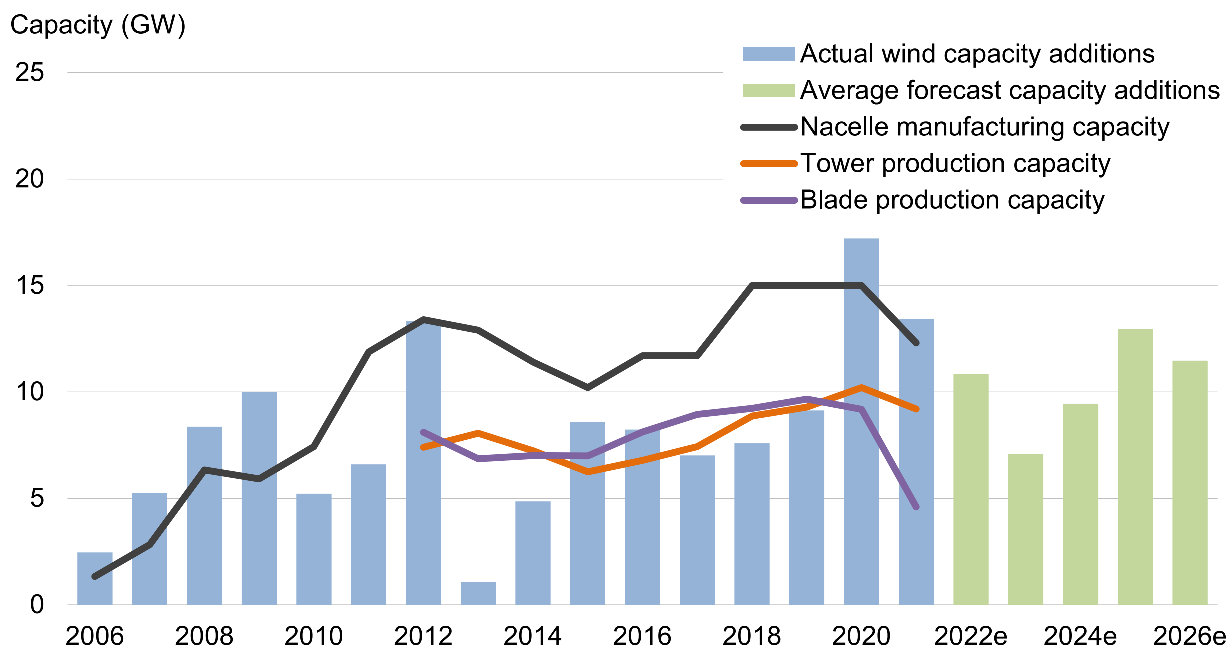
In aggregate, domestic turbine nacelle assembly15 capability—defined here as the maximum annual nacelle assembly capability of U.S. plants if all were operating at full utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, fell to roughly 10 GW in 2015, and then rose to 15 GW in 2020 before declining to 12.3 GW in 2021 (Figure 16).

In addition, from 2012 through 2020, domestic blade and tower manufacturing capability was largely stable or growing, in each case increasing from around 7 to 8 GW/year in 2012 to around 10 GW/year. In 2021, however, the supply chain contracted—modestly for nacelle assembly and towers, but a 50% drop in blade manufacturing capability to ~4.6 GW/year. Based on ACP (2022), three blade manufacturing plants closed or idled production in 2021: TPI Composites (Newton, IA), Molded Fiber Glass (Aberdeen, SD), and Vestas (Brighton, CO). Arcosa (Clinton, IL), meanwhile, idled one of its tower manufacturing facilities. A combination of competition from foreign suppliers and uncertain future deployment for land-based wind in the United States are conspiring to weaken domestic wind manufacturing capabilities.

Figure 16 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 towers and nacelle assembly remains reasonably well balanced with projected wind additions in the United States, but that blade manufacturing capability has fallen well below near-term wind additions as international suppliers outcompete domestic ones. Note that manufacturing facilities do not typically operate at maximum capability; see the next section of the report for estimates of domestic manufacturing content.

---

[15] Nacelle assembly is defined 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.

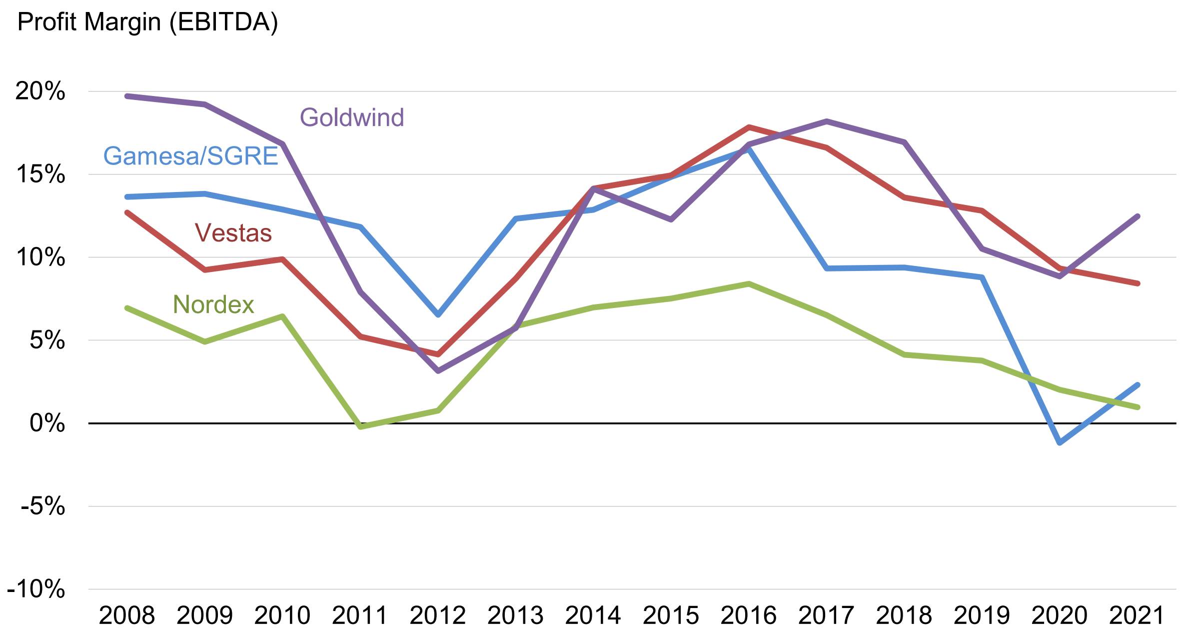


Sources: ACP, independent analyst projections, Berkeley Lab

Figure 16. Domestic wind manufacturing capability vs. U.S. wind power capacity installations

More generally, fierce competition among manufacturers has generally reduced turbine OEM profitability over the last several years. High recent commodity and transportation costs along with COVID-19 restrictions have also limited manufacturer profitability (Figure 17).[16]

[16] 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.



Note: EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization

Sources: OEM annual reports and financial statements

Figure 17. Turbine OEM global profitability

Despite these supply-chain challenges, wind-related job totals in the United States increased by 2.9% in 2021, to 120,164 full-time workers—benefitting from continued robust development (DOE 2022). These jobs include, among others, those in construction (43,371) and manufacturing (23,644).

Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports, which totaled $3.1 billion in 2021

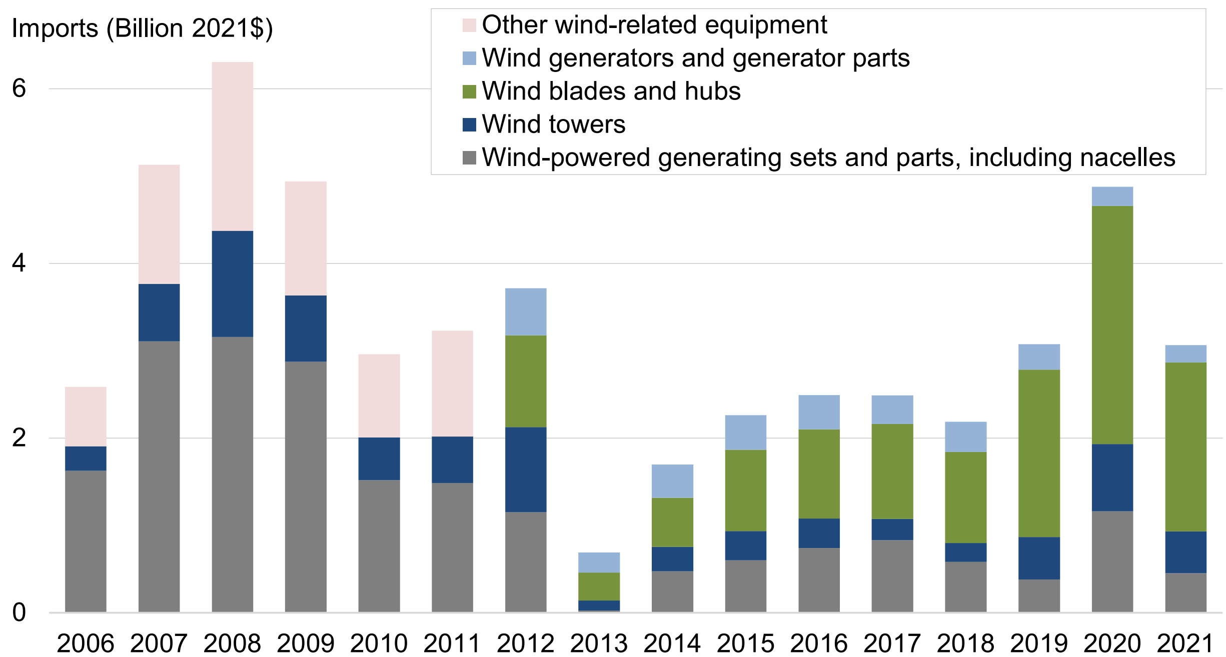
Despite the breadth of the domestic wind industry supply chain, the U.S. wind sector is reliant on imports of wind equipment. The level of dependence varies by component: some components have a relatively high domestic share, whereas others remain largely imported. These trends are revealed, in part, by data on wind equipment trade from the U.S. Department of Commerce.[17]

Figure 18 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. The figure shows imports of wind-powered generating sets and parts, including 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.[18] 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.[19]

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

[18] 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.

[19] Though all of the import estimates are specific to wind equipment in 2020 and 2021, import trends should be viewed with particular caution because the underlying data from earlier years used to produce Figure 17 are based on trade categories that are not all exclusive to wind. Some of the import estimates shown in Figure 17 for years prior to 2020 therefore required



Note: Wind-related trade codes and definitions are not consistent over the full time period.

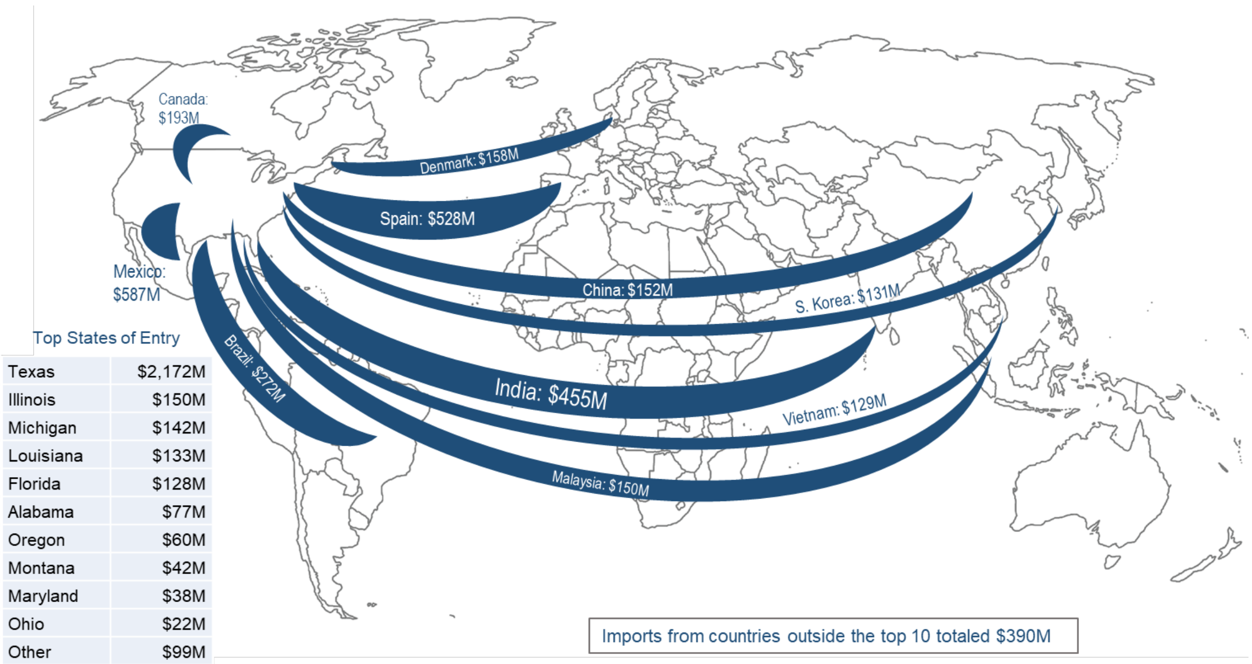
Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 18. Imports of wind-related equipment that can tracked with trade codes

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 2021, imports of wind-related turbine equipment generally followed U.S. wind installation trends, bouncing back from the low of 2013 and then with a marked decline in 2021 as wind plant installations declined from the previous year. Interpreting time trends in these data is challenging, however, given changes in annual wind additions from year to year, time lags between equipment import and installation, and fluctuations in wind turbine and equipment pricing. Also, because imports of component parts occur in additional, broad trade categories different from those included in Figure 18, the data presented here understate the aggregate amount of wind equipment imports.

Figure 19 shows the total value of tracked wind-specific imports to the United States in 2021, by country of origin, as well as states of entry. Major countries from which the U.S. imports wind equipment include Mexico, Spain, and India, which together account for more than $1.5 billion in wind-specific exports to the U.S. in 2021. Texas is the dominant entry point, a persisting trend in the last five years, with over $2 billion of wind-specific equipment flowing through it in 2021, followed distantly by Illinois, Michigan, Louisiana, and Florida.

assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. For example, from 2013 through 2019, nacelles (when shipped alone) are included in a trade category that is not largely exclusive to wind. 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.

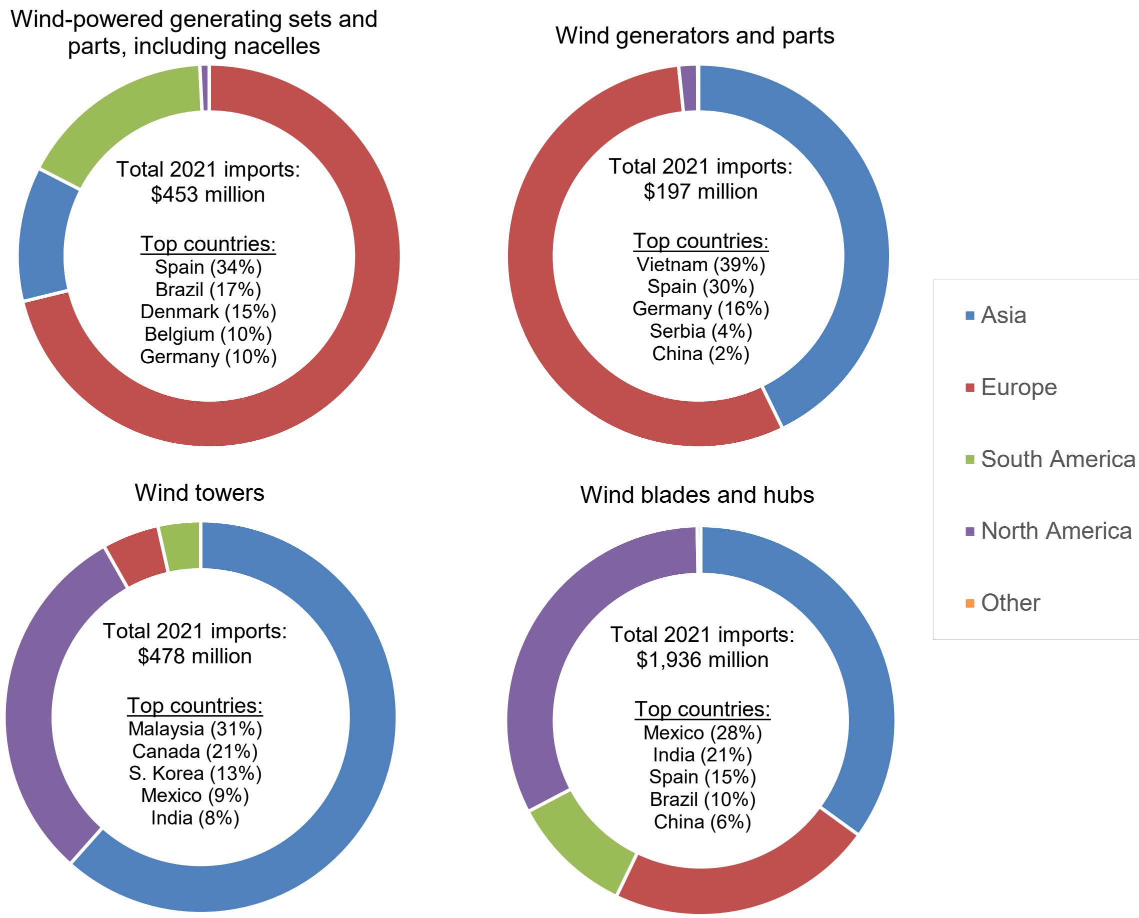


Top States of Entry	
Texas	$2,172M
Illinois	$150M
Michigan	$142M
Louisiana	$133M
Florida	$128M
Alabama	$77M
Oregon	$60M
Montana	$42M
Maryland	$38M
Ohio	$22M
Other	$99M

Note: Line widths are proportional to import amount by country. Figure does not intend to depict the destination of these imports, by state.
Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 19. Summary map of tracked wind-specific imports in 2021: top-10 countries of origin and states of entry

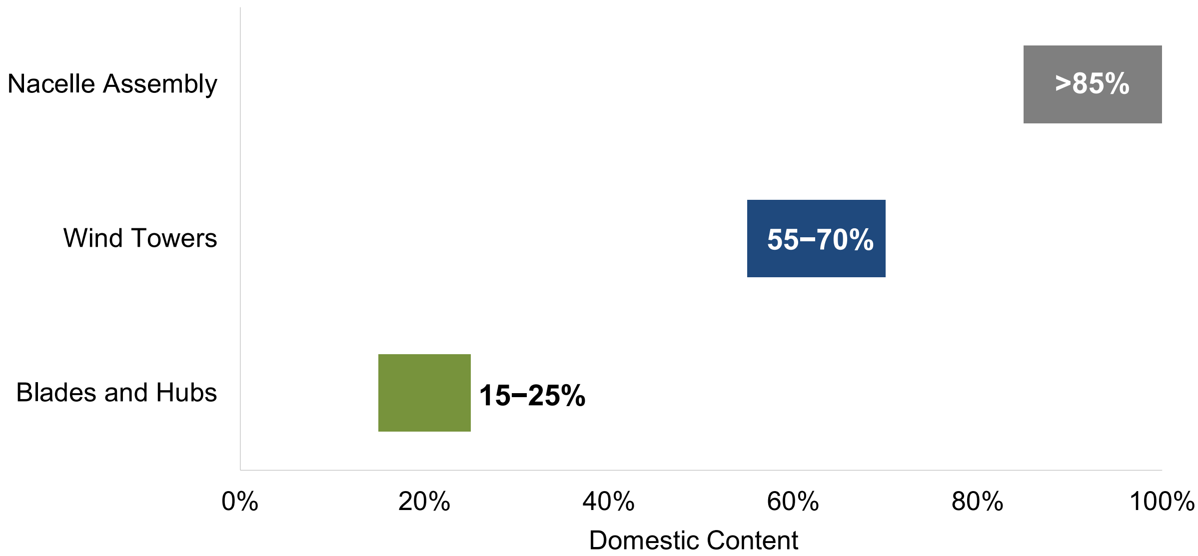
Looking behind these data, Spain, followed by Brazil, Denmark, Belgium, and Germany, were the primary source countries for wind-powered generating sets and parts, including nacelles, in 2021 (Figure 20). Tower imports came from a mix of countries near and far—Malaysia, Canada, South Korea, Mexico, and India. With regard to blades and hubs, Mexico and India accounted for almost 50% of imports, with Spain, Brazil, and China the next largest source countries in 2021. Finally, over two thirds of wind-related generators and generator parts in 2021 came from Vietnam and Spain, the rest primarily coming from Germany, Serbia, and China.



Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 20. Origins of U.S. imports of selected wind turbine equipment in 2021

Figure 21 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 2021. Domestic content remains relatively strong for larger components such as towers and also for nacelle assembly. The domestic manufacturing content of blades, on the other hand, has declined precipitously in recent years. More broadly, these figures may understate the wind industry's reliance on foreign suppliers, because significant wind-related imports occur under trade categories not captured in this figure, including equipment (such as mainframes, converters, pitch and yaw systems, main shafts, bearings, bolts, controls) and manufacturing inputs (such as foreign steel in domestic manufacturing).



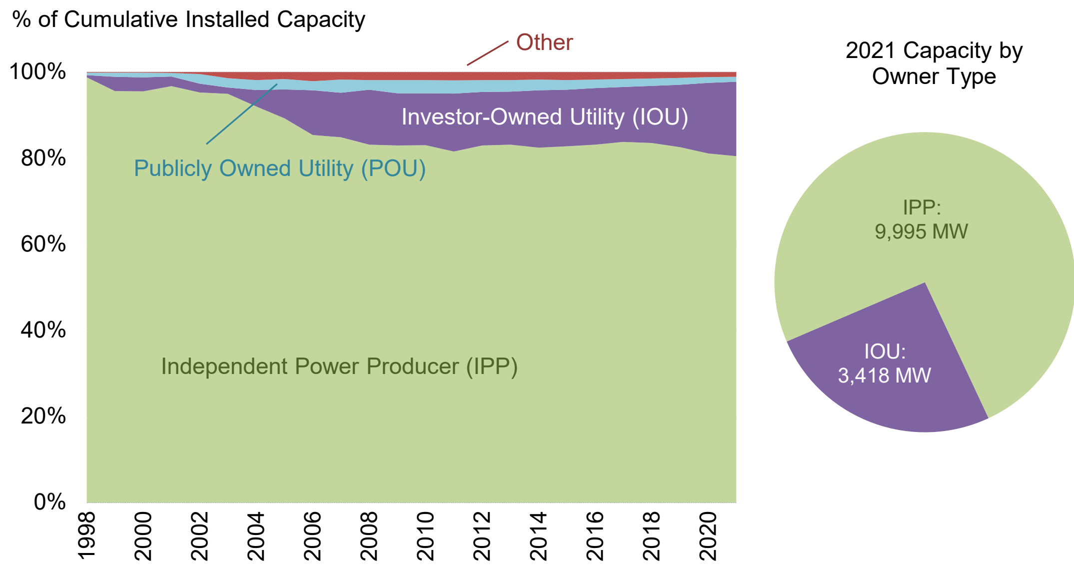
Source: Berkeley Lab analysis

Figure 21. Approximate domestic content of major components in 2021

Independent power producers own the majority of wind assets built in 2021, following historical trends

Independent power producers (IPPs) own 9,995 MW or 75% of the 13.4 GW of new wind capacity installed in the United States in 2021 (Figure 22, right pie chart). Investor-owned utilities (IOUs)—most notably Pacificorp (589 MW), AEP's PSO and SWEPCO (486 MW), the Empire District Electric Company (450 MW), and Xcel Energy (436 MW), but including ten IOUs in all—installed a total of 3,418 MW (25%). Of the cumulative installed wind power capacity at the end of 2021 (Figure 22, left chart), IPPs own 80% and utilities own 18% (17% IOU and 1% publicly owned utility, or POU), with the remaining 1% falling into the "other" category of projects owned by neither IPPs nor utilities (e.g., owned by towns, schools, businesses, farmers).[20]

[20] 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.



Source: Berkeley Lab estimates based on ACP

Figure 22. Cumulative and 2021 wind power capacity categorized by owner type

Direct retail sales and merchant offtake arrangements for wind, in combination, matched or surpassed long-term contracted wind sales to utilities in 2021

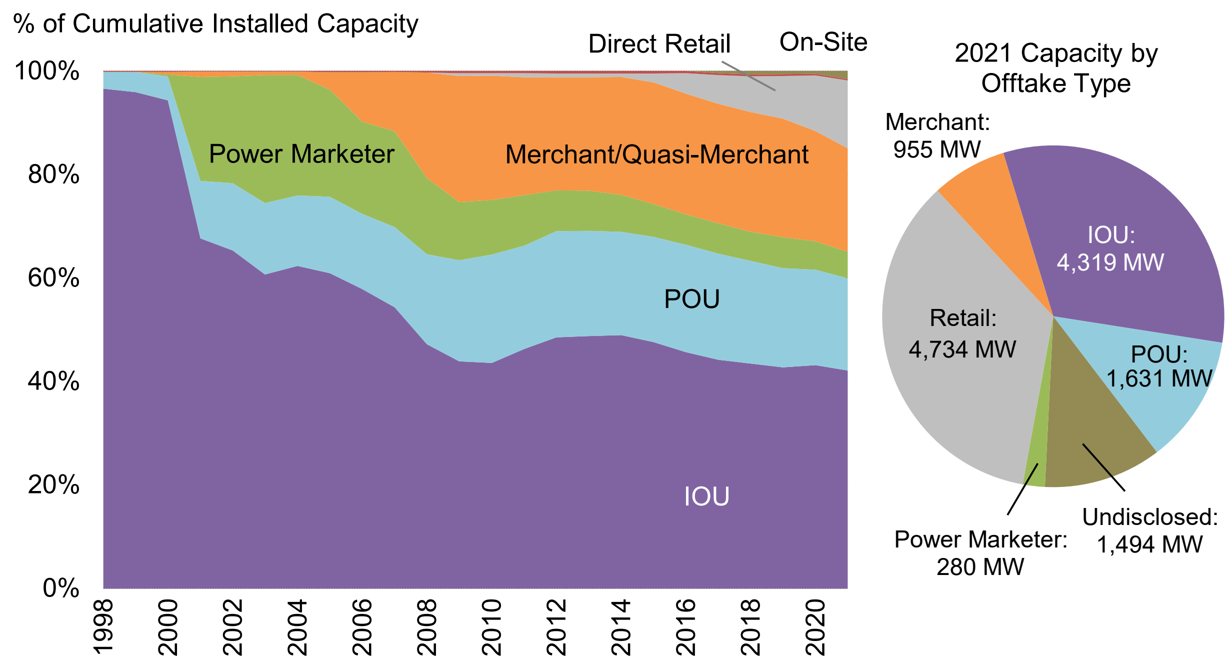
Electric utilities either own (25%) or buy the electricity from wind projects (19%) that, in total, represent 44% of the new capacity installed last year (with the 44% split between 32% IOU and 12% POU—Figure 23, right pie chart). On a cumulative basis, utilities own (18%) or buy (42%) power from 60% of all wind power capacity installed in the United States (with the 60% split between 42% IOU and 18% POU, with the POU category including community choice aggregators (CCAs)).

Direct retail purchasers of wind power, including a diverse and growing set of corporate and non-corporate offtakers, are supporting at least 35% of the new wind power capacity installed in the United States in 2021 (and 13% of cumulative wind power capacity). Such purchasers historically have spanned a wide range of organizations, from technology companies, retailers, finance, and telecommunication firms to governments and universities. Merchant/quasi-merchant projects accounted for at least 7% of all new 2021 capacity and 20% of cumulative capacity.[21] Finally, power marketers—defined here to include commercial intermediaries that purchase power under contract and then resell that power to others[22]—are buying at least the remaining 2% of new 2021 wind capacity and 5% of cumulative capacity. We qualify the level of support from these non-utility offtakers as "at least" because it is likely that much of the 1.5 GW of 2021 capacity that has not yet disclosed an offtaker is being sold to corporate buyers, power marketers, or into merchant arrangements, rather than to utilities.

---

[21] 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), rather than being locked in through a long-term PPA. Most of these projects are located within ERCOT, though there are some merchant/quasi-merchant projects within other markets, including PJM, MISO, SPP, and NYISO. Associated 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 with the swap counterparty.

[22] These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.



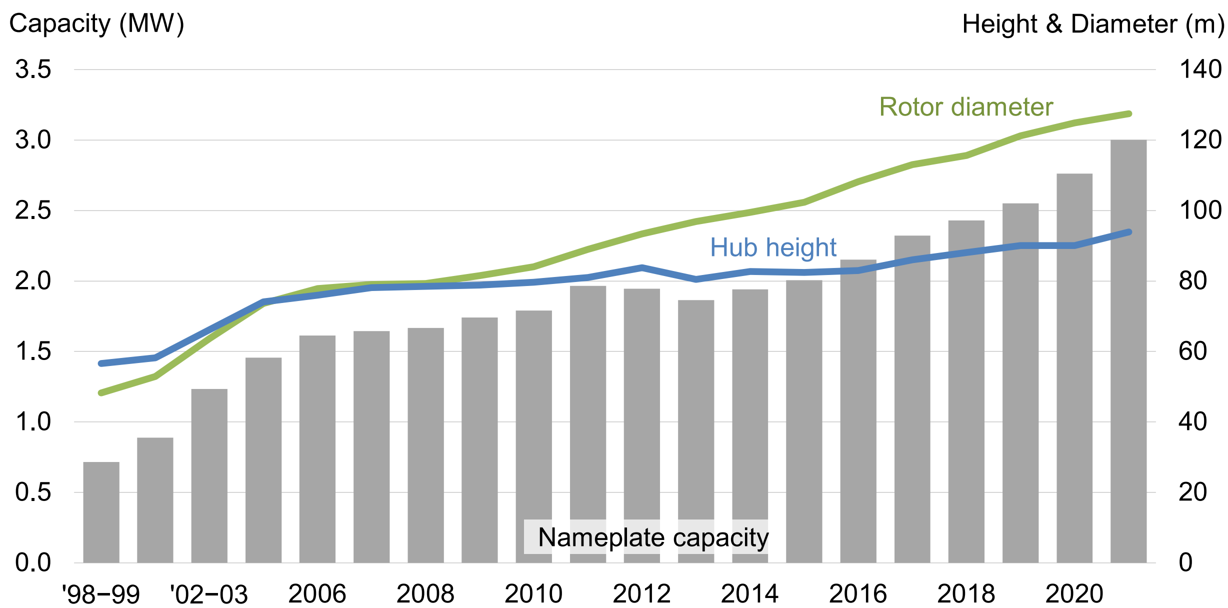
Source: Berkeley Lab estimates based on ACP

Figure 23. Cumulative and 2021 wind power capacity categorized by power offtake arrangement

4 Technology Trends

Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term

The average nameplate capacity of newly installed wind turbines in the United States in 2021 was 3.0 MW, 9% larger than in 2020 and up 319% since 1998–1999 (Figure 24).[23] The average hub height of turbines installed in 2021 was 93.9 meters, 4% larger than in 2020 and up 66% since 1998–1999. The average rotor diameter in 2021 was 127.5 meters, 2% larger than in 2020 and up 164% since 1998–1999. Trends in rotor scaling in particular, but also hub height, are two of several factors impacting the project-level capacity factors highlighted later in this report.

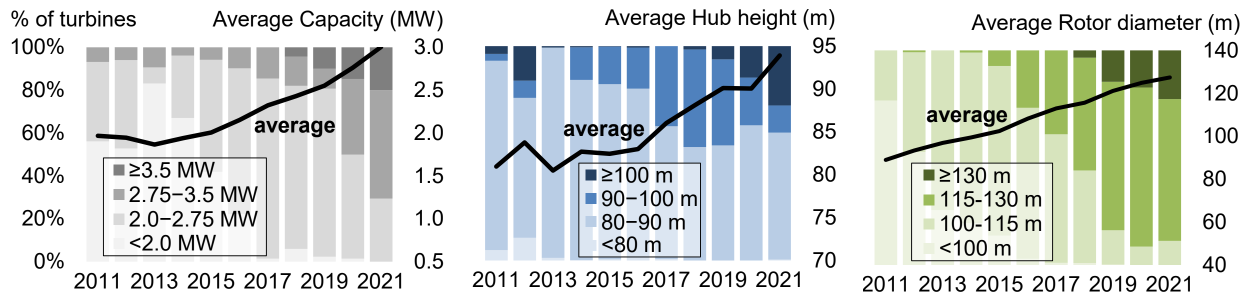


Sources: ACP, Berkeley Lab

Figure 24. Average turbine nameplate capacity, hub height, and rotor diameter for land-based wind projects

Figure 25 presents these same trends since 2011, but with additional detail on the relative distribution of turbines with different capacities, hub heights, and rotor diameters. For example, 2021 saw an increase in the proportion of turbines installed in the 2.75–3.5 MW range, while the proportion of turbines at 3.5 MW or larger also increased. The percentage of turbines with hub heights larger than 100 meters increased in 2021, to 28%—up from just 15% in 2020. Finally, the steady progression toward larger rotors continued. In 2011, no turbines employed rotors that were 115 meters in diameter or larger, while 89% of newly installed turbines featured such rotors in 2021 (and 23% of those were at least 130 meters).

[23] Figure 24 and a number of the other figures and tables included in this report combine 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.



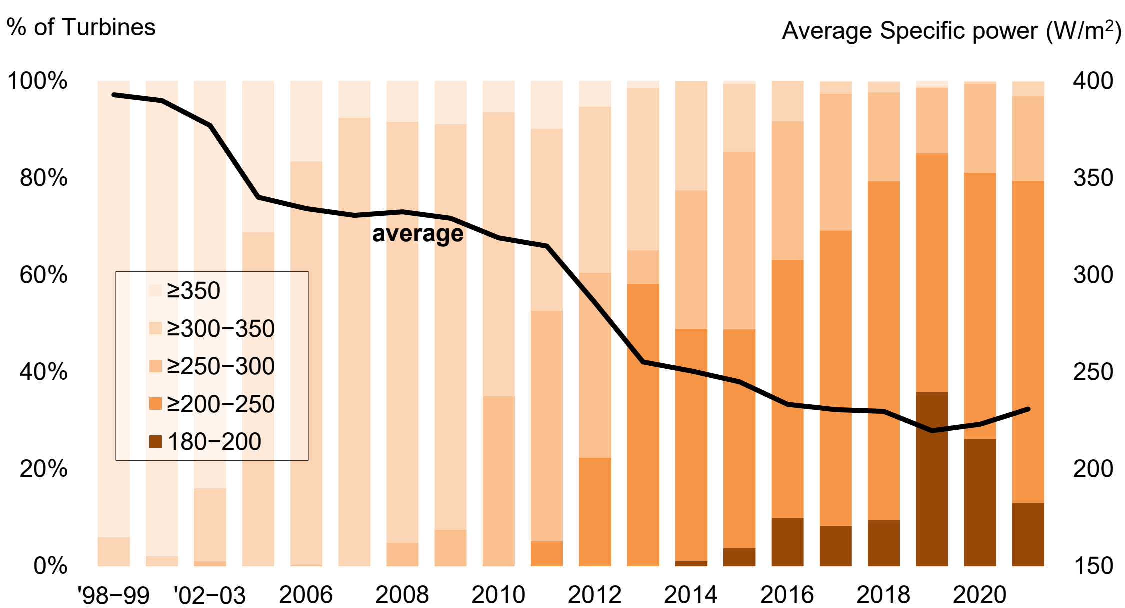
Sources: ACP, Berkeley Lab

Figure 25. Trends in turbine nameplate capacity, hub height, and rotor diameter

Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has reversed over the last two years

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 393 W/m^2 among projects installed in 1998–1999 to 231 W/m^2 among projects installed in 2021. However, as shown in Figure 26, the long-term decline in specific power has reversed in recent years, with specific power rising slightly in both 2020 and 2021.

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 26 and as detailed later, however, such turbines are 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: ACP, Berkeley Lab

Figure 26. Trends in turbine specific power

Wind turbines were deployed in somewhat lower wind-speed sites in 2021 than in the previous seven years

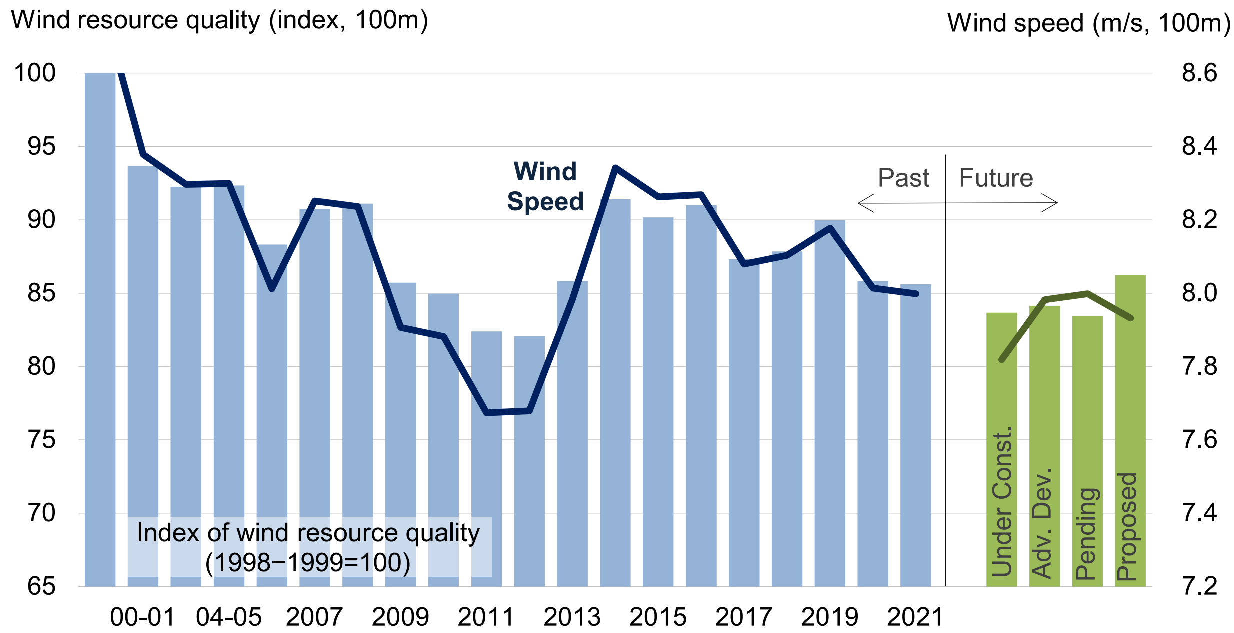
Figure 27 shows the long-term average wind resource at wind project sites, by commercial operation date. The figure depicts both the long-term site-average wind speed (in meters per second) at 100 meters for projects installed in each year (right scale) and an index of wind resource quality at 100 meters (left scale).[24]

Wind plants that came online in 2021 are located—on average—at sites with an estimated long-term average 100-meter wind speed of 8.0 meters per second (m/s). This is the lowest average site wind speed in the last eight years. Federal Aviation Administration (FAA) and industry data on projects that are “under construction,” in “advanced development,” “pending,” or “proposed” suggest that the sites likely to be built out over the several years will, on average, have even lower long-term average wind speeds.[25] 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 broadly similar. These trends signal changes in site-average wind speeds at a common reference height of 100 meters. Increasing hub heights over this period, thereby accessing higher wind speeds, help to partially offset these trends in 100-meter wind speeds and resource quality.

Several factors could have driven these observed trends in average site quality at 100 meters. First, the availability of low-wind-speed turbines that feature lower specific power have enabled the economic build-out of lower-wind-speed sites. Second, transmission constraints (or other siting 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 (for example, the completion of major transmission additions in West Texas in 2013), 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 incentive 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.

[24] The wind resource quality index is based on site estimates of gross capacity factor at 100 meters by AWS Truepower. A single, common wind turbine power curve is used across all sites and timeframes in this case, and no losses are assumed. The values are indexed to projects built in 1998—1999. Further details are found in the Appendix. A benefit of this wind resource quality index is that changes in the index value will better approximate expected changes in actual wind project performance than will changes in average annual wind speed.

[25] “Under construction” turbines are part of a project where construction has begun, but the project has not yet been commissioned. Turbines in “advanced development” have one of the following in place: a signed PPA (or similar long-term contract), a firm turbine order, or an announcement to proceed under utility ownership, indicating a high-likelihood that they will be built. “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 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.

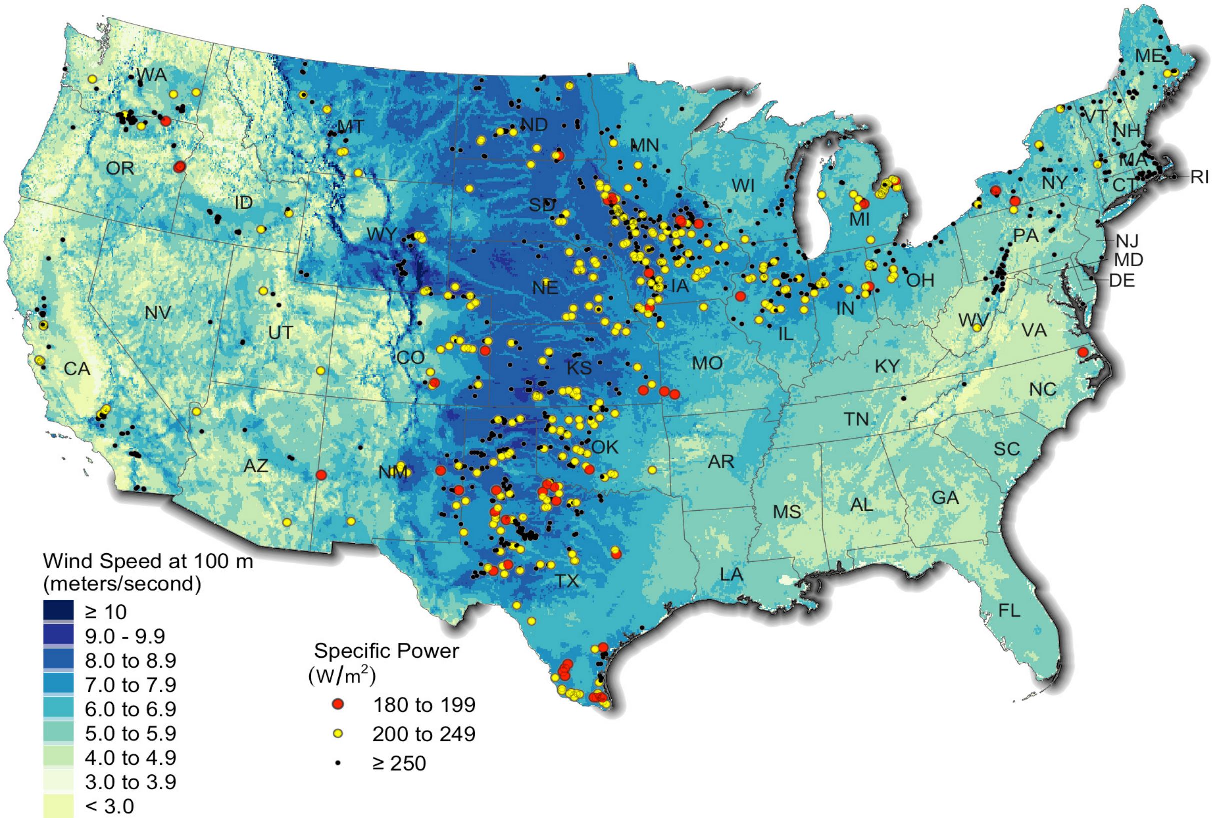


Sources: ACP, Berkeley Lab, AWS Truepower, FAA Obstacle Evaluation / Airport Airspace Analysis files

Figure 27. Wind resource quality at 100 meter height by year of installation

Low-specific-power turbines are deployed on a widespread basis; taller towers are seeing increased use in a wider variety of sites

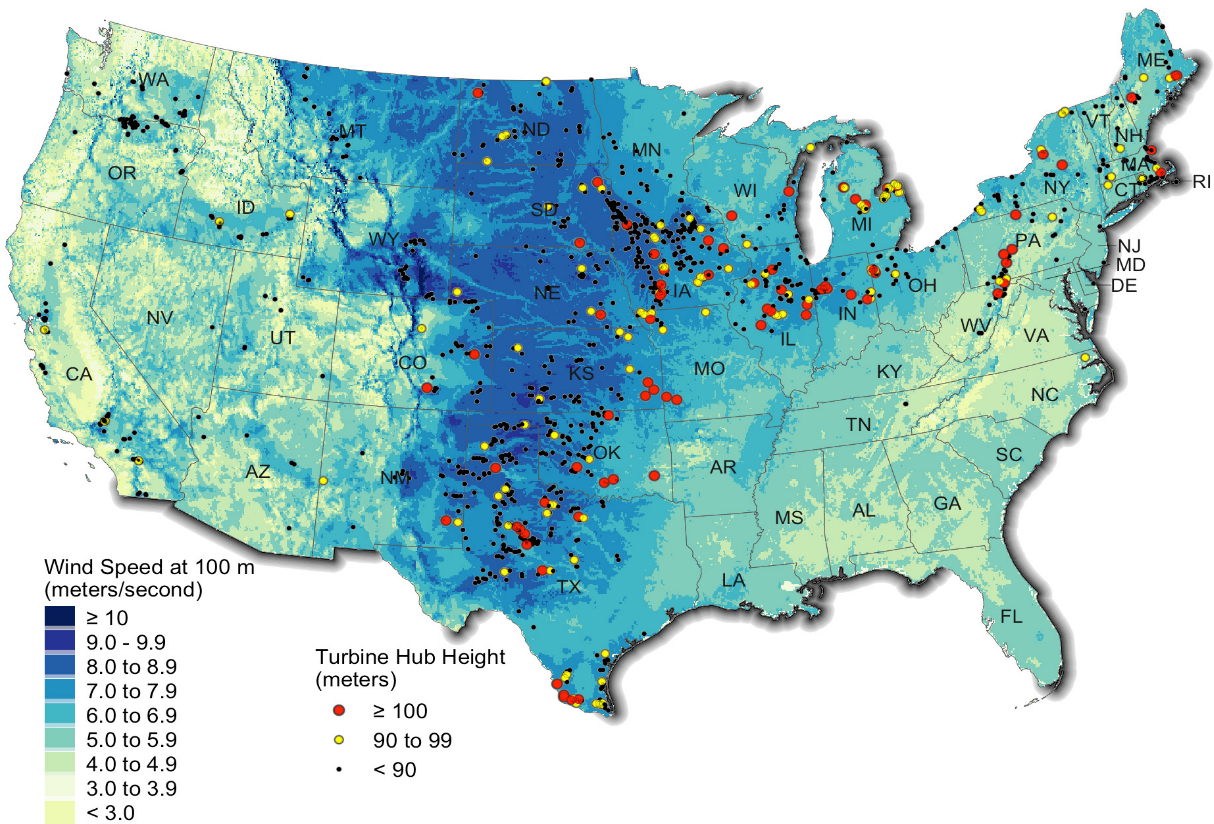
One might expect that the increasing market share of low-specific-power turbines (defined here as turbines with specific power < 250 W/m^2) would be due to a movement by developers to deploy turbines in lower wind speed sites. There is some evidence of this movement historically (see Figure 27), but it is clear in Figure 28 (which shows all U.S. wind projects) that low-specific-power turbines have established a strong foothold across the nation and over a wide range of wind speeds.



Sources: ACP, U.S. Wind Turbine Database, AWS Truepower, Berkeley Lab

Figure 28: Location of low specific power turbine installations: all U.S. wind plants

Likewise, taller towers are also being deployed across a wide array of sites (Figure 29). That said, very tall towers (>100m) still tend to be most concentrated within the upper Midwest and Northeast regions, two regions known to have higher-than-average wind shear (i.e., greater increases in wind speed with height), which makes taller towers more economical.



Sources: ACP, U.S. Wind Turbine Database, AWS Truepower, Berkeley Lab

Figure 29: Location of tall tower turbine installations: all U.S. wind plants

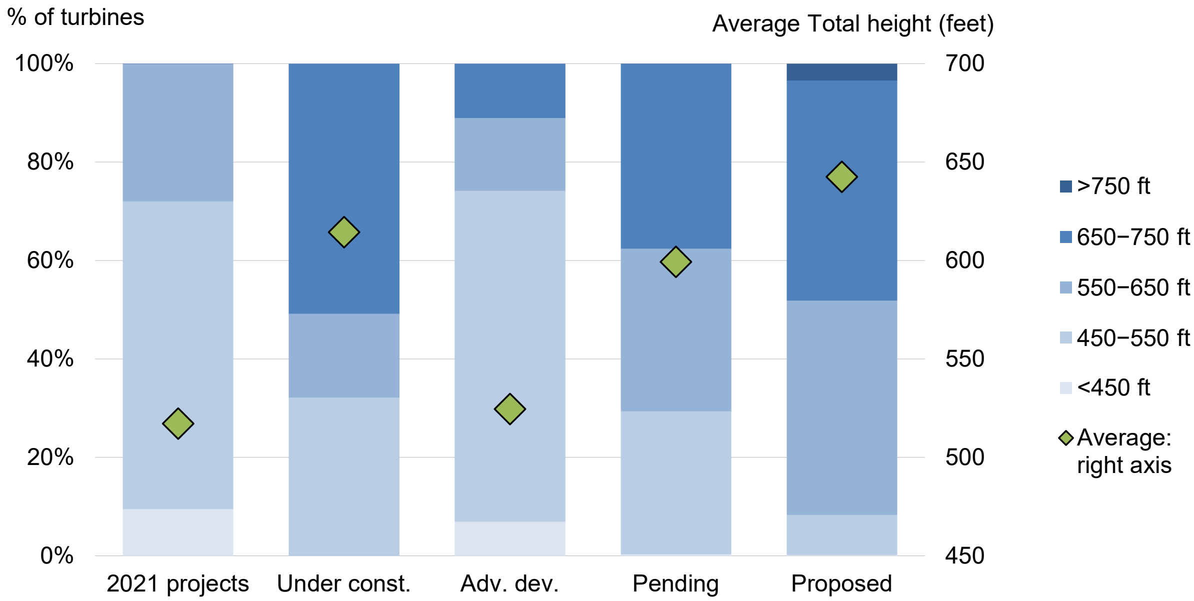
Wind projects planned for the near future are poised to continue the trend of ever-taller turbines

FAA data on total proposed turbine heights (from ground to blade tip extended directly overhead) in permit applications are reported in Figure 30. Note that these data represent total turbine height or "tip height"—not hub height—and include the combined effect of both the tower and half the rotor. Figure 30 shows the average FAA tip height, along with the distribution, for actual 2021 installations as well as turbines under construction, in advanced development, pending, and proposed.[26]

Average tip heights for projects that came online in 2021 are 517 feet (158 meters), and seem destined to climb higher in the next few years, reaching an average of 643 feet (196 meters) among the "proposed" turbines. The tallest turbines in the permitting process are over 750 feet (229 meters), while turbines of at least 650 feet appear likely to be installed in every region of the United States (Figure 31).

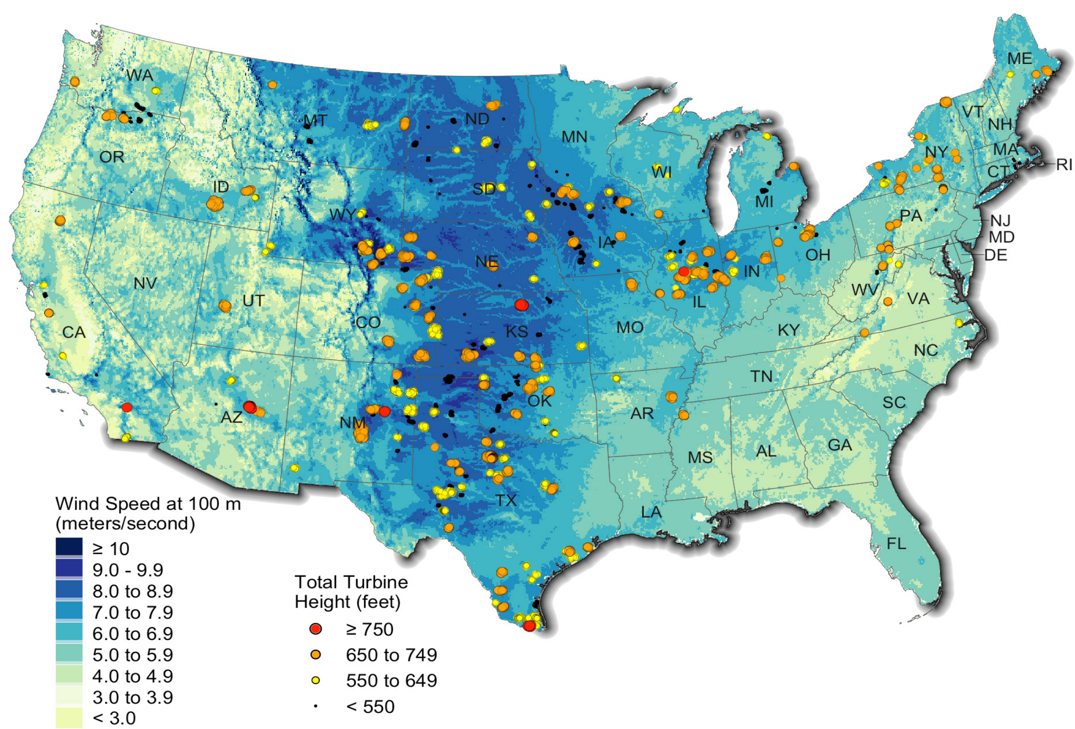
---

[26] Turbine heights reported in FAA permit applications represent the maximum height and can differ from what is ultimately installed. Historically, however, the FAA permit datasets have strongly conformed to subsequent actual installations on average.



Sources: ACP, FAA files, Berkeley Lab

Figure 30. Total turbine heights proposed in FAA applications, over time



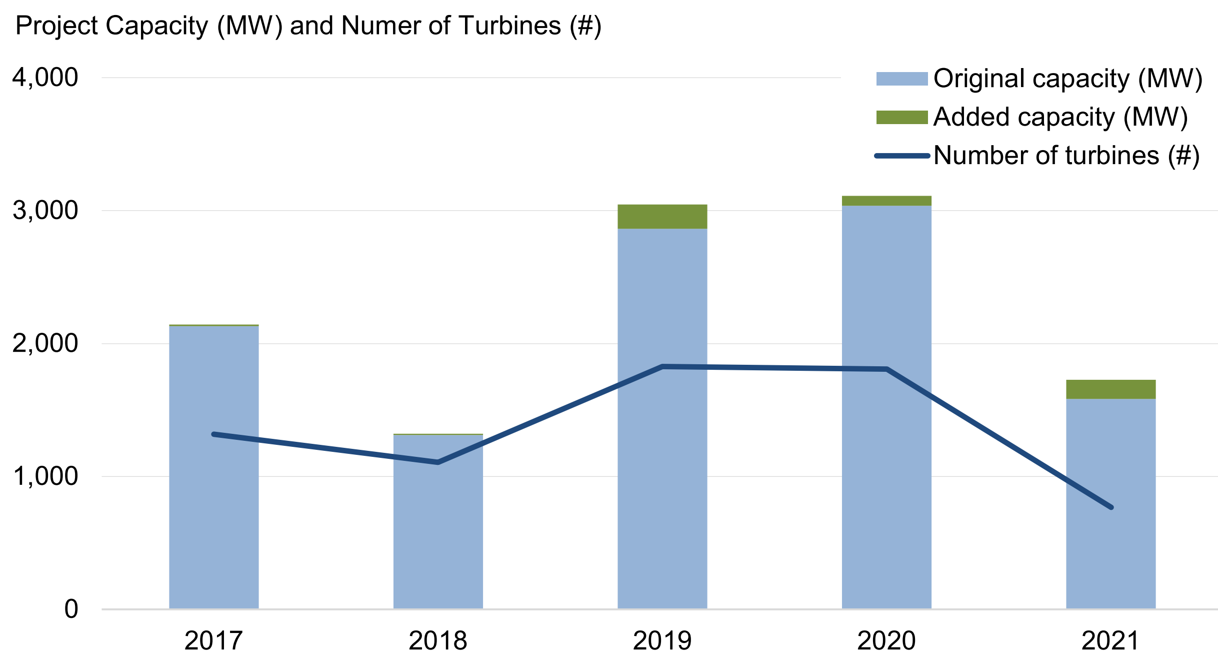
Note: Figure includes FAA data on under-construction, advanced development, pending, and proposed turbines

Sources: FAA Obstacle Evaluation / Airport Airspace Analysis files, AWS Truepower, ACP, Berkeley Lab

Figure 31. Total turbine heights proposed in FAA applications, by location

In 2021, twelve wind projects were partially repowered, most of which now feature significantly larger rotors and lower specific power ratings

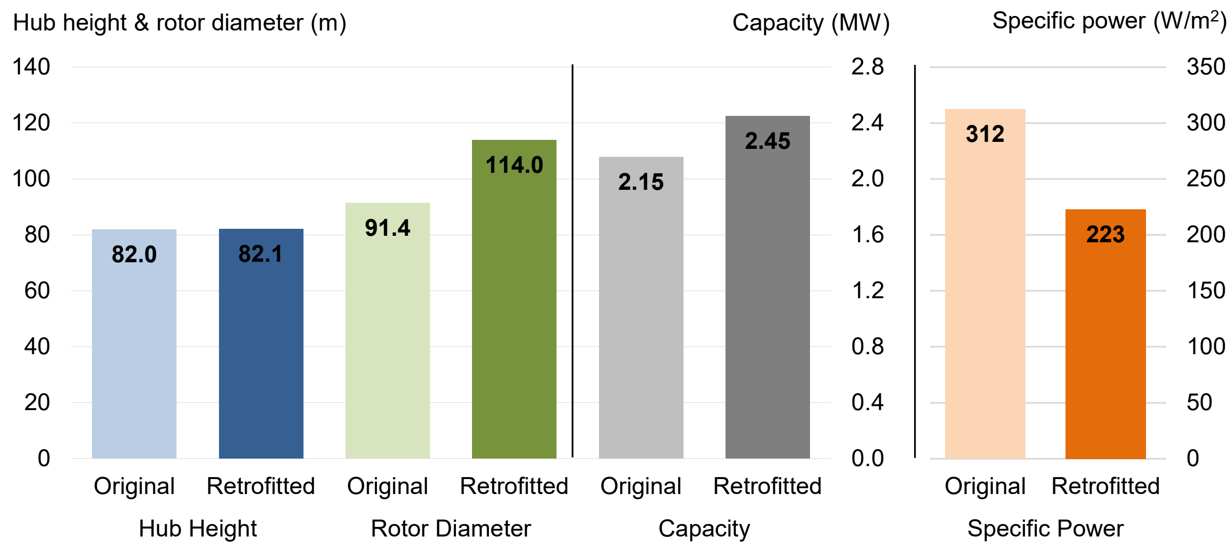
The trend of partial wind project repowering continued in 2021, albeit at a slower pace, and involved replacing major components of turbines with more-advanced technology to increase energy production, extend project life, and access favorable tax incentives. In 2021, 12 projects were partially repowered, involving 769 turbines that totaled 1.6 GW prior to repowering. Retrofitted turbines ranged in age from 9 to 16 years old; the median was 10 years. The 1.6 GW of retrofitted turbines in 2021 is a decline from the previous two years, when roughly 3 GW were retrofitted each year (Figure 32).



Sources: ACP, Berkeley Lab, turbine manufacturers

Figure 32. Annual amount of partially repowered wind power capacity and number of turbines

The most common retrofit in 2021 was the replacement of shorter with longer blades, but changes in turbine nameplate capacity were also common. Overall, the average turbine nameplate capacity of the retrofitted projects increased modestly, but rotor diameters strongly increased (Figure 33). A very small number of the turbines saw changes in hub heights. With the relatively small change in capacity but the larger change in rotor diameter, these retrofits drove a significant decrease in average specific power.



Sources: ACP, Berkeley Lab, turbine manufacturers

Figure 33. Change in average physical specifications of all turbines that were partially repowered in 2021

5 Performance Trends

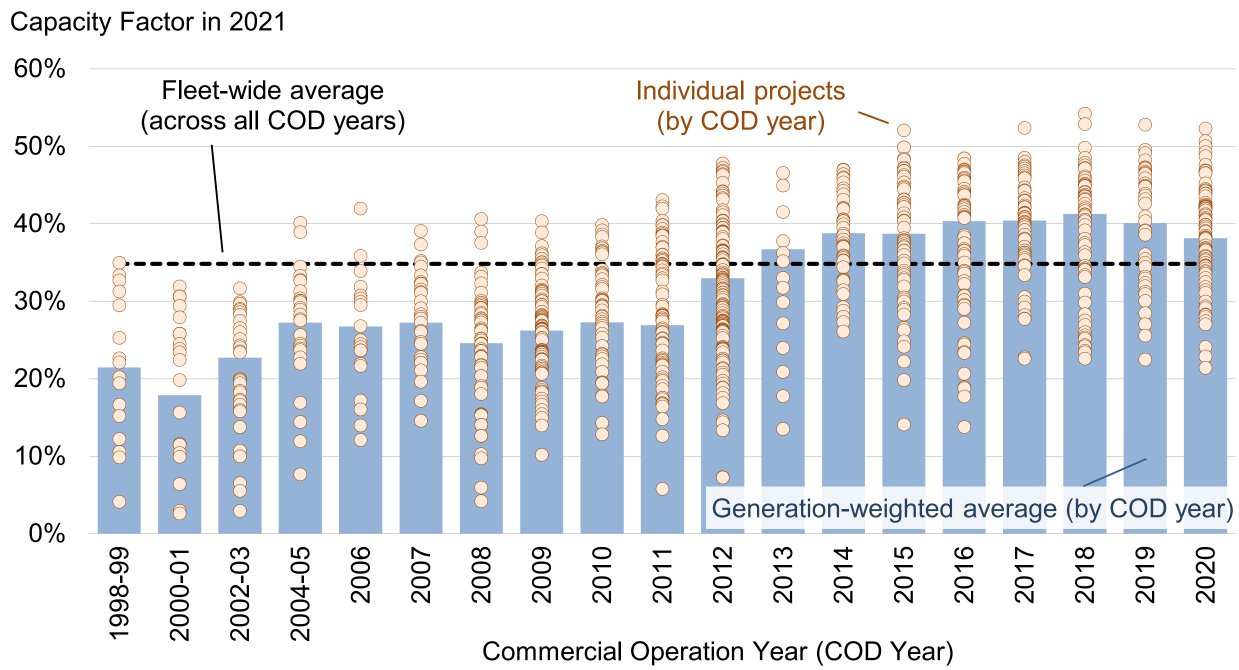
The average capacity factor in 2021 was 35% on a fleet-wide basis and 39% among wind projects built in recent years

Following the previous discussion of technology trends, this chapter presents data from a compilation of project-level capacity factors.[27] The full data sample consists of 989 wind projects built between 1998 and 2020 and totaling 103.1 GW. Excluded from this assessment are older projects installed prior to 1998. In addition, projects that either partially or fully repowered in 2021 are excluded from the 2021 capacity factor sample, given that they were at least partly offline during a portion of the year. 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.). When looking at performance degradation over time, however, adjustments are made for inter-annual variability in the wind resource.

To start, Figure 34 shows both individual project and average capacity factors in 2021, broken out by commercial operation date.[28] Projects built in 2021 are excluded, as full-year performance data are not yet available for those projects. From left to right, Figure 34 shows an increase in weighted-average 2021 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 2021. This pattern of stagnation is broken by projects installed in 2012–2013, and even more so by those that achieved commercial operations in 2014–2020.[29]

The average 2021 capacity factor among projects built from 2014 to 2020 was 39%, compared to an average of 26% among all projects built from 2004 to 2011, and 19% among all projects built from 1998 to 2001. Cumulative, fleet-wide performance has also increased over time, growing from under 27% in 1999 (not shown) to 35% in 2021 (shown in Figure 34). The 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. The 2021 capacity factor for projects built most recently, in 2020, was 38%, somewhat lower than for projects built from 2014 to 2020 and continuing a capacity factor decline that began with wind projects built in 2019.

[27] 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.
[28] Focusing on capacity factors in a single year, 2021, 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 33 may not be representative over longer terms if 2021 was not a representative year in terms of curtailment or the strength of the wind resource (though, as noted later, 2021 was a fairly average wind year overall).
[29] The 2021 capacity factor of projects that were built in 2020 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.

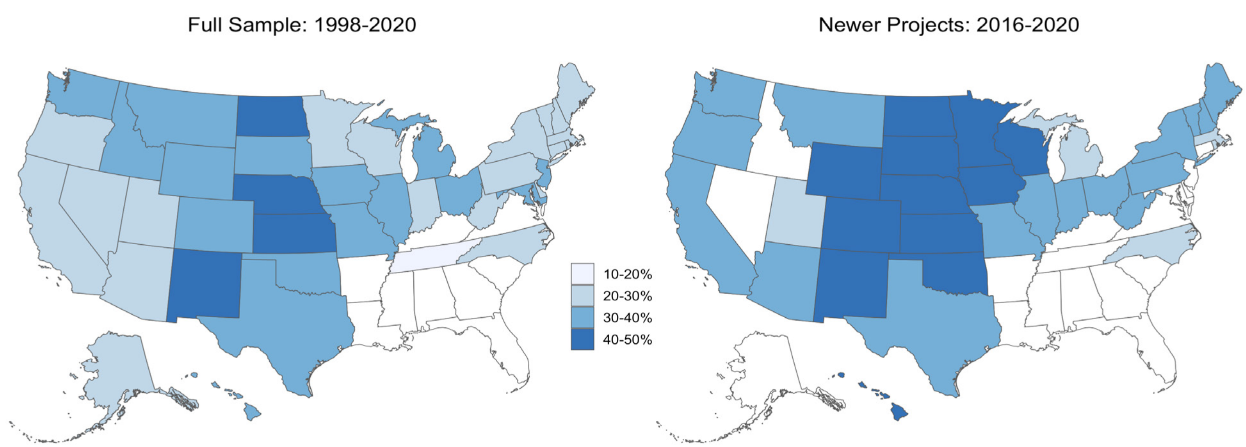


Sources: EIA, FERC, Berkeley Lab

Figure 34. Calendar year 2021 capacity factors by commercial operation date

State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country

The project-level spread in capacity factors shown in Figure 34 is enormous, with capacity factors in 2021 ranging from a minimum of 21% to a maximum of 52% among those projects built in 2020. Some of the spread—for projects built in 2020 and earlier—is attributable to regional variations in average wind resource quality. Figure 35 includes data on the full sample of projects built from 1998 through 2020 and also a subset of newer projects built from 2016 through 2020, and shows average state-level capacity factors in 2021. The overall range runs from 12%–46%, with considerably higher capacity factors in the interior of the country—where the wind resource is the strongest.



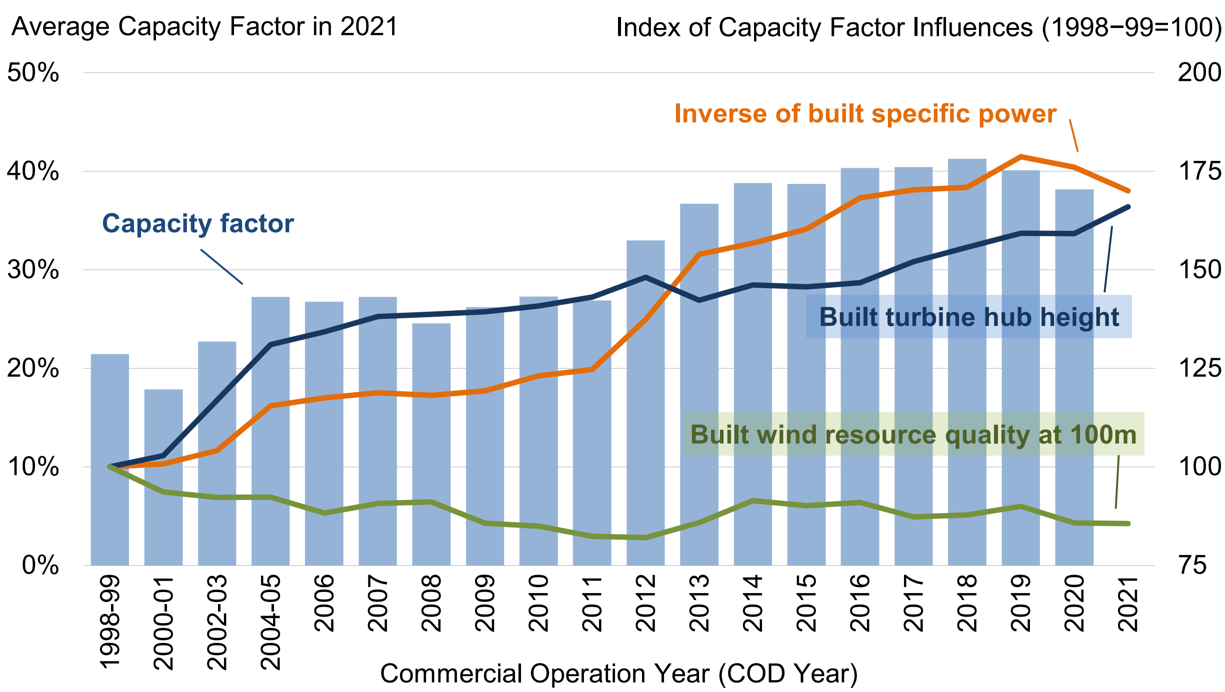
Note: States shaded in white have no projects in full sample (left) or in newer sample (right)

Sources: EIA, FERC, Berkeley Lab

Figure 35. Average calendar year 2021 capacity factor by state

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

The trends in average capacity factor by commercial operation date seen in Figure 34 can largely be explained by several underlying influences described in Chapter 4 and shown again in Figure 36. First, as documented in Chapter 4, there has been a trend toward lower specific power and higher hub heights. These two drivers are shown again in Figure 36 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. Meanwhile, increasing turbine hub heights generally helps the rotor access higher wind speeds. Second, and potentially counterbalancing these drivers, there has been a tendency to build new wind projects in areas that feature lower average wind speeds,[30] especially among projects installed from 2009 through 2012 as shown by the wind resource quality index in Figure 36. This trend reversed course in 2013 and 2014, but has since drifted lower once again (these wind resource trends are easier to see in Figure 27, where the y-axis scale is less-expansive). Finally, as shown later, two other drivers might include project age (given the possible degradation in performance among older projects) and increasing curtailment over the past few years (curtailment is baked into the capacity factors shown throughout this chapter).



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).

Sources: EIA, FERC, Berkeley Lab

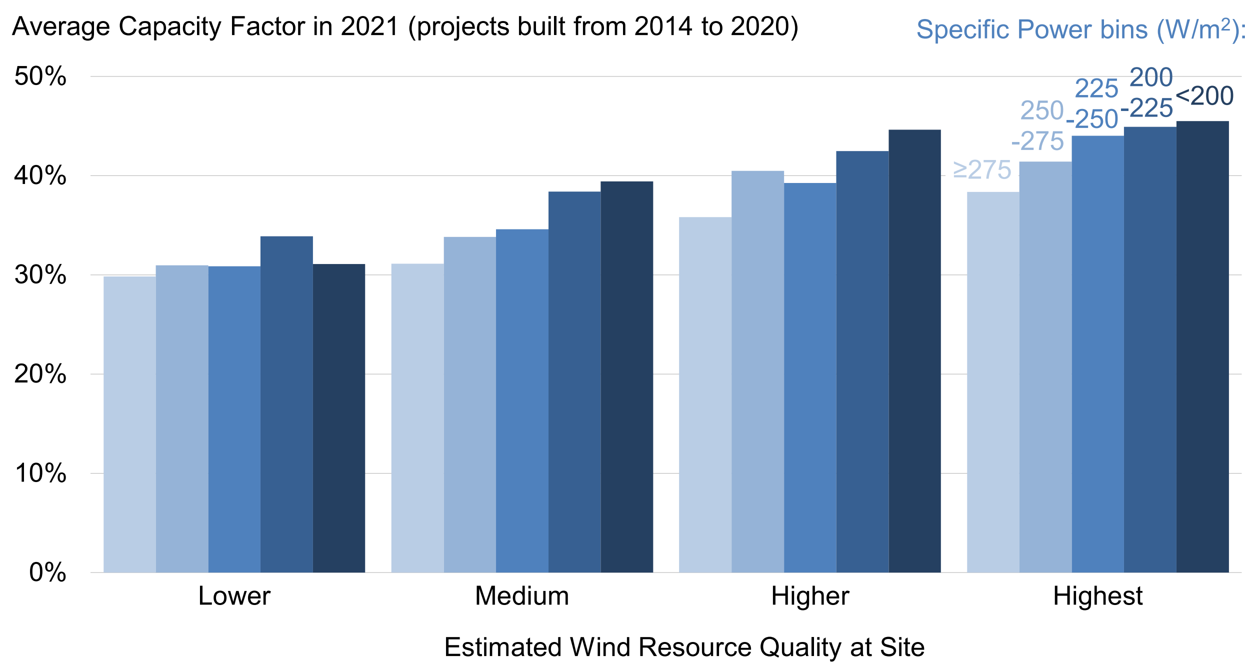
Figure 36. 2021 capacity factors and various drivers by commercial operation date

---

[30] As described earlier relating to Figure 27 (with further details in the Appendix), estimates of wind resource quality are based on site estimates of *gross* capacity factor at 100 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower. Those site estimates are indexed to projects built in 1998–1999.

In Figure 36, the significant improvement in average 2021 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. The sharp increase in average capacity factors among projects built after 2011 is driven by a steep reduction in average specific power coupled with—for a time—a marked improvement in the quality of wind resource sites. Average hub height increased modestly over this period. Finally, projects built most recently have somewhat lower 2021 capacity factors, perhaps due in part to teething issues that often confront projects in their first years but also due to a slight rise in specific power and a continuing move towards lower-quality wind resource sites. Looking ahead to 2022, projects with commercial operation dates in 2021 could possibly record lower capacity factors on average than those built in 2020, in light of a slight increase in average specific power coupled with a slight decline in average site quality.

To help disentangle the primary and sometimes competing influences of turbine design evolution and wind resource quality on capacity factor, Figure 37 controls for each. Across the x-axis, projects built from 2014 to2020 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 would be expected, projects sited in higher wind speed areas generally realized higher capacity factors in 2021 than those in lower wind speed areas, regardless of specific power. Likewise, within the three higher wind resource categories in particular, projects that fall into a lower specific power range realized higher capacity factors in 2021 than those in a higher specific power range.



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

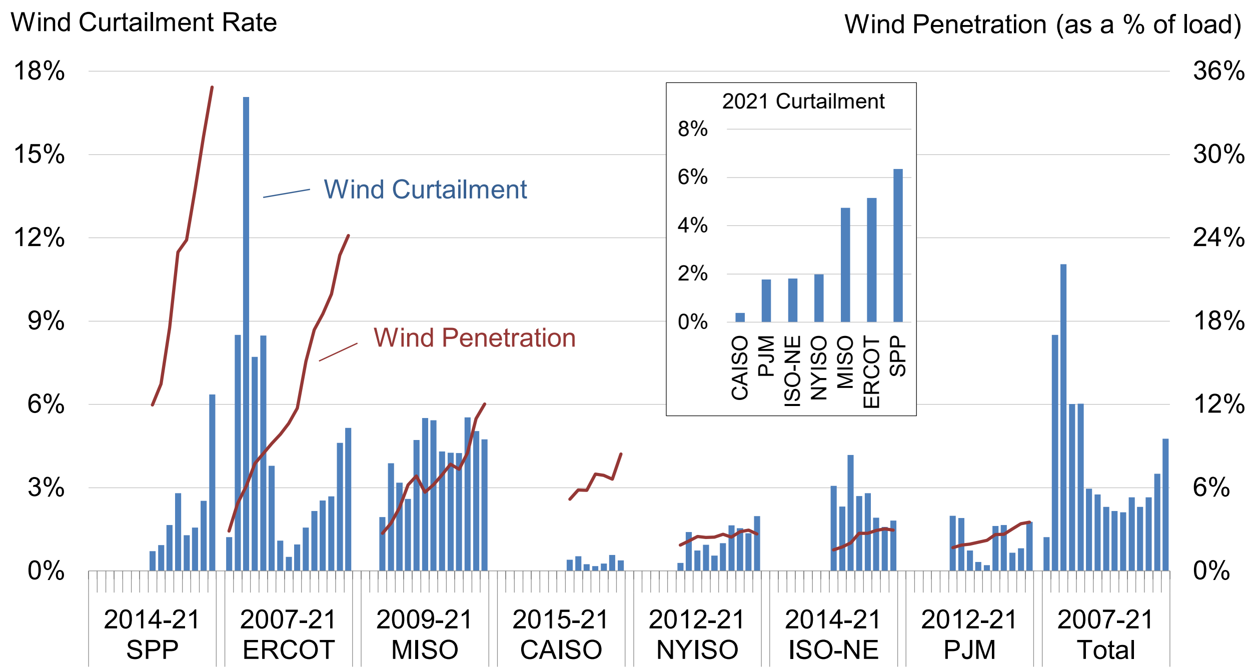
Sources: EIA, FERC, Berkeley Lab

Figure 37. Calendar year 2021 capacity factors by wind resource quality and specific power: 2014-2020 projects

Wind power curtailment in 2021 across seven regions averaged 4.8%, up from a low of 2.1% in 2016

Curtailment of wind project output results from transmission inadequacy and other forms of grid and generator inflexibility in concert with wind over-supply. 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 wind curtailment especially among projects not earning the PTC.

Curtailment might be expected to increase as wind energy penetrations rise, though—as shown in Figure 38—this has not always been the case. Moreover, in areas where curtailment has been particularly acute in the past, steps taken to address the issue have borne fruit. For example, Figure 38 shows that just 0.5% of potential wind energy generation within ERCOT was curtailed in 2014, down sharply from 17% in 2009. This decline in curtailment corresponds to a significant build-out of new transmission serving West Texas, most of which was completed by the end of 2013. Since 2014, however, wind penetration has continued to increase in ERCOT, and so too has wind curtailment, which rose to 5.2% in 2021 (just ahead of MISO's 4.7% but less than SPP's 6.4%—which itself represents more than a doubling from 2020's 2.5%).



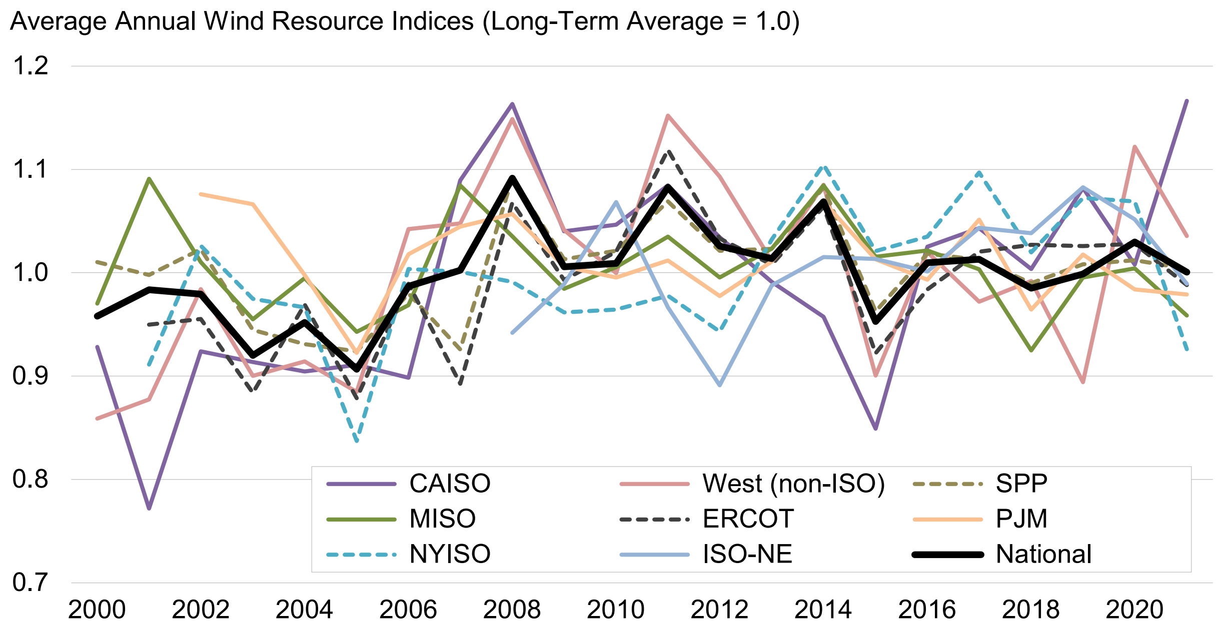
Sources: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

Figure 38. Wind curtailment and penetration rates by ISO

Outside of SPP, ERCOT, and MISO, curtailment percentages in 2021 were relatively low: 2.0% in NYISO, 1.8% in ISO-NE and PJM, and 0.4% in CAISO. The overall wind power curtailment rate in 2021 across all seven regions was 4.8%, up from a low of 2.1% in 2016.

2021 was an average wind resource year across most of the country

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 39 shows national and regional indices of the historical inter-annual variability in the wind resource among the U.S. fleet over time.[31] Though inter-annual variation has, at times, exceeded +/-20% at the regional level, geographical averaging has enabled nationwide variation to remain within +/-10%. In 2021, the national wind index stood at its long-term average, as most regions experienced a fairly average wind year (CAISO and NYISO excepted).



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

Figure 39. Inter-annual variability in the wind resource by region and nationally

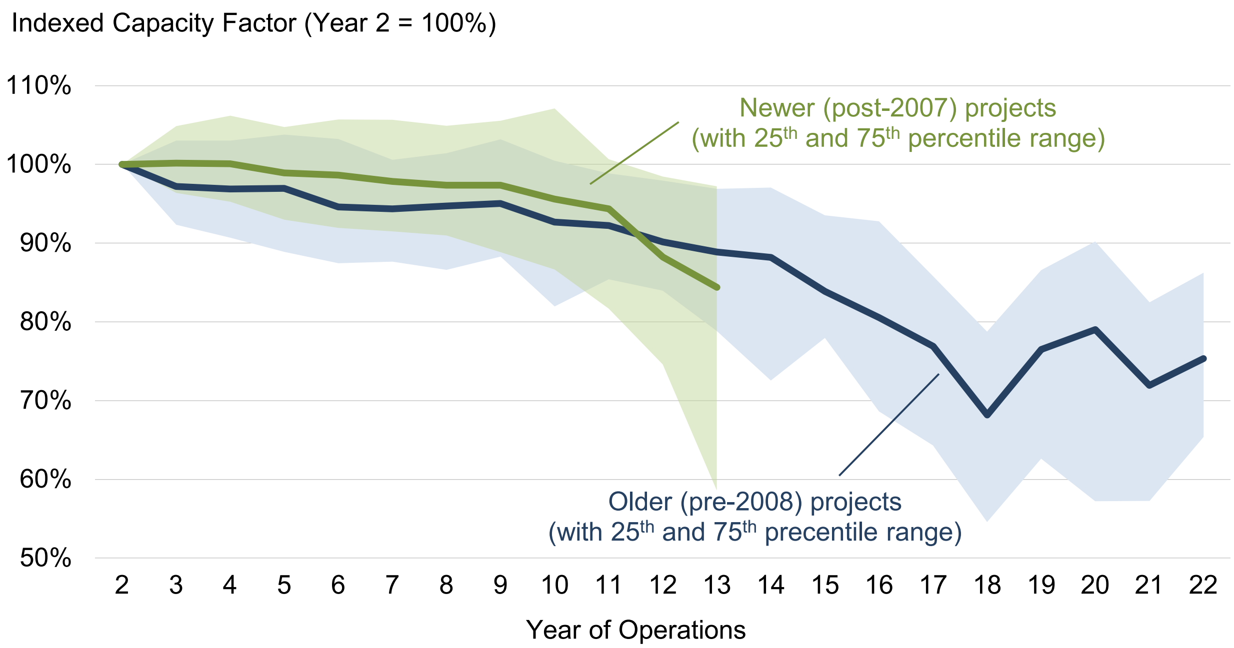
Wind project performance degradation also explains why older projects did not perform as well in 2021

A final variable that could influence the improvement in 2021 capacity factors 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 2021 than more recent projects simply due to their relative age. Figure 40 explores this question by graphing median (and 25th to 75th percentile ranges) "weather-normalized" (i.e., correcting 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, and each project's capacity factor is indexed to 100% in year two in order to focus solely on changes in capacity factor over time, rather than on absolute capacity factor values. Year two is chosen as the index base to reflect the initial production ramp-up period commonly experienced by wind projects as their operators work through and resolve initial "teething" issues during the first year of operations.

---

[31] These indices estimate changes in the strength of the average region- or fleet-wide wind resource from year to year (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 focus on the multi-year long-term average wind resource at specific wind project sites.

Figure 40 suggests some amount of performance decline, especially in later years and among older projects built before 2008. Projects built in 2008 and later appear, on average, to have experienced only a modest decline in capacity factor during their first decade, followed by a turn for the worse in the few years thereafter—perhaps reflecting a change in how projects are operated once they age beyond the 10-year PTC window. Hamilton et al. (2020) explore these performance trends in more depth. Overall, from year 15 to 20, average project performance appears to be roughly 75% of early-year performance.



Sources: EIA, FERC, Berkeley Lab

Figure 40. Changes in project-level capacity factors as projects age

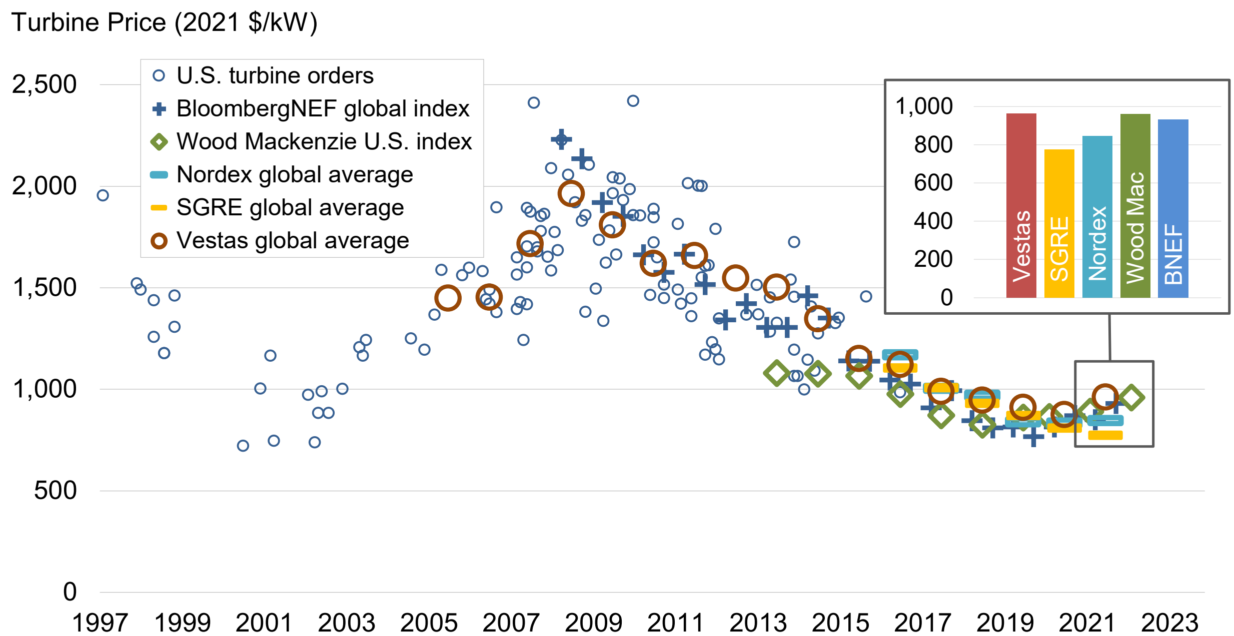
Taken together, Figure 34 through Figure 40 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of parameters. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial 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

Wind turbine prices increased by an average of 5% to 10% in 2021 given supply chain pressures

Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. However, with supply chain pressures and rising materials prices, turbine prices generally increased in 2021.

Figure 41 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) BloombergNEF (2021a) and Wood Mackenzie (2022a), on those companies' turbine price indices by contract signing date; and (3) 121 U.S. wind turbine transactions announced from 1997 through 2016, as previously collected by Berkeley Lab. 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. These differences drive 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, annual financial reports, forecast providers

Figure 41. Reported wind turbine transaction prices over time

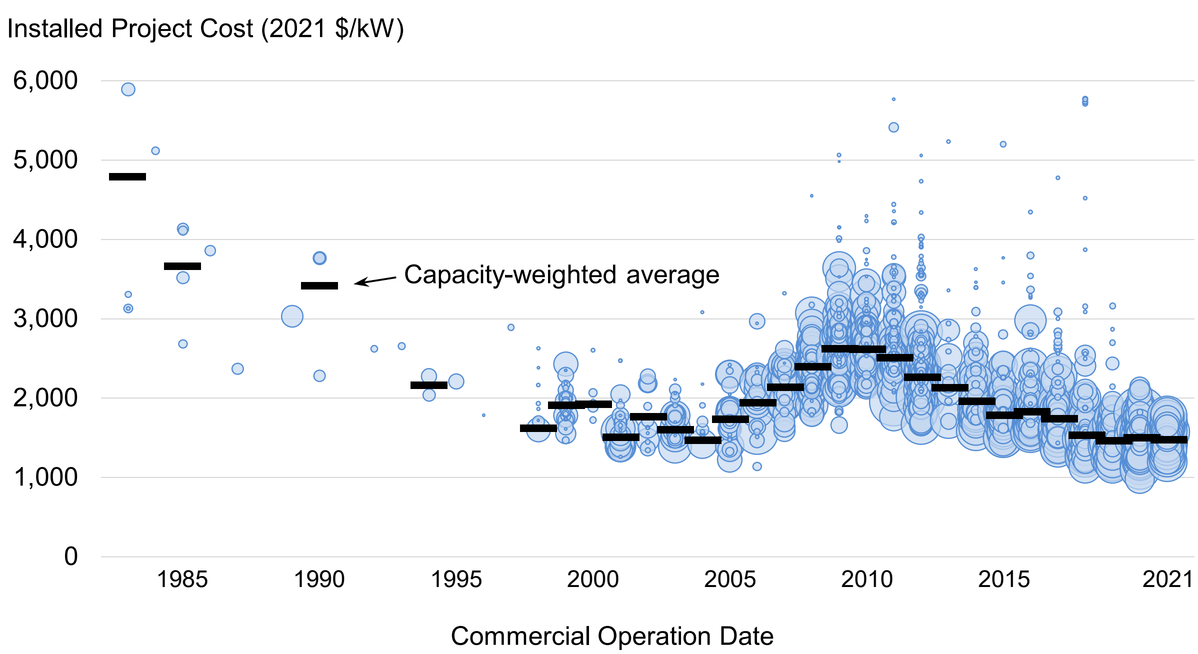
After hitting an initial low of roughly $900/kW, on average, from 2000 to 2002, wind turbine prices increased by approximately $1000/kW through 2008, rising to an average of $1,900/kW. This increase in turbine prices was caused by several factors, including a decline in the value of the U.S. dollar relative 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).

Wind turbine prices have declined by 50% since 2008, in part reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as significant cost-cutting measures on the part of turbine and component suppliers. Nonetheless, recent supply-chain pressures and rising commodity prices led to increased turbine prices in 2021 (IEA 2021, 2022). Data indicate recent average pricing generally in the range of $800/kW to $950/kW, roughly 5% to 10% higher than a year prior.

Installed project costs in 2021 held steady at an average of $1,500/kW even as turbine prices rose

Berkeley Lab also compiles data on the total installed cost of wind projects in the United States, including data on 31 projects completed in 2021 and totaling 6.5 GW, or 48% of the wind power capacity installed in that year. In aggregate, the dataset includes 1,159 completed wind power projects in the continental United States totaling 113.5 GW and equaling roughly 84% of all wind power capacity installed as of the end of 2021. 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 42, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of the last decade. Costs peaked in 2009–2010. Though project-level costs have declined since 2010, they have largely held steady over the last few years—and with rising turbine prices may increase in the near term given the lag between turbine orders and project commissioning.



Note: Area of “bubble” is proportional to project capacity

Sources: Berkeley Lab, EIA (some data points suppressed to protect confidentiality)

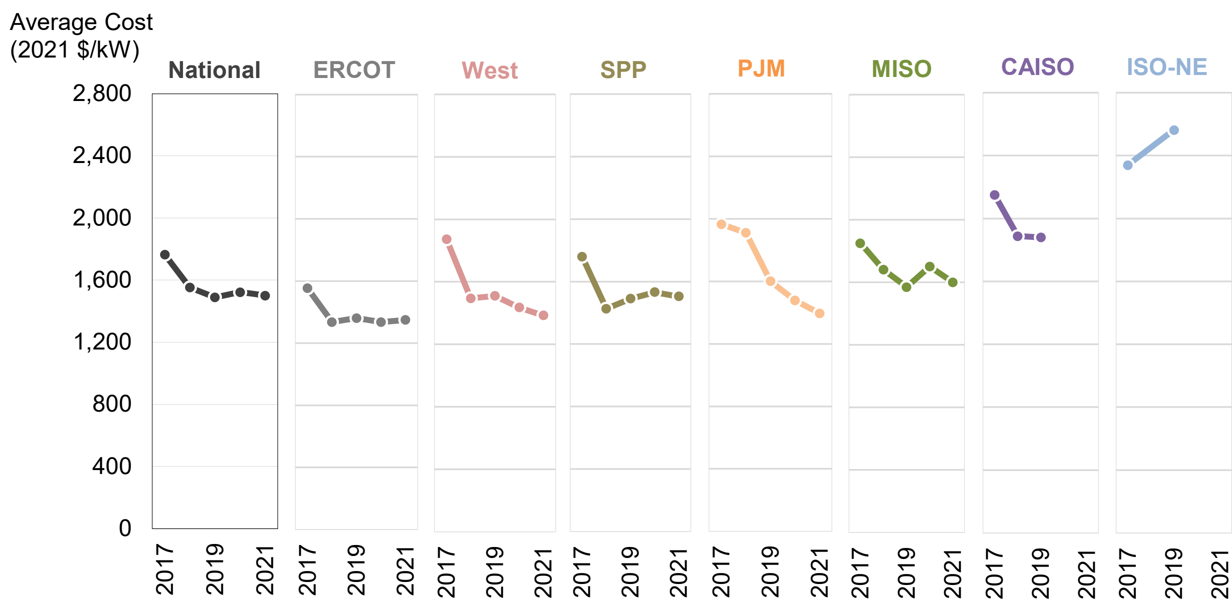
Figure 42. Installed wind power project costs over time

In 2021, the capacity-weighted average installed project cost within the sample stood at $1,500/kW. This is down by more than 40% from the average reported costs in 2009 and 2010, but is roughly on par with the installed costs experienced in the early 2000s.

Installed costs differed by region, from $1,350/kW to $1,600/kW

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 average project size and the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources).

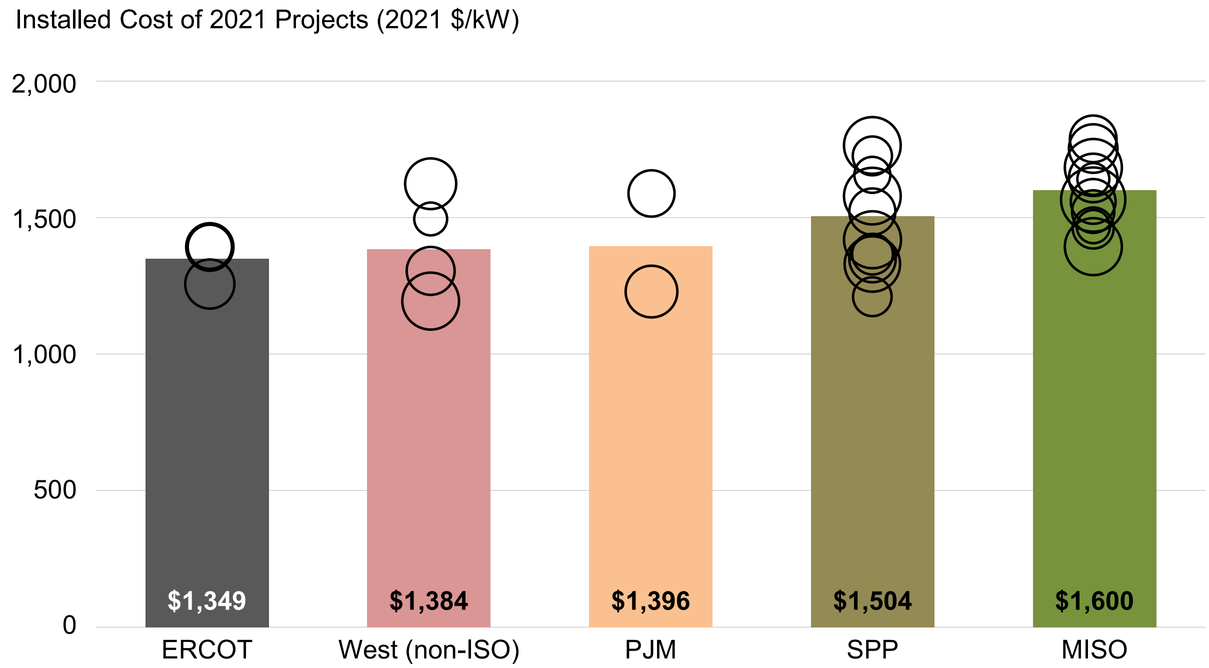
Figure 43 presents capacity-weighted average installed costs over the previous five years, by region. Figure 44 presents data only from the latest year—2021. Sample size is limited in some regions and years; for example, the data for ERCOT and PJM as shown in Figure 44 are very limited. Nonetheless, costs have generally held steady over the last four years, with the exception of projects in PJM, which have exhibited a steady decline. The lowest-cost projects installed in 2021 were located in ERCOT and the Western states (excluding California), with average costs of $1,350/kW and $1,380/kW respectively. Average costs in SPP and MISO were $1,500/kW and $1,600/kW, respectively.



Note: Data for NYISO and the Southeast are not available over this period. Other regions are missing data for specific years.

Sources: Berkeley Lab, EIA

Figure 43. Installed wind power project costs by region, over time



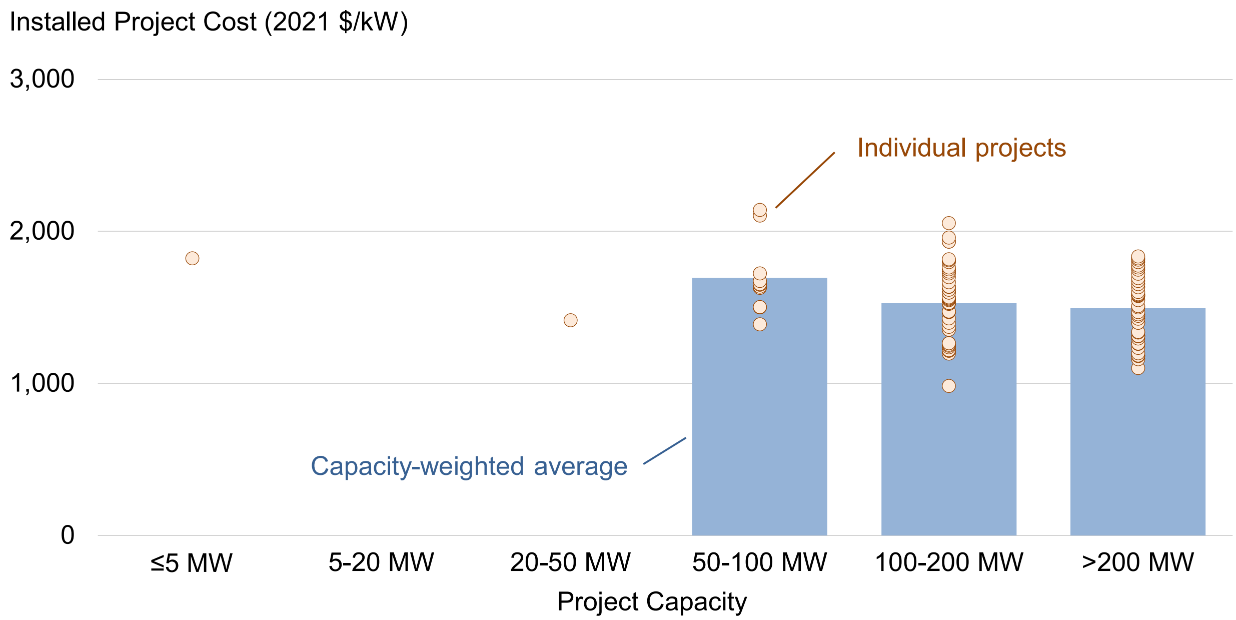
Note: Size of bubble reflects project capacity. Other regions lack adequate data for inclusion.

Sources: Berkeley Lab

Figure 44. Installed wind power project costs by region, in 2021

Installed costs (per megawatt) generally decline with project size; are lowest for projects over 200 MW

Installed costs exhibit economies of scale, which is perhaps the primary reason why small projects are increasingly rare. Among a sample of projects installed in 2020 and 2021 (Figure 45), there is not enough sample size to calculate average costs for the lower-capacity bins, but economies of scale are evident when moving from projects in the 50–100 MW range to those that are 100–200 MW or >200 MW.



Source: Berkeley Lab

Figure 45. Installed wind power project costs by project size: 2020 and 2021 projects

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

Operations and maintenance (O&M) costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available 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 changes in wind turbine technology that have occurred over time (see Chapter 4).

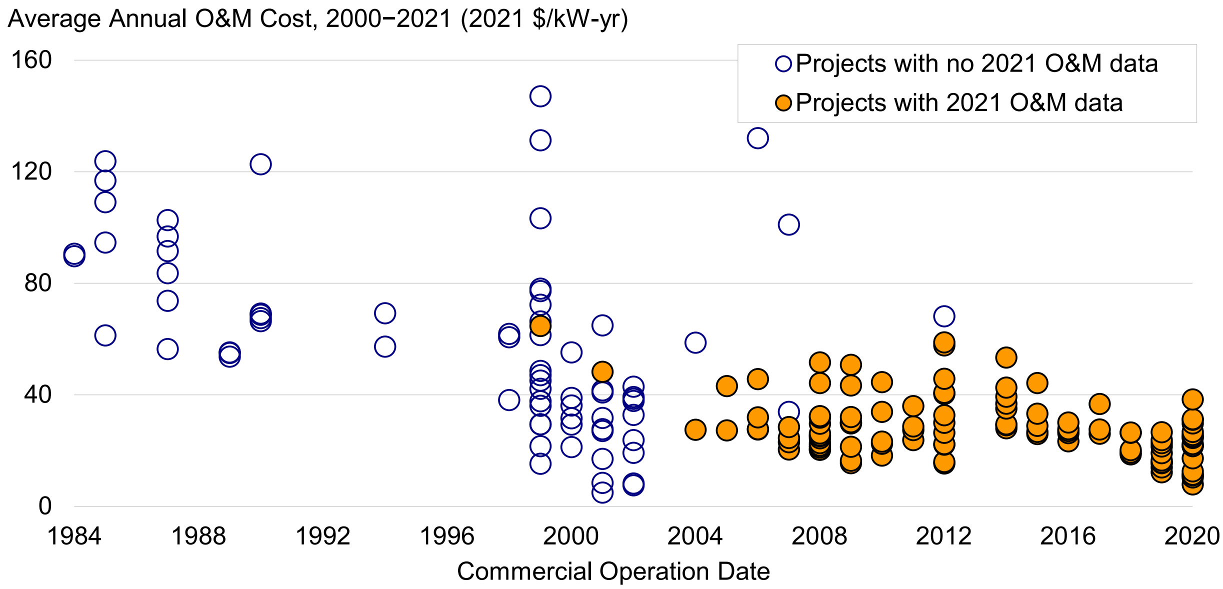
Berkeley Lab has compiled limited O&M cost data for 202 installed wind power projects, totaling 22,393 MW and with commercial operation dates of 1982 through 2020.[32] These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects and 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 not all data sources 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.[33] Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance are generally not included. As such, Figure 46 and Figure 47 are not representative of *total* operating expenses for wind power projects.

---

[32] 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. No data for projects installed in 2021 are included, as such projects would not have a full-year of O&M data available by the end of 2021.

[33] 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 46 shows O&M costs by commercial operation date. Here, each project's O&M costs are depicted as average annual O&M costs from 2000 through 2021, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2020, only 2021 data are available, and that is what is shown. Many other projects only have data for a subset of years, so each data point in the chart may represent a different averaging period within the overall 2000–2021 period. The chart highlights the 112 projects, totaling 18,330 MW, for which 2021 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

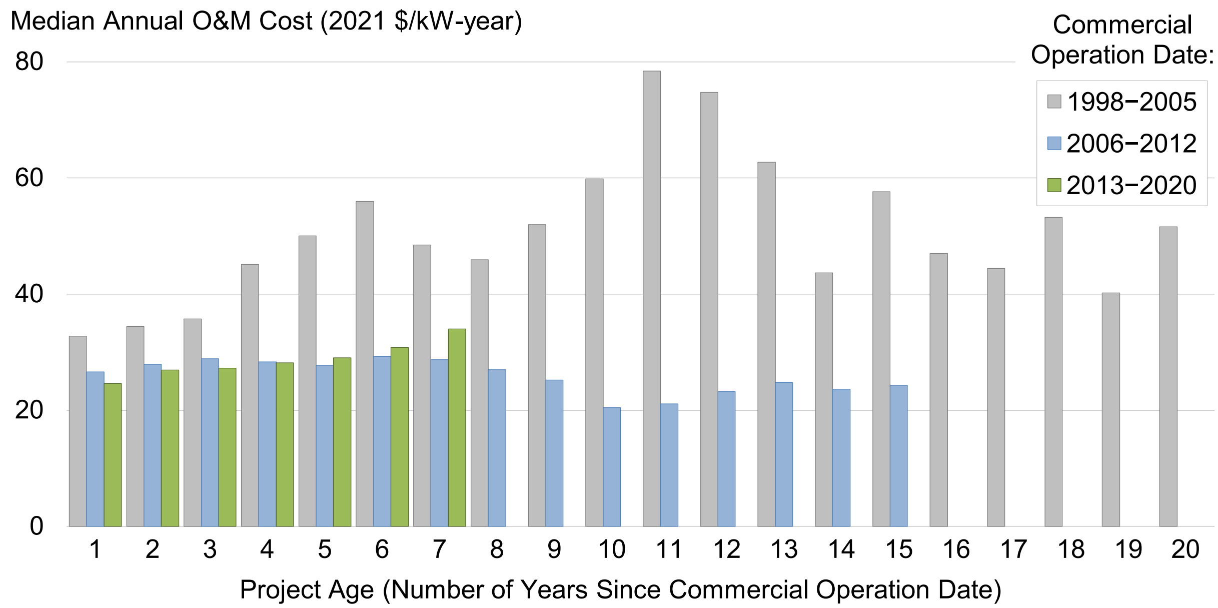


Source: Berkeley Lab; some data points suppressed to protect confidentiality

Figure 46. Average O&M costs for available data years from 2000 to 2021, by commercial operation date

The data demonstrate that O&M costs are far from uniform across projects. Figure 46 also suggests that projects installed in the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2021 O&M costs for the 24 projects in the sample constructed in the 1980s equal $79/kW-year, dropping to $64/kW-year for the 37 projects installed in the 1990s, to $29/kW-year for the 65 projects installed in the 2000s, and $21/kW-year for the 76 projects installed since 2010. This decline may be due to at least two factors: (1) O&M costs generally increase as turbines age and component failures become more common; and (2) projects installed more recently, with larger and more mature turbines and more sophisticated O&M practices, may experience lower overall O&M costs.

Limitations in the underlying data do not permit the influence of these two factors to be clearly distinguished. Nonetheless, to help illustrate key trends, Figure 47 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Though sample size is limited, the data show a general upward trend in project-level O&M costs as projects age, at least among the oldest projects in the sample. Figure 47 also shows that projects installed over the last 15 years have had, in general, lower O&M costs than those installed in the earlier years of 1998–2005, at least for the first 15 years of operation.



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

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

As indicated previously, these data include only a subset of total operating expenses. 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 these estimates of total operating costs and the costs reported in Figure 46 and Figure 47 reflects, in large part, differences in the scope of expenses reported; the survey noted that turbine O&M is expected to constitute less than half of total operating costs (Wiser et al. 2019).

7 Power Sales Price and Levelized Cost Trends

Wind power purchase agreement prices have been drifting higher since about 2018, with a recent range from below $20/MWh to more than $30/MWh

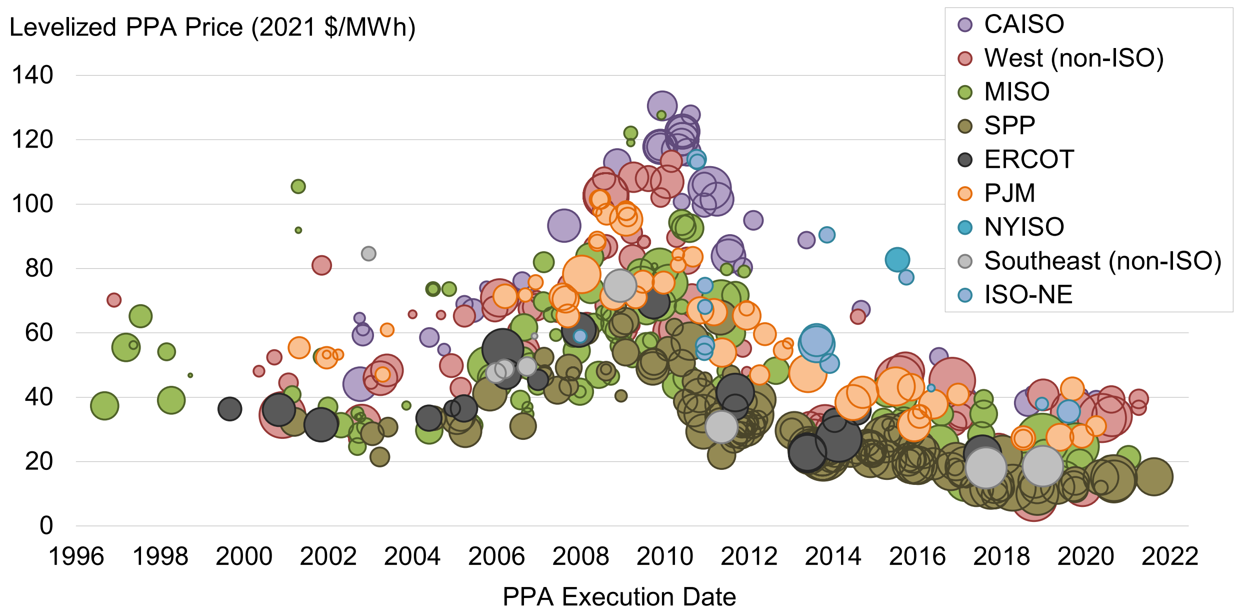
Earlier chapters documented trends in capacity factors, installed project costs, O&M costs, and project financing—all of which are determinants of the wind power purchase agreement (PPA) prices and levelized cost of energy (LCOE) estimates presented in this chapter.

Berkeley Lab collects data on wind PPA prices, resulting in a dataset that includes 525 PPAs totaling nearly 53 GW from wind projects that have either been built or are planned for installation later in 2022 or beyond. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs; a later text box highlights REC prices), and most of them have a utility as the counterparty.[34] Except where noted, PPA prices are expressed on a levelized basis over the full term of each contract and are reported in real 2021 dollars.[35] Whenever individual PPA prices are averaged together, the average is generation-weighted. Whenever they are broken out by time, the date on (or year in) which the PPA was executed is used. Because PPA prices are reduced by the receipt of state and federal incentives and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs. Accordingly, at the end of this chapter, the data presented earlier in this report are leveraged to estimate project-level and average wind LCOE for a large sample of U.S. wind projects.

Figure 48 plots contract-level levelized wind PPA prices by contract execution date, showing a clear decline in PPA prices since 2009–2010, both overall and by region. As a result of the low average project costs and high average capacity factors shown earlier in this report, ERCOT and SPP tend to be the lowest-priced regions. Of note, PPA prices have not smoothly declined over time. Instead, prices declined through 2003, then rose though 2009 with the increased turbine and installed costs presented earlier as well as with general price increases during this period in the power and natural gas markets. Following that rise was a steep reduction and, more recently, stabilization and then an increase in PPA prices—partly due to supply chain pressures, including higher material prices and transportation costs, and perhaps also due to the gradual phase-out of the PTC.

[34] Though some PPAs with corporate offtakers are included in the sample, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a "contract for differences" with the corporate offtaker 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).

[35] Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables these PPA prices to be presented 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 54% of the sample; 87% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 4% real discount rate.

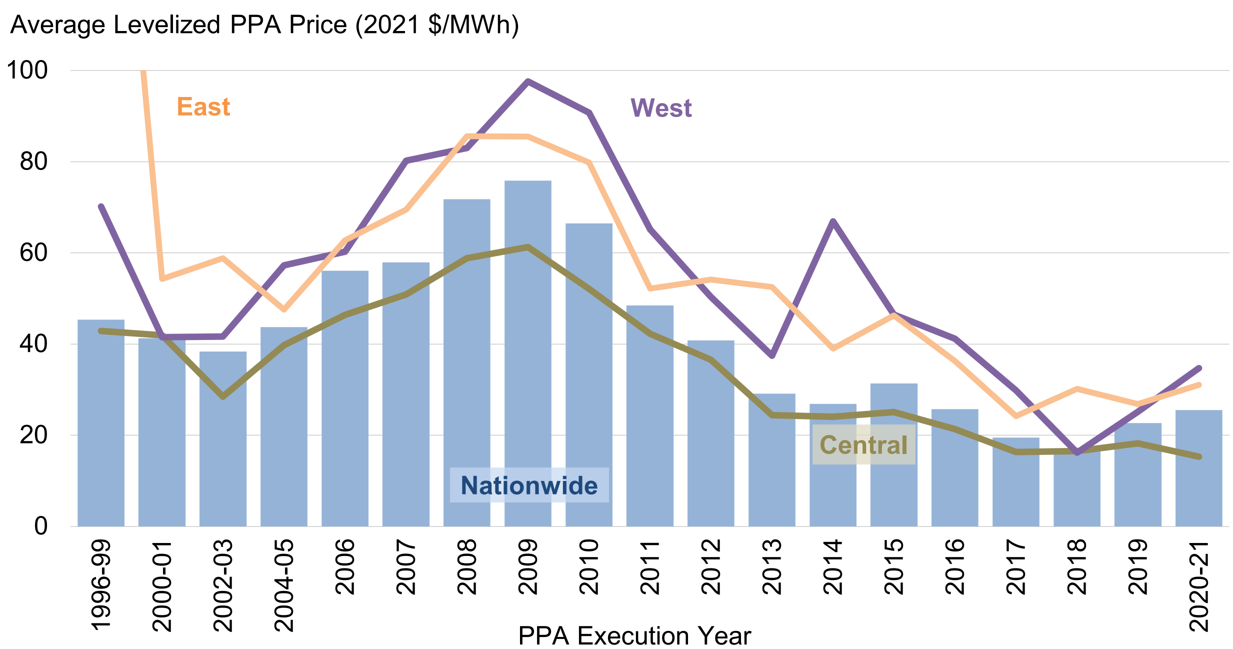


Note: Size of bubble reflects contract capacity.

Source: Berkeley Lab, FERC

Figure 48. Levelized wind PPA prices by PPA execution date and region (full sample)

Figure 49 provides a smoother look at the time trend nationwide and regionally by averaging the individual levelized PPA prices shown in Figure 48, and consolidating the regional breakdown into just three categories: West, Central, and East. After topping out above $75/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped. In the Central region of the country, recent pricing is around $20/MWh. In the West and East, prices tend to average above $30/MWh. On average, however, PPA prices have risen over the last several years, since roughly 2018.



Note: West = CAISO, West (non-ISO); Central = MISO, SPP, ERCOT; East = PJM, NYISO, ISO-NE, Southeast (non-ISO)

Source: Berkeley Lab, FERC

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

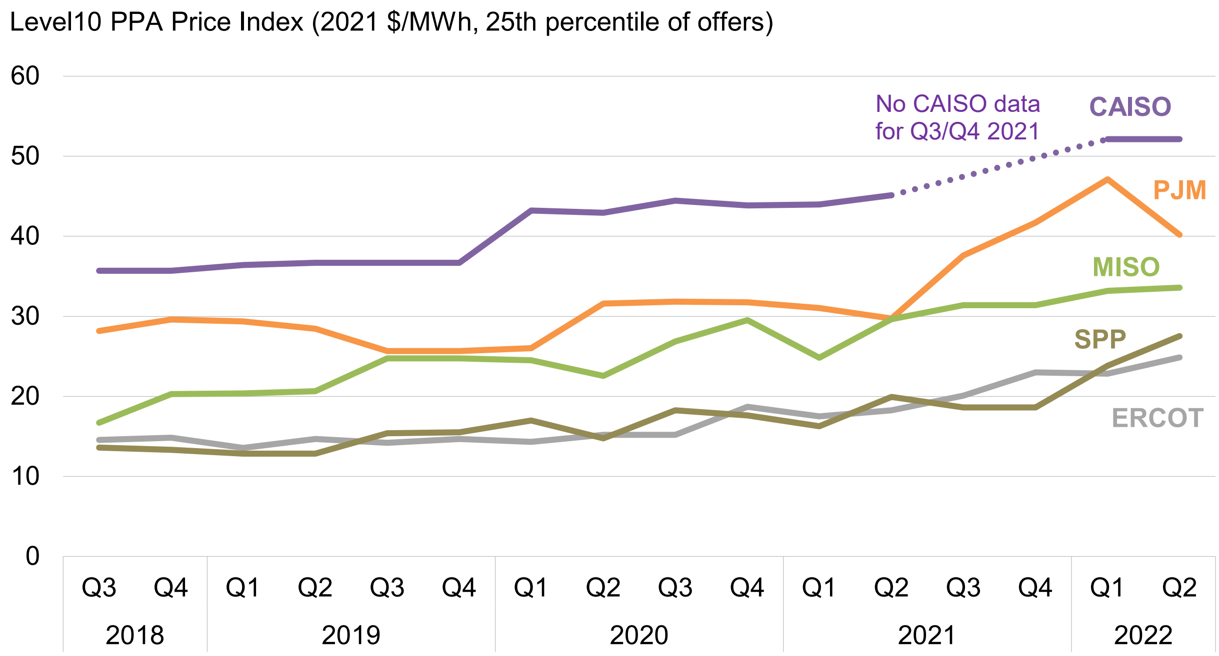
These PPA price trends are directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent projects, as documented in Chapter 5. Scaling has also enabled reductions in operating costs, as described in Chapter 6. This combination of declining CapEx and OpEx and improved performance drove wind PPA prices to all-time lows through 2018, though prices have since increased.

LevelTen Energy's PPA price indices confirm rising PPA prices, and regional variations

In contrast to the PPAs summarized above, which principally involve utility purchasers, LevelTen Energy (2022) provides an index of wind PPA offers made to large, end-use customers.

Each quarter, the LevelTen Energy PPA Price Index reports the prices that wind and solar developers have offered for PPAs available on the LevelTen Marketplace. Contract terms tend to range from 10 to15 years, reflective of the shorter terms typically pursued by end-use customers that purchase wind energy relative to the utility PPAs summarized earlier. Price data are aggregated and reported in nominal dollars on a 'P25' basis, referring to the most competitive 25th percentile of offer prices.

As shown in Figure 50, prices have risen over the last couple years, and vary by ISO; here, LevelTen data are converted to real, levelized 2021$ to enhance comparability with data presented elsewhere in this report. Among regions reporting data, CAISO features the highest wind PPA pricing (~$52/MWh when converted to real dollar terms), whereas the lowest prices are found in ERCOT and SPP (~$25/MWh). In real dollar terms, LevelTen's reported price trends since 2018 are similar to those described in the prior section.



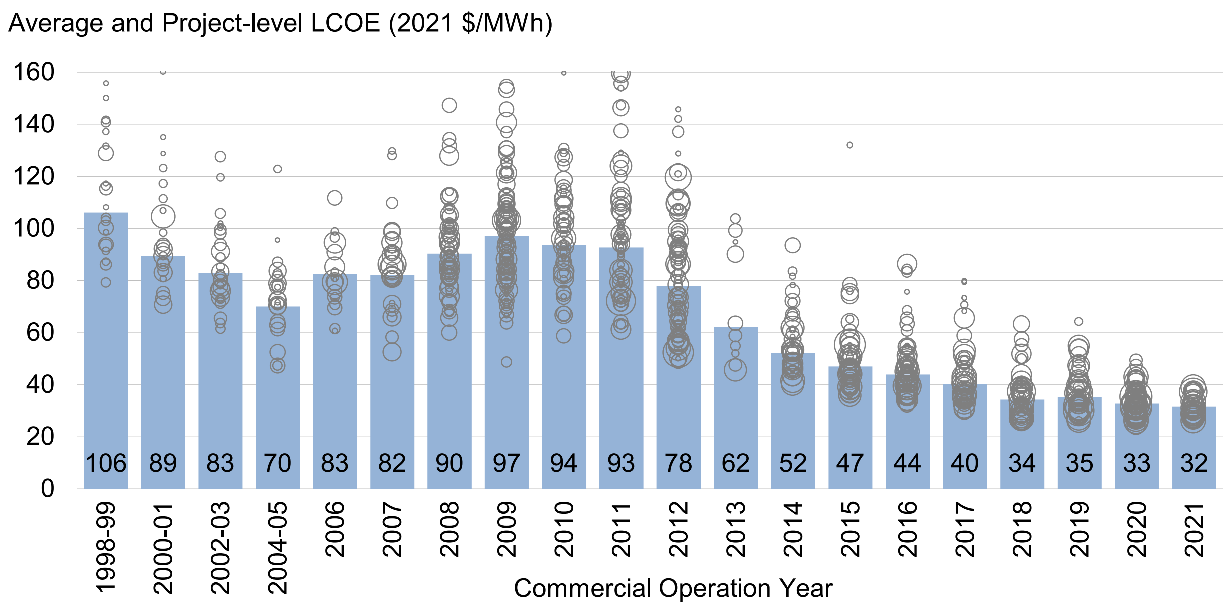
Source: LevelTen Energy

Figure 50. LevelTen Energy wind PPA price index by quarter of offer

The (unsubsidized) average levelized cost of wind energy has fallen to around $32/MWh

In a competitive market, long-term PPA prices can be thought of as reflecting the LCOE reduced by the 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, and Berkeley Lab has data on both the installed cost and capacity factor of 112 GW of wind power projects installed from 1998 through 2021, representing 83% of all capacity built over that period. Here, those data are used, in conjunction with estimates of operational costs, financing costs, project life and other factors, to estimate LCOE in real 2021 dollars (see the Appendix for details on the data and calculations). 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 PPA sample.

Figure 51 depicts the resulting average LCOE values over time on a national basis. As shown, average wind LCOE declined from $106/MWh in 1988−1999 to $70/MWh in 2004−2005, before rising to $97/MWh in 2009. Subsequently, average LCOE declined rapidly through 2018, to $34/MWh. The national average LCOE of newly built wind projects has largely held steady since 2018, and stood at $32/MWh in 2021.With rising turbine prices and stagnating capacity factor improvements, LCOE may increase in 2022.



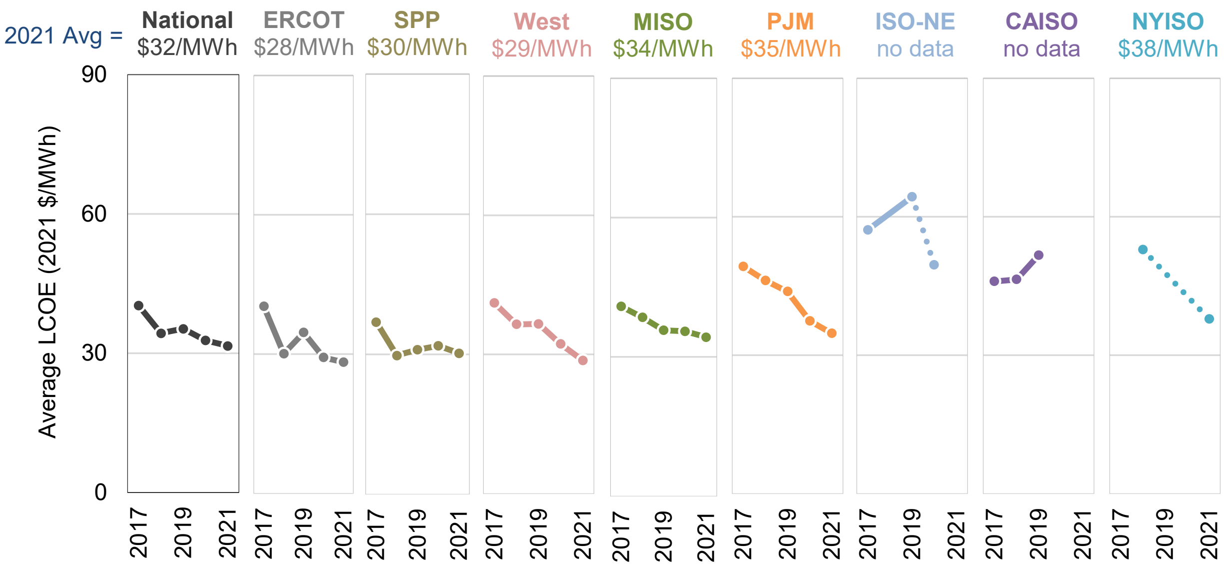
Note: Size of bubble reflects project capacity.

Source: Berkeley Lab

Figure 51. Estimated levelized cost of wind energy by commercial operation date

Levelized costs vary by region, with the lowest costs in ERCOT, SPP, and the non-ISO West

Regional LCOE estimates span a wide range, and sample size is small in some regions and years. Nonetheless, the lowest average LCOEs for projects built in 2021—only considering regions with a larger sample—are found in ERCOT ($28/MWh), SPP ($30/MWh), and the non-ISO West ($29/MWh).



Source: Berkeley Lab

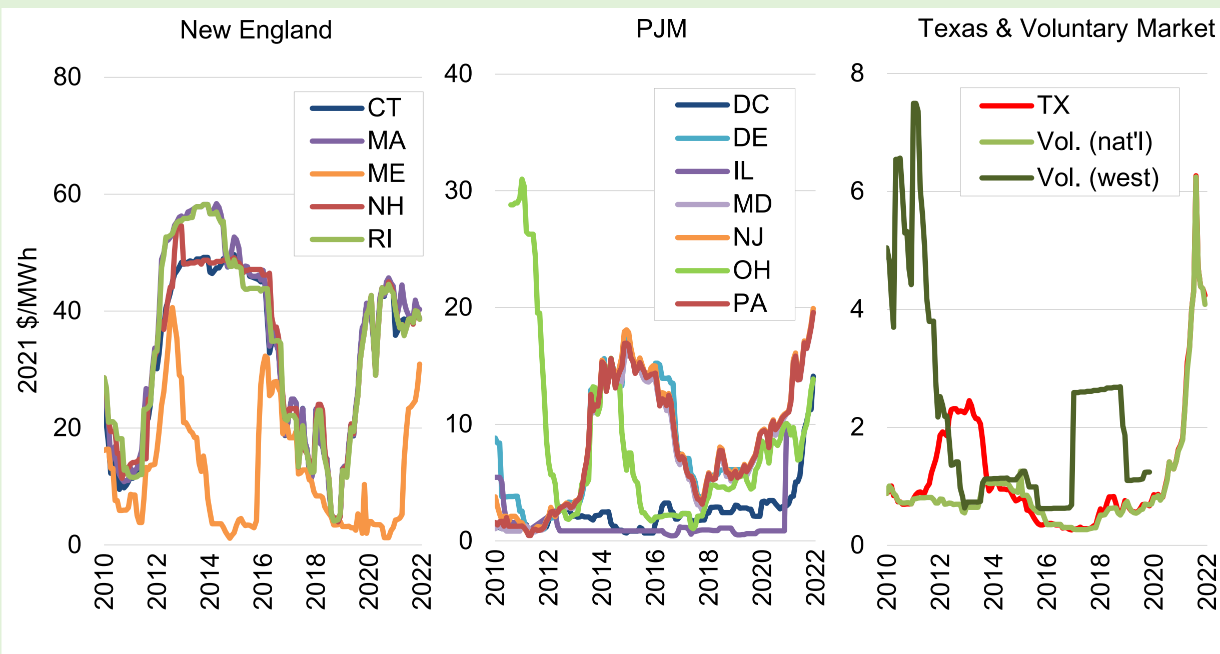
Figure 52. Estimated levelized cost of wind energy, by region

Renewable Energy Certificate (REC) Prices

Wind power sales prices presented in this report reflect bundled sales of both electricity and RECs. Projects that sell RECs separately from electricity, thereby generating two sources of revenue, are excluded. REC markets are fragmented, 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. Mandatory RPS programs exist in 29 states and Washington, D.C. In recent years, roughly one-third of these states have increased their RPS targets, in many cases to levels ranging from 50% to 100% of retail electricity sales. Voluntary markets for renewable energy have also grown.

The figure below presents 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 across states within common regional power markets (New England and PJM) are linked to varying degrees.

In New England, REC prices in 2021 (outside of ME) stabilized around $40/MWh, following a steep rise over the preceding years. These prices remain well below the relevant alternative compliance payment (ACP) rates in these states, suggestive of balanced RPS supply and demand. In PJM, REC prices continued on their upward trajectory of the past several years, reflecting a gradual tightening of supplies. Within the premium markets of MD, NJ, and PA, prices ended the year just above $20/MWh, an all-time high. Prices for RECs offered in the national voluntary market and for RPS compliance in Texas, which track each other closely, witnessed an unprecedented spike in 2021, rising to more than $6/MWh before falling slightly by year-end. Though the causes of this rise are not altogether known, some in the industry attribute it to rising corporate demand for green energy purchases and higher project development costs.



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.

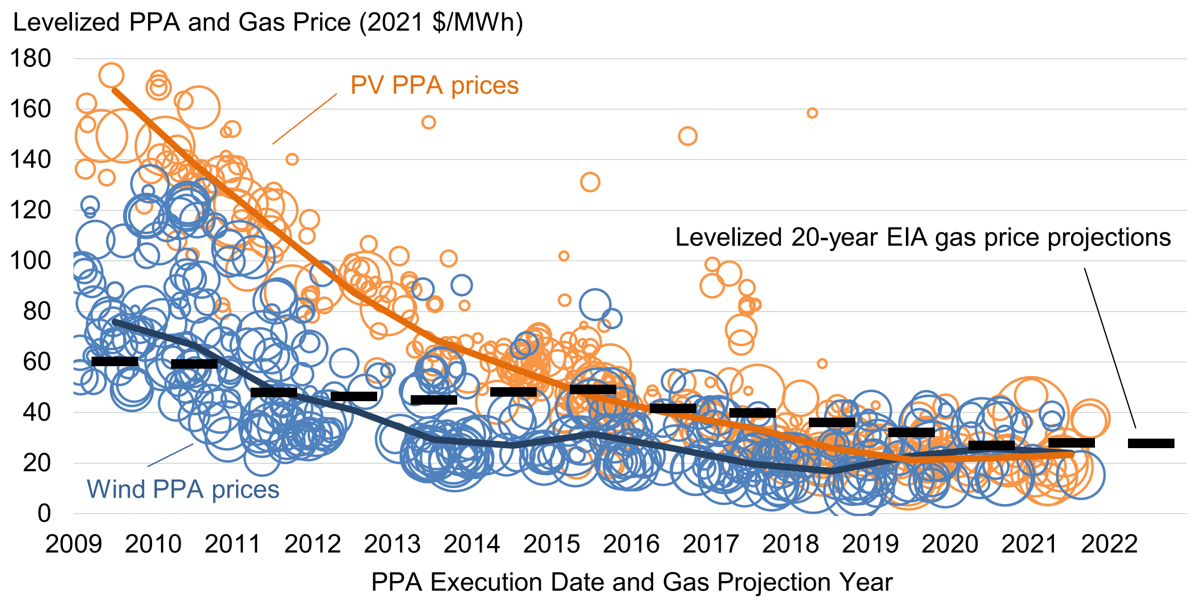
Source: Marex Spectron

8 Cost and Value Comparisons

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

Figure 53 plots wind PPA prices against utility-scale solar PPA prices on a levelized basis since 2009 (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.[36]

The figure also shows that wind PPA prices—and, more recently, utility-scale solar PPA prices—have, in many cases, been competitive with the projected fuel costs of gas-fired combined cycle generators. 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 million British Thermal Units (MMBtu) per MWh—from then-current EIA projections of natural gas prices delivered to electricity generators.[37] Supported by federal tax incentives, the average levelized wind and solar PPA prices within this contract sample have, for several years now, been below the projected levelized cost of burning natural gas in existing gas-fired combined cycle units.



Note: Smallest bubble sizes reflect smallest-volume PPAs (<5 MW), whereas largest reflect largest-volume PPAs (400 MW)

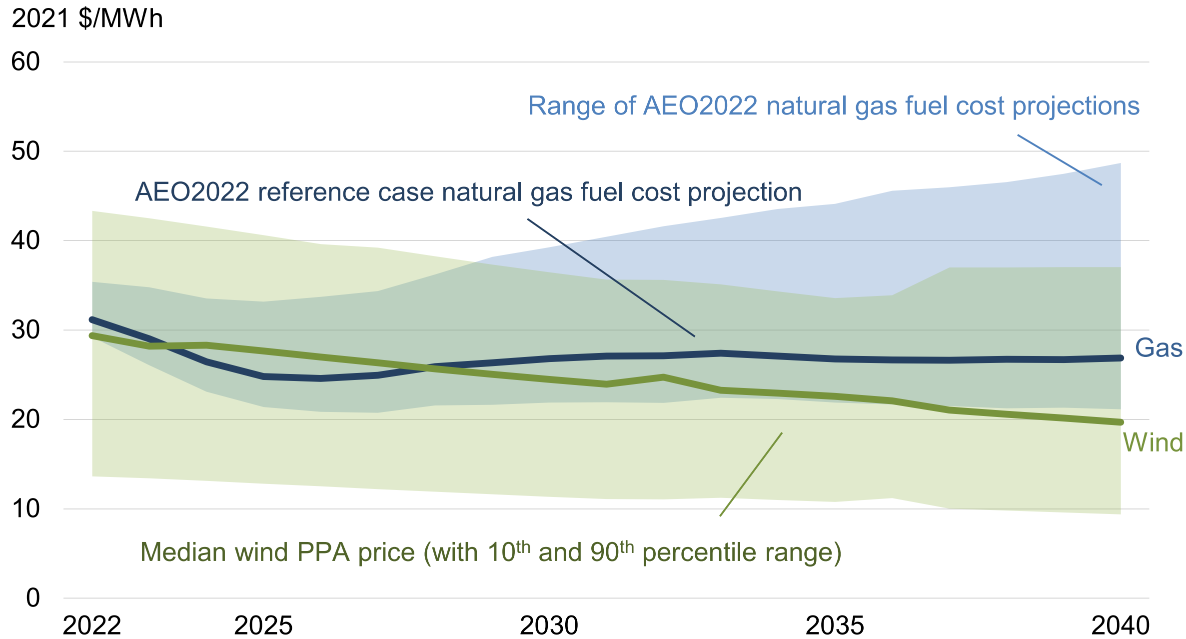
Sources: Berkeley Lab, FERC, EIA

Figure 53. Levelized wind and solar PPA prices and levelized gas price projections

[36] The solar PPA prices are sourced from Berkeley Lab's "Utility-Scale Solar" data series.

[37] For example, the black dash marker in 2009 shows the 20-year levelized gas price projection from Annual Energy Outlook 2009, while the black dash in 2022 shows the same from Annual Energy Outlook 2022 (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh).

Rather than levelizing the wind PPA prices and gas price projections, Figure 54 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown) from PPAs executed in 2019–2021 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[38] As shown, median wind PPA prices from contracts executed in the past three years roughly track the median gas price projection until the late 2020s, after which the median wind price falls below the median gas price (and eventually even below the low gas price in the second half of the 2030s). Meanwhile, the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall within the overall range by 2030. Wind PPA pricing declines over time, in real 2021$.



Sources: Berkeley Lab, FERC, EIA

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Figure 54 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 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.

[38] The fuel cost projections come from the EIA's *Annual Energy Outlook 2022* publication. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (which start at roughly 7.7 MMBtu/MWh in 2022 and gradually decline to roughly 7.0 MMBtu/MWh by 2040).

The grid-system market value of wind rebounded in 2021 to levels last seen in 2018, and is roughly consistent with recent PPA prices of under $20/MWh to $40/MWh

In many regions of the country, wind projects participate in organized wholesale electricity markets. 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 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. PPAs between wind generators and commercial customers are often a hybrid of these two models.

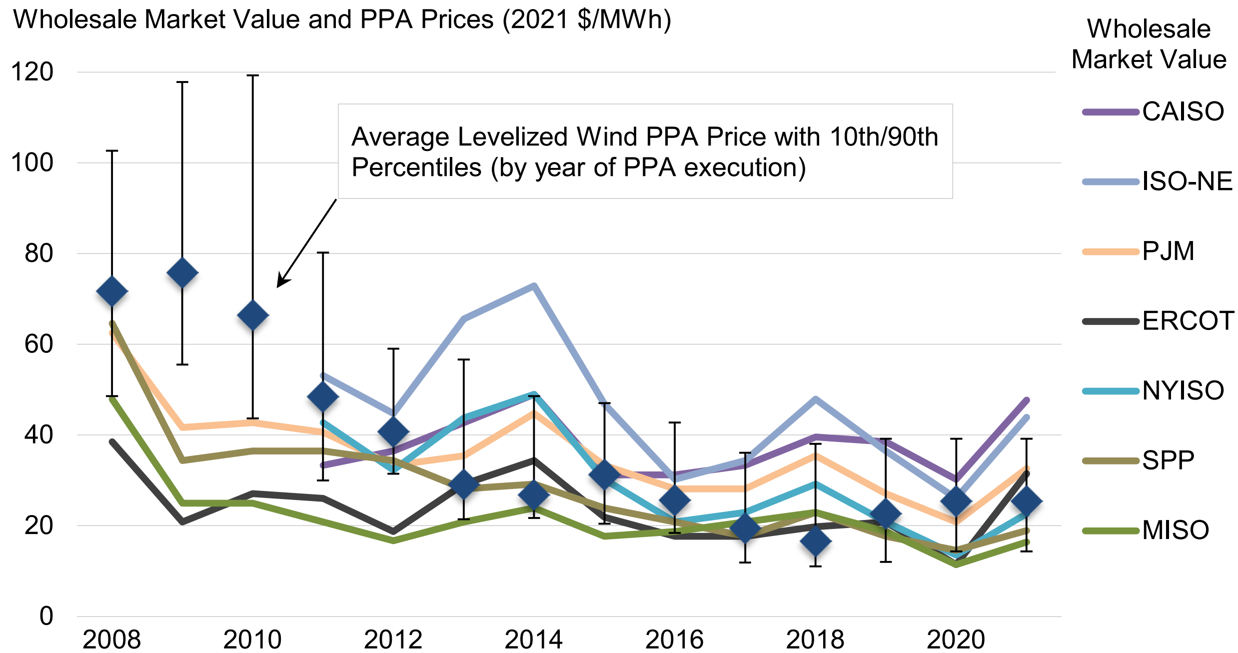
In all of these cases, the revenue earned (or that could have been earned) from the sale of wind into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system. In the case of merchant wind projects, the link is direct and affects the revenue 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 instance, 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. They are strongly influenced by the cost of natural gas. 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 and the relationship to the cost of natural gas is diminished. Even absent transmission constraints, wind plants push wholesale energy prices lower when wind output is high. More generally, the temporal profile of wind output is not always well-aligned with customer load and system needs, potentially further reducing the energy market value of wind generation. Some of these tendencies also apply 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.

Figure 55 estimates the historical wholesale energy and capacity market value of wind across a number of different regions of the country. Specifically, the energy market value of wind is estimated 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.[39] 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 possible 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 to the purchaser, whereas wholesale market value reflects a portion of the value of that wind generation.

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

These estimates show that the wholesale market value of wind has generally declined over the last 13 years and varies by region. With the sharp drop in wholesale 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 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 developers and offtakers are successfully contracting at levels that are generally comparable in terms of both cost and value. In 2020, natural gas and wholesale electricity prices hit new lows, in part a result of the economic impacts of the pandemic. Natural gas prices have since risen substantially above 2020 levels, however, and for 2021 averaged higher than in any year since 2014 (in real dollar terms, based on the Henry Hub spot price). With the increase in natural gas and electricity prices, 2021 wind market values rebounded to levels last seen in 2018, and are roughly consistent with recent PPA prices. With even higher natural gas and wholesale electricity prices so far in 2022, wind's market value may increase again this year.



Note: Hourly wind output profiles and wholesale prices are not available for all historical years for all regions.

Sources: Berkeley Lab, Hitachi, ISOs

Figure 55. Regional wholesale market value of wind and average levelized long-term wind PPA prices over time

Important Note on Price and Value Comparisons

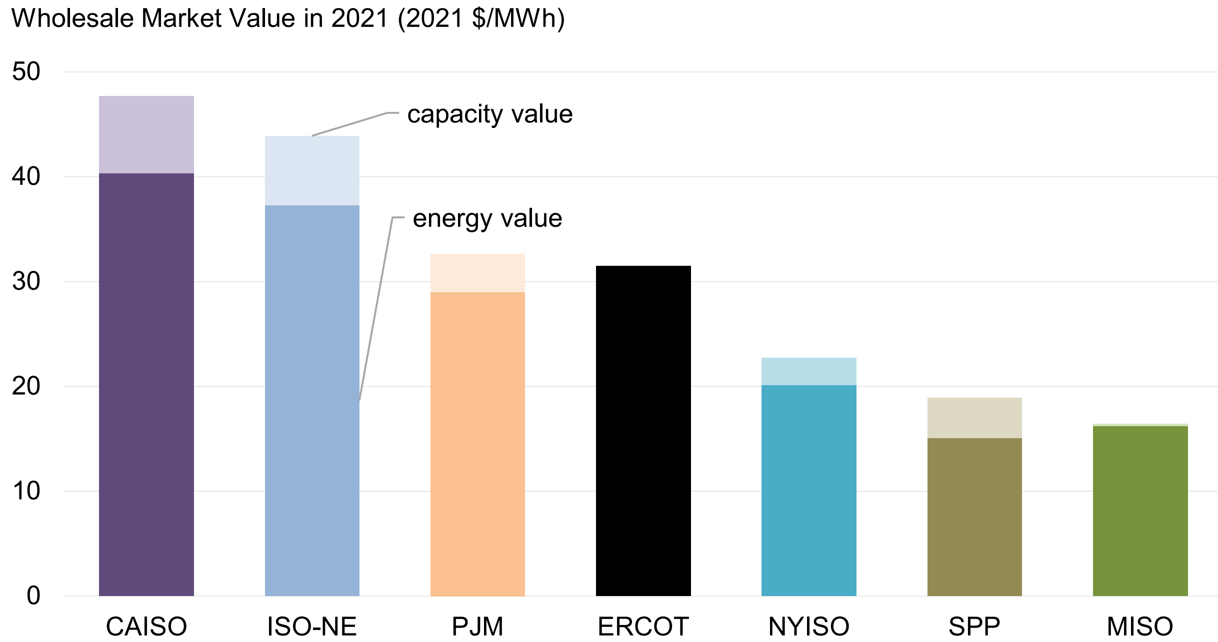
Notwithstanding the comparisons made in this chapter, neither the wind prices nor wholesale market value estimates (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind (and solar) PPA prices with wholesale value and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

- Wind (and solar) PPA prices are reduced by federal and state incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by any financial incentives provided to thermal generation and its fuel production. Wholesale prices may also not fully account for the health and environmental costs of various generation technologies (though a later section within this chapter assesses the health and climate benefits of wind), and for other societal concerns such as fuel diversity 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.

The grid-system market value of wind in 2021 varied by project location, from an average of $16/MWh in MISO to $48/MWh in CAISO

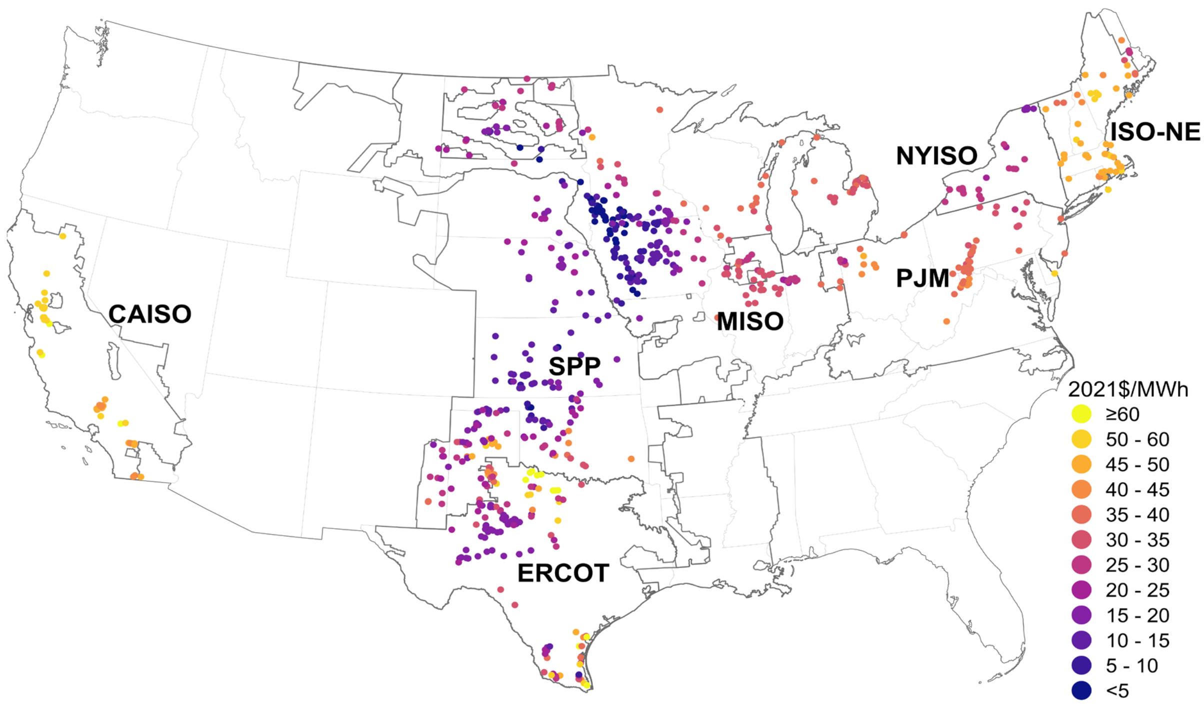
Figure 56 presents estimates of wind's wholesale market value, by region, but only for the latest year—2021. The figure also disaggregates the market value estimates into their constituent parts: energy and capacity. The average market value of wind in 2021 was the lowest in MISO ($16/MWh), SPP ($19/MWh) and NYISO ($23/MWh), whereas the higher-value markets were CAISO ($48/MWh), ISO-NE ($44/MWh), and PJM ($33/MWh). Unlike recent past years, wind's value in ERCOT ($31/MWh) was relatively high compared to several other regions, in part due to high prices associated with extreme weather in the region in 2021. In all regions, energy value represented the largest share of the total value, with capacity value varying widely regionally and being considerably lower in absolute magnitude.



Sources: Berkeley Lab, Hitachi, ISOs

Figure 56. Regional wholesale market value of wind in 2021, by region

Figure 57 presents the 2021 wind power market value estimates at a project level. These estimates span a wide range in 2021, with the 10^{th}, 50^{th}, and 90^{th} percentile values equaling $7, $25, and $48 per MWh, respectively. The figure shows variability in market value within each region, with areas facing transmission congestion and high wind penetrations generally 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. (Developments related to new transmission and wind energy are discussion in an accompanying text box).

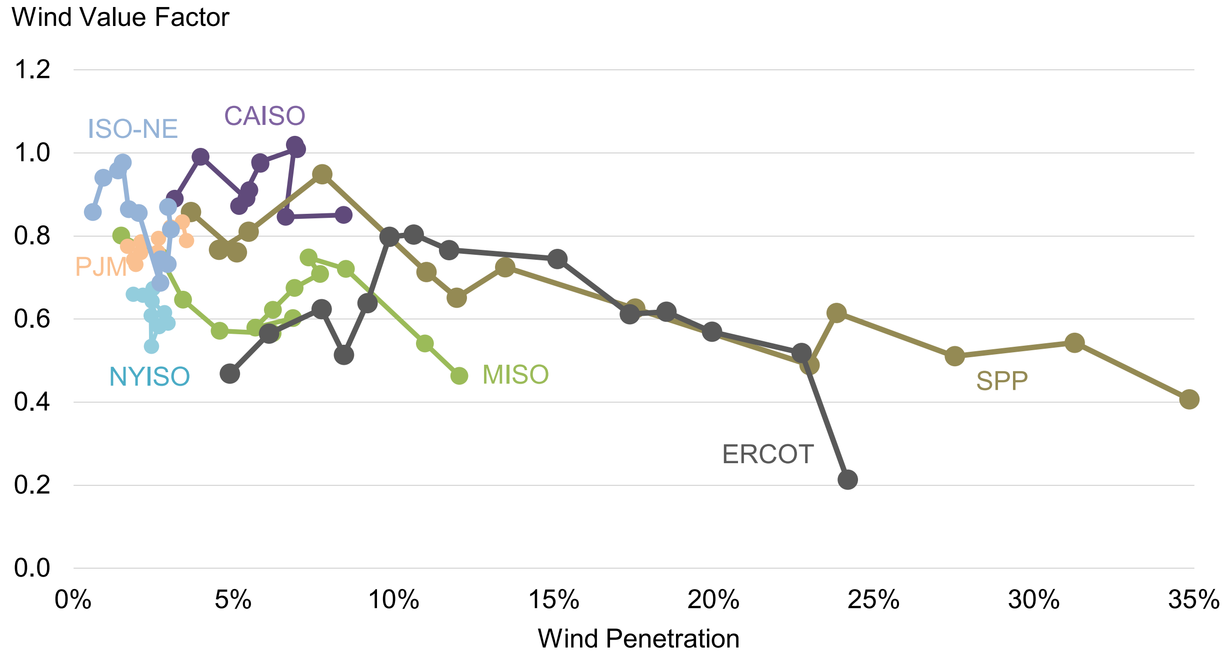


Sources: Berkeley Lab, Hitachi, ISOs

Figure 57. Project-level wholesale market value of wind in 2021

The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment

The regions with the highest wind penetrations (SPP at 35%, ERCOT at 24%, and MISO at 12%) have generally experienced the largest reduction in wind's value relative to the regional average value of a 24x7 flat-profile generator. The "value factor" of wind generation in 2021 was roughly 0.4, 0.2, and 0.5 in each of these high-penetration regions, respectively. Value factor is calculated separately in each region and represents the ratio of the average value of wind generation to the average value of a 24x7 flat profile at all generator locations. The 2021 wind value factor in NYISO was 0.6, but was higher in ISO-NE (0.9), CAISO (0.9), and PJM (0.8). The progression of each region's value factor with wind penetration can be seen in Figure 58. While there is a loose correlation between penetration level and value factor, each region's value factor progressed along a convoluted path as penetration increased. Millstein et al. (2021) show that differences between the regions' transmission infrastructure, and upgrades to that infrastructure, is one of the primary reasons value factor does not correlate more closely with penetration level.



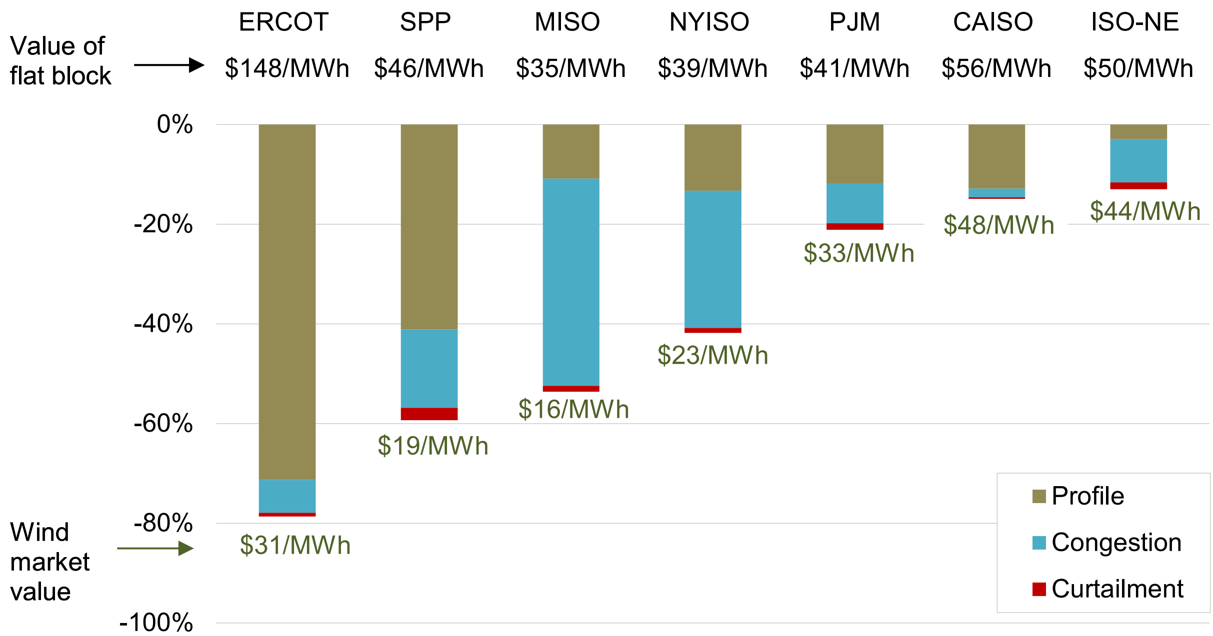
Sources: Berkeley Lab, Hitachi, ISOs

Figure 58. Trends in wind value factor as wind penetrations increase

Using methods further described in Millstein et al. (2021), Figure 59 shows the impact of three separate causes of reduction to the value of wind generation in 2021. As used here, the term value reduction is the opposite of value factor: a total value reduction of 40% would indicate a value factor of 0.6. The three causes of value reduction are: (1) profile value reductions: caused by the temporal correlation of wind generation with low market prices, (2) congestion value reductions: caused by the inability to serve the most valuable locations in a region due to transmission congestion, and (3) curtailment value reductions: caused by curtailment of output, typically due to wind plant operator response to low (usually negative) local prices.

Figure 59 shows that the causes of wind value reductions vary from region to region. In contrast to recent years, 2021 ERCOT and SPP value reductions were dominated by profile-based value reductions (as opposed to congestion value reductions). In ERCOT and SPP, 2021 profile value reductions were 71% and 41%, respectively, much larger than the 7% and 16% value reductions from congestion in those regions. ERCOT and SPP both faced episodes of extreme weather that drove annual average pricing and value trends for the year. If these particular weather conditions do not repeat in future years, the 2021 profile value reductions observed in ERCOT and, to a lesser extent in SPP, are not likely to be representative of future years.

MISO and NYISO faced large congestion value reductions in 2021 of 42% and 27%, respectively. Curtailment value reductions did not reach above 2% in any region. The value reductions associated with congestion could potentially be addressed with new within-region transmission infrastructure. Conversely, mitigating the large profile value reductions found in ERCOT and SPP in 2021 (or the more consistent but slightly smaller profile value reductions found in those regions in recent past years) would require strategies beyond expansion of within-regional transmission. Millstein et al. (2021) discusses a range of possible strategies to address profile value reductions, including cross-regional transmission and storage deployment, new demand sources (e.g., coordinated electric vehicle charging), and regulatory and rate changes supporting responsive load.



Sources: Berkeley Lab, Hitachi, ISOs

Figure 59. Impact of transmission congestion, output profile, and curtailment on wind energy market value in 2021

The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind

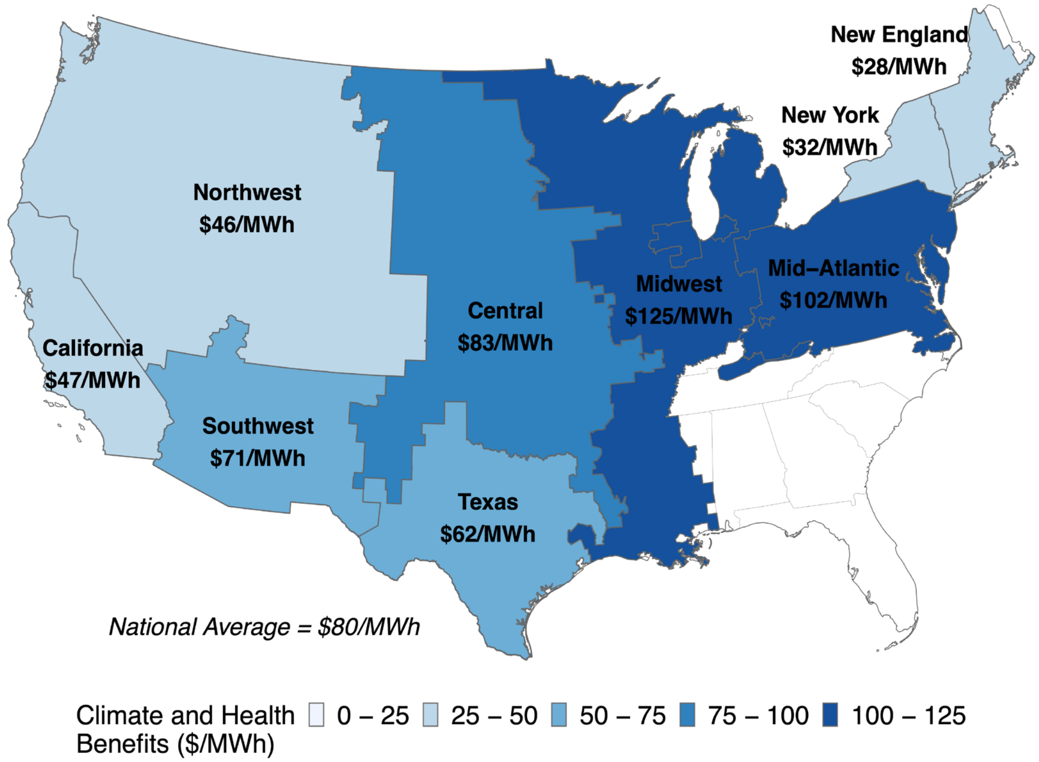
The benefits of wind in reducing health and climate burdens from polluting energy sources are not included in the earlier estimates of grid-system value and the comparisons of that value with PPA prices. Wind generation reduces power-sector emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), and sulfur dioxide (SO_2). These reductions, in turn, provide public health and climate benefits (Millstein et al. 2017). In this section, the health and climate benefits of wind power are estimated and compared, along with grid-system value, to the unsubsidized levelized cost of new wind plants built in 2021.[40]

Using methods described in detail in the Appendix,[41] Figure 60 presents the summed health and climate benefits from wind by region in the year 2021, considering all wind plants. Nationally, health and climate benefits together averaged $80/MWh-wind. Benefits were largest, ranging from $83/MWh to $120/MWh, in the Central, Midwest, and Mid-Atlantic regions (incorporating SPP, MISO, and PJM). In these regions, wind offsets more-polluting power plants than in other regions. Health and climate benefits were lowest in New York ($32/MWh) and New England ($28/MWh); and are not reported in the Southeast due to the small number of wind plants in that region. Regional and national values presented here include both in-region emission impacts as well as cross-region impacts due to electricity trade across regional boundaries.

---

[40] The goal was to compare the most important cost and benefit components from a societal perspective, but this comparison is not exhaustive. Not included are considerations of employment; local environmental, ecological, land-use, and community impacts; water use; mercury and primary particulate matter; and transmission or grid-integration costs not covered by grid-value estimates.

[41] Briefly, the per-MWh health and climate benefits of wind were estimated through a two-step process: first, determine the marginal avoided emission rate; second, multiply avoided emissions by a regional damage rate (i.e., health or climate impacts per ton of pollutant emitted). Marginal avoided emission rates are derived from Fell and Johnson (2021). Damage rates for CO_2 emissions are set to equal the social cost of carbon (IWG 2021; 2.5% discount rate), and health damage rates for SO_2 and NO_x come from EPA (2015). Health damage rates vary by the region in which the emissions occurred.

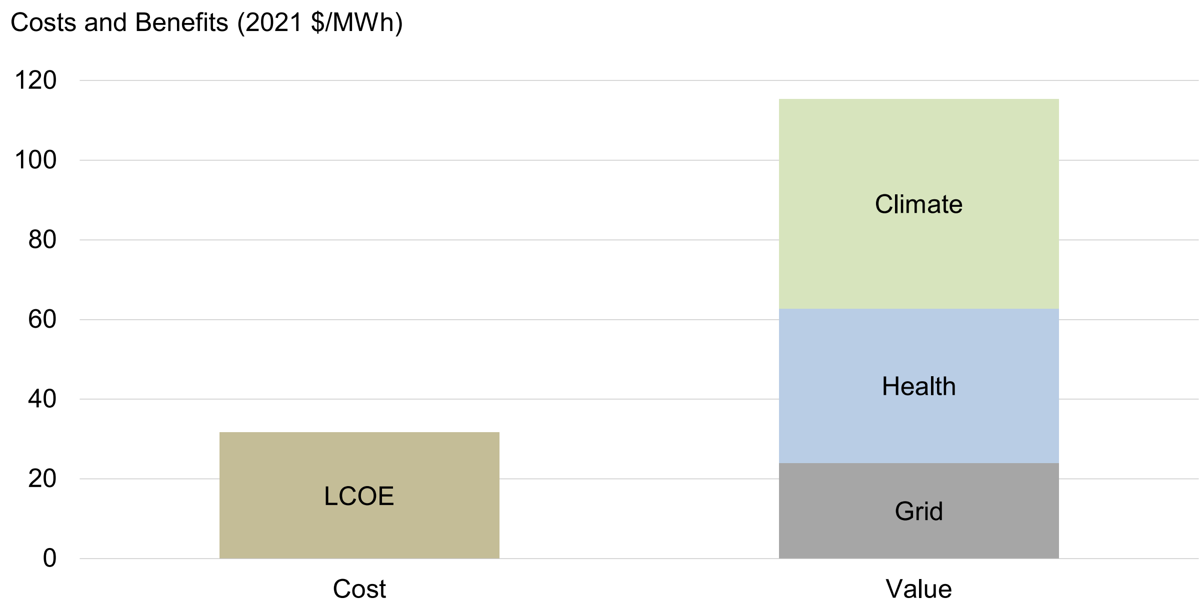


Note: Estimates not provided for Southeast due to small number of wind plants in that region.

Sources: Berkeley Lab, Form EIA-930, Fell and Johnson (2021)

Figure 60. Marginal health and climate benefits from wind generation by region in 2021

Focusing just on the smaller subset of wind plants that came online in 2021, the average climate, health, and grid-system value sums to almost four times the average LCOE (see Figure 61). Specifically, climate, health, and grid-system values averaged $53/MWh, $39/MWh and $24/MWh, respectively, compared to an average LCOE of $32/MWh.



Sources: Berkeley Lab, EIA Form 930, Fell and Johnson (2021)

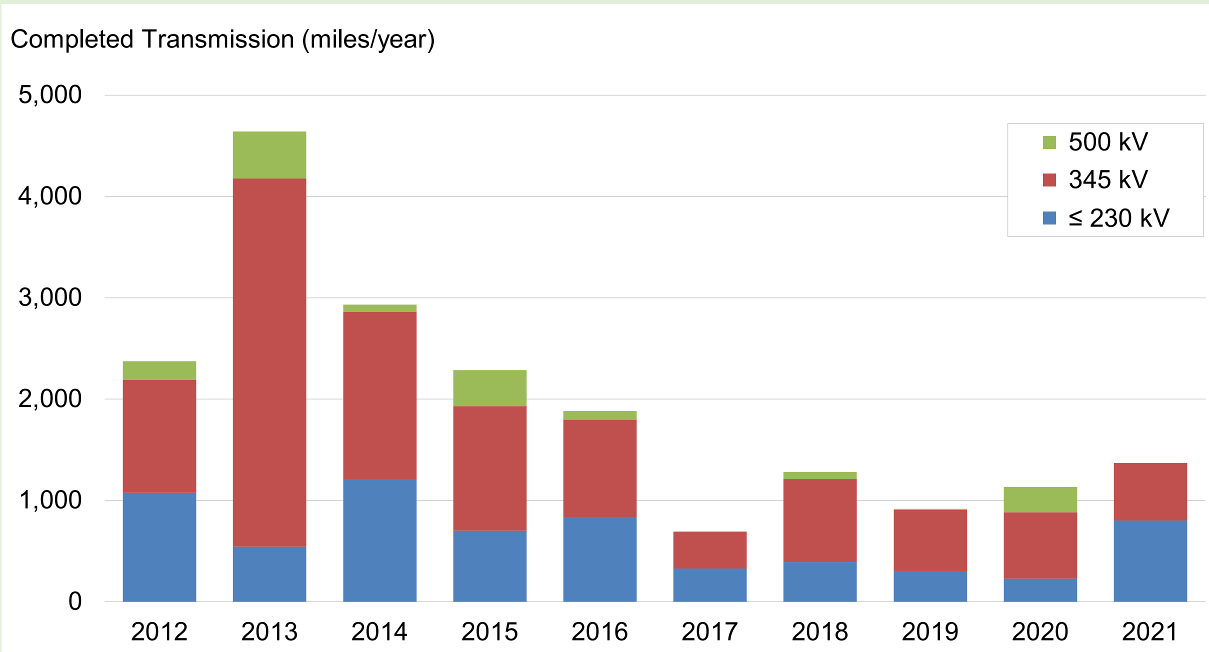
Figure 61. Marginal health, climate and grid-value benefits from new wind plants versus LCOE in 2021

For simplicity, single values for health and climate benefits are presented. However, these values represent central estimates from a range of plausible values. The central health values presented here are based on the average of high and low estimates, which are ±40% relative to the central value (representing a range of equally valid epidemiological research on the impact of human exposure to air pollutants). The climate benefits use a representative social cost of carbon from IWG (2021), but a range of estimates exist in the literature. Further discussion on the range of health impacts can be found in Millstein et al. (2017). Likewise, further discussion of the range of social cost of carbon estimates can be found in IWG (2021).

Transmission Investments and Wind Power

The areas with the greatest wind speeds are often distant from electricity load centers, making wind dependent on transmission infrastructure. Related, the low grid-system market value of wind in some areas of the country is, in part, driven by limited transmission and the resulting grid congestion.

Transmission additions remained relatively low in 2021, with about 1,400 miles of new transmission lines coming online according to the Federal Energy Regulatory Commission (see figure below). The decline since the peak in 2013 is partly due to the completion of the transmission buildout in West Texas in 2013, as well as a significant buildout of larger-scale transmission in SPP and MISO in that same timeframe. Since that time, much of the transmission buildout in the Unites States has focused on local reliability projects, and not the large-scale, long distance new transmission intended in part to access wind resources.



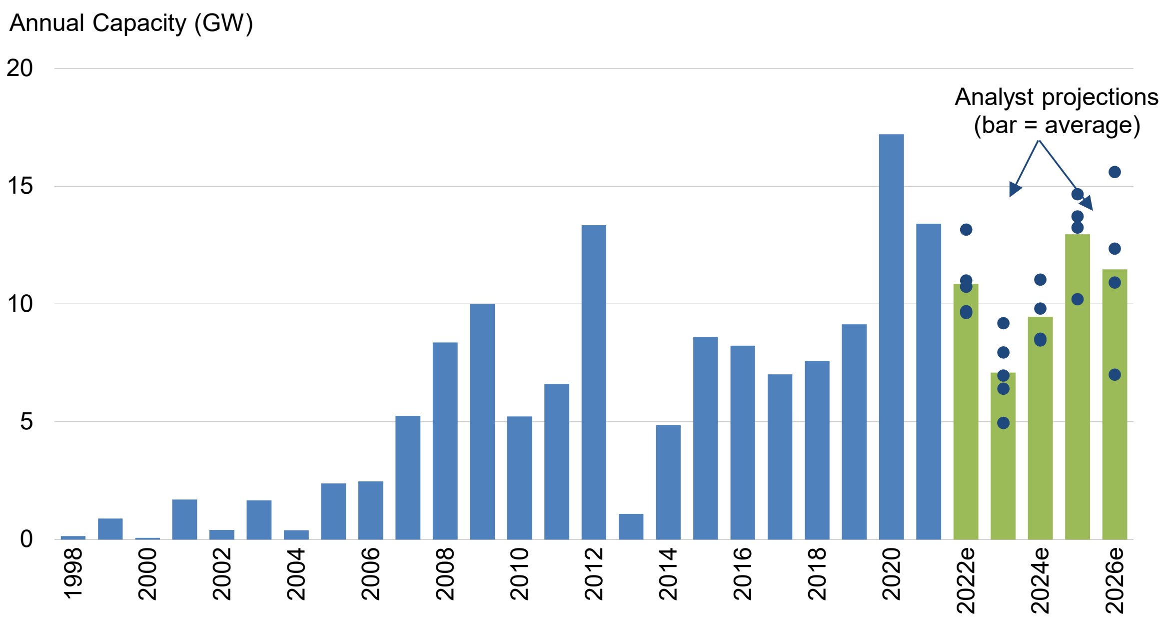
Source: FERC monthly infrastructure reports

9 Future Outlook

Energy analysts project that total annual wind additions will generally decline through 2023 before rebounding

Energy analysts project that annual wind additions will generally decline through 2023 (BloombergNEF 2022, Wood Mackenzie 2022b, GWEC 2022, EIA 2022c, IEA 2021, IEA 2022). Among the forecasts for the domestic market presented in Figure 62, expected capacity additions range from 9.6 GW to 13.2 GW in 2022 and 5.0 GW to 9.2 GW in 2023. Expected annual additions then increase, supported by anticipated growth in offshore wind; all forecasts reported here include both land-based and offshore wind.

These projected trends are driven in part by expectations about the expiration of the federal PTC, and by anticipated growth in offshore wind in the mid-2020s. Near-term additions are also influenced by the cost and performance of wind technologies, corporate wind energy purchases, and state-level renewable energy policies. Limited transmission infrastructure and competition from solar dampen growth expectations, while continuing supply chain pressures also impact expected deployment levels.



Sources: ACP, BloombergNEF (2022), Wood Mackenzie (2022b), GWEC (2022), EIA (2022c), IEA (2021, 2022)

Figure 62. Wind power capacity additions: historical installations and projected growth

Longer term, the prospects for wind energy will be influenced by the sector's ability to continue to improve its economic position even in the face of challenging competition and near-term supply chain constraints.

The prospects for wind energy in the longer term will be influenced by the sector's ability to continue to improve its economic position even in the face of challenging competition from other generation resources, such as solar and natural gas. Additionally, the speed with which supply chain constraints are addressed will impact deployment volumes. Corporate demand for clean energy and state-level policies will also continue to impact wind power deployment, as will the buildout of transmission infrastructure and the future uncertain cost of natural gas. Finally, the Biden Administration has established strong goals for clean energy, including a zero-carbon power sector by 2035 (The White House 2021). Consistent with those goals, there have been recent legislative proposals for a long-term extension of the PTC and other national policies to support a clean energy transition. The fate of these legislative proposals will greatly impact the sector's upside potential to exceed the projections shown above.

References

American Clean Power Association (ACP). 2022. *Clean Power Annual Market Report 2021*. Washington, D.C.: American Clean Power Association. https://cleanpower.org/market-report-2021/

BloombergNEF. 2017. *Tax Equity Update: 2017.* March 7.

BloombergNEF. 2021a. *2H 2021 Wind Turbine Price Index*. December 2021.

BloombergNEF. 2021b. *2H 2021 Wind O&M Price Index*. December 2021.

BloombergNEF. 2022. *1H 2022 U.S. Clean Energy Market Outlook*. April 2022.

Davidson, M.R. and D. Millstein. 2022. "Limitations of reanalysis data for wind power applications." *Wind Energy*. https://doi.org/10.1002/we.2759.

Energy Information Administration (EIA). 2022a. *Annual Energy Outlook 2022.* Washington D.C.: Energy Information Administration. https://www.eia.gov/outlooks/aeo/

Energy Information Administration (EIA). 2022b. *Electric Power Monthly, with Data for March 2022.* Washington D.C.: Energy Information Administration. https://www.eia.gov/electricity/monthly/

Energy Information Administration (EIA). 2022c. *Short-Term Energy Outlook, June 2022.* Washington D.C.: Energy Information Administration. https://www.eia.gov/outlooks/steo/

Federal Energy Regulatory Commission (FERC). 2022. *Energy Infrastructure Update for March 2022* (and previous editions). Washington, D.C.: Federal Energy Regulatory Commission. https://www.ferc.gov/staff-reports-and-papers

Fell, H. and J.X. Johnson. 2021. "Regional disparities in emissions reduction and net trade from renewables." *Nature Sustainability*, 4: 358-365.

Global Wind Energy Council (GWEC). 2022. *Global Wind Report 2022.* Brussels, Belgium: Global Wind Energy Council. https://gwec.net/global-wind-report-2022/

Hamilton, S., D. Millstein, M. Bolinger, and R. Wiser. 2020. "How Does Wind Project Performance Change with Age in the United States?" *Joule* 4: 1004-1020.

Hitachi. 2022. *Velocity Suite Data Product*. Accessed June 2022.

IEA. 2021. *Renewables 2021: Analysis and forecast to 2026.* Paris, France: International Energy Agency. https://www.iea.org/reports/renewables-2021

IEA. 2022. *Renewable Energy Market Update: Outlook for 2022 and 2023.* Paris, France: International Energy Agency. https://www.iea.org/reports/renewable-energy-market-update-may-2022/renewable-electricity

Interagency Working Group (IWG). 2021. *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990.* Washington D.C.: Interagency Working Group on Social Cost of Greenhouse Gases. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

LevelTen Energy. 2022. *Q2 2022 PPA Price Index: Executive Summary, North America*. Seattle, Washington: LevelTen Energy. https://www.leveltenenergy.com/resources

Millstein, D., R. Wiser, A.D. Mills, M. Bolinger, J. Seel, S. Jeong. 2021. "Solar and wind grid system value in the United States: The effect of transmission congestion, generation profiles, and curtailment." *Joule* 5: 1-27.

Millstein, D., R. Wiser, M. Bolinger, and G. Barbose. 2017. "The climate and air-quality benefits of wind and solar power in the United States." *Nature Energy*, 2: 17134.

Moné, C., M. Hand, M. Bolinger, J. Rand, D. Heimiller, and J. Ho. 2017. *2015 Cost of Wind Energy Review.* Golden, Colorado: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy17osti/66861.pdf

Norton Rose Fulbright. 2021. "Cost of Capital: 2021 Outlook." *Project Finance Newswire.* February. https://www.projectfinance.law/publications/2021/february/cost-of-capital-2021-outlook/

Rand, J., R. Wiser, W. Gorman, D. Millstein, J. Seel, S. Jeong and D. Robson. 2022. *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021.* Berkeley, California: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/queued-characteristics-power-plants

United States Wind Turbine Database (USWTDB). U.S. Geological Survey, American Wind Energy Association, and Lawrence Berkeley National Laboratory data release. https://eerscmap.usgs.gov/uswtdb

U.S. Department of Energy (DOE). 2022. *United States Energy & Employment Report 2022*. Washington, DC: U.S. Department of Energy. https://www.energy.gov/us-energy-employment-jobs-report-useer

U.S. Environmental Protection Agency (EPA). 2015. *Regulatory Impact Analysis for the Clean Power Plan Final Rule*. Research Triangle Park, North Carolina: U.S. Environmental Protection Agency. https://www3.epa.gov/ttnecas1/docs/ria/utilities_ria_final-clean-power-plan-existing-units_2015-08.pdf

The White House. 2021. *FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies*. https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

Wiser, R., M. Bolinger, and E. Lantz. 2019. "Assessing wind power operating costs in the United States: Results from a survey of wind industry experts." *Renewable Energy Focus* 30: 46-57.

Wiser, R., and M. Bolinger. 2019. *Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals*. Berkeley, California: Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/wind_useful_life_report.pdf

Wood Mackenzie. 2022a. *Global Wind Turbine Order Analysis: Q1 2022*. March 2022.

Wood Mackenzie. 2022b. *Global Wind Power Market Outlook Update: Q1 2022.* March 2022.

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 ACP (2022). 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 Hitachi's Velocity Suite database, except that solar data come from Wood Mackenzie Power & Renewables.

Global cumulative (and 2021 annual) wind power capacity data are sourced from GWEC (2022) but are revised, as necessary, to include the U.S. wind power capacity used in the present report. Country-level wind energy penetration is compiled by ACP (2022).

The wind project installation map was created based on ACP's 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 2021. Data on online hybrid power plants comes largely from EIA (updated, when erroneous data are discovered).

The wind hybrid/co-located data are compiled from the 2021 early release EIA 860 dataset. Projects are identified as hybrids with two approaches. The first approach involves identifying distinct power plants (e.g. wind and storage) that share the same EIA ID. This approach identifies the majority of the hybrid data summarized in the report. The second approach involves compiling data from Hitachi's Velocity Suite and matching power plants that have the same Hitachi Plant ID but different fuel types. These plants were then found in the EIA dataset and cross-checked against latitude and longitude information to confirm co-location.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO or utility. For more information see Rand et al. (2022).

Industry Trends

Turbine manufacturer market share data are derived from the ACP project database. Data on recent U.S. nacelle assembly capability come from ACP (2022), as do data on U.S. tower and blade manufacturing capability. Manufacturer profitability data come from corporate financial reports.

Data on U.S. imports of selected wind turbine equipment come 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.

All trade codes used to track wind equipment imported in 2020 and 2021 are exclusive to wind. In some previous years, some 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 U.S. International Trade Commission and wind industry experts; U.S. International Trade Commission trade cases; and import patterns in the larger HTS trade categories.

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	2005–2021	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	2011–2021	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	2012–2021	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	2012–2021	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	2012–2021	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014–2019	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[42]
8503.00.9570	machinery parts for wind-powered generating sets	2020–2021	exclusive to wind turbine components; nacelles when shipped without blades are included in this category

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

Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, and specific power was compiled by Berkeley Lab within the U.S. Wind Turbine Database based on information provided by ACP, 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 2021. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

FAA "Obstacle Evaluation / Airport Airspace Analysis" data containing prospective turbine locations and total proposed heights, in combination with ACP data on near-term installations, were used to estimate future technology trends. Any data with expiration dates between March 02, 2022 and September 02, 2023 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). A portion of those turbines are categorized by Berkeley Lab, with input from ACP data and Hitachi's Velocity Suite data, as either "under construction" or in "advanced development." The former are projects that have been partially or fully constructed but have not

[42] The explicit inclusion of nacelles without blades 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.

been fully commissioned. The latter are not under construction but are highly likely to be in the next few years and have one of the following in place: a signed PPA (or similar long-term contract), a firm turbine order, or an announcement to proceed under utility ownership.

Performance 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-NE, 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 U.S. Wind Turbine Database, 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 Obstacle Evaluation / Airport Airspace Analysis files, combined with Berkeley Lab and ACP 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 100-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%. 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, which includes all projects or turbines with an estimated gross capacity factor of less than 42%; the "medium" category, which corresponds to ≥42%–48%; the "higher" category, which corresponds to ≥48%–54%; and the "highest" category, which corresponds to ≥54%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 66,774 turbines of the 67,143 installed from 1998 through 2021 in the continental United States (i.e., over 99%). Most of the turbines that are *not* mapped are more than a decade old.

Separate from the above, 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 1998-2021). 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. In this case, 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; some newer power curves are derived from NREL's System Advisor Model, v2020.11.29 and based on turbine characteristics, such as specific power. 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. The analyses uses AWS Truepower estimates for the latter need due to their higher geographic resolution.

Cost Trends

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, BloombergNEF, and Wood Mackenzie.

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 2019, 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.

Sales Price and Levelized Cost Trends

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. Supplemental data from Level10 Energy are also reported, in both nominal (as reported—see associated data file) and real 2021 dollars. The 2021 dollar conversion assumes that LevelTen's reported prices in each quarter are for 12-year, flat-priced (in nominal dollars) PPAs that commence in the following calendar year. In each quarter, we deflate the 12-year nominal dollar price series to 2021 dollars using the GDP deflator (actual deflators historically, along with projected future deflators from the EIA's *Annual Energy Outlook 2022*), and then levelize the resulting 12-year real-dollar price series using a 4% real discount rate. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.

The analysis calculates the LCOE of wind based on LCOE input data collected, in large part, by Berkeley Lab and presented elsewhere in this report—and assessed as *expected* LCOE as of the listed commercial operation dates. These inputs include capital costs, capacity factors, operational expenses, financing costs, and assumptions about useful life. Specifically:

- For capacity factors, project-level data are levelized over the assumed useful life of each plant, applying degradation assumptions from Hamilton et al. (2020) as appropriate. For projects built in 2021 (that have not yet been operating for a full year), capacity factors are assumed to match the average capacity factor of projects built in the same regions from 2017 to 2019.
- Based on Wiser et al. (2019), total operational expenses are assumed to fall from a levelized cost of \$88/kW-year in 1998 (expressed in 2021 dollars) to \$66/kW-year by 2003, \$56/kW-year by 2010, and \$47/kW-year by 2018 (and are interpolated linearly between these years). Projects built from 2019-2021 are indexed to the 2018 value but vary by COD year based on BloombergNEF's North American wind

O&M price index (BloombergNEF 2021b). Note that these are projected future costs; actual operational expenditures could diverge from industry expectations, as they have in the past.

- The weighted average cost of capital assumes a 70%:30% debt-to-equity split (possible in the absence of the PTC), with the cost of debt varying over time based on historical changes in the 20- and 30-year swap rates and bank spread, while the cost of equity declines from 15% in 1998 to 8.25% in 2021. Financing costs are estimated as if the PTC were not available. These are assumptions for future returns; actual returns could differ depending on how performance, operational expenditures and project lifetimes track expectations.
- Project life is assumed to increase linearly from 20 years for projects built in 1998 to 30 years for projects built in 2020 and after, based on industry expectations (see Wiser and Bolinger 2019).
- A 35% corporate tax rate is assumed from 1998–2017 and 21% thereafter, with a constant 5% state tax rate over the entire period. Inflation expectations range from 1.9% to 3.0%. Five-year accelerated depreciation is applied for all vintages of wind projects.

Cost and Value Comparisons

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 2022* is converted from $/MMBtu into $/MWh using heat rates derived from the modeling output.

To calculate the historical wholesale energy market value of wind, estimated hourly wind generation profiles are matched to hourly nodal real-time wholesale prices. The capacity value at each plant is also calculated, based on the modeled wind profiles and ISO-specific rules for wind's capacity credit and ISO-zone-specific capacity prices. The resulting estimates reflect the average $/MWh energy and capacity value for each plant and year. ISO-level average values are estimated by weighting plant-level value estimates by plant output.

To calculate the average energy and capacity value in $/MWh, the numerator is based on actual hourly generation after curtailment but the denominator is based on the total generation without curtailment. Curtailment is accounted for 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, the modeled wind generation estimates described earlier are leveraged, albeit adjusted for *curtailment* and corrected for *bias*. For the 2021 modeled hourly profiles we use a different input meteorological model than was used for the wind index calculation described earlier. Instead of ERA5 we use HRRR. Compared to ERA5, HRRR reduces biases and increases hourly correlation to recorded generation (Davidson and Millstein 2022). We are not able to use HRRR for the long term wind index calculation because the HRRR records begin in 2014 (and HRRR methodology is updated over time). By applying a bias correction process to the generation estimates we are able to incorporate publicly available information on actual generation as well as site-specific HRRR 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, those reported values are utilized.

Total *curtailment* is reported by each ISO for either each hour or each month. To correct HRRR output estimates for curtailment, plants are divided into three groups: plants receiving the PTC, plants that have aged out of the PTC, and plants that elected the 1603 Treasury Grant instead of the PTC. Total reported hourly curtailment is distributed evenly across all plants within a particular ISO that face local hourly prices below a threshold defined for each group (initially, –$23/MWh for PTC plants and $0/MWh for the other two groups). A similar process is used to distribute monthly curtailment data.

Bias correction involves an iterative linear scaling approach so that: (1) the sum of estimated generation across all plants within each ISO matches the total wind generation reported by each ISO in each hour and (2) the annual total generation from each individual plant matches its expected annual output. The expected annual output is based on the modeled annual output adjusted for age-related performance decline (Hamilton et al.

2020) and curtailment. Also, a region-wide annual correction factor was applied based on EIA reported plant-level generation from the prior year (2020). These region-wide correction factors were generally small, MISO and SPP correction factors were 0.99 and 1.02 for example, but HRRR generation estimates were biased high in some regions, for example CAISO and NYISO correction factors were 1.18 and 1.17. Overall, this ensures that both the hourly distribution of generation and the total annual generation matches both modeled and recorded ISO-level data.

Hourly nodal real-time wholesale electricity prices and hourly regional wind output profiles are from Hitachi's Velocity Suite database. Curtailment data are downloaded directly from each ISO, or in some cases, from Hitachi's Velocity Suite database. For each wind power plant, the nearest or most-representative pricing node is identified, which allows representative prices to be matched to each plant. For some regions, hourly wind output profiles are only available for a subset of the relevant years of the analysis; as such, estimates of the wholesale energy value of wind are not available for all years for all regions.

Capacity value is estimated for each plant based on the bias-corrected, modeled wind profiles and ISO and ISO-zone specific capacity prices or costs, as well as relevant regional rules for wind's capacity credit. A separate capacity value is not calculated for ERCOT, because ERCOT runs an energy-only market that does not require load-serving entities to meet a resource adequacy obligation. In ERCOT, however, hourly Operating Reserve Demand Curve prices are added to nodal energy prices. Capacity value in ERCOT is essentially incorporated into the energy markets. As for capacity prices and costs, many regions have organized capacity markets. In those cases, the analysis uses market-clearing prices from capacity market auctions in concert with ISO-rules or estimates for the capacity credit of wind. For regions where load-serving entities have a resource adequacy obligation but lack organized capacity markets, the analysis uses data from regulatory bodies to approximate capacity costs and regional estimates or rules for wind's capacity credit.

The analysis calculates the difference between wind value and flat-profile value (called "value reduction") and then further decomposes the value reduction into three separate causes: profile, congestion, and curtailment. Flat profile value is calculated in two steps. First, the average value of flat ("always-on") generation is calculated at all power plant pricing nodes in a region (both wind and other types of power plants). The regional flat value is then calculated by taking the weighted-average value across all these power plants with weights based on recorded energy output at each plant. The profile value of wind is calculated in a similar manner to the regional flat value, but instead of using a flat profile, a wind plant output profile is applied to all power plants in a region (both wind and other types) and the regional weighted average value is calculated. This process is repeated for the profiles for all wind plants in a region to develop the regional average wind plant profile value. The reduction in wind value due to its profile is then calculated as the difference between the regional wind profile value and the regional flat value. Next, the value of wind generation at each wind plant is calculated given its output profile, and the regional average value is calculated across all wind plants. This provides a value of wind profiles at wind plants—in effect, the value of wind generation (not yet adjusted for curtailment). The profile value calculation finds the value of wind output at all generator locations and the wind generation value finds wind value only at wind generators, so the difference represents the impact of transmission congestion. Finally, the value of wind is adjusted for curtailment by increasing the total energy over which energy and capacity revenue are normalized. This final adjustment provides the overall value of wind at each plant. These methods are described in further detail in Millstein et al. (2021).

Turning to health and climate benefits, the marginal rate of health benefits is estimated based on a two-step process. First, the marginal rate of avoided emissions for wind is calculated based on estimates developed by Fell and Johnson (2021) for nine regions of the United States. Fell and Johnson (2021) also estimate the impact of wind on emissions in neighboring regions, and these additional impacts are included in the present analysis. An exception is that Fell and Johnson (2021) do not estimate the emission impacts on neighboring regions for wind generation within New York, New England, and Texas. Fell and Johnson (2021) do, however, estimate wind's per MWh impact on net exports for all regions. This impact on net exports is used in the present analysis to estimate the cross region impact on emissions where Fell and Johnson (2021) do not calculate it directly. The exported wind energy is assumed here to cause a reduction to natural gas generation, with natural gas emission rates by region calculated based on the EPA's eGRID2019 data.

Note that the Fell and Johnson (2021) estimates are based on regressions that used data over the period July 2018 through March 2020; as such, the emission factors used here do not precisely reflect calendar year 2021. That said, power sector emission rates (i.e., per MWh) of SO_2, NO_x, and CO_2, have undergone little change from 2019. Note also that the Fell and Johnson (2021) regressions find that an increase in wind offsets a small amount of hydropower. Over the course of a year, however, hydropower generation can be assumed to be fixed. To estimate the emissions impacts of wind in the current analysis, wind is assumed to shift hydropower generation in time, which in turn reduces another source of generation. The type of generation reduced in response to the shifting of hydropower is unknown; to maintain a conservative estimate, natural gas is assumed to be reduced, again employing regional emissions rates from eGRID2019.

A reduced-order health impacts model is then used to estimate the value of the avoided emissions from wind. Reduced-order health impacts models use the results of full meteorological and air quality models to provide more generalized estimates of the marginal impacts of emissions from specific regions. This analyses uses a model developed in EPA (2015), which contains marginal impact estimates (as dollars of health damage per ton of emitted SO_2 and NO_x emissions) for power-sector emissions in three large regions for 2020. Marginal impact estimates were adjusted for inflation to a 2021 dollar year. EPA (2015) provides a high and low estimate for the marginal damage rate, based on differing epidemiological studies. This analysis uses marginal damage estimates from the EPA based on a 3% discount rate. The product of these damage estimates with the marginal emission rate provides a monetized marginal benefit per MWh of wind generation. The estimated health benefits include reduced hospitalizations and reduced work-days missed, but the monetization is dominated by the cost of premature mortality due to population exposure to air pollution.

The value of avoided CO_2 emissions due to wind was calculated in a similar manner. Specifically, marginal CO_2 emissions factors were also derived from Fell and Johnson (2021), and include the additional processing described above to account for hydropower impacts in all regions and exports in New York, New England, and Texas. The marginal emission factors were then multiplied by the social cost of carbon from IWG (2021), using the 2.5% discount rate case, and were adjusted for inflation (to 2021$) to derive a monetized per-MWh benefit for wind generation by region.

Both estimates of health and climate benefits are subject to uncertainty. Central estimates of these benefits are presented, though both estimates have a wide range of plausible values. More detail about this uncertainty is available in Millstein et al. (2017) and Fell and Johnson (2021).

Land-Based Wind Market Report: 2022 Edition

U.S. DEPARTMENT OF ENERGY
Office of ENERGY EFFICIENCY & RENEWABLE ENERGY

For more information visit, energy.gov/eere/wind

DOE/GO-102022-5763 · August 2022

Cover details: California Wind Farm
Photo courtesy of Ed Collier Photography