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2013 WIND TECHNOLOGIES MARKET REPORT

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2013 Wind Technologies Market Report

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List of Acronyms and Abbreviations

AWEA	American Wind Energy Association
Bloomberg NEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CREZ	Competitive Renewable Energy Zone
DOE	U.S. Department of Energy
EDPR	EDP Renováveis
EEI	Edison Electric Institute
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GE	General Electric Corporation
GW	gigawatt
HTS	Harmonized Tariff Schedule
ICE	Intercontinental Exchange
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
ITC	investment tax credit
kV	kilovolt
kVA	kilovolt-amp
kW	kilowatt
kWh	kilowatt-hour
m^2	square meter
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NSP	Northern States Power Company
NYISO	New York Independent System Operator
O&M	operations and maintenance
OEM	original equipment manufacturer
PGE	Portland General Electric
PJM	PJM Interconnection
POU	publicly owned utility
PPA	power purchase agreement

PSCo	Public Service Company of Colorado
PTC	production tax credit
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	renewables portfolio standard
RTO	regional transmission organization
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
USITC	U.S. International Trade Commission
W	watt
WAPA	Western Area Power Administration

Executive Summary

Annual wind power capacity additions in the United States were modest in 2013, but all signals point to more-robust growth in 2014 and 2015. With the industry's primary federal support—the production tax credit (PTC)—only available for projects that had begun construction by the end of 2013, the next couple years will see those projects commissioned. Near-term wind additions will also be driven by recent improvements in the cost and performance of wind power technologies. At the same time, the prospects for growth beyond 2015 are uncertain. The PTC has expired, and its renewal remains in question. Continued low natural gas prices, modest electricity demand growth, and limited near-term demand from state renewables portfolio standards (RPS) have also put a damper on industry growth expectations. These trends, in combination with increasingly global supply chains, continue to impact domestic manufacturing of wind equipment. What they mean for wind power additions through the end of the decade and beyond will be dictated in part by future natural gas prices, fossil plant retirements, and policy decisions. At the same time, recent declines in wind energy costs and prices and the potential for continued technological advancements have boosted future growth prospects.

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

Installation Trends

- **Wind power additions stalled in 2013, with only 1,087 MW of new capacity added in the United States and $1.8 billion invested.** Wind power installations in 2013 were just 8% of those seen in the record year of 2012. Cumulative wind power capacity grew by less than 2% in 2013, bringing the total to 61 GW.
- **Wind power represented 7% of U.S. electric-generating capacity additions in 2013.** Overall, wind power ranked fourth in 2013 as a source of new generation capacity, standing in stark contrast to 2012 when it represented the largest source of new capacity in the United States. The 2013 result is also a notable departure from the six years preceding 2013 during which wind constituted between 25% and 43% of capacity additions in each year. Since 2007, wind power has represented 33% of all U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (54%) and Great Lakes (48%) regions. Its contribution to generation capacity growth over that period is somewhat smaller in the West and Northeast (both 29%), and considerably less in the Southeast (2%).
- **The United States fell to sixth place in annual wind additions in 2013, and was well behind the market leaders in wind energy penetration.** After leading the world in annual wind power additions from 2005 through 2008, and then narrowly regaining the lead in 2012, in 2013 the United States represented only 3% of global additions. In terms of cumulative capacity, the United States remained the second leading market. A number of countries are beginning to achieve high levels of wind penetration: end-of-2013 installed wind power is estimated to supply the equivalent of 34% of Denmark's electricity demand and approximately 20% of Spain, Portugal and Ireland's demand. In the United States, the wind power capacity installed by the end of 2013 is estimated, in an average year, to equate to nearly 4.5% of electricity demand.

- **California installed the most capacity in 2013 with 269 MW, while nine states exceed 12% wind energy penetration.** New large-scale wind turbines were installed in thirteen states, and Puerto Rico, in 2013. On a cumulative basis, Texas remained the clear leader. Notably, the wind power capacity installed in Iowa and South Dakota supplied 27% and 26%, respectively, of all in-state electricity generation in 2013, with Kansas close behind at more than 19%. In six other states wind supplied between 12% and 17% of all in-state electricity generation in 2013.
- **No commercial offshore turbines have been commissioned in the United States, but offshore project and policy developments continued in 2013.** At the end of 2013, global offshore wind capacity stood at roughly 6.8 GW, with Europe being the primary locus of activity. No commercial offshore projects have been installed in the United States, and the emergence of a U.S. market faces both challenges and opportunities. Strides continued to be made in the federal arena in 2013, both through the U.S. Department of the Interior's responsibilities with regulatory approvals (the first competitive leases were issued in 2013) and the U.S. Department of Energy's (DOE's) investments in offshore wind energy research and development, including funding for demonstration projects. Navigant, meanwhile, has identified 14 projects totaling approximately 4.9 GW that are somewhat more advanced in the development process. Two of these have signed power purchase agreements (PPAs), and both sought to commence construction in 2013 in order to qualify for the federal tax credits.
- **Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration.** At the end of 2013, there were 114 GW of wind power capacity within the transmission interconnection queues reviewed for this report. 95% of this capacity is planned for Texas, the Midwest, Southwest Power Pool, PJM Interconnection, the Northwest, the Mountain region, and California. Wind power represented 36% of all generating capacity within these queues at the end of 2013, higher than all other generating sources except natural gas. In 2013, 21 GW of gross wind power capacity entered the interconnection queues, compared to 42 GW of natural gas and 11 GW of solar. Of note is that the absolute amount of wind, coal, and nuclear power in the sampled interconnection queues has generally declined in recent years, whereas natural gas and solar capacity has increased.

Industry Trends

- **GE captured 90% U.S. market share in a slow 2013.** Siemens came in a distant second, with 8% of the 2013 buildout. Globally, Vestas recaptured the mantle of top supplier, while GE dropped to the fifth spot. Chinese turbine manufacturers continue to occupy positions of prominence in the global ratings, with eight of the top 15 spots. To date, however, their growth has been based almost entirely on sales to the Chinese market; Sany was the only Chinese manufacturer to install turbines (just 8 MW) in the United States in 2013.
- **The manufacturing supply chain experienced substantial growing pains.** With recent cost-cutting moves, the profitability of turbine suppliers rebounded in 2013, after a number of years in decline. Five of the 10 turbine suppliers with the largest share of the U.S. market had one or more domestic manufacturing facilities at the end of 2013. Nine years earlier there was only one active utility-scale turbine manufacturer assembling nacelles in the United States. Domestic nacelle assembly capability stood at roughly 10 GW in 2013, and the

United States also had the capability of producing approximately 7 GW of blades and 8 GW of towers annually. Despite the significant growth in the domestic supply chain over the last decade, prospects for further expansion have dimmed. More domestic wind manufacturing facilities closed in 2013 than opened. Additionally, the entire wind energy sector employed 50,500 full-time workers in the United States at the end of 2013, a deep reduction from the 80,700 jobs reported for 2012. With significant wind installations expected in 2014 and 2015, turbine orders have now rebounded. But, with uncertain demand after 2015, manufacturers have been hesitant to commit additional resources to the U.S. market.

- **Despite challenges, a growing percentage of the equipment used in U.S. wind power projects has been sourced domestically since 2006-2007**. Trade data show that growth in installed wind power capacity has outpaced growth in selected, tracked wind equipment imports since 2006-2007. As a result, a decreasing percentage of the equipment (in dollar-value terms) used in wind power projects has been imported, when focusing on selected trade categories. When presented as a fraction of total equipment-related wind turbine costs, the combined import share of wind equipment tracked by trade codes (i.e., blades, towers, generators, gearboxes, and wind-powered generating sets) is estimated to have declined from nearly 80% in 2006–2007 to approximately 30% in 2012–2013; the overall import fraction is considerably higher when considering equipment not tracked in wind-specific trade codes. Domestic content has increased and is relatively high for blades, towers, and nacelle assembly; domestic content is considerably lower for much of the equipment internal to the nacelle. Exports of wind-powered generating sets from the United States have increased, rising from $16 million in 2007 to $422 million in 2013.
- **The project finance environment held steady in 2013.** In a relatively lackluster year for project finance, both tax equity yields and debt interest rates were essentially unchanged in 2013. Financing activity is likely to pick up in 2014 based on the number of projects with signed power purchase agreements that will need to achieve commercial operations in 2014 and 2015 in order to stay within the PTC safe harbor guidelines provided by the IRS. Investors seem confident that sufficient capital will be available to finance this expansion. Perhaps the most notable development in 2013 (and persisting into 2014) is that several large project sponsors—including NRG, Pattern, and most recently NextEra—spun off so-called "yieldcos" as a way to raise capital from public equity markets. These "yieldcos" hold a subset of each sponsor's operating projects, and pay out the majority of cash revenue from long-term electricity sales.
- **Independent power producers own 95% of the new wind capacity installed in 2013**. Moreover, on a cumulative basis considering *all* wind installed in the United States by the end of 2013, independent power producers (IPPs) own 83% of wind power capacity, while utilities own 15%, with the final 2% owned by entities that are neither IPPs nor utilities (e.g., towns, schools, commercial customers, farmers).
- **Long-term contracted sales to utilities remained the most common off-take arrangement, but merchant projects may be regaining some favor, at least in Texas.** Electric utilities continued to be the dominant off-takers of wind power in 2013, either owning (4%) or buying (70%) power from 74% of the new capacity installed last year. Merchant/quasi-merchant projects accounted for another 25%, and that share may increase in the next two years as wind energy prices have declined to levels competitive with wholesale market price expectations in some regions, most projects currently under construction will

come online this year or next in order to stay within the IRS safe harbor with respect to the PTC, and wind power purchase agreements remain in short supply. On a cumulative basis, utilities own (15%) or buy (54%) power from 69% of all wind power capacity in the United States, with merchant/quasi-merchant projects accounting for 23% and competitive power marketers 8%.

Technology Trends

- **Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly over the long term.** The average nameplate capacity of newly installed wind turbines in the United States in 2013 was 1.87 MW, up 162% since 1998–1999. The average hub height in 2013 was 80 meters, up 45% since 1998-1999, while the average rotor diameter was 97 meters, up 103% since 1998–1999.
- **Growth in rotor diameter has outpaced growth in nameplate capacity and hub height in recent years.** Rotor scaling has been especially significant in recent years, and more so than increases in nameplate capacity and hub heights, both of which have seen a modest reversal of the long-term trend in the most recent years. In 2012, almost 50% of the turbines installed in the United States featured rotors of 100 meters in diameter or larger. Though 2013 was a slow year for wind additions, this figure jumped to 75% in that year.
- **Turbines originally designed for lower wind speed sites have rapidly gained market share.** With growth in average swept rotor area outpacing growth in average nameplate capacity, there has been a decline in the average "specific power" [i] (in W/m^2) among the U.S. turbine fleet over time, from 400 W/m^2 among projects installed in 1998–1999 to 255 W/m^2 among projects installed in 2013. In general, turbines with low specific power were originally designed for lower wind speed sites. Another indication of the increasing prevalence of lower wind speed turbines is that, in 2012, more than 50% of installations used IEC Class 3 and Class 2/3 turbines; in 2013, based on the small sample of projects installed that year, the percentage increased to 90%.
- **Turbines originally designed for lower wind speeds are now regularly employed in both lower and higher wind speed sites, whereas taller towers predominate in lower wind speed sites.** Low specific power and IEC Class 3 and 2/3 turbines, originally designed for lower wind speeds, are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites. In parts of the interior region, in particular, relatively low wind turbulence has allowed turbines designed for low wind speeds to be deployed across a wide range of site-specific resource conditions. The tallest towers, on the other hand, have principally been deployed in lower wind resource areas, presumably focused on those sites with higher wind shear.

Performance Trends

- **Trends in sample-wide capacity factors have been impacted by curtailment and inter-year wind resource variability.** Wind project capacity factors have generally been higher on

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

average in more recent years (e.g., 32.1% from 2006–2013 versus 30.3% from 2000–2005), but time-varying influences—such as inter-year variations in the strength of the wind resource or changes in the amount of wind power curtailment—have tended to mask the positive influence of turbine scaling on capacity factors in recent years. Positively, the degree of wind curtailment has declined recently in what historically have been the most problematic areas, as a result of concrete steps taken to address the issue. For example, only 1.2% of all wind generation within ERCOT was curtailed in 2013; this was the lowest level of curtailment in Texas since 2007, and is down sharply from the peak of 17% in 2009.

- **Competing influences of lower specific power and lower quality wind project sites have left average capacity factors among newly built projects stagnant in recent years, averaging 31 to 34 percent nationwide.** Even when controlling for time-varying influences by focusing only on capacity factors in 2013 (parsed by project vintage), it is difficult to discern any improvement in *average* capacity factors among projects built after 2005 (although the *maximum* 2013 capacity factors achieved by individual projects within each vintage have increased in the past five years). This is partially attributable to the fact that average "specific power" remained largely unchanged from 2006–2009, before resuming its downward trend from 2010 through 2013. At the same time, the average quality of the wind resource in which new projects are located has declined; this decrease was particularly sharp—at 15%—from 2009 through 2012, and counterbalanced the drop in specific power. Controlling for these two competing influences confirms this offsetting effect and shows that turbine design changes are driving capacity factors significantly higher over time among projects located within a given wind resource regime.
- **Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology.** Based on a sub-sample of wind projects built in 2012, average capacity factors in 2013 were the highest in the Interior (38%) and the lowest in the West (26%). Not surprisingly, these regional rankings are roughly consistent with the relative quality of the wind resource in each region, but also reflect the degree to which each region has, to this point, applied new turbine design enhancements (e.g., turbines with a lower specific power rating, or taller towers) that can boost project capacity factors. For example, the Great Lakes (which ranks second among regions in terms of 2013 capacity factor) has thus far adopted these new designs to a much larger extent than has the West (which ranks last).

Cost Trends

- **Wind turbine prices remained well below levels seen several years ago.** After hitting a low of roughly $750/kW from 2000 to 2002, average turbine prices increased to more than $1,500/kW by the end of 2008. Wind turbine prices have since dropped substantially, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Recently announced turbine transactions have often been priced in the $900–$1,300/kW range. These price reductions, coupled with improved turbine technology and more-favorable terms for turbine purchasers, have exerted downward pressure on total project costs and wind power prices.
- **Reported installed project costs continued to trend lower in 2013.** The capacity-weighted average installed project cost within our limited 2013 sample stood at roughly $1,630/kW,

down more than $300/kW from the reported average cost in 2012 and down more than $600/kW from the apparent peak in average reported costs in 2009 and 2010. With just 11 projects totaling 650 MW, however, the 2013 sample size is limited, perhaps enabling a few projects to unduly influence the weighted average. Early indications from a larger sample (16 projects totaling more than 2 GW) of projects currently under construction and anticipating completion in 2014 suggest that capacity-weighted average installed costs are closer to $1750/kW—still down significantly from 2012 levels.

- **Installed costs differed by project size, turbine size, and region.** Installed project costs exhibit some economies of scale, at least at the lower end of the project and turbine size range. Additionally, among projects built in 2013, the windy Interior region of the country was the lowest-cost region.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, it appears that projects installed over the past decade have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first several years of operation, and that O&M costs increase as projects age.

Wind Power Price Trends

- **Wind PPA prices have reached all-time lows.** After topping out at nearly $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs that were signed in 2013 (and that are within the Berkeley Lab sample) fell to around $25/MWh nationwide—a new low, but admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country. This new low average price level is notable given that installed project costs have not similarly broken through previous lows and that wind projects increasingly have been sited in lower-quality wind resource areas.
- **The relative competitiveness of wind power improved in 2013.** The continued decline in average levelized wind PPA prices (which embeds the value of federal incentives, including the PTC), along with a bit of a rebound in wholesale power prices, put wind back at the bottom of the range of nationwide wholesale power prices in 2013. Based on our sample, wind PPA prices are most competitive with wholesale power prices in the Interior region. The average price stream of wind PPAs executed in 2013 also compares favorably to a range of projections of the fuel costs of gas-fired generation extending out through 2040.

Policy and Market Drivers

- **Availability of Federal incentives for wind projects built in the near term has helped restart the domestic market, but policy uncertainty persists.** In January 2013, the PTC was extended, as was the ability to take the 30% investment tax credit (ITC) in lieu of the PTC. Wind projects that had begun construction before the end of 2013 are eligible to receive the PTC or ITC. These provisions have helped restart the domestic wind market and are expected to spur capacity additions in 2014 and 2015. With the PTC now expired and its renewal uncertain, however, wind deployment beyond 2015 is also uncertain. On the other hand, the prospective impacts EPA's proposal regulations to reduce carbon emissions from existing and new power plants may create new markets for wind energy.

- **State policies help direct the location and amount of wind power development, but current policies cannot support continued growth at recent levels.** As of June 2014, RPS policies existed in 29 states and Washington D.C. From 1999 through 2013, 69% of the wind power capacity built in the United States was located in states with RPS policies; in 2013, this proportion was 93%. However, given renewable energy growth over the last decade, existing RPS programs are projected to require average annual renewable energy additions of just 3–4 GW/year through 2025 (only a portion of which will be from wind), which is well below the average growth rate in wind capacity in recent years, demonstrating the limitations of relying exclusively on RPS programs to drive future deployment.
- **Solid progress on overcoming transmission barriers continued.** Over 3,500 miles of transmission lines came on-line in 2013, a significant increase from recent years. Four transmission projects of particular importance to wind, including the Competitive Renewable Energy Zones project in Texas, were completed in 2013. A decrease in transmission investment is anticipated in 2014 and 2015. Nonetheless, the wind industry has identified 15 near-term transmission projects that—if all were completed—could carry almost 60 GW of additional wind power capacity. The Federal Energy Regulatory Commission continued to implement Order 1000 in 2013, which requires public utility transmission providers to improve intra- and inter-regional transmission planning processes and to determine cost allocation methodologies for new transmission facilities. Despite this progress, siting, planning, and cost-allocation issues remain key barriers to transmission investment.
- **System operators are implementing methods to accommodate increased penetration of wind energy.** Recent studies show that wind energy integration costs are almost always below $12/MWh—and often below $5/MWh—for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. Two recent integration studies include a detailed assessment of cycling costs. In both, cycling was found to increase with more renewables, though the associated costs were modest. Studies on frequency response with higher shares of wind highlight technical options to maintain adequate frequency response, including the potential participation of wind plants.

Because federal tax incentives are available for projects that initiated construction by the end of 2013, significant new builds are anticipated in 2014 and 2015. Near-term wind additions will also be driven by the recent improvements in the cost and performance of wind power technologies, leading to the lowest power sales prices yet seen in the U.S. wind sector. Projections for 2016 and beyond are much less certain. Despite the lower price of wind energy and the potential for further technological improvements and cost reductions, federal policy uncertainty—in concert with continued low natural gas prices, modest electricity demand growth, and the aforementioned slack in existing state policies—may put a damper on growth.

1. Introduction

Annual wind power capacity additions in the United States were modest in 2013, but all signals point to more-robust growth in 2014 and 2015. With the industry's primary federal support—the production tax credit (PTC)—only available for projects that had begun construction by the end of 2013, the next couple years will see those projects commissioned. Near-term wind additions will also be driven by recent improvements in the cost and performance of wind power technologies, leading to the lowest power sales prices yet seen in the U.S. wind sector. At the same time, the prospects for growth beyond 2015 are uncertain. The PTC has expired, and its renewal remains in question. Continued low natural gas prices, modest electricity demand growth, and limited near-term demand from state renewables portfolio standards (RPS) have also put a damper on industry growth expectations. These trends, in combination with increasingly global supply chains, continue to impact domestic manufacturing of wind equipment. What they mean for wind power additions through the end of the decade and beyond will be dictated in part by future natural gas prices, fossil plant retirements, and policy decisions. At the same time, recent declines in wind energy costs and prices and the potential for continued technological advancements have boosted future growth prospects.

This annual report—now in its eighth year—provides a detailed overview of developments and trends in the U.S. wind power market, with a particular focus on 2013. The report begins with an overview of key installation-related trends: trends in wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual states; the status of offshore wind power development; and the quantity of proposed wind power capacity in various interconnection queues in the United States. Next, the report covers an array of wind power industry trends, including: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into and exports from the United States; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a summary of wind turbine technology trends: turbine size, hub height, rotor diameter, specific power, and IEC Class. After that, the report discusses wind power performance, cost, and pricing trends. In so doing, it describes trends in project performance, wind turbine transaction prices, installed project costs, operations and maintenance (O&M) expenses. It also reviews the prices paid for wind power in the United States and how those prices compare to short-term wholesale electricity prices and forecasts of future natural gas prices. Next, the report examines policy and market factors impacting the domestic wind power market, including federal and state policy drivers, transmission issues, and grid integration. The report concludes with a preview of possible near-term market developments.

This edition of the annual report updates data presented in previous editions while highlighting key trends and important new developments from 2013. New to this edition are the following: a new chapter of the report that contains further details on wind turbine technology trends; a comparison of wind power prices to projections of future natural gas prices; and expansion and refinement of the manufacturing, supply chain and domestic content assessments. The report concentrates on larger-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[1] The U.S. wind power sector is multifaceted, however, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Data on these smaller turbines are not the focus of this report, although a brief discussion on *Smaller Wind Turbines* is provided on page 4. Further information on the larger category of *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).[2] Additionally, because this report has an historical focus, and all U.S. wind power projects have been land based, its treatment of trends in the offshore wind power sector is limited to a brief summary of recent developments. A companion annual report funded by DOE that focuses exclusively on offshore wind energy also will be published later this year.

Much of the data included in this report were compiled by Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the American Wind Energy Association (AWEA), the U.S. Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). The Appendix provides a summary of the many data sources used in the report, and a list of specific references follows the Appendix. Data on wind power capacity additions in the United States (as well as wind power projects) are based largely on information provided by AWEA, although minor methodological differences may yield slightly different numbers from AWEA (2014a) in some cases. In other cases, the data shown here represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market information, with an emphasis on 2013; with some limited exceptions (including the final section of the report), the report does not seek to forecast future trends.

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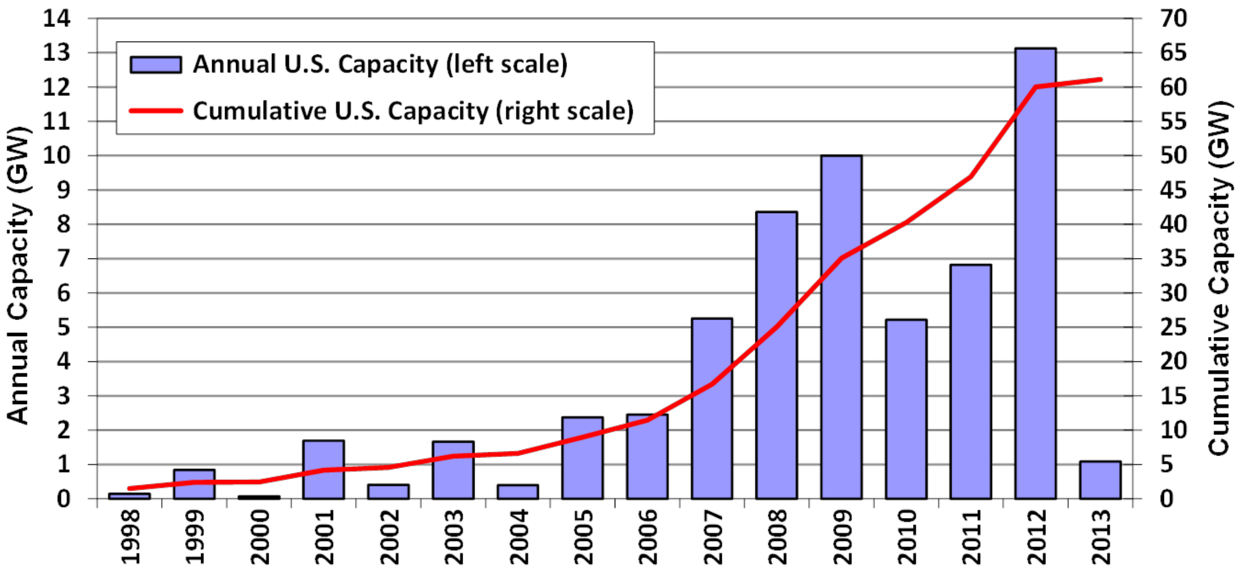
[1] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match AWEA's historical methodology, and is also justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, different cut-offs are used to better match AWEA's reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.

[2] As used by the U.S. DOE, distributed wind is defined in terms of technology application based on a wind project's location relative to end use and power distribution infrastructure, rather than on technology size or project size. Distributed wind systems are connected either on the customer side of the meter (to meet the onsite load) or directly to the local grid (to support grid operations or offset large loads nearby).

2. Installation Trends

Wind power additions stalled in 2013, with only 1,087 MW of new capacity added in the United States and $1.8 billion invested

The U.S. wind power market slowed dramatically in 2013, with only 1,087 MW of new capacity added, bringing the cumulative total to 61,110 MW (Figure 1).[3] This growth required $1.8 billion of investment in wind power project installations in 2013, for a cumulative investment total of $125 billion since the beginning of the 1980s (all cost and price data are reported in real 2013$).[4] Wind power installations in 2013 were just 8% of those seen in the record year of 2012. Cumulative wind power capacity grew by less than 2% in 2013.



Source: AWEA project database

Figure 1. Annual and cumulative growth in U.S. wind power capacity

A key factor driving the meager growth in 2013 was the limited motivation for projects to achieve commercial operations by year-end 2013 as a result of a late extension of the production tax credit (PTC) in January 2013 that altered PTC-eligibility guidelines to only require construction to have begun by the end of that year. Because federal tax incentives are available for projects that initiated construction by the end of 2013, however, significant new builds are anticipated in 2014 and 2015. Near-term wind additions will also be driven by the recent improvements in the cost and performance of wind power technologies, and by state renewables portfolio standards (RPS).

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[3] When reporting annual wind power capacity additions, this report focuses on *gross* capacity additions of large wind turbines. The *net* increase in capacity each year can be somewhat lower, reflecting turbine decommissioning.
[4] 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.

Smaller Wind Turbines (≤ 100 kW)

Small wind turbines can provide power directly to homes, farms, schools, businesses, and industrial facilities, offsetting the need to purchase some portion of the host's electricity from the grid; such wind turbines can also provide power to off-grid sites. Wind turbines used in these applications are sometimes much smaller than the larger-scale (larger than 100-kW) turbines that are the primary focus of this report.

The table below summarizes sales of smaller (100-kW and smaller) wind turbines into the U.S. market from 2003 through 2013. As shown, 5.6 MW of small wind turbines were sold in the United States in 2013, with 88% of that capacity coming from U.S. suppliers (Orrell and Rhoads-Weaver 2014). These installation figures represent a very substantial decline in sales relative to recent years. The average installed cost of U.S. small wind turbines in 2013 was reportedly $6,940/kW (Orrell and Rhoads-Weaver 2014).

Year	Annual Sales of Smaller Wind Turbines (≤ 100 kW) into the United States	
	Capacity Additions	Number of Turbines
2003	3.2 MW	3,200
2004	4.9 MW	4,700
2005	3.3 MW	4,300
2006	8.6 MW	8,300
2007	9.7 MW	9,100
2008	17.4 MW	10,400
2009	20.4 MW	9,800
2010	25.6 MW	7,800
2011	19.0 MW	7,300
2012	18.4 MW	3,700
2013	5.6 MW	2,700

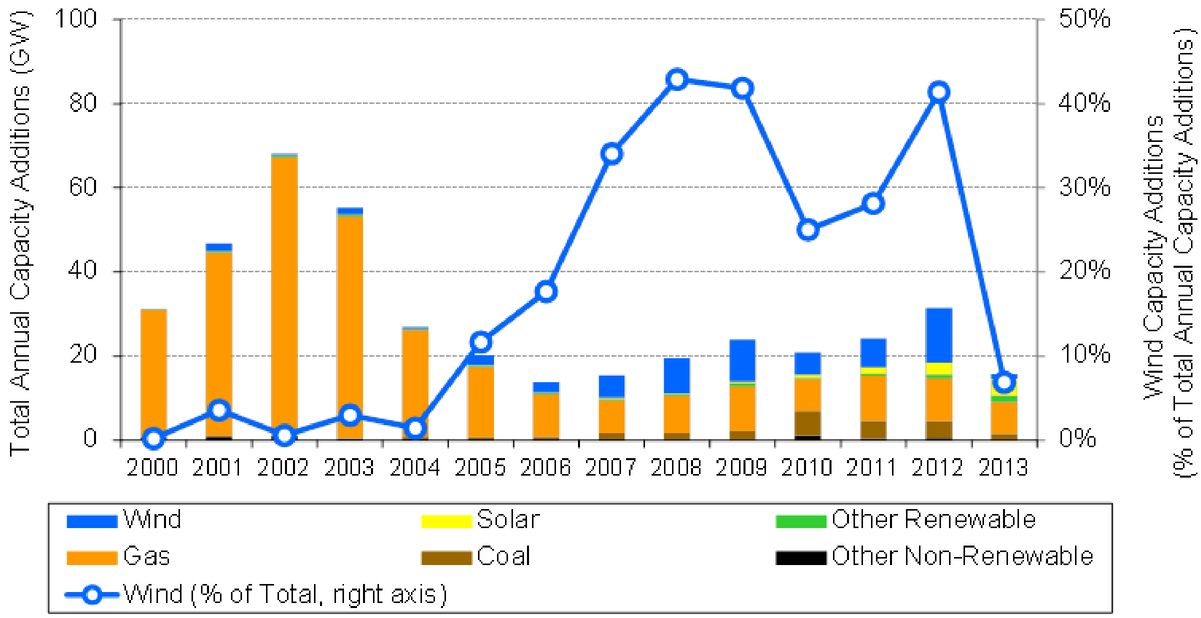
Source: Orrell and Rhoads-Weaver (2014)

Sales in this sector historically have been driven—at least in part—by a variety of state incentive programs. In addition, wind turbines of 100 kW or smaller are eligible for an uncapped 30% federal investment tax credit (ITC, in place through 2016). The Section 1603 Treasury Grant Program and programs administered by the U.S. Department of Agriculture have also played a role in the sector. According to AWEA (2014a), competitive PV and natural gas prices, suspended state incentives, and a weak economy have all contributed to recent declines in sales.

Further information on small wind turbines, as well as the broader category of distributed wind power that also includes larger turbines used in distributed applications, is available through a separate annual report funded by DOE: *2013 Distributed Wind Market Report.*

Wind power represented 7% of U.S. electric-generating capacity additions in 2013

With the drop-off in annual wind power capacity additions in 2013, wind power's share of total U.S. electric generation capacity additions in that year shrank to 7% (Figure 2).[5] Overall, wind power ranked fourth in 2013 as a source of new generation capacity, behind natural gas (48% of total U.S. capacity additions), solar (26%), and coal (10%). This diminished contribution stands in stark contrast to 2012 when wind power represented the largest source of new capacity in the United States, and it marks a notable divergence from the six years preceding 2013 during which it constituted between 25% and 43% of capacity additions in each year.

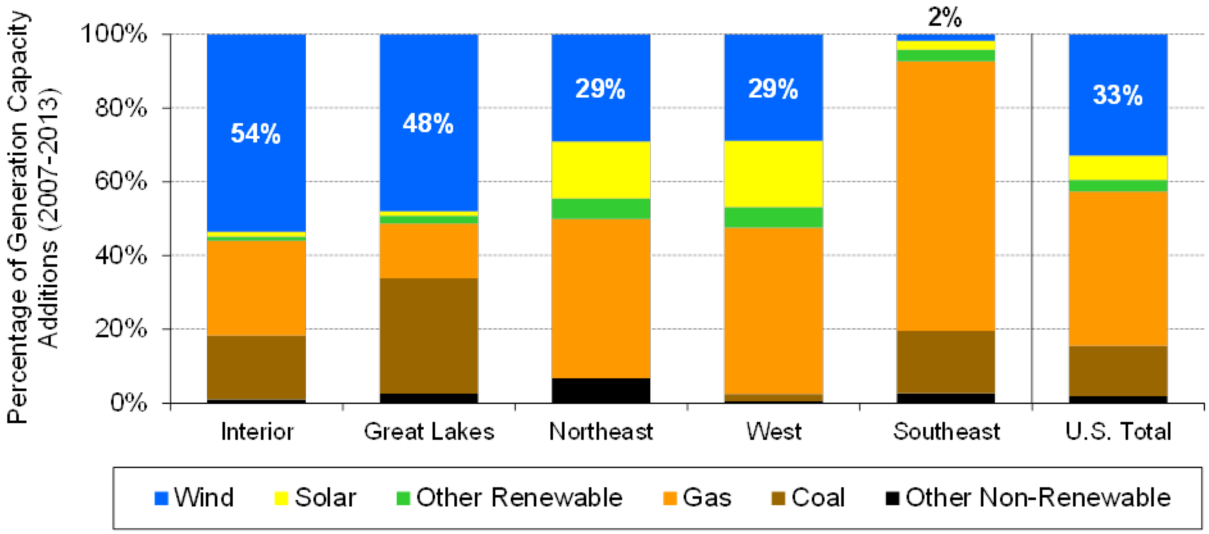


Source: EIA, Ventyx, AWEA, Interstate Renewable Energy Council, SEIA/GTM Research, Berkeley Lab

Figure 2. Relative contribution of generation types in annual capacity additions

Notwithstanding this recent dip, wind power has nevertheless comprised a sizable share of generation capacity additions in recent years. In particular, since 2007, wind power has represented 33% of all U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (54%) and Great Lakes (48%) regions (Figure 3; see Figure 30, later, for regional definitions). Its contribution to generation capacity growth over that period is somewhat smaller in the West and Northeast (both 29%), and considerably less in the Southeast (2%).

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



Source: EIA, Ventyx, AWEA, Interstate Renewable Energy Council, SEIA/GTM Research, Berkeley Lab

Figure 3. Generation capacity additions by region (2007–2013)

EIA's (2014a) reference-case forecast projects that total U.S. electricity supply will increase at an average pace of roughly 1% per year over the next decade. Growth in wind power capacity over the 2007–2013 period averaged 7.1 GW per year. If wind power additions continued over the next decade at the same pace as in 2007–2013, then roughly 40% of the nation's projected increase in electricity generation would be met with wind electricity.

The United States fell to sixth place in annual wind additions in 2013, and was well behind the market leaders in wind energy penetration

Led by the decline in the U.S. market, global wind additions contracted to approximately 36,000 MW in 2013, 20% below the record of roughly 45,000 MW added in 2012. Cumulative global capacity stood at approximately 321,000 MW at the end of the year (Navigant 2014; Table 1).[6] The United States ended 2013 with 19% of total global wind power capacity, a distant second to China by this metric (Table 1).[7] Annual growth in cumulative capacity in 2013 was 2% for the United States and 13% globally.

After leading the world in annual wind power capacity additions from 2005 through 2008, and then losing the mantle to China from 2009 through 2011, the United States narrowly regained the global lead in 2012. In 2013, however, the United States dropped precipitously to 6th place in annual wind additions (Table 1). The U.S. wind power market represented just 3% of global

[6] Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from Navigant (2014) but are updated with the U.S. data presented here. Some disagreement exists among these data sources and others.

[7] Wind power additions and cumulative capacity in China include capacity that was installed but that had not yet begun to deliver electricity by the end of 2013, due to a lack of coordination between wind developers and transmission providers and the lengthier time that it takes to build transmission and interconnection facilities. All of the U.S. capacity reported here, on the other hand, was capable of electricity delivery.

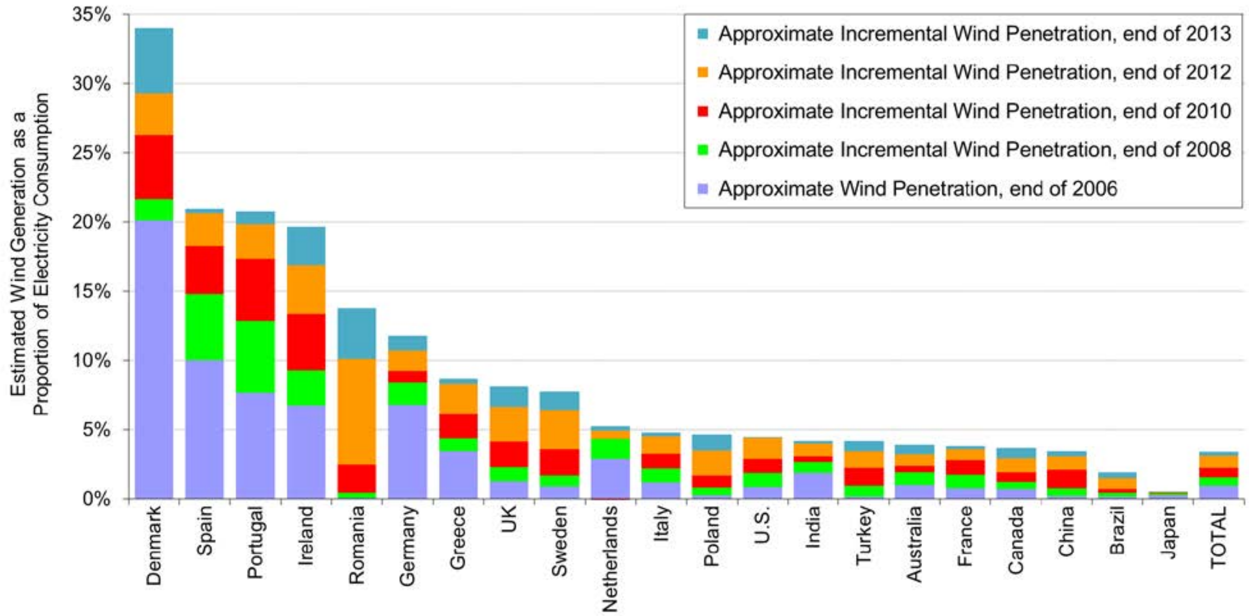
installed capacity in 2013. The top five countries in 2013 for annual capacity additions were China, Germany, India, the UK, and Canada.

Table 1. International rankings of wind power capacity

Annual Capacity (2013, MW)		Cumulative Capacity (end of 2013, MW)	
China	16,088	China	91,460
Germany	3,237	**United States**	**61,110**
India	1,987	Germany	34,468
United Kingdom	1,833	Spain	22,637
Canada	1,599	India	20,589
United States	**1,087**	United Kingdom	10,946
Brazil	948	Italy	8,448
Poland	894	France	8,128
Sweden	724	Canada	7,813
Romania	695	Denmark	4,747
Rest of World	7,045	*Rest of World*	51,031
TOTAL	**36,137**	**TOTAL**	**321,377**

Source: Navigant; AWEA project database for U.S. capacity

A number of countries have achieved relatively high levels of wind energy penetration in their electricity grids. Figure 4 presents data on end-of-2013 (and earlier years') installed wind power capacity, translated into projected annual electricity supply based on assumed country-specific capacity factors and then divided by projected 2014 (and earlier years') electricity consumption. Using this approximation for the contribution of wind power to electricity consumption, and focusing only on those countries with the greatest cumulative installed wind power capacity, end-of-2013 installed wind power is estimated to supply the equivalent of 34% of Denmark's electricity demand and approximately 20% of Spain, Portugal and Ireland's demand. In the United States, the cumulative wind power capacity installed at the end of 2013 is estimated, in an average year, to equate to almost 4.5% of the nation's electricity demand. On a global basis, wind energy's contribution is estimated to be 3.4%.



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

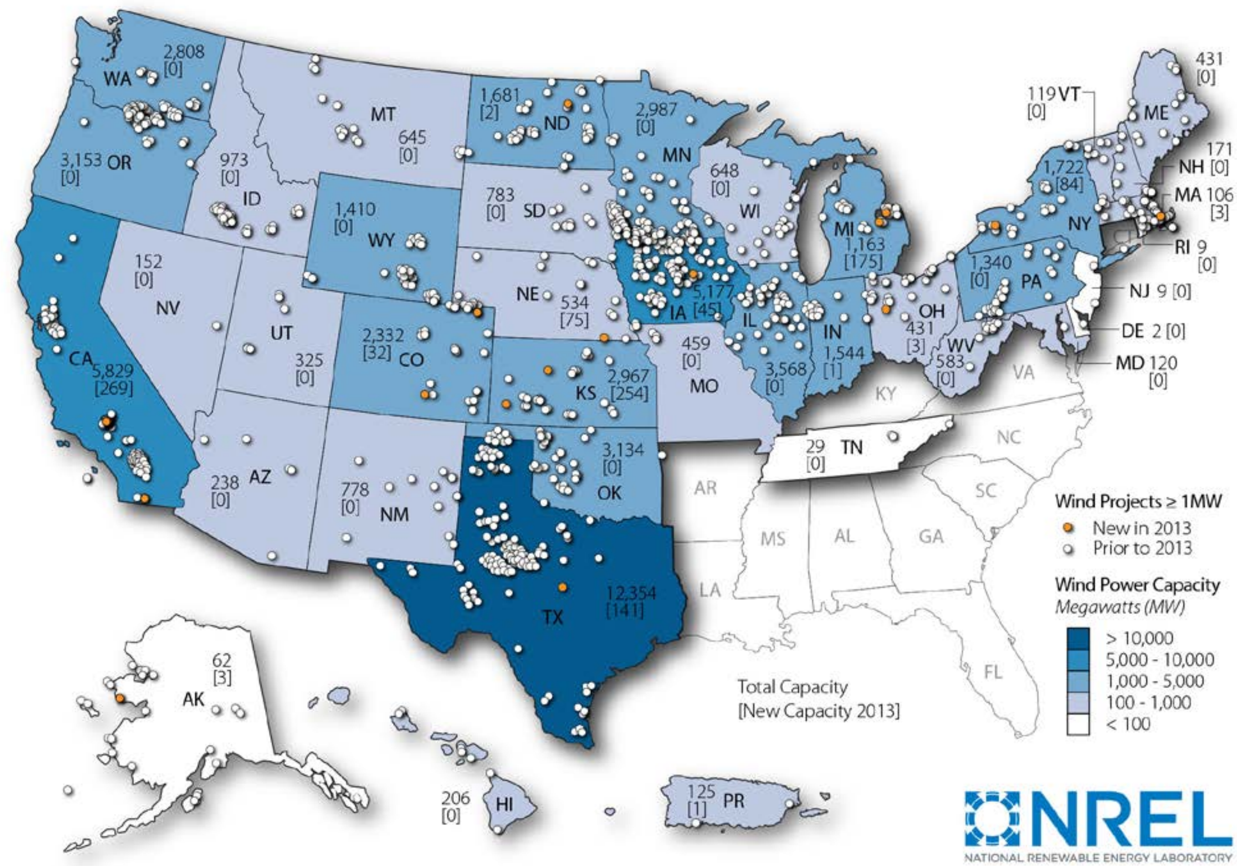
Figure 4. Approximate wind energy penetration in the countries with the greatest installed wind power capacity

California installed the most capacity in 2013 with 269 MW, while nine states exceed 12% wind energy penetration

New large-scale[8] wind turbines were installed in thirteen states, and Puerto Rico, in 2013. California installed the most new wind capacity of any state in 2013, though with just 269 MW. As shown in Figure 5 and Table 2, other leading states in terms of new capacity included Kansas (254 MW), Michigan (175 MW) and Texas (141 MW).

On a cumulative basis, Texas remained the clear leader among states, with 12,354 MW installed at the end of 2013—*more than twice as much as the next-highest state* (California, with 5,829 MW). In fact, Texas has more installed wind capacity than all but five countries (including the United States) worldwide. States (distantly) following Texas in cumulative installed capacity include California, Iowa, Illinois, Oregon, and Oklahoma—all with more than 3,000 MW. Thirty-four states, plus Puerto Rico, had more than 100 MW of wind capacity installed as of the end of 2013, with 23 of these topping 500 MW, 16 topping 1,000 MW, and 10 topping 2,000 MW. Although all commercial wind projects in the United States to date have been installed on land, offshore development activities continued in 2013, as discussed in the next section.

[8] "Larger-scale" turbines are defined consistently with the rest of this report, i.e., turbines larger than 100 kW.



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2013.

Figure 5. Location of wind power development in the United States

Some states are beginning to realize high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2013 divided by total in-state electricity generation in 2013.[9] Iowa and South Dakota lead the list, each with more than 25% wind penetration. A total of nine states have achieved wind penetration levels of above 12% of in-state generation.

[9] Wind energy penetration can either be expressed as a percentage of in-state load or in-state generation. In-state generation is used here, primarily because wind energy (like other energy resources) is often sold across state lines, which tends to distort penetration levels expressed as a percentage of in-state load. Also note that by focusing on generation in 2013, Table 2 does not fully capture the impact of new wind power capacity added during 2013 (particularly if added towards the end of the year).

Table 2. U.S. wind power rankings: the top 20 states

Installed Capacity (MW)				Percentage of In-State Generation	
Annual (2013)		Cumulative (end of 2013)		Actual (2013)*	
California	269	Texas	12,354	Iowa	27.4%
Kansas	254	California	5,829	South Dakota	26.0%
Michigan	175	Iowa	5,177	Kansas	19.4%
Texas	141	Illinois	3,568	Idaho	16.2%
New York	84	Oregon	3,153	Minnesota	15.7%
Nebraska	75	Oklahoma	3,134	North Dakota	15.6%
Iowa	45	Minnesota	2,987	Oklahoma	14.8%
Colorado	32	Kansas	2,967	Colorado	13.8%
Ohio	3	Washington	2,808	Oregon	12.4%
Massachusetts	3	Colorado	2,332	Wyoming	8.4%
Alaska	3	New York	1,722	Texas	8.3%
North Dakota	2	North Dakota	1,681	Maine	7.4%
Indiana	1	Indiana	1,544	California	6.6%
Puerto Rico	1	Wyoming	1,410	Washington	6.2%
		Pennsylvania	1,340	New Mexico	6.1%
		Michigan	1,163	Montana	6.0%
		Idaho	973	Hawaii	5.1%
		South Dakota	783	Nebraska	4.8%
		New Mexico	778	Illinois	4.7%
		Montana	645	Vermont	3.4%
Rest of U.S.	0	*Rest of U.S.*	4,762	*Rest of U.S.*	0.8%
TOTAL	**1,087**	**TOTAL**	**61,110**	**TOTAL**	**4.1%**

* Based on 2013 wind and total generation by state from EIA's *Electric Power Monthly*.
Source: AWEA project database, EIA

No commercial offshore turbines have been commissioned in the United States, but offshore project and policy developments continued in 2013[10]

At the end of 2013, global cumulative offshore wind power capacity stood at roughly 6,800 MW (Navigant 2014), with Europe (and to a much lesser extent, China) being the primary locus of activity. In 2013, 1,721 MW of new offshore wind capacity was commissioned, up from 1,131 MW in 2012; Navigant (2014) projects that almost 2,300 MW are likely to be installed in 2014.

No commercial offshore projects have been installed in the United States, and the emergence of a U.S. market faces both challenges and opportunities. Perhaps most importantly, the projected near-term cost of offshore wind energy remains high (though some data suggest that the prior upward trend may be stabilizing). Additionally, planning, siting, and permitting can be challenging. At the same time, interest in developing offshore wind energy exists in several parts

[10] A companion annual report funded by DOE that focuses exclusively on offshore wind will be published later this year and will provide a detailed summary of the status of the offshore wind sector in the United States.

of the country. Driving this interest is the proximity of offshore wind resources to population centers, the potential for local economic development benefits, and superior capacity factors compared to the finite set of developable land-based wind power projects available in some regions. Moreover, strides continue to be made in the federal arena, both through the U.S. Department of the Interior's responsibilities with regards to regulatory approvals (the first competitive leases were issued in 2013) and DOE's investments in offshore wind energy research and development, including funding for seven advanced demonstration project partnerships (three of which were selected in May 2014 to receive an additional $46.7 million each for deployment, with two others receiving $3 million each for additional research).

Figure 6 identifies 14 proposed offshore wind power projects in the United States that have been identified by Navigant Consulting as being more advanced in the development process; generally, this includes projects that have a signed power purchase agreement (PPA), have received approval for an interim limited lease or a commercial lease in state or federal waters, and/or have conducted baseline or geophysical studies at the proposed site with a meteorological tower erected and collecting data, boreholes drilled, or geological and geophysical data acquisition systems in place. In total, these projects equal approximately 4.9 GW of anticipated capacity and are primarily located in the Northeast and Mid-Atlantic, with one project located in each of the Great Lakes, the Gulf of Mexico, and the Pacific Northwest, and a smaller near-shore project in the U.S. Virgin Islands. It is not certain which of these projects will ultimately come to fruition, while many other proposed projects not listed in Figure 6 are in earlier planning phases.

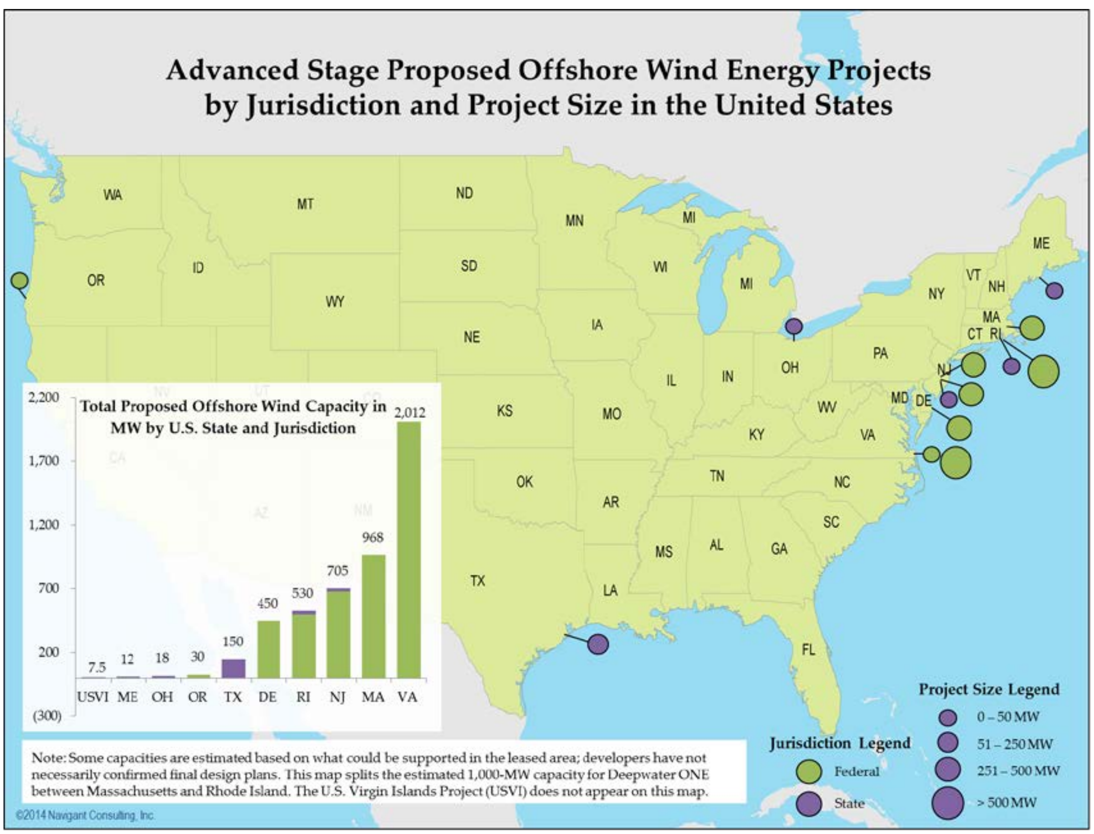


Figure 6. Proposed offshore wind power projects in a relatively advanced state of development

Of the projects identified in Figure 6, two have signed PPAs: Cape Wind (Massachusetts) and Deepwater Wind's Block Island project (Rhode Island). Both of these projects have also sought to qualify for the PTC/ITC by initiating construction activities in 2013, and Cape Wind in July 2014 received conditional approval for a $150 million loan guarantee from the DOE. In Maine, the first small, 1:8 scale-model prototype floating offshore wind turbine was deployed in 2013. Also of note, in 2013 Maryland passed legislation that will establish a set-aside for roughly 200 MW of offshore wind power in the state's RPS. As noted earlier, DOE selected three innovative projects for additional federal funding: Dominion Virginia Power (12 MW, Virginia), Principle Power (30 MW, Oregon), and Fishermen's energy (25 MW, New Jersey). The last of these projects, however, Fishermen's Atlantic City, was previously denied access to the state's offshore renewable energy certificate program, putting that project in some doubt; additionally, a project in Maine developed by Statoil was cancelled in 2013, while in 2014 Baryonyx withdrew its permit applications for an 18 MW demonstration project and a 1,000 MW commercial project, both in Texas.

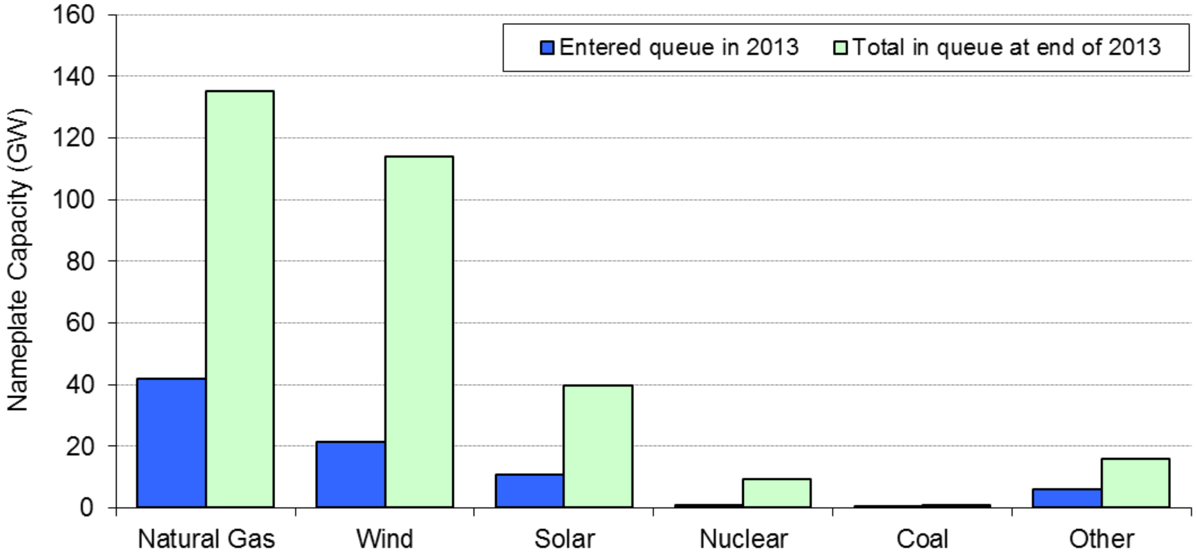
Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration

One testament to the continued interest in land-based wind energy is the amount of wind power capacity currently working its way through the major transmission interconnection queues across the country. Figure 7 provides this information for wind power and other resources aggregated across 37 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.[11] These data should be interpreted with caution: although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project actually will get built. Efforts have been made by FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have—in recent years—clogged these queues. One consequence of those efforts, as well as perhaps the uncertain size of the future U.S. wind market, is that the total amount of wind power capacity in the nation's interconnection queues has declined dramatically since 2009.

Even with this important caveat, the amount of wind capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2013, there were 114 GW of wind power capacity within the interconnection queues reviewed for this report—almost two times the installed wind power capacity in the United States. This 114 GW represented 36% of all generating capacity within these selected queues at that time, higher than all other generating sources except for natural gas. In 2013, 21 GW of gross wind power capacity entered the interconnection queues, compared to 42 GW of natural gas and 11GW of solar; virtually no coal or nuclear entered interconnection queues in 2013.

[11] The queues surveyed include PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), New York ISO (NYISO), ISO-New England (ISO-NE), California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and 27 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 about 90% of the U.S. total. Figures 7 and 8 only include projects that were active in the queue at the end of 2013 but that had not yet been built; suspended projects are not included.

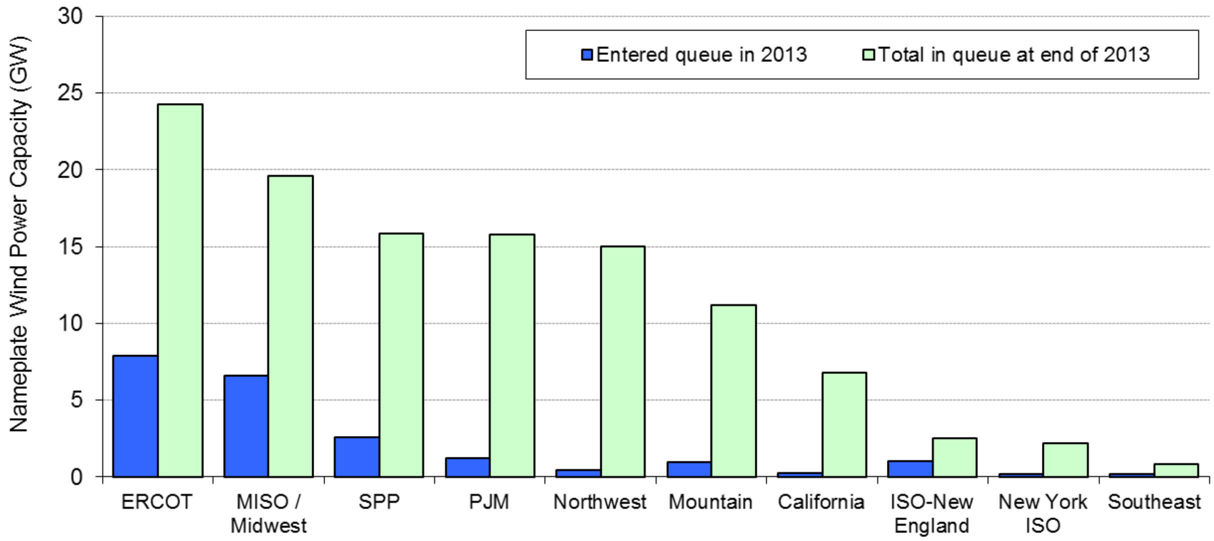
Of note, however, is that the absolute amount of wind, coal, and nuclear power in the sampled interconnection queues (considering gross additions and project drop-outs) has generally declined in recent years, whereas natural gas and solar capacity has increased. Since 2009, for example, the amount of wind power capacity has dropped by 62%, coal by 97%, and nuclear by 68%, whereas solar capacity has increased by 17% and natural gas by 22%.



Source: Exeter Associates review of interconnection queues

Figure 7. Nameplate resource capacity in 37 selected interconnection queues

Much of the wind capacity in the interconnection queues is planned for Texas, the Midwest, Southwest Power Pool (SPP), PJM Interconnection, the Northwest, the Mountain region, and California; wind power projects in the interconnection queues in these regions at the end of 2013 accounted for 95% of the aggregate 114 GW of wind power in the selected queues (Figure 8). Smaller amounts of wind power capacity were represented in the interconnection queues of ISO-New England (ISO-NE, 2.5%), the New York ISO (NYISO, 1.9%), and the Southeast (0.7%).



Source: Exeter Associates review of interconnection queues

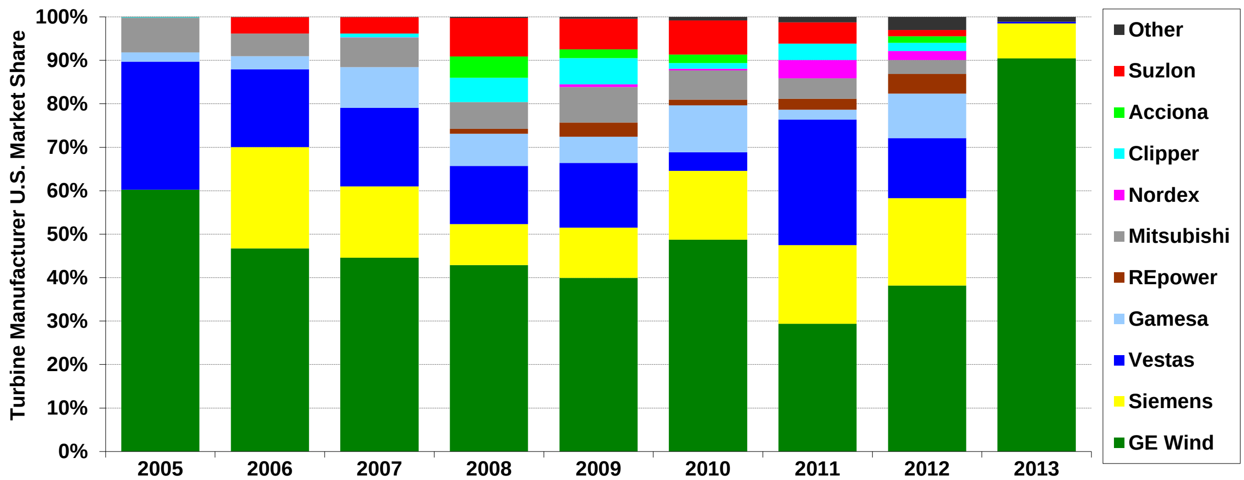
Figure 8. Wind power capacity in 37 selected interconnection queues

As a measure of the near-term development pipeline, Ventyx (2014) estimates that—as of June 2014—approximately 35 GW of wind power capacity was either: (a) under construction or in site preparation (15 GW), (b) in development and permitted (10 GW), or (c) in development with a pending permit and/or regulatory applications (10 GW). This total is significantly higher than the 28 GW that was in the development pipeline as of last year at approximately the same time (June 2013), indicating that the development pipeline has returned after shrinking during the previous year's PTC expiration and late term extension. AWEA (2014b), meanwhile, reports that more than 13,000 MW of wind power capacity was under construction at the end of the first quarter of 2014, with 214 MW installed in the first quarter of 2014.

3. Industry Trends

GE captured 90% U.S. market share in a slow 2013

Of the 1,087 MW of new U.S. wind capacity installed in 2013, 90% (984 MW) deployed turbines from GE Wind (Figure 9 and Table 3).[12] Siemens came in a distant second with 87 MW, or 8% market share, followed by Sany Electric (8 MW), Vestas (4 MW), Emergya Wind Technologies (2.7 MW), PowerWind (0.9 MW), and Vergnet (0.825 MW).



Source: AWEA project database

Figure 9. Annual U.S. market share of wind manufacturers by MW, 2005–2013

Table 3. Annual U.S. turbine installation capacity, by manufacturer

Manufacturer	Turbine Installations (MW)								
	2005	2006	2007	2008	2009	2010	2011	2012	2013
GE Wind	1,431	1,146	2,342	3,585	3,995	2,543	2,006	5,016	984
Siemens	0	573	863	791	1,162	828	1,233	2,638	87
Vestas	699	439	948	1,120	1,489	221	1,969	1,818	4
Gamesa	50	74	494	616	600	566	154	1,341	0
REpower	0	0	0	94	330	68	172	595	0
Mitsubishi	190	128	356	516	814	350	320	420	0
Nordex	0	0	3	0	63	20	288	275	0
Clipper	3	0	48	470	605	70	258	250	0
Acciona	0	0	0	410	204	99	0	195	0
Suzlon	0	92	198	738	702	413	334	187	0
Other	2	2	2	23	43	41	86	398	12
TOTAL	2,374	2,453	5,253	8,362	10,005	5,220	6,819	13,133	1,087

Source: AWEA project database

[12] Market share reported here is in MW terms and is based on project installations in the year in question, not turbine shipments or orders.

Despite its weak showing in the United States, Vestas recaptured the mantle of top supplier of turbines worldwide in 2013, after losing that position in 2012 to GE (Navigant 2014). Goldwind, Enercon, and Siemens follow, with GE dropping to the 5th spot. Other than GE, no other U.S.-owned turbine manufacturer plays a prominent role in global or U.S. turbine supply.[13]

On a worldwide basis, Chinese turbine manufacturers continued to occupy positions of prominence, with eight of the top 15 spots in the ranking. To date, the growth of Chinese turbine manufacturers has been based almost entirely on sales to the Chinese market. Chinese (and South Korean) manufacturers have begun to look abroad, however, with limited success. Sany Electric was the only Chinese or South Korean manufacturer to install turbines in the United States in 2013.

The manufacturing supply chain experienced substantial growing pains

With a slow year in 2013, but with anticipated growth in 2014 and 2015, the wind industry's domestic supply chain dealt with conflicting pressures this past year. As the cumulative capacity of wind projects has grown over the last decade, foreign and domestic turbine equipment manufacturers have localized and expanded operations in the United States. But with uncertain medium- to long-term demand expectations and with growing global competition, prospects for further supply-chain expansion have dimmed. As a result, though some manufacturers increased the size of their U.S. workforce later in 2013 in anticipation of near-term market growth, the general trend in 2013 was towards a significantly reduced workforce or closed facilities.

Figure 10 presents a non-exhaustive list of the more than 160 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2013, focusing on the utility-scale wind market.[14] Due to the steep decline in installations in 2013 as well as longer-term demand uncertainty, only one new manufacturing facility opened in 2013, compared to seven in 2012. Additionally, at least four existing wind turbine or component manufacturing facilities were closed or stopped serving the wind industry in 2013. Moreover, unlike previous years, no major new announcements were made in 2013 about prospective future wind turbine and component manufacturing and assembly facilities.

[13] These statements emphasize the sale of large wind turbines. U.S. manufacturers are major players in the global market for smaller-scale turbines.

[14] The data on existing, new, and announced manufacturing facilities presented here differ from those presented in AWEA (2014a) due, in part, to methodological differences. For example, AWEA (2014a) has access to data on a large number of smaller component suppliers that are not included in this report; the figure presented here also does not include research and development and logistics centers. Note that, unlike previous years, this year's map excludes manufacturing facilities that only serve smaller wind turbine applications.

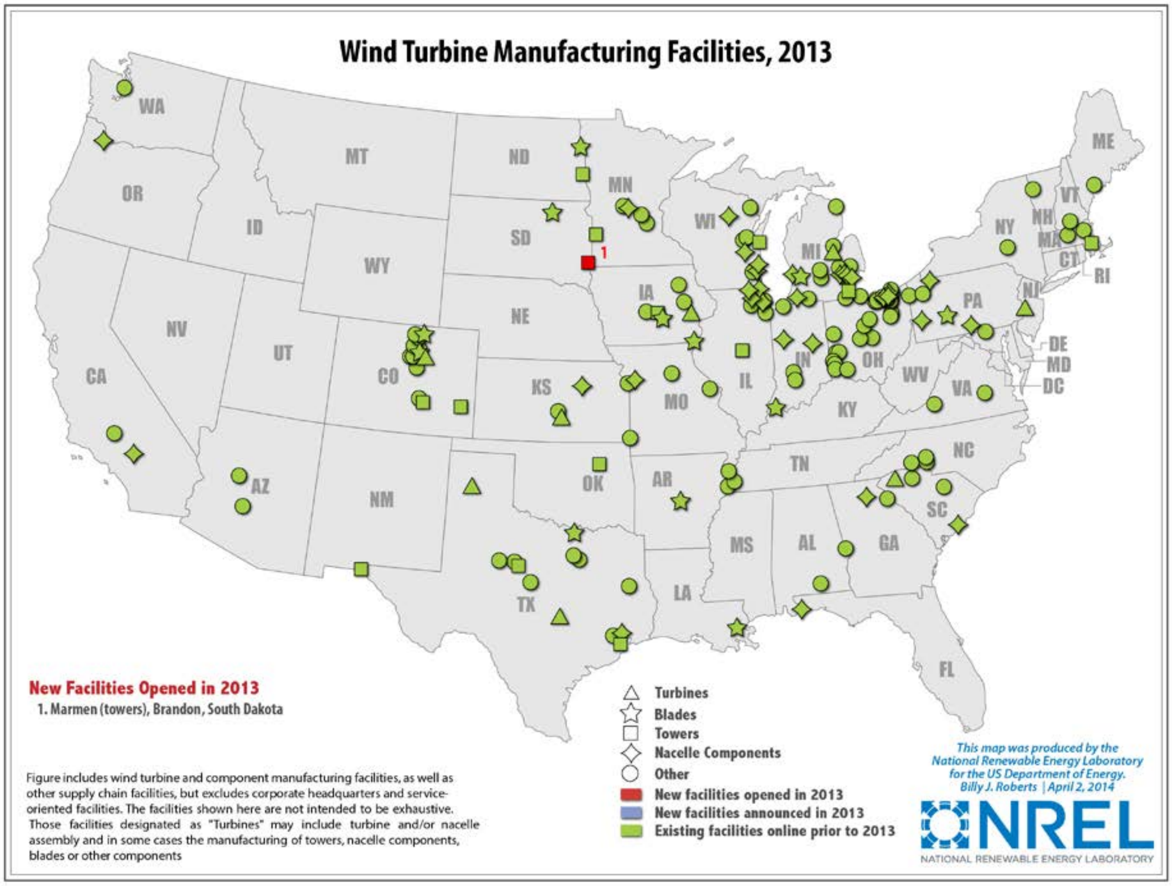
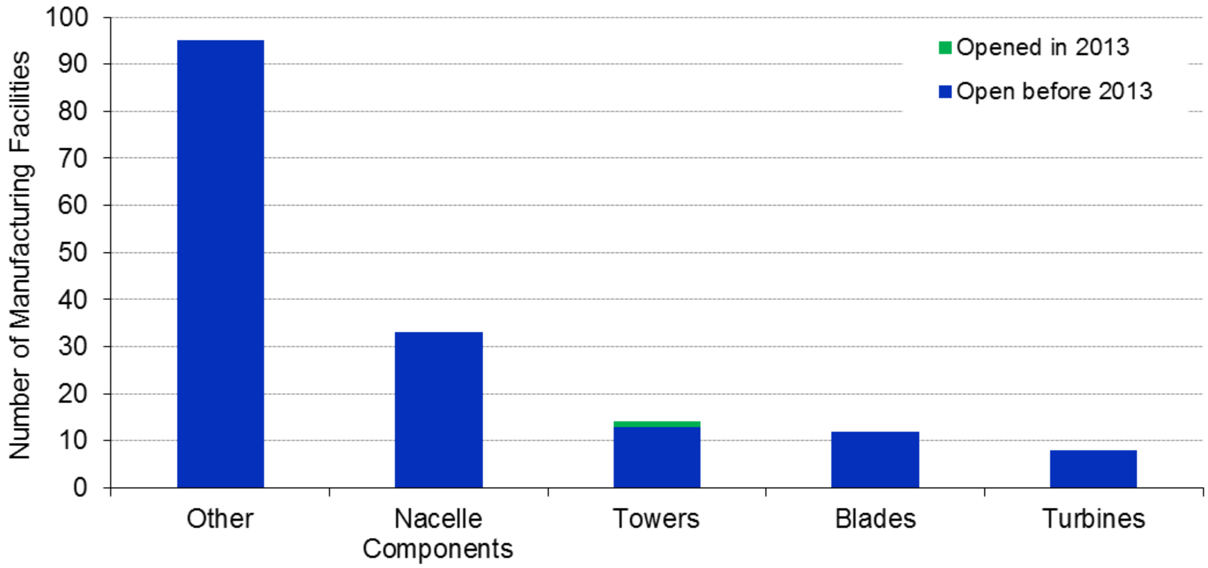


Figure 10. Location of existing and new turbine and component manufacturing facilities

Figure 11 segments the manufacturing facilities identified in Figure 10 by major component, including those that opened prior to and in 2013. Marmen, Inc., a tower manufacturer, was the single facility that opened in 2013. Located in Brandon, South Dakota, the facility may support 250 jobs when fully operational and at-capacity. As shown in Figure 10, the full set of turbine and component manufacturing facilities are spread across the country. A number of manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers (OEMs). However, even states that are relatively far from major wind power markets often have manufacturing facilities. Most states in the Southeast, for example, have wind manufacturing facilities despite the fact that there are still relatively few wind power projects in region. Workforce considerations, transportation costs, and state and local incentives are among the factors that typically drive location decisions.



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

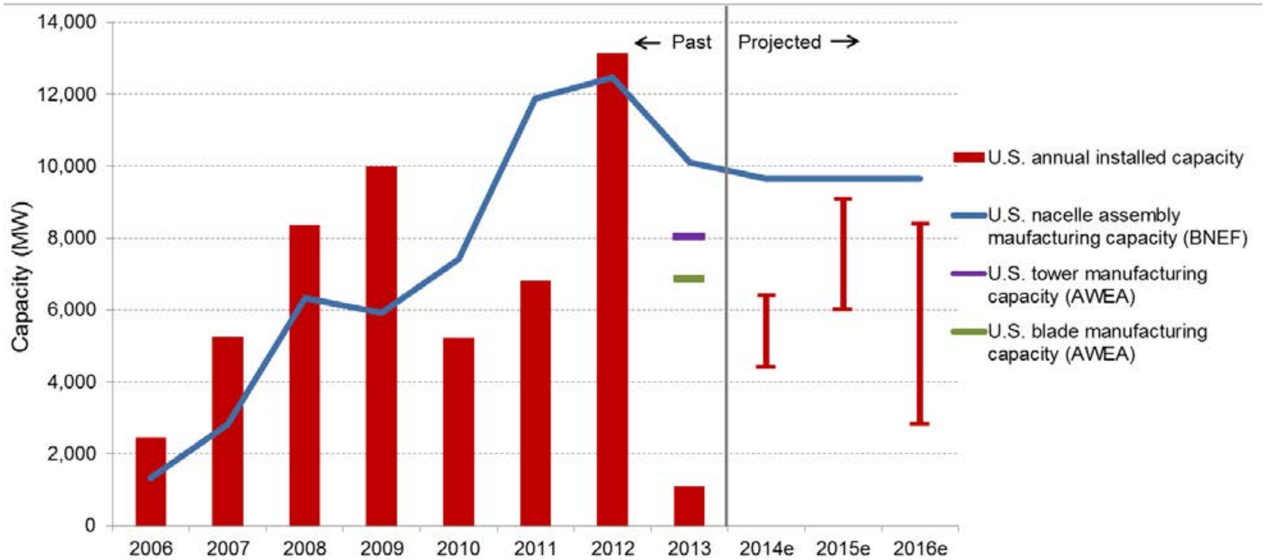
Figure 11. Number of operating wind turbine and component manufacturing facilities in the United States

Five of the ten wind turbine OEMs with the largest share of the U.S. market through 2013 (GE, Vestas, Siemens, Gamesa, Acciona) had one or more manufacturing facilities in the United States at the end of 2013. In contrast, nine years earlier (2004), there was only one active utility-scale wind energy OEM assembling nacelles in the United States (GE).[15] In 2013, however, several of the OEMs' manufacturing facilities were largely if not entirely dormant given the lack of turbine orders, and at least one of these facilities was subsequently closed in 2014. Another major OEM, Nordex, ceased U.S. manufacturing in 2013, while several others stopped U.S. manufacturing in past years (e.g., Clipper and Suzlon).

In aggregate, domestic turbine nacelle assembly capability—defined here as the *maximum* nacelle assembly capability of U.S. plants if all were operating at maximum utilization—grew from less than 1.5 GW in 2006 to exceed 12 GW in 2012, before dropping to roughly 10 GW in 2013 (Figure 12; Bloomberg NEF 2014a). In addition, AWEA (2014a) reports that U.S. manufacturing facilities have the capability to produce more than 10,000 individual blades (~7 GW) and 4,300 towers (~8 GW) annually. Figure 12 contrasts this equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future U.S. installations (see Chapter 9, "Future Outlook"). It demonstrates that domestic manufacturing capability for blades, towers, and nacelle assembly is reasonably well balanced against near-term market growth forecasts. That said, such comparisons should be made with care because

[15] Nacelle assembly is defined here as the process of combining the multitude of components included in a turbine nacelle to produce a complete turbine nacelle unit.

maximum factory utilization is uncommon, and because turbine imports into and exports from the United States also impact the balance of supply and demand (see next section).



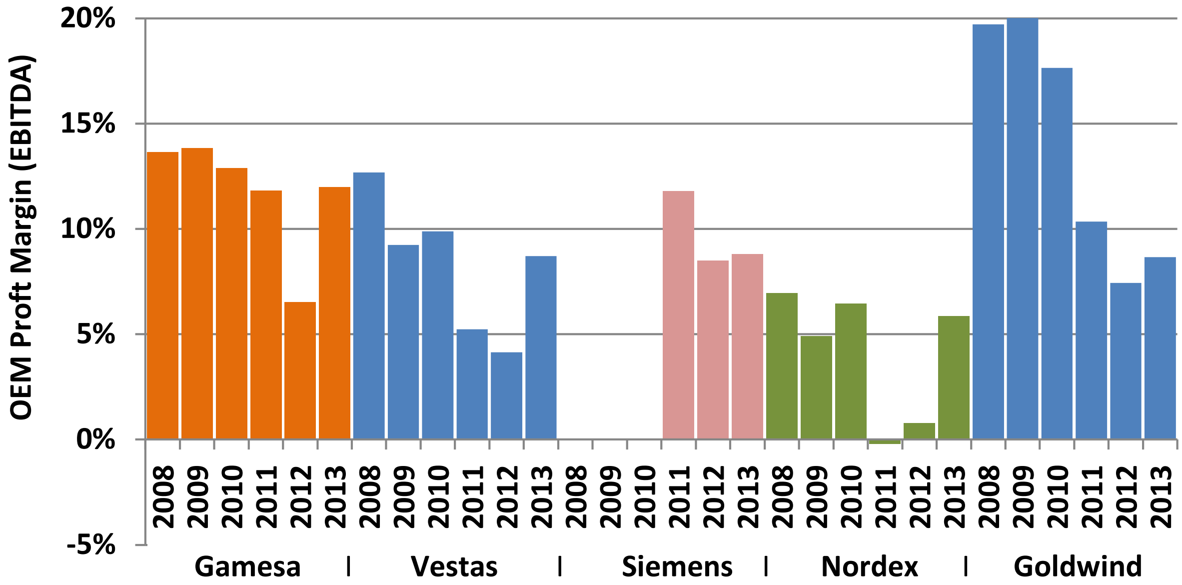
Source: Bloomberg NEF, AWEA, HIS-EER, Navigant, MAKE, EIA, Berkeley Lab

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

Given the overall compression of turbine OEM and component manufacturer profit margins experienced in previous years, many manufacturers continued to execute corporate realignments and other cost-cutting strategies in 2013. As a result, in addition to those companies and facilities that ceased operations, others experienced layoffs or furloughs, especially towards the beginning of 2013. AWEA (2014a) estimates that the wind energy industry directly and indirectly employed 50,500 full-time[16] workers in the United States at the end of 2013—a deep reduction from the 80,700 jobs reported for 2012. The 50,500 jobs include manufacturing, project development, construction and turbine installation, O&M, transportation and logistics, and financial, legal, and consulting services. Though wind project operations jobs increased from 2012 to 2013, employment in all other categories decreased due to the severe decline in new builds in 2013 (e.g., manufacturing jobs saw a decrease from 25,500 in 2012 to 17,400 in 2013).

Though jobs cuts and cost-cutting moves have been painful, as a result of these actions (both in the United States and globally), the profitability of turbine OEMs rebounded in 2013, after a number of years of decline (Figure 13). Moreover, with significant domestic wind power installations expected in 2014 and 2015, turbine orders have rebounded and turbine OEMs and component manufacturers began—in many cases—to increase their workforces towards the end of 2013. At the same time, with uncertain demand for wind power after 2015, manufacturers have generally been hesitant to commit additional resources to the U.S. market.

[16] Jobs are reported as full-time equivalents. For example, two people working full-time for 6 months are equal to one full-time job in that year.



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

Figure 13. Turbine OEM global profitability over time

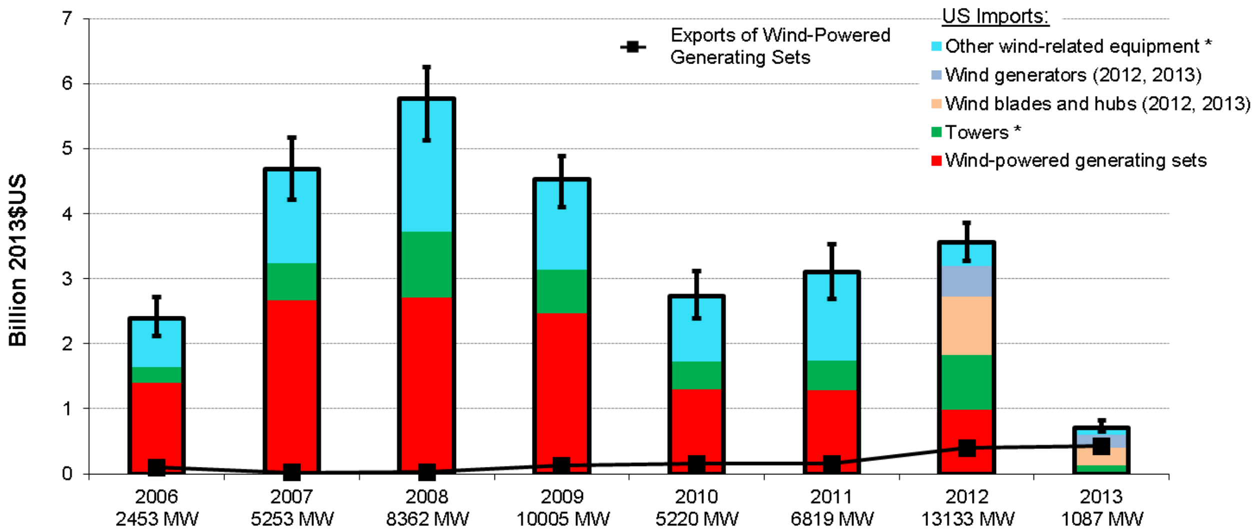
Despite challenges, a growing percentage of the equipment used in U.S. wind power projects has been sourced domestically since 2006-2007

Despite strain throughout the domestic supply chain, the share of *domestically manufactured* wind power equipment has grown since 2006-2007. This trend is not universal, however, with some components witnessing an increasing and relatively high domestic share, whereas other components remain largely imported. These trends are supported, in part, by data on wind power equipment trade from the U.S. Department of Commerce.[17]

Figure 14 presents calendar-year data on the dollar value of *estimated* imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating sets (i.e., nacelles and, when imported with the nacelle, other turbine components) as well as imports of select turbine components that are shipped *separately* from the generating sets.[18] The selected wind turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (and generator parts), blades and hubs, and gearboxes. Prior to 2012, estimates provided for many of these component-level imports should be viewed with caution because the underlying data used to produce the figure are based on trade categories that were not exclusive to wind energy (e.g., they could include generators for non-wind applications). The component-level import estimates shown in Figure 14 therefore required assumptions about the fraction of larger trade categories

[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, generators, and gearboxes are included in the data on wind-powered generating sets if shipped with the nacelle. Otherwise, these component imports are reported separately.

likely to be represented by wind turbine components (see the appendix for details); the error bars included in the figure account for uncertainty in these assumed fractions. By 2012, however, many of the trade categories were either specific to or largely restricted to wind power: wind-specific generators (and generator parts), wind-specific blades and hubs, and tubular towers. As such, by 2012, only the trade category for gearboxes was not specific to wind energy. To be clear, the figure excludes comprehensive data on the import of wind equipment not tracked in clearly identified trade categories; the impact of this omission on import and domestic content is discussed later.



* estimated imports

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

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

As shown, the *estimated* imports of *tracked* wind-related equipment into the United States substantially increased from 2006–2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then declined sharply in 2013 with the simultaneous drop in U.S. wind installations. These overall trends are driven by a combination of factors: changes in the share of domestically manufactured wind turbines and components (versus imports), changes in the annual rate of wind power capacity installations, and changes in wind turbine prices. Because imports of wind turbine component parts occur in additional, broad trade categories not captured by those included in Figure 14, the data presented here understate the aggregate amount of wind equipment imports into the United States.

Figure 14 also shows that exports of wind-powered generating sets from the United States have increased over time, rising from $16 million in 2007 to $152 million in 2010, staying relatively constant in 2011, increasing substantially in 2012 to $394 million, and then rising moderately in 2013 to $421 million. The largest destination markets for these exports over the entire 2006–2013 timeframe were Canada (52%) and Brazil (33%), while 2013 exports were also dominated by Canada (51%) and Brazil (47%). U.S. exports of 'towers and lattice masts' in 2013 totaled $129 million, including substantial amounts to Canada, Uruguay, and Mexico. The trade data for tower exports do not differentiate between tubular towers (used in wind power applications) and other types of towers, unlike the *import* classification for towers from 2011–2013 which does differentiate. Although it is likely that most of the tower exports are wind related, the exact proportion is not known. Other wind turbine component exports (e.g., blades, gearboxes, and generators) are not reported because such exports are likely a small and/or uncertain fraction of the broader trade category totals. Despite overall growth in exports, over the last decade, the United States has remained a sizable net importer of wind turbine equipment.

Figure 15 shows the total value of selected, *tracked* wind-specific imports to the United States in 2013, by country of origin, as well as the main ports of entry.[19] As shown, 45% of the import value in 2013 came from Asia (led by China), 38% from the Americas (led by Brazil), and 16% from Europe (led by Spain). The principal ports of entry for this wind equipment were Houston-Galveston, TX (30%), Savannah, GA (23%), and Los Angeles, CA (16%).

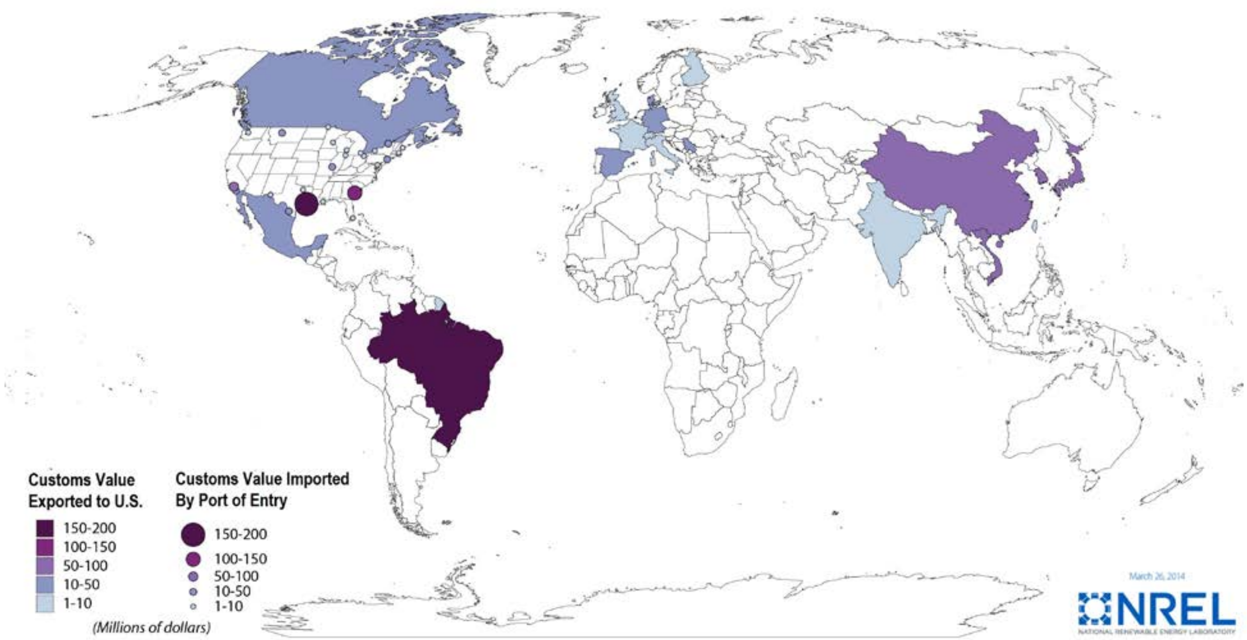


Figure 15. Summary map of tracked wind-specific imports in 2013: countries of origin and U.S. ports of entry

Looking behind the import data presented in Figures 14 and 15 in more regional and temporal detail, Figure 16 shows a number of trends over time in the origin of the U.S. imports of wind-powered generating sets, towers, wind blades and hubs, and wind generators and parts.[20] For *wind-powered generating sets*, the primary source markets during 2006–2013 have been the home countries of the major international turbine manufacturers: Denmark, Spain, Japan, India, and Germany. Since 2011, the share of imports from Europe has declined, offset by an increase

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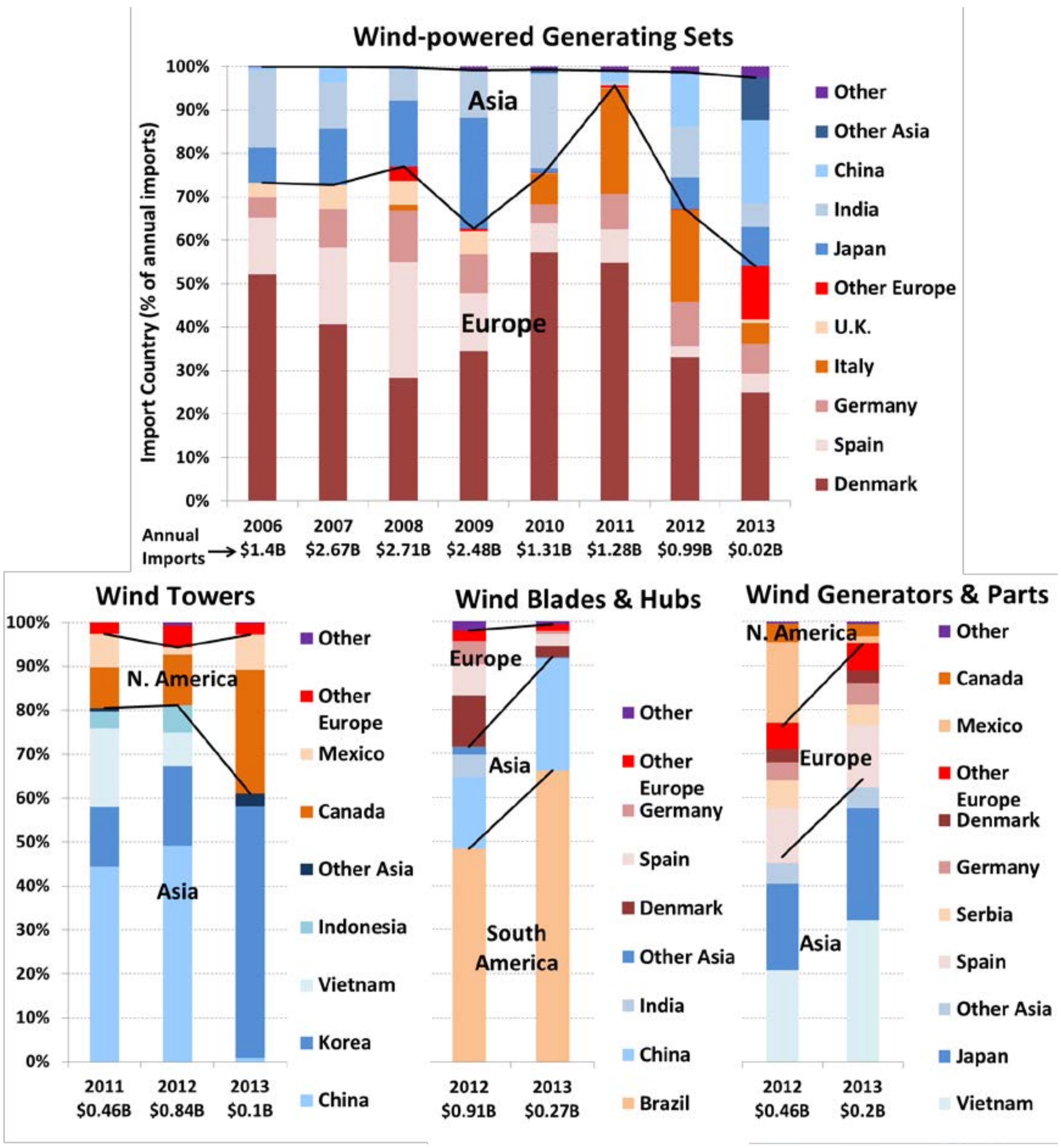
[19] The trade categories included here are the same as in Figure 14, except that gearboxes are excluded because that trade category is not specific to wind power. In addition, as noted earlier, imports of many wind turbine component parts occur in broad trade categories not captured by those included here. As such, the data presented in the figure understate the aggregate amount of wind equipment imports into the United States.

[20] As with Figure 15, gearboxes are not included because the trade category is not specific to wind power.

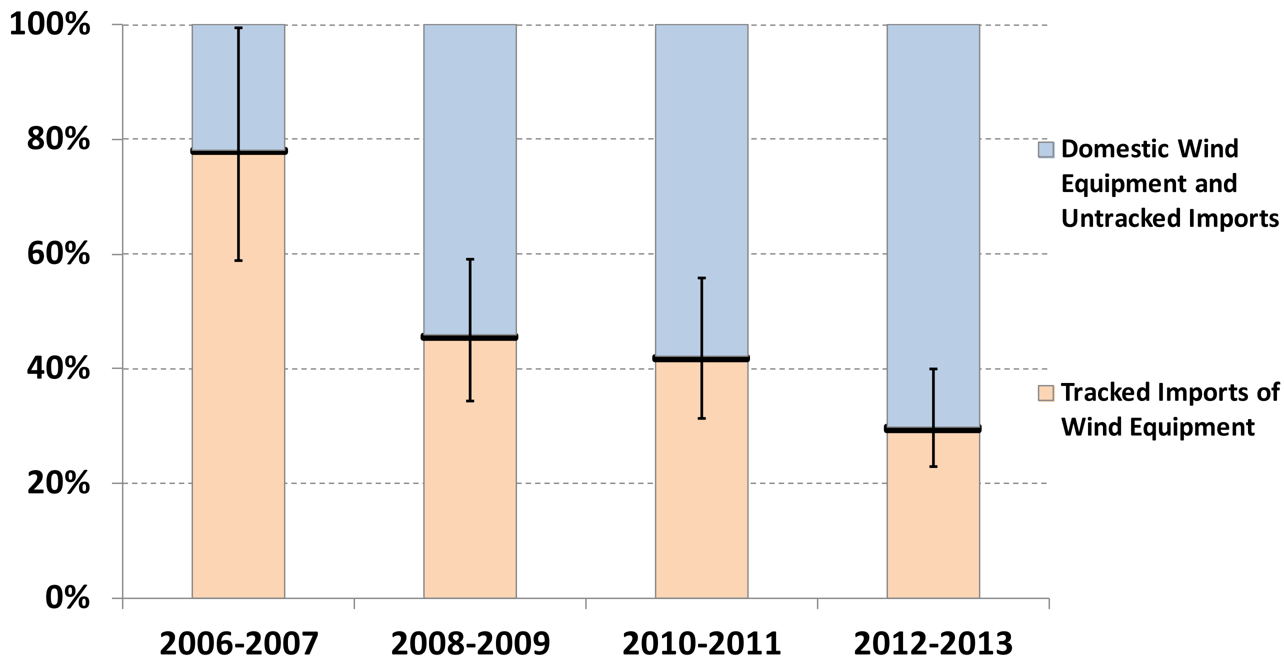
in the share of imports from China and, to a lesser extent, other Asian countries. The share of imports of *tubular towers* from Asia was over 80% in 2011 and 2012 (almost 50% from China), with much of the remainder from Canada and Mexico. In 2013, not only did the total import value plummet, but there were almost no imports from China and Vietnam, likely a result of the tariff measures that were imposed on wind tower manufacturers from each of these countries. With regards to *wind blades and hubs*, the total import value also declined from 2012 to 2013, while the share of imports from Brazil increased to 65%. The rest primarily came from Asia (especially China), with an overall decline in the share of imports from Europe. Finally, the import origins for *wind-related generators and generator parts* were distributed across a large number of countries in 2012 and 2013. The share of imports from Asia increased from 2012 to 2013 (with a decline in imports from North America), with the remainder mostly from Europe.



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

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

Although the U.S. wind industry imports a significant amount of turbines and components, the level of overall reliance on imports has declined over time, especially for certain wind equipment. To estimate the percentage share of *selected*, *tracked* imports over time, one must account for the fact that wind turbines and components imported at the end of one year may not be installed until the following year. As such, in Figure 17 the combined imports of wind-powered generating sets and *tracked* turbine components are determined by using a 4-month lag.[21] The resulting import figures are then compared to total wind turbine equipment-related costs.[22] Data are presented over two-year periods to further avoid "noise" in the resulting estimates. The error bars around the estimated import shares correspond to the combination of uncertainty around import quantities of selected turbine equipment (reported in Figure 14) as well as uncertainty in total wind turbine equipment costs (described in footnote 22).[23]



Source: Berkeley Lab

Figure 17. Tracked wind power equipment imports as a fraction of total turbine equipment cost

Ultimately, when presented as a fraction of total equipment-related turbine costs in this fashion, the combined import share of *tracked* wind equipment (i.e., blades, towers, generators,

[21] Specifically, monthly import data from September of the previous year to August of the current year are used to estimate the value of imports in wind turbine installations in the current year.

[22] Total wind turbine costs ($/kW) are assumed to equal 67.5% of the average project-level costs reported later in this report (with a range of 60% to 75% used to generate the error bars in the figure). Wind turbine equipment-related costs, meanwhile, are assumed to equal 85% of total wind turbine costs, with the remaining 15% consisting of transportation, project management, and other soft costs (a range of 80% to 90% is used to generate the error bars in the figure). To calculate total calendar-year wind turbine equipment-related costs, the wind turbine equipment-related cost figure in $/kW is multiplied by annual wind power capacity installations.

[23] If, in addition to these uncertainties, we also consider a range of lags for the combined imports of wind-powered generating sets and tracked turbine components in 2012–2013, from one month (December 2011 to November 2013) to six months (July 2011 to November 2013), the import fraction in 2012–2013 ranges from 22% to 46%.

gearboxes, and wind-powered generating sets) is estimated to have declined considerably, from nearly 80% in 2006–2007 to approximately 30% in 2012–2013. Conversely, the combined value of domestic wind equipment and untracked imports of wind equipment increased from about 20% in 2006-2007 to about 70% in 2012–2013.

Because trade data do not cleanly track all imports of wind equipment, it is not possible to use those data to establish a clear overall distinction between import and domestic content—thus the use of the term *tracked* wind equipment. The trade data also do not allow for a precise estimate of the domestic content of specific wind turbine components. Nonetheless, based on those data and a variety of assumptions, Table 4 presents rough estimates of the domestic content for some major wind turbine components used in U.S. wind power projects in the 2012–2013 period. On a component-by-component basis, domestic content varied widely in 2012–2013, with the United States most-heavily reliant on imports of generators relative to other selected major components.

Table 4. Approximate domestic content of major components in 2012–2013

Generators	Towers	Blades	Wind-Powered Generating Sets
< 10%	50-70%	60-80%	> 80% of nacelle assembly

These figures understate the wind industry's reliance on turbine and component imports. This is because significant wind-related imports occur under trade categories not captured here, including wind equipment (such as mainframe, converter, pitch and yaw systems, main shaft, bearings, bolts, controls) and manufacturing inputs (such as foreign steel and oil used in domestic manufacturing).[24] An alternative interview-based approach to estimating domestic content indicates *overall* domestic content of all wind turbine equipment used in the United States of about 40% in 2012. These interviews reveal that domestic content is relatively high for blades, towers, nacelle assembly and nacelle covers, supporting the analysis presented in Table 4. At the same time, the domestic content of most of the equipment internal to the nacelle—much of which is not specifically tracked in wind-specific trade data—is considerably lower. This approach to estimating domestic content, relying on over 50 interviews with persons familiar with different stages of the wind supply chain, thus complements the analysis of trade data presented earlier and presents a more complete picture of domestic content trends.[25]

Notwithstanding limitations mentioned in the previous paragraphs, the data presented here demonstrate that a growing amount of the turbine equipment used in U.S. wind power projects has been sourced domestically since 2006–2007. Domestic content has increased and is relatively high for blades, towers, and nacelle assembly. Though not otherwise discussed in this section, various balance-of-plant costs are also largely domestic.[26] Such trends do not hold for all

[24] On the other hand, this analysis also assumes that all components imported into the United States are used for the domestic market and not used to assemble wind-powered generating sets that are exported from the United States. If this were not the case, the resulting import fraction would be lower than that presented here. This concern is limited primarily to generator parts and gearboxes, however, and basic calculations show that it is unlikely to create much error in the estimates.

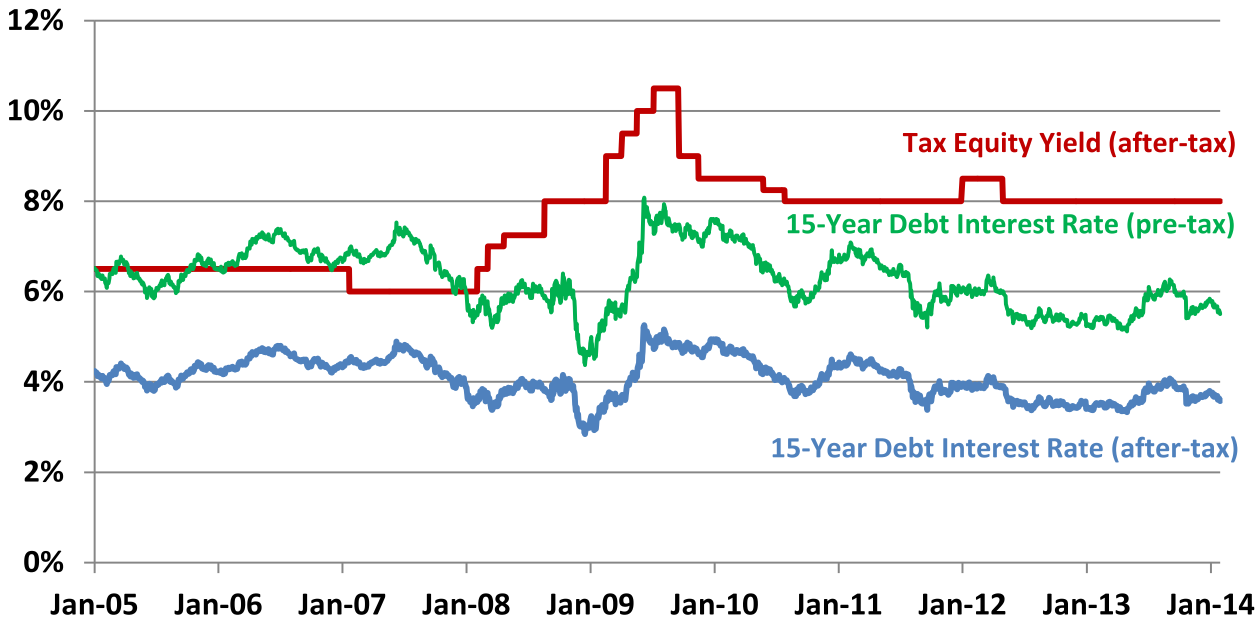
[25] The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab, and remain unpublished at this time.

[26] The import and domestic content figures reported in this section are focused solely on wind turbine equipment, and do not include any balance-of-plant costs. Those latter costs represent a significant proportion of wind project

turbine components, however, with equipment internal to the nacelle typically experiencing much lower levels of domestic content. How domestic content evolves in the future will depend on the size and stability of the U.S. wind market as well as the manufacturing strategies of equipment suppliers.

The project finance environment held steady in 2013

Other than the launch of several renewable energy “yieldcos,” the wind project finance market was largely uneventful in 2013. As shown in Figure 18, adapted from Bloomberg NEF (2014a), both tax equity and term debt yields held more or less steady in 2013, with tax equity yields (for high quality projects) continuing to hover around 8% (on an after-tax unlevered basis), while 15-year debt interest rates held below 6% all-in (on a pre-tax basis).[27]



Source: Adapted from Bloomberg NEF (2014a)

Figure 18. Cost of 15-year debt and tax equity for utility-scale wind projects over time

Project sponsors raised $3.1 billion of new tax equity in 2013—up slightly from 2012—to help finance 23 wind projects totaling 3 GW (AWEA 2014a, Chadbourne & Parke 2014). Many of these projects will achieve commercial operations in 2014.

On the debt side, AWEA (2014a) reports that 1,720 MW of new wind capacity raised $2.4 billion in debt in 2013—down significantly from the three prior years, reflecting in large part the

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capital investment, and are expected to be primarily domestic in nature. As a result, if the entire capital investment of wind project installations were considered, domestic content would be higher than presented in this section.

[27] The returns of equity investors in renewable energy projects are most often expressed on an after-tax basis, because of the significant value that Federal tax benefits provide to such projects (e.g., after-tax returns can be higher than pre-tax returns). In order to accurately compare the cost of debt (which is quoted on a pre-tax basis) to tax equity (described in after-tax terms), one must first convert the pre-tax debt interest rate to its after-tax equivalent (to reflect the tax-deductibility of interest payments) by multiplying it by 65%, or 100% minus an assumed marginal tax rate of 35%.

slow installation year in 2013, but also perhaps the inability of projects built in 2013 to access the Section 1603 grant.[28] For quality projects with strong sponsors, however, debt availability remained high, with banks continuing to focus more on shorter-duration loans (7–10 year mini-perms remained the norm in the bank market[29]), leaving longer-duration, fully amortizing instruments to the institutional lenders (Chadbourne & Parke 2014).

Looking ahead to the remainder of 2014, financing activity (in both the tax equity and debt markets) is likely to pick up based on the number of projects with signed PPAs that will need to achieve commercial operations in 2014 or 2015 in order to stay within the PTC safe harbor guidelines provided by the IRS.[30] Despite the fact that a dollar of tax equity does not stretch quite as far as it used to,[31] and that there will be increasing competition for tax equity from the solar market over the next few years, tax equity investors are confident that there will be enough capital to meet the market's needs (Chadbourne & Parke 2014). Debt is also expected to remain plentiful.

Finally, the trend towards large sponsors electing to refinance operating projects via so-called "yieldcos" is likely to continue, at least as long as interest rates remain low, leaving the market with an appetite for yield. Following on the success of NRG Yield's trend-setting initial public offering, Transalta Renewables, Pattern Energy, and most recently NextEra Energy have all since launched their own yieldcos in order to raise capital from public equity markets.[32]

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[28] From 2009–2012 (i.e., the years in which the Section 1603 grant was available), some project sponsors who lacked tax appetite financed their projects using the grant in combination with project-level term debt, carrying forward depreciation losses as necessary. With the grant no longer available, most projects now elect the PTC (instead of the ITC), and rely upon third-party tax equity investors to monetize the losses and credits. Because most tax equity investors will not allow leverage on projects in which they invest (Chadbourne & Parke 2014), the loss of the Section 1603 grant and the correspondingly greater reliance on the PTC could be a contributor to the decline in debt raised by new wind projects in 2013.

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

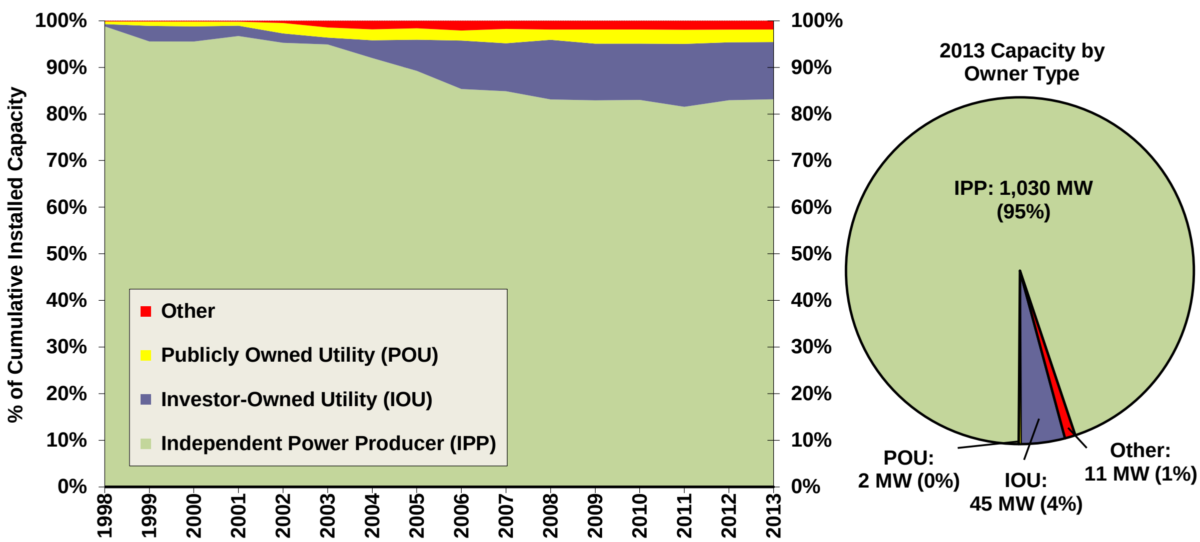
[30] Wind projects that had started construction by the end of 2013 and that achieve commercial operations prior to the end of 2015 will be eligible to receive the PTC under safe harbor guidance provided by the IRS in late 2013.

[31] As described later, a significant decline in the average "specific power" (W/m^2 of rotor swept area) of wind turbines installed in recent years has driven capacity factors higher across all wind regimes, resulting in a greater number of PTCs generated per project. All else equal, a larger tax equity investment is required to capture these PTCs. For example, AWEA (2014a) reports that the average tax equity investment has risen from $757,000/MW in 2010 to $1,032,000/MW in 2013.

[32] A number of solar project sponsors, including SunEdison and Abengoa, are also launching yieldcos.

Independent power producers own 95% of the new wind capacity installed in 2013

Independent power producers (IPPs) own 1,030 MW, or 95%, of the 1,087 MW of new wind capacity installed in the United States in 2013 (Figure 19). New utility ownership continued to languish for the second year in a row, with investor-owned utilities (IOUs) owning 45 MW (4%) and publicly owned utilities (POUs) owning just 2 MW (0.2%). The remaining 1% (11 MW) of new 2013 wind capacity is owned by "other" entities that are neither IPPs nor utilities (e.g., towns, schools, commercial customers, farmers).[33] Of the *cumulative* installed wind power capacity at the end of 2013, IPPs owned 83% and utilities owned 15% (12% IOU and 3% POU), with the remaining 2% falling into the "other" category.



Source: Berkeley Lab estimates based on AWEA project database

Figure 19. Cumulative and 2013 wind power capacity categorized by owner type

Long-term contracted sales to utilities remained the most common off-take arrangement, but merchant projects may be regaining some favor, at least in Texas

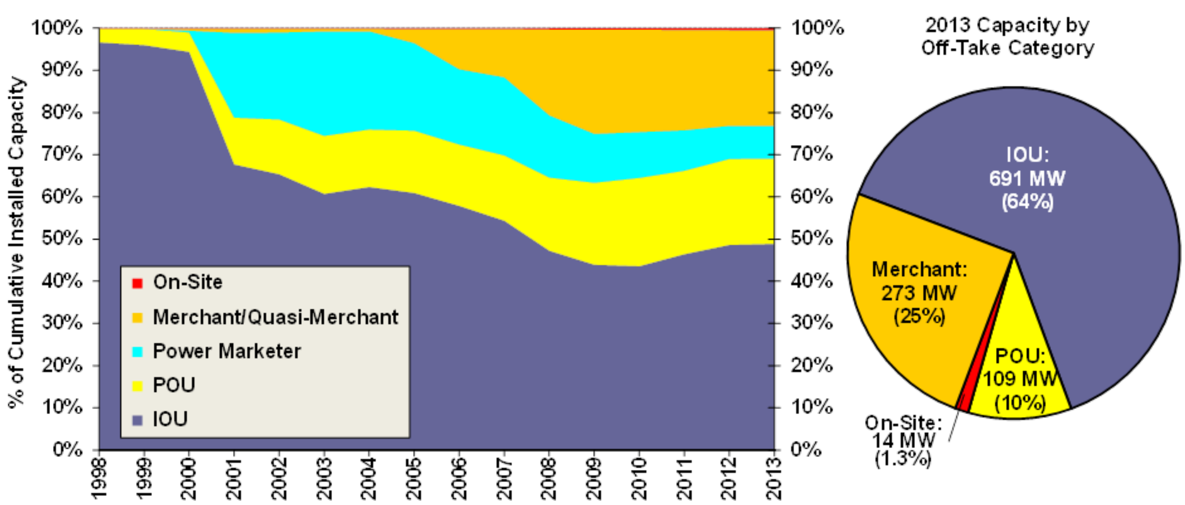
Electric utilities continued to be the dominant off-takers of wind power in 2013 (Figure 20), either owning (4%) or buying (70%) power from 74% of the new capacity installed last year (with the 74% split between 64% IOU and 10% POU). On a cumulative basis, utilities own (15%) or buy (54%) power from 69% of all wind power capacity installed in the United States (with the 69% split between 49% IOU and 20% POU)—up from a low of 63% in 2009.

[33] Most of these "other" projects, along with some IPP- and POU-owned projects, might also be considered "community wind" projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project. According to AWEA (2014a), 2% of 2013 capacity additions, or roughly 22 MW, qualified as community wind projects.

The role of power marketers—defined here as corporate intermediaries that purchase power under contract and then resell that power to others, sometimes taking some merchant risk[34]—in the wind power market has waned in recent years. In fact, none of the new wind power capacity installed in the United States in 2013 is selling to power marketers, while just 8% of cumulative wind power capacity does so (down from more than 20% in the early 2000s).

Merchant/quasi-merchant projects rebounded slightly in 2013, accounting for 25% of all new capacity (compared to ~20% in each of the previous three years) and 23% of cumulative capacity. Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracted and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 10- to 12-year period[35]) rather than being locked in through a long-term PPA. A number of factors may drive a further increase in quasi-merchant offtake arrangements in the next two years, particularly in certain regions (like Texas): wind energy prices have declined to levels competitive with wholesale market price expectations in some regions, wind PPAs remain in short supply, most projects currently under construction will come online this year or next in order to stay within the IRS safe harbor with respect to the PTC, and the recent completion of the CREZ transmission lines in Texas provides market access to a significant amount of new wind capacity within a hedge-friendly market.

Finally, 14 MW (1.3%) of the wind power additions in 2013 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.



Source: Berkeley Lab estimates based on AWEA project database

Figure 20. Cumulative and 2013 wind power capacity categorized by power off-take arrangement

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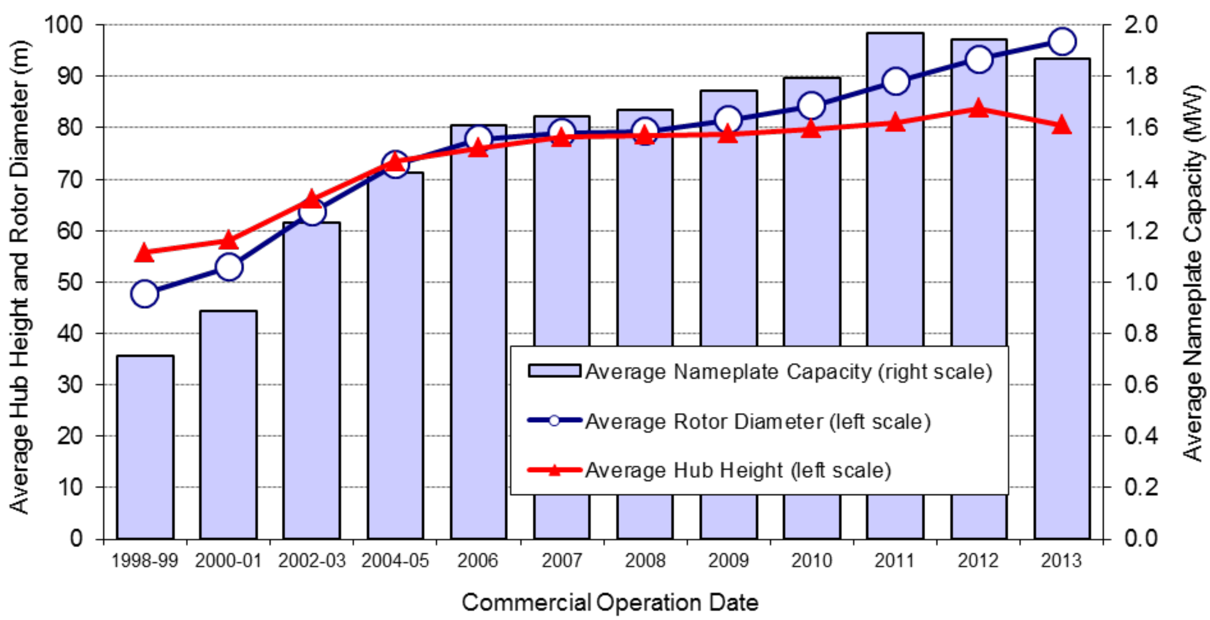
[34] Power marketers are defined here to include not only traditional marketers, but also the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates. Direct sales to end users are also included, because in these few limited cases the end user is effectively acting as a power marketer.

[35] Hedges are often structured as a "fixed-for-floating" power price swap—a purely financial arrangement whereby the wind power project swaps the "floating" revenue stream that it earns from spot power sales for a "fixed" revenue stream based on an agreed-upon strike price. For some projects, the hedge is structured in the natural gas market rather than the power market.

4. Technology Trends

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

The average nameplate capacity of the small sample of newly installed wind turbines in the United States in 2013 was 1.87 MW, up 162% since 1998–1999 (Figure 21).[36] In addition to nameplate capacity ratings, average hub heights and rotor diameters have also scaled with time. The average hub height of wind turbines installed in the United States in 2013 was 80 meters, up 45% since 1998–1999. Average rotor diameters have increased at an even more rapid pace, especially recently; the average rotor diameter of wind turbines installed in the United States in 2013 was 97 meters, up 103% since 1998–1999, which translates into a 310% growth in rotor swept area. These trends in hub height and rotor scaling are two of several factors impacting the project-level capacity factors highlighted later in this report.



Source: AWEA project database

Figure 21. Average turbine nameplate capacity, rotor diameter, and hub height installed during period (only turbines larger than 100 kW)

Apart from (but related to) turbine size, turbine configuration has also changed somewhat over time. In particular, there were 194 direct drive (as opposed to geared) turbines installed in the United States in 2012 (totaling 429.7 MW, or 3.3% of new capacity installed that year), up from just 17 in 2011 (totaling 35.3 MW) and no more than three (totaling no more than 4.5 MW) in

[36] Figure 21 (as well as a number of the other figures and tables included in this report) combines data into both 1- and 2-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004; although not a PTC lapse year, 1998 is grouped with 1999 due to the small sample of 1998 projects. Though 2013 was a slow year for wind additions, it is shown separately here despite the small sample size.

any of the previous three years from 2008–2010.[37] In 2013, however, given the dominance of GE's geared turbines, only three direct-drive turbines were installed (all from Emergya Wind Technologies, and totaling 2.7 MW).

Growth in rotor diameter has outpaced growth in nameplate capacity and hub height in recent years

As indicated in Figure 21, and as detailed in Figures 22–24, rotor diameter scaling has been especially significant in recent years, and more so than increases in nameplate capacity and hub heights, both of which have seen some reversal or at least stabilization of the long-term trend in the most recent years.

Starting with turbine nameplate capacity, Figure 22 presents not only the trend in *average* nameplate capacity (as also shown earlier, in Figure 21) but also how the prevalence of different turbine capacity ratings has changed over time. The average nameplate capacity of newly installed wind turbines has declined slightly for two consecutive years, and the longer-term pace of growth has slowed since 2006. While it took just six years (2000–2005) for MW-class turbines to almost totally displace sub-MW-class turbines, it took another seven years (2006–2012) for multi-MW-class turbines (i.e., 2 MW and above) to gain nearly equal market share with MW-class turbines. Though 2013 was a slow year for wind turbine additions, it marked a departure from the recent past in that sub-2 MW turbines gained market share.

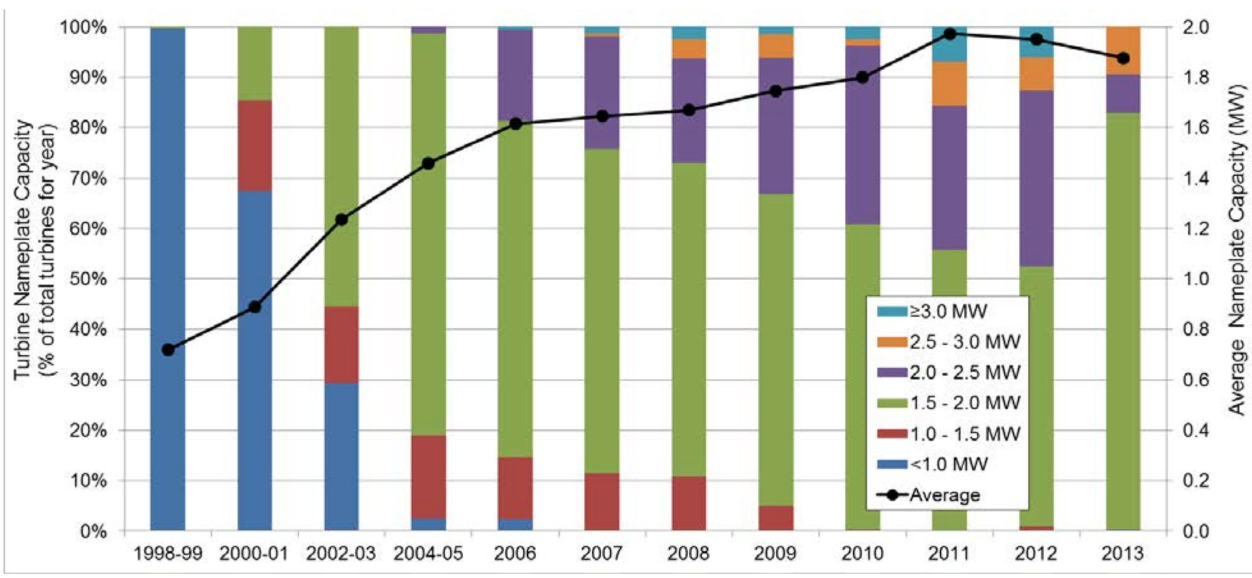


Figure 22. Trends in turbine nameplate capacity

[37] Direct drive technology has been relatively slow to enter the U.S. market in comparison to global trends—e.g., Navigant (2014) reports that 28% of *global* wind turbine supply in 2013 featured direct drive turbines—in part because Enercon, a German leader in direct drive technology, has not entered the U.S. market, while Chinese sales of direct-drive turbines into the United States have been limited.

As with nameplate capacity, the average hub height of wind turbines installed in the United States in 2013 was down from that seen in 2012 (Figure 23). This slight reversal is perhaps more-indicative of the small number of projects installed in 2013 than reflective of an underlying trend, though it may also be due to the greater concentration of 2013 projects in the windy Interior of the country. Growth in average hub height has been limited since 2004, with 80 meter towers dominating the overall market, but 2011 and 2012 saw the strong emergence of towers that are 90 meters and higher. While that trend did not persist into 2013, perhaps because much of the development in 2013 occurred in the windy Interior region, only time will tell whether taller towers take significant market share from standard 80 meter towers going forward.

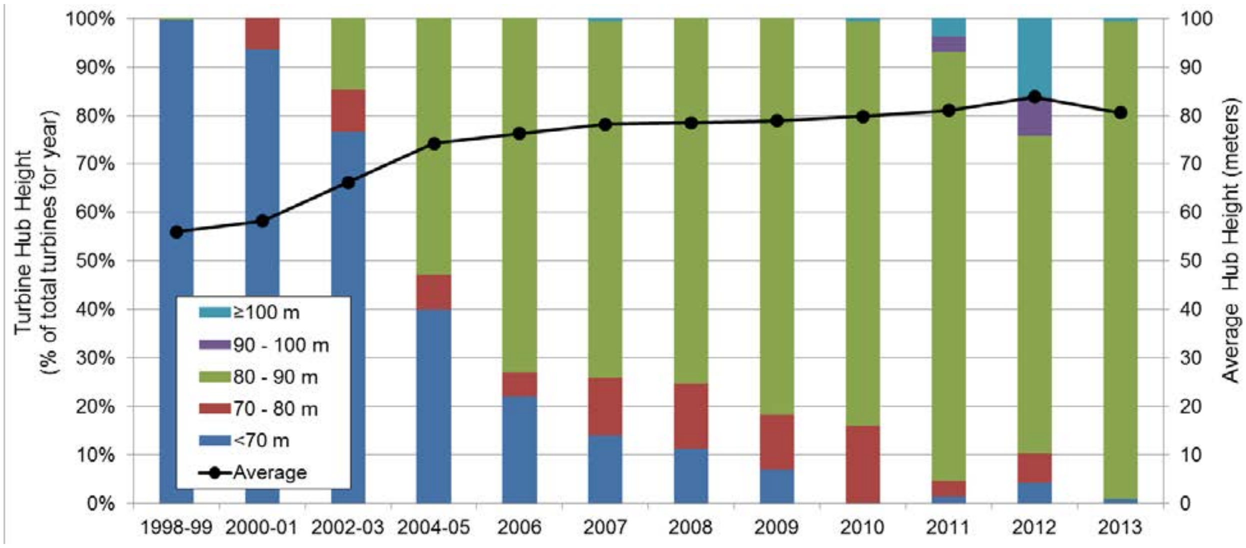


Figure 23. Trends in turbine hub height

The movement towards larger-rotor machines has dominated the U.S. industry in recent years, with OEMs progressively introducing larger-rotor options for their standard turbine offerings and introducing new turbines that feature larger rotors. As shown in Figure 24, this recent increase has been especially apparent since 2009. In 2012, almost 50% of the turbines installed in the United States featured rotors of 100 meters in diameter or larger. In 2013, this figure jumped to 75% (though again, based on a relatively small sample).

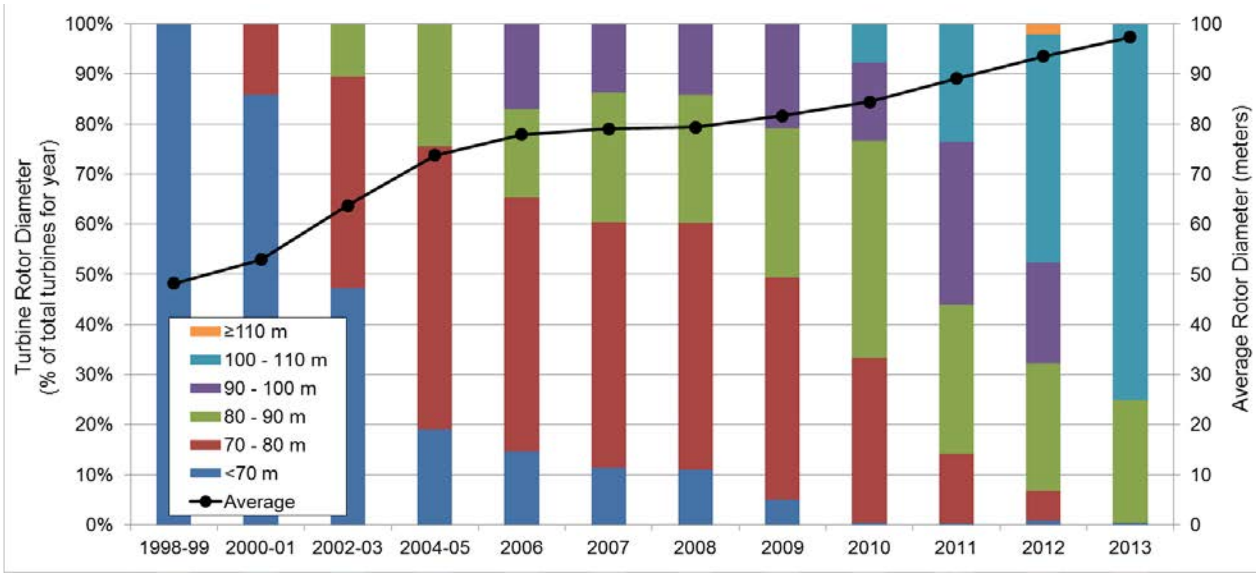


Figure 24. Trends in turbine rotor diameter

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

Though trends in the average hub height, rotor diameter, and nameplate capacity of turbines have been notable, the growth in the swept area of the rotor has been particularly rapid. With growth in average swept area (in m^2) outpacing growth in average nameplate capacity (in W), there has been a decline in the average "specific power" (in W/m^2) among the U.S. turbine fleet over time, from around 400 W/m^2 among projects installed in 1998–1999 to 255 W/m^2 among projects installed in 2013 (Figure 25). The decline in specific power was especially rapid from 2001 to 2004 and, more recently, from 2011 to 2013. Though a slow year for wind installations overall, 2013 saw a significant jump in market share for turbines with a specific power of less than 220.

All else equal, a lower average specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity, meaning 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. In other words, they were intended to maximize energy capture in areas where the wind resource is modest, and where large rotor machines would not be placed under undue stress. As suggested in Figure 25 and as detailed in the next section, however, such turbines are clearly now in widespread use in the United States—even in sites not considered to have low wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in a Chapter 5.

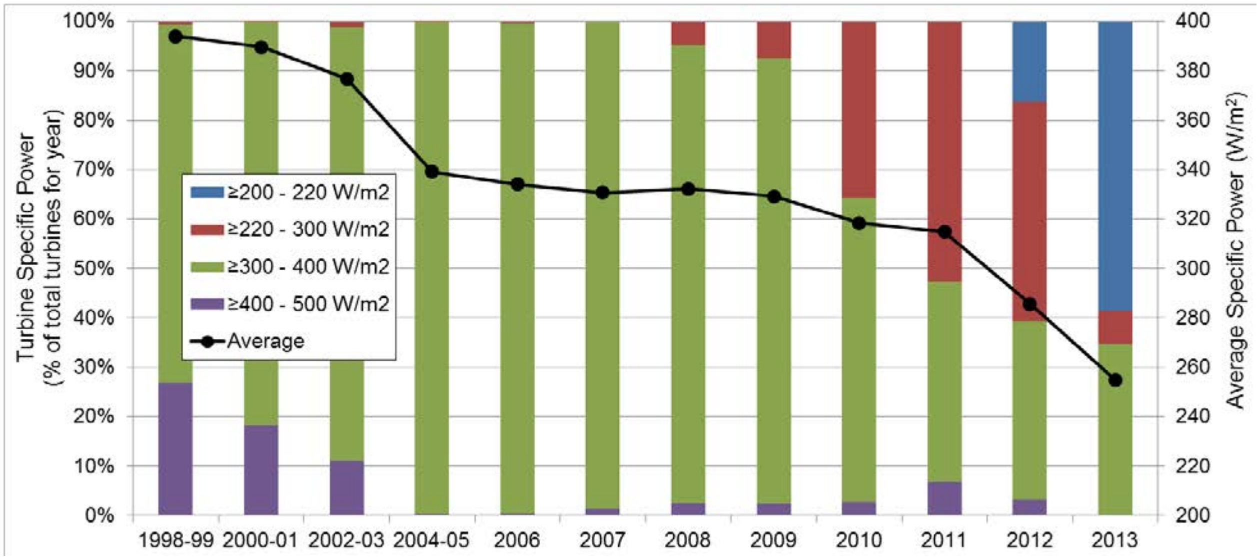


Figure 25. Trends in turbine specific power

Another indication of the increasing prevalence of machines designed for lower wind speeds is revealed in Figure 26, which presents trends in wind turbine installations by IEC Class. The IEC classification system considers multiple site characteristics, including wind speed, gusts, and turbulence. Class 3 turbines are generally designed for lower wind speed sites (7.5 m/s and below), Class 2 turbines for medium wind speed sites (up to 8.5 m/s), and Class 1 turbines for higher wind speed sites (up to 10 m/s). Some turbines are designed at the margins of two classifications, and are labeled as such (e.g., Class 2/3).

In 1998–1999, nearly all wind turbines installed in the United States were Class 1 machines. From 2002 through 2008, Class 2 machines penetrated the market substantially, with a roughly equal split between Class 1 and Class 2 turbines. Since 2008, there has been a substantial decline in the use of Class 1 turbines, and a concomitant increasing market share of Class 3 and Class 2/3 turbines. In 2012, more than 50% of installations used Class 3 and Class 2/3 turbines; in 2013, that percentage increased to 90% (though, again, of a relatively small sample of projects).

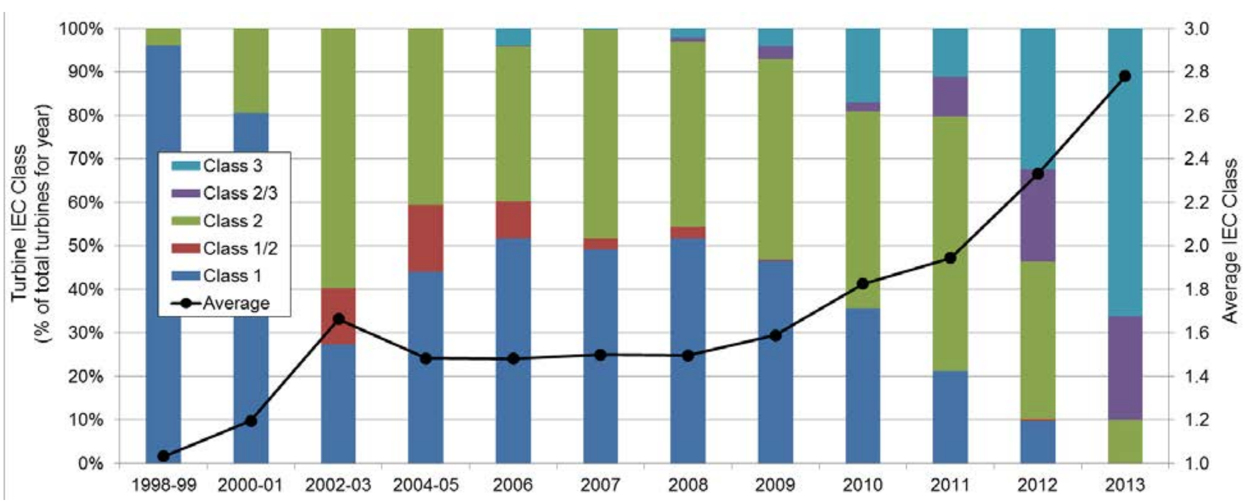
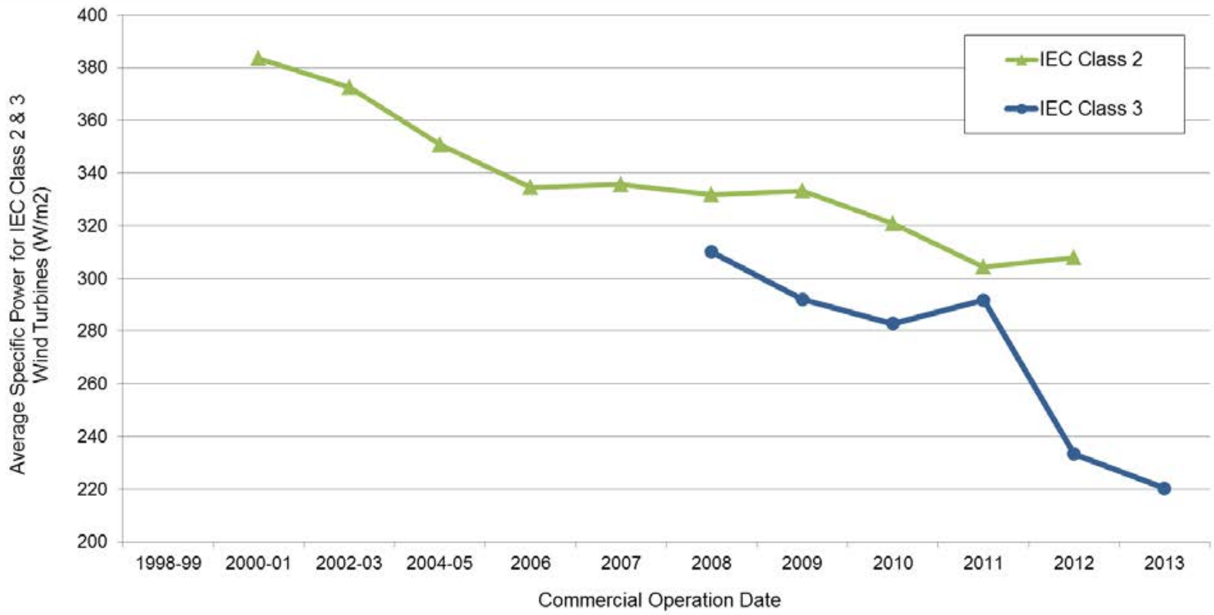


Figure 26. Trends in turbine IEC class

Moreover, Class 2 and 3 turbine technology has not remained stagnant, namely through expanded rotors that drive even-lower specific power ratings. Whereas Figure 25 shows the trend in average specific power across all turbines installed in each year (regardless of IEC Class), Figure 27 demonstrates that the average specific power rating of Class 2 and 3 (i.e., medium and lower wind speed) turbines installed in the United States has also dropped with time. As such, not only has the average specific power declined across all wind turbine installations (Figure 25), but the marked shift to Class 2 and then to Class 3 turbines shown in Figure 27 is even more significant in that it has been a shift to Class 2 and 3 turbines *with progressively lower specific power ratings* over time.



Note: Data only shown for years in which sample exceeds 100 turbines

Figure 27. Trends in specific power for IEC class 2 and 3 turbines

Turbines originally designed for lower wind speeds are now regularly employed in both lower and higher wind speed sites, whereas taller towers predominate in lower wind speed sites

One might expect that the increasing market share of turbines designed for lower wind speeds might be due to a movement by wind developers to deploy turbines in lower wind speed sites. Though there is some evidence of this movement (see Chapter 5), it is clear in Figures 28 and 29 that turbines originally designed for lower wind speeds are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites.

Figure 28 presents the percentage of turbines installed in four distinct regions of the United States[38] (see Figure 30 for regional definitions) that have: (a) a higher hub height, (b) a lower specific power, and (c) a higher IEC Class. It focuses solely on turbines installed in the 2011–

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

2013 time period. Figure 29 presents similar information, but segments the data by the wind resource quality of the site[39] rather than the region in which the turbines are located.

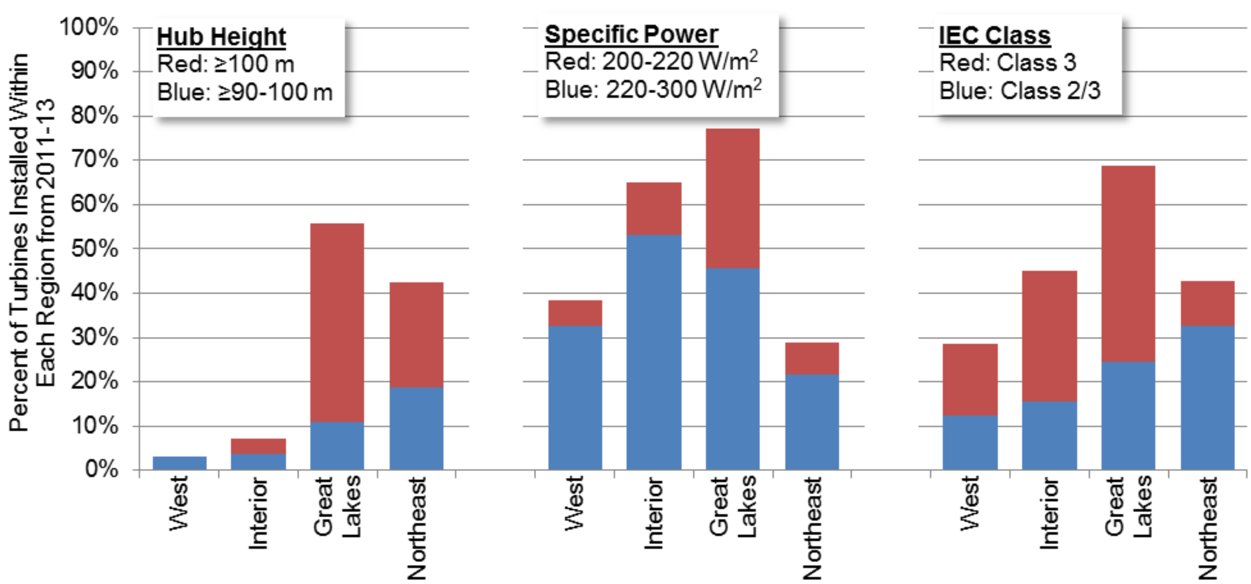


Figure 28. Deployment of turbines originally designed for lower wind speed sites, by region

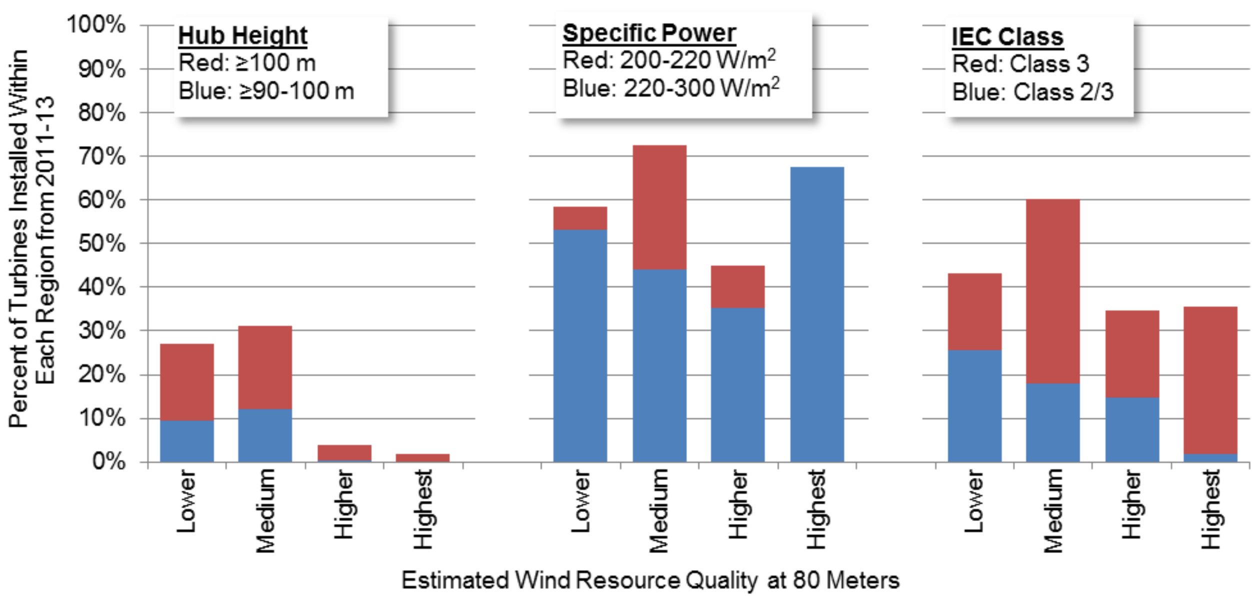


Figure 29. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality

Low specific power machines installed over this three-year period have been regularly deployed in all regions of the country, though their market share in the Great Lakes (77%) and Interior

[39] Estimates of wind resource quality are based on site estimates of *gross* capacity factor at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower; further details are found in the Appendix.

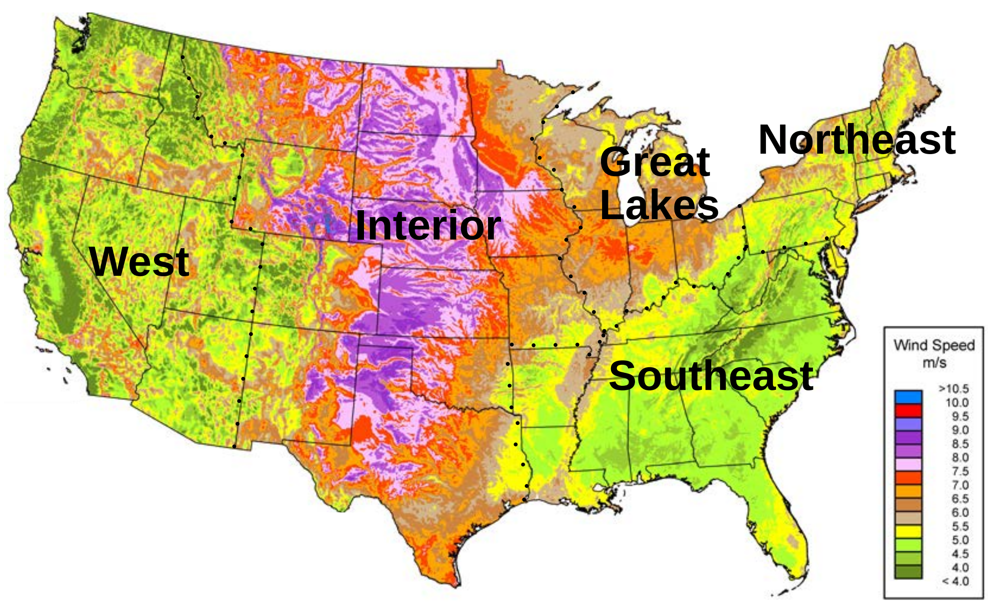
(65%) exceeds that in the West (38%) and Northeast (29%). Similarly, these turbines have been commonly used in all resource regimes, as shown in Figure 29, including at sites with very high wind speeds. At the same time, turbines with the lowest specific power ratings (200-220 W/m^2) have largely been installed in somewhat lower wind speed sites to this point, and are relatively less prevalent in the windy Interior than in the Great Lakes region.

Turning to IEC Class, we see a somewhat similar story. Over this three-year period, Class 3 and Class 2/3 machines have had the largest market share in the Great Lakes (69%), but have also gained significant market in the Interior (45%), Northeast (43%), and West (29%). Moreover, while these turbines have seen somewhat higher shares in lower-quality resource sites, these turbines have also been regularly deployed in higher-quality resources sites.

Finally, and not surprisingly, taller towers have seen higher market share in the Great Lakes (56%) and Northeast (43%) than in the Interior (7%) and West (3%). This is largely due to the fact that such towers are most commonly used in lower wind speed sites, and presumably those with higher wind shear, to access the better wind speeds that are typically higher up.

In combination, these findings demonstrate that turbines originally designed for lower wind speed sites are, in fact, being deployed in such sites: see the prevalence of tall towers, low specific power, and Class 3 or 2/3 turbines in the Great Lakes region. Moreover, taller towers have—to this point—been largely restricted to such lower wind speed sites.

At the same time, low specific power and Class 3 and 2/3 turbines have also established a strong foothold across the nation and over a wide range of wind speeds. In many parts of the interior region, in particular, relatively low wind turbulence has allowed turbines designed for low wind speeds to be deployed across a wide range of site-specific resource conditions. Time will tell to what extent these deployment patterns are pushing the envelope on design life considerations.



Source: AWS Truepower, National Renewable Energy Laboratory

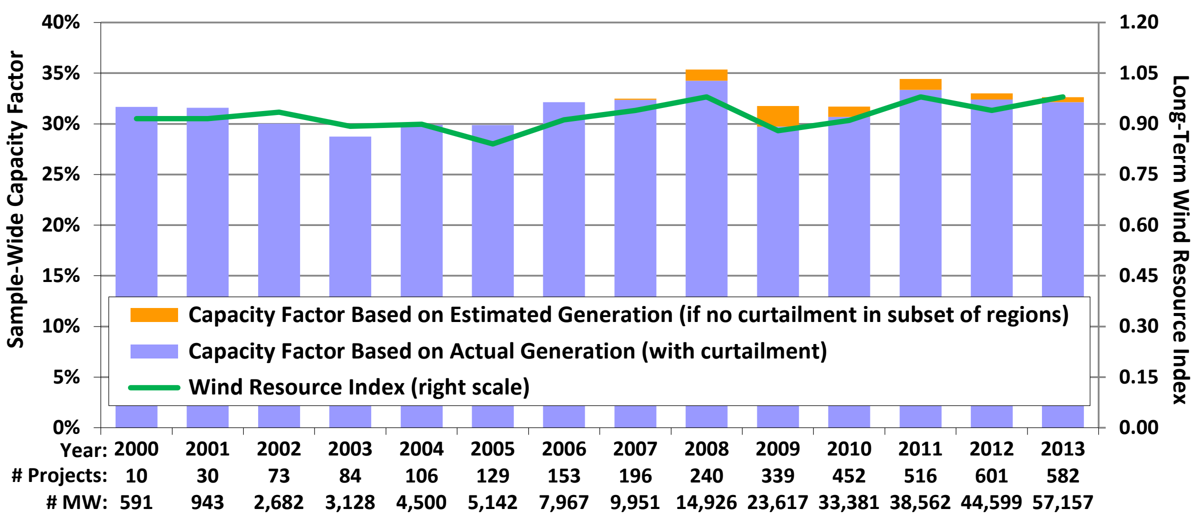
Figure 30. Regional boundaries overlaid on a map of average annual wind speed at 80 meters

5. Performance Trends

This chapter presents data from a Berkeley Lab compilation of project-level capacity factors. The full data sample consists of 582 wind power projects built between 1998 and 2012 and totaling 57,157 MW (95% of nationwide installed wind power capacity at the end of 2012).[40] The following discussion of performance trends is divided into three subsections: the first analyzes trends in sample-wide capacity factors over time, the second looks at variations in capacity factors by project vintage, and the third focuses on regional variations.

Trends in sample-wide capacity factors have been impacted by curtailment and inter-year wind resource variability

The blue bars in Figure 31 show the average sample-wide capacity factor in each calendar year among a progressively larger cumulative sample in each year.[41] Viewed this way—on a cumulative, sample-wide basis—one might expect to see a gradual improvement in capacity factor over time, as newer and larger turbines are added to the fleet each year. Although capacity factors have generally been higher on average in more recent years (e.g., 32.1% from 2006–2013 versus 30.3% from 2000–2005), the trend is not as significant or consistent as expected. Two key factors that influence these trends are discussed below: wind power curtailment and inter-year variability in the strength of the wind resource. A third factor, the average quality of the wind resource in which projects are located, is discussed in the next section.



Source: Berkeley Lab

Figure 31. Average cumulative sample-wide capacity factor by calendar year

[40] Although some performance data for wind power projects installed in 2013 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on projects with commercial operation dates from 1998 through 2012.

[41] There are fewer individual projects—although more capacity—in the 2013 cumulative sample than there are in 2012. This is due to the sampling method used by EIA, which focuses on a subset of larger projects throughout the year, before eventually capturing the entire sample some months after the year has ended. As a result, it might be late 2014 before EIA reports 2013 performance data for all of the wind power projects that it tracks, and in the meantime this report is left with a smaller sample consisting mostly of the larger projects in each state.

Table 5. Estimated wind curtailment in various areas, in GWh (and as a percentage of potential wind generation)

	2007	2008	2009	2010	2011	2012	2013
Electric Reliability Council of Texas (ERCOT)	109 (1.2%)	1,417 (8.4%)	3,872 (17.1%)	2,067 (7.7%)	2,622 (8.5%)	1,175 (3.8%)	363 (1.2%)
Southwestern Public Service Company (SPS)	N/A	0 (0.0%)	0 (0.0%)	0.9 (0.0%)	0.5 (0.0%)	N/A**	N/A**
Public Service Company of Colorado (PSCo)	N/A	2 (0.1%)	19 (0.6%)	82 (2.2%)	64 (1.4%)	115(e) (2.0%)	112(e) (1.7%)
Northern States Power Company (NSP)	N/A	25 (0.9%)	42 (1.7%)	44 (1.7%)	59 (1.6%)	125 (3.0%)	284 (5.9%)
Midwest Independent System Operator (MISO), less NSP	N/A	N/A	250 (2.0%)	780 (4.2%)	792 (3.4%)	724 (2.5%)	1,470 (4.6%)
Bonneville Power Administration (BPA)	N/A	N/A	N/A	5* (0.1%)	129* (1.4%)	71* (0.7%)	6* (0.1%)
New York Independent System Operator (NYISO)	N/A	N/A	N/A	N/A	N/A	9 (0.3%)	50 (1.4%)
PJM	N/A	N/A	N/A	N/A	N/A	125# (2.0%)#	284 (1.9%)
Total Across These Eight Areas:	**109 (1.2%)**	**1,444 (5.7%)**	**4,183 (9.7%)**	**2,978 (4.9%)**	**3,665 (5.0%)**	**2,345 (2.6%)**	**2,569 (2.5%)**

*A portion of BPA's curtailment is estimated assuming that each curtailment event lasts for half of the maximum possible hour for each event.

#2012 curtailment numbers for PJM are for June through December only (data for January through May 2012 are not available).

**Xcel Energy declined to provide 2012 and 2013 curtailment data for its SPS and PSCo service territories; PSCo 2012/2013 data are estimated from Bird et al. (2014).

Source: ERCOT, Xcel Energy, MISO, BPA, PJM, NREL

Wind Power Curtailment. Curtailment of wind project output due to transmission inadequacy, minimum generation limits, and/or other forms of grid inflexibility (and, as a consequence, low or negative wholesale electricity prices) has become more common across the United States as wind development has become more significant and widespread. That said, in areas where curtailment has been particularly problematic in the past—principally in Texas—steps taken to address the issue are now bearing fruit. For example, Table 5 shows that only 1.2% of potential wind energy generation within the Electric Reliability Council of Texas (ERCOT) was curtailed in 2013, down sharply from 17% in 2009, roughly 8% in both 2010 and 2011, and nearly 4% in 2012. Primary causes for the decrease were the Competitive Renewable Energy Zone transmission line upgrades, most of which were completed by the end of 2013, and a move to more-efficient wholesale electric market designs.

Elsewhere, the only region shown in Table 5 in which wind curtailment exceeded 2% in 2013 was MISO (and NSP, which is a subset of MISO), which experienced a rather significant increase due not only to a strong buildout of wind capacity in the region in recent years, but also to a change in how curtailment is defined and tracked. Specifically, in 2013, MISO finished transitioning most wind generators into its Dispatchable Intermittent Resource (DIR) program, which (among other things) enables it to track both "forced" (i.e., required by the grid operator) and "economic" (i.e., voluntary as a result of market prices) curtailment. Prior to implementing the DIR program, MISO only tracked forced curtailment, and did so using a relatively simple method that likely understated the true magnitude of the impact.

Several other regions shown in Table 5 (ERCOT, NYISO, PJM) also track both forced and economic curtailment, while the rest (BPA, NSP, PSCo, SPS) likely only capture forced curtailment. In these latter regions, the data presented in Table 5 may therefore understate the true level of curtailment experienced by wind power projects. In addition, several other key regions in which curtailment has reportedly become an issue—e.g., SPP and ISO-NE—are not yet included in Table 5, because they have only recently developed the tools to enable them to track curtailment in the future.

In aggregate, assuming a 33% average capacity factor, the total amount of curtailed wind generation tracked in Table 5 for 2013 equates to the annual output of roughly 890 MW of wind power capacity. Looked at another way, wind power curtailment has reduced sample-wide average capacity factors in recent years. While the blue bars in Figure 31 reflect actual capacity factors—i.e., including the negative impact of curtailment events—the orange bars add back in the estimated amount of wind generation that has been forced to curtail in recent years within the eight territories shown in Table 5, to estimate what the sample-wide capacity factors would have been absent this curtailment. As shown, sample-wide capacity factors would have been on the order of 0.5–2 percentage points higher nationwide from 2008 through 2013 absent curtailment in just this *subset* of regions. Estimated capacity factors would have been even higher if comprehensive forced and economic curtailment data were available for *all* regions.[42]

Inter-Year Wind Resource Variability. The strength of the wind resource varies from year to year, in part in response to significant persistent weather patterns such as El Niño/La Niña. The green line in Figure 31 shows that 2013 was a generally good wind year, at least in terms of the national average wind energy resource as measured by one large project sponsor.[43] It is also evident from the figure that movements in sample-wide capacity factor from year to year are influenced by the natural inter-year variability in the strength of the national wind resource.

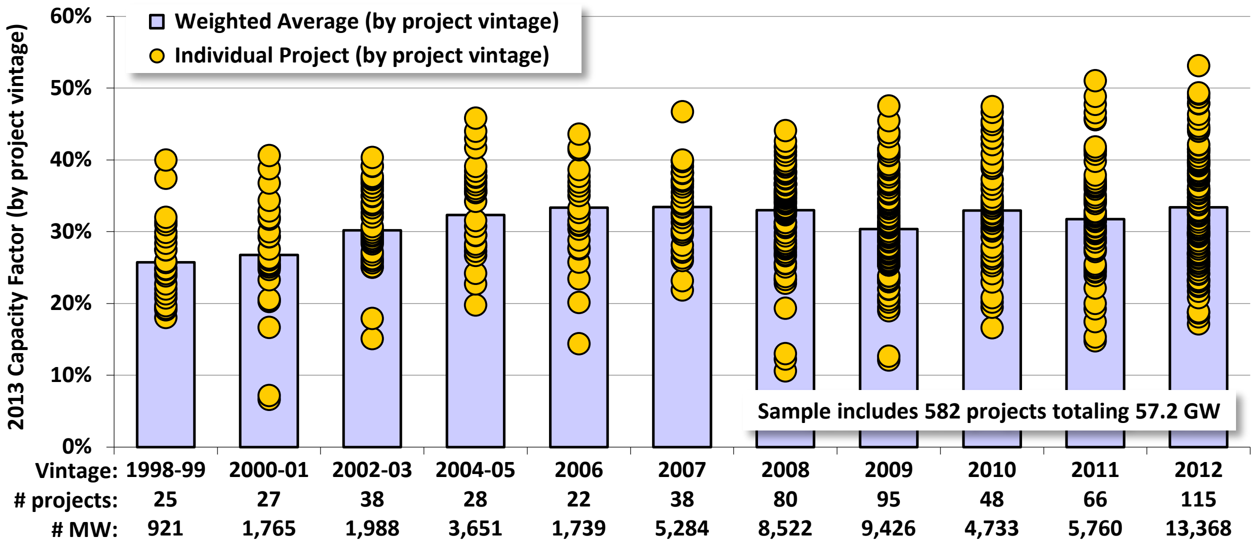
Competing influences of lower specific power and lower quality wind project sites have left average capacity factors among newly built projects stagnant in recent years, averaging 31 to 34 percent nationwide

One way to control for the time-varying influences described in the previous section (e.g., annual wind resource variations or changes in the amount of wind curtailment) is to focus exclusively on capacity factors in a single year, such as 2013.[44] As such, whereas Figure 31 presents capacity factors in each calendar year, Figure 32 instead shows only capacity factors in 2013, broken out

[42] The eight regions included in Table 5 collectively accounted for roughly 34 GW of installed wind power capacity as of the end of 2013, or roughly 56% of total wind power capacity installed in the United States at that time.
[43] The green line in Figure 31 estimates changes in the strength of the average nationwide wind resource from year to year and is derived from data presented by NextEra Energy Resources in its quarterly earnings reports.
[44] Although focusing just on 2013 does control (at least loosely) for some of these known time-varying impacts, it also means that the *absolute* capacity factors shown in Figure 32 may not be representative over longer terms if 2013 was not a representative year in terms of the strength of the wind resource or wind power curtailment.

by project vintage. As with the previous analysis, wind power projects built in 2013 are not included here, as full-year performance data are not yet available.

Figure 32 shows an increase in weighted average 2013 capacity factors when moving from projects installed in the 1998–1999 period to those installed in the 2004–2005 period. There is also a clear increase among more recent vintages in the *maximum* 2013 capacity factor attained by any individual project. Somewhat surprisingly, however, given the significant scaling in turbine design in recent years (reported earlier in Chapter 4), weighted average 2013 capacity factors *do not* show an increasing trend among post-2005 project vintages.

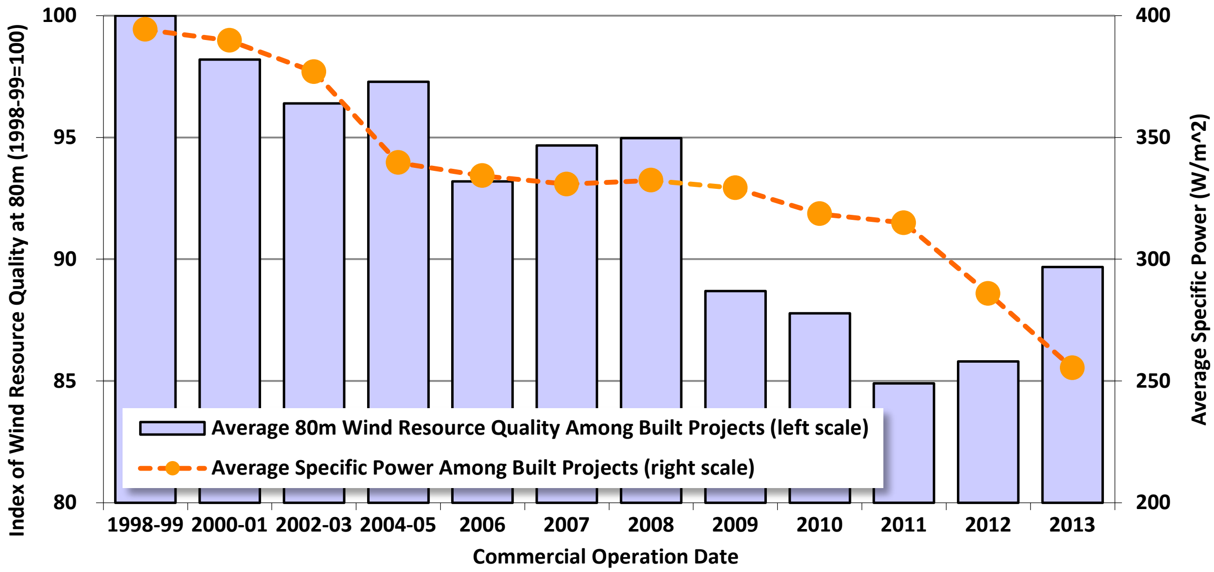


Source: Berkeley Lab

Figure 32. 2013 project capacity factors by commercial operation date

The lack of an obvious post-2005 trend in average capacity factors can be at least partially explained by two competing influences among more recent project vintages: a continued decline in average specific power (which should boost capacity factors, all else equal) versus a build-out of lower-quality wind resource sites (which should hurt capacity factors, all else equal).

The first of these competing influences—the decline in average "specific power" (i.e., W/m^2 of rotor swept area) among more recent turbine vintages—has already been well-documented in Chapter 4 (see, in particular, Figures 25 and 27), but is shown yet again in Figure 33. All else equal, a lower average specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity, meaning that the generator is likely to run closer to or at its rated capacity more often.



Source: Berkeley Lab

Figure 33. Index of wind resource quality at 80 meters vs. specific power

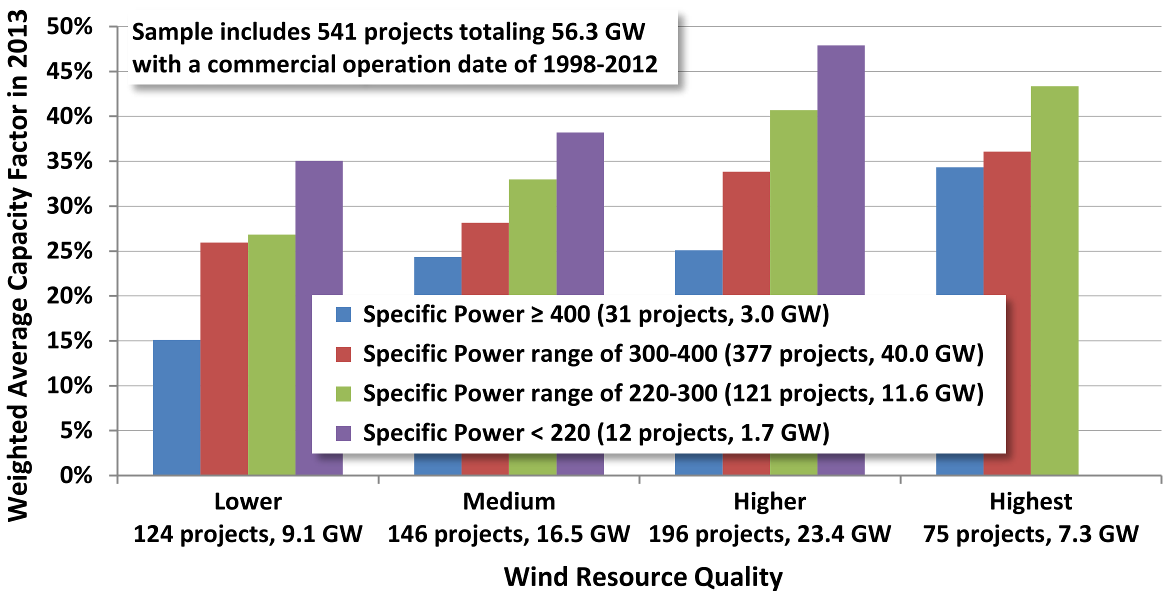
Counterbalancing the decline in specific power, however, has been a tendency to build new wind projects in lower-quality wind resource areas; this is especially the case among projects installed from 2009 through 2012. Figure 33 shows that the average estimated quality of the wind resource at 80 meters among projects built in 2012 (i.e., the most recent project vintage in our capacity factor sample included in figure 32) is roughly 15% lower than it is among projects built back in 1998–1999 and that the decline has been particularly sharp since 2008.[45] Although there was a bit of a rebound in 2013 (which will impact our sample in future years), this trend of building wind power projects in progressively lower-quality wind resource areas is a key reason why overall average capacity factors have not increased for projects installed in recent years. The trend may also come as a surprise, given that the United States still has an abundance of undeveloped high-quality wind resource areas. Several factors could be driving this trend:

- **Technology Change.** The increased availability of low-wind-speed turbines that feature higher hub heights and a lower specific power may have enabled the economic build-out of lower-wind-speed sites.
- **Transmission and Other Siting Constraints.** Developers may have reacted to increasing transmission constraints (or other siting constraints, or even just regionally differentiated wholesale electricity prices) by focusing on those projects in their pipeline that may not be located in the best wind resource areas but that do have access to transmission (or higher-priced markets, or readily available sites without long permitting times).
- **Policy Influence.** Projects built in the 4-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC. Because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that

[45] Estimates of wind resource quality are based on site estimates of *gross* capacity factor at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower; further details are found in the Appendix.

developers seized this limited opportunity to build out the less-energetic sites in their development pipelines. Additionally, state RPS requirements sometimes require or motivate in-state or in-region wind development in lower wind resource regimes.

In an attempt to disentangle the competing influences of turbine design evolution and lower wind resource quality on capacity factor, Figure 34 controls for each. Across the x-axis, projects are grouped into four different categories of wind resource quality.[46] Within each wind resource category, projects are further differentiated by their specific power. As one would expect, projects sited in higher-wind-speed areas generally have higher capacity factors than those in low-wind-speed areas, regardless of specific power. Likewise, within each of the four wind resource categories along the x-axis, projects that fall into a lower specific power range have higher capacity factors than those in a higher specific power range.

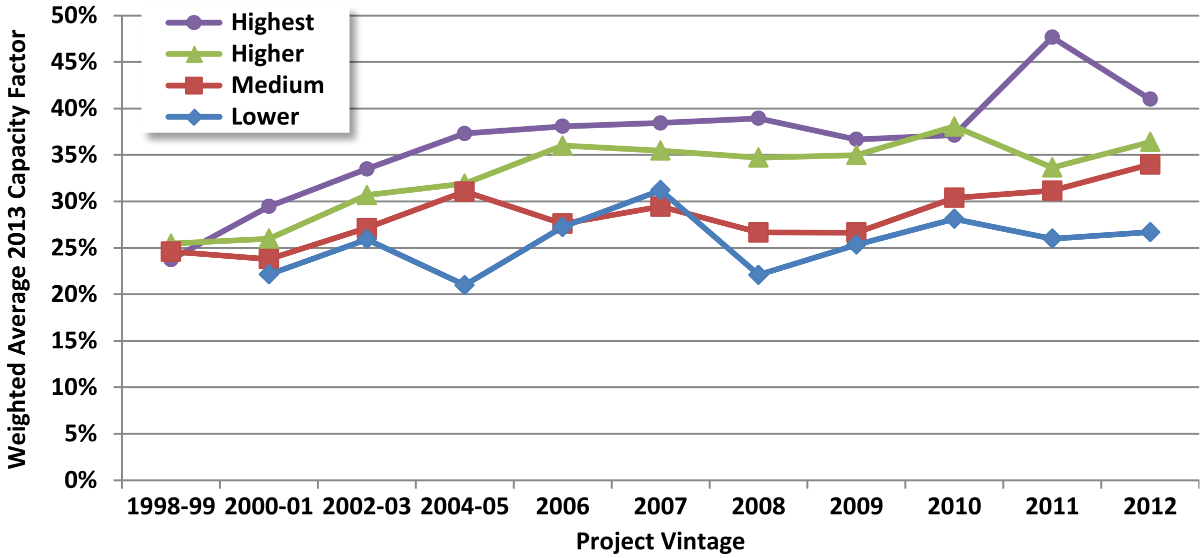


Source: Berkeley Lab

Figure 34. Impact of wind resource quality and specific power on capacity factor

As a result, notwithstanding the recent build-out of lower-quality wind resource sites, it is clear that turbine design changes (specifically, larger rotors and therefore also lower specific power, but also to a lesser extent higher hub heights) are driving capacity factors higher among projects located within a given wind resource regime. This finding is further illustrated in Figure 35, which again groups projects into four different categories of wind resource quality, and then reports average 2013 capacity factors by commercial operation date within each category. As before, projects sited in higher-wind-speed areas have, on average, higher capacity factors. More importantly, although there is some variability in the year-to-year trends, it is clear that within each of the four wind resource categories there has been a marked improvement in capacity factors over time, by commercial operation date.

[46] Based on site estimates of *gross* capacity factor at 80 meters by AWS Truepower, the “lower” category includes all projects with an estimated *gross* capacity factor of <35%, the “medium” category corresponds to 35%–42.5%, the “higher” category corresponds to 42.5%-50%, and the “highest” category includes any project at or exceeding 50%.



Source: Berkeley Lab

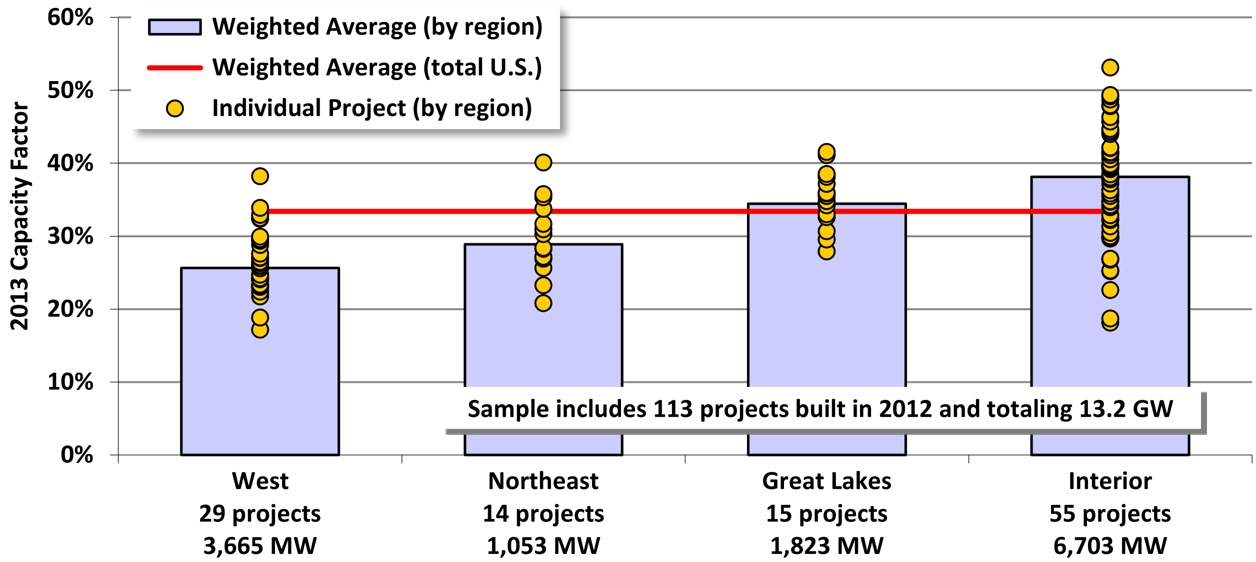
Figure 35. Impact of commercial operation date and wind resource quality on average 2013 capacity factors

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

The project-level spread in capacity factors shown in Figure 32 is enormous, with 2013 capacity factors ranging from a minimum of 17% to a maximum of 53% among those projects built in 2012. Some of this spread is attributable to regional variations in average wind resource quality.

Figure 36 shows the regional variation in 2013 capacity factors (using the regional definitions shown in Figure 30, earlier) based on a sample of wind power projects built in 2012; the Southeast region is excluded due to limited sample. For this sample of projects, generation-weighted average capacity factors are the highest in the Interior region (38%) and the lowest in the West (26%).[47] Even within each region, however, there is still considerable spread—e.g., 2013 capacity factors range from 18% up to 53% for projects installed in the Interior region in 2012.

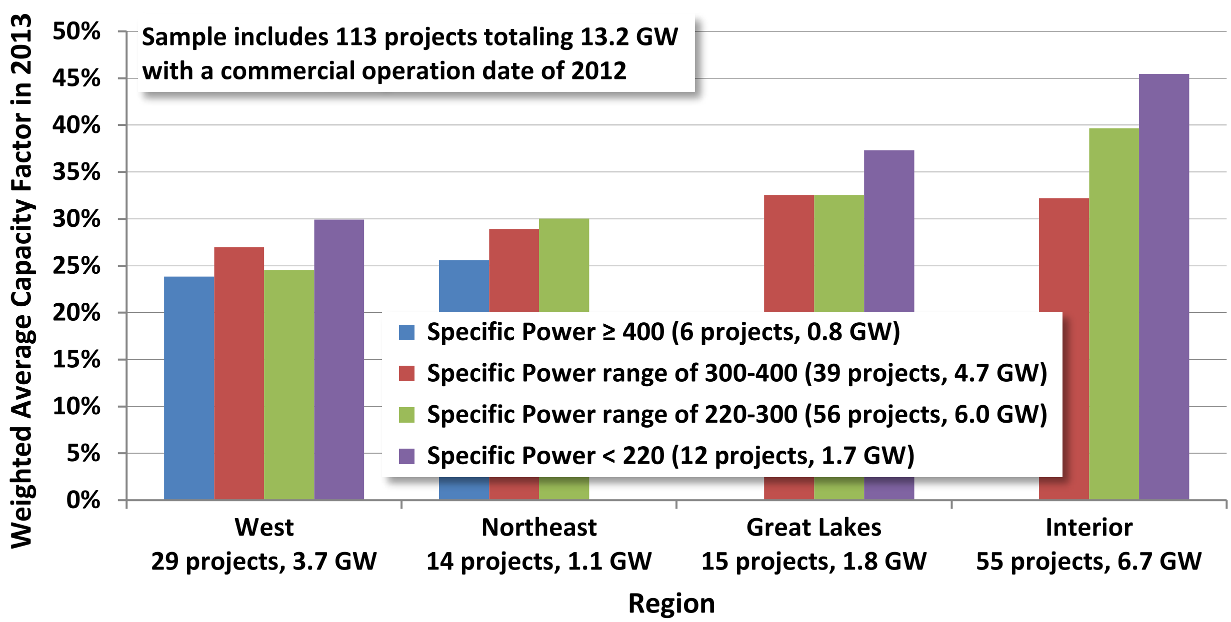
[47] Given the relatively small sample size in some regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2013, care should be taken in extrapolating these results.



Source: Berkeley Lab

Figure 36. 2013 capacity factors by region: 2012 projects only

Some of this intra-regional variation can be explained by turbine technology. Figure 37 looks at the same sample as shown above in Figure 36, but within each region, projects are further differentiated by their average specific power. As one would expect, within each of the four regions along the x-axis, projects using turbines that fall into a lower specific power range generally have higher capacity factors than those in a higher specific power range.



Source: Berkeley Lab

Figure 37. Impact of region and specific power on capacity factor

As shown earlier in Chapter 4 (“Technology Trends”), the rate of adoption of turbines with lower specific power ratings has varied by region. For example, Figure 28 (earlier) shows that roughly 30% of all turbines installed in the Great Lakes region from 2011–2013 have a specific power rating of less than 220 W/m^2, while the comparable number in the West is 5%. Similarly, roughly 55% of all turbines installed in the Great Lakes region from 2011–2013 have tower heights of at least 90 meters, compared to 3% in the West. The relative degree to which these regions have embraced these turbine design enhancements influences, to some extent, their ranking in Figures 36 and 37.

Taken together, Figures 32–37 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of factors. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—for example, the quality of the wind resource where projects are located as well as inter-year wind resource variability.

6. Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally O&M costs. Later chapters present data on wind project performance and then the price at which wind energy is being sold.

Wind turbine prices remained well below levels seen several years ago

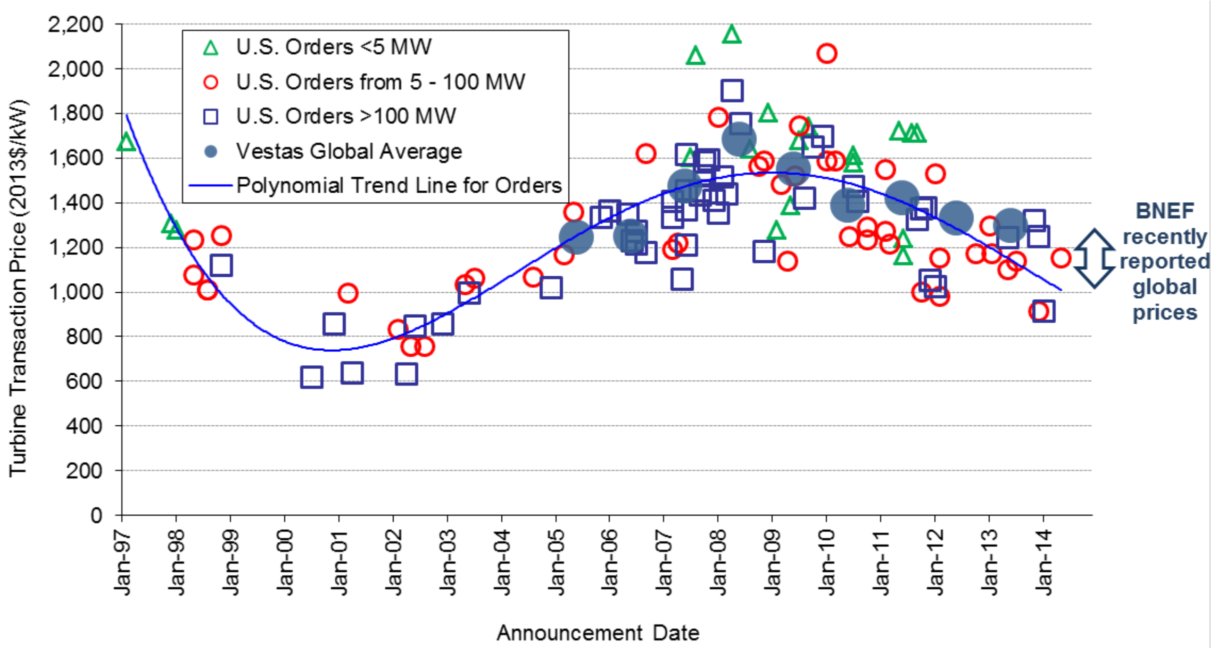
Wind turbine prices have dropped substantially in recent years, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. This downward pricing pressure continued in 2013, partly a result of stiff competition among turbine OEMs and equipment suppliers and related cost-cutting measures.

Berkeley Lab has gathered price data for 112 U.S. wind turbine transactions totaling 29,250 MW announced from 1997 through the beginning of 2014, including ten transactions (2,082 MW) announced in 2013/14. Sources of turbine price data vary, including SEC and other regulatory filings, as well as press releases and news reports. Most of the transactions included in the Berkeley Lab dataset include turbines, towers, delivery to site, and limited warranty and service agreements.[48] Nonetheless, wind turbine transactions differ in the services included (e.g., whether towers and installation are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices.

Unfortunately, collecting data on U.S. wind turbine transaction prices is a challenge: only a fraction of the announced turbine transactions have publicly revealed pricing data. In part as a result, Figure 38—which depicts these U.S. wind turbine transaction prices—also presents data from: (1) Vestas on that company's global average turbine pricing from 2005 through 2013, as reported in Vestas' financial reports; and (2) a range of recent global average wind turbine prices for both older turbine models (smaller rotors) and newer models (larger rotors), as reported by Bloomberg NEF (2014b).

After hitting a low of roughly $750/kW from 2000 to 2002, average wind turbine prices increased by approximately $800/kW (more than 100%) through 2008, rising to an average of more than $1,500/kW. The increase in turbine prices over this period was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth and turbine and component supply shortages; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter (Bolinger and Wiser 2011).

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



Source: Berkeley Lab

Figure 38. Reported wind turbine transaction prices over time

Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 38, our limited sample of recently announced U.S. turbine transactions shows pricing in the $900–$1,300/kW range. Bloomberg NEF (2014b) reports global average pricing for the most-recent contracts of approximately $1,000/kW for older turbine models and $1,300/kW for newer turbine models that feature larger rotors. Data on average global pricing from Vestas largely confirm these pricing points.

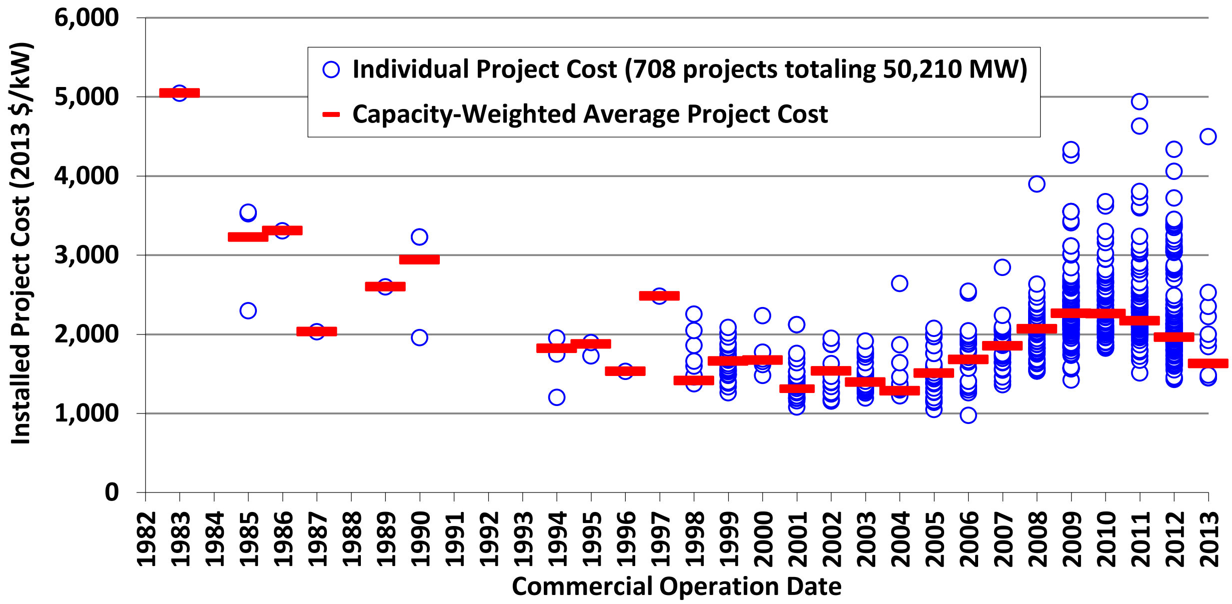
Overall, these figures suggest price declines of 20%–40% since late 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., the recent growth in average hub heights and rotor diameters shown in Chapter 4) and more-favorable terms for turbine purchasers (e.g., reduced turbine delivery lead times and less need for large frame-agreement orders, longer initial O&M contract durations, improved warranty terms, and more-stringent performance guarantees). These price reductions and improved terms have exerted downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights are improving capacity factors and further reducing wind power prices.

Reported installed project costs continued to trend lower in 2013

Berkeley Lab compiles data on the total installed cost of wind power projects in the United States, including data on 11 projects completed in 2013 totaling 650 MW, or 60% of the wind power capacity installed in that year. In aggregate, the dataset (through 2013) includes 708 completed wind power projects in the continental United States totaling 50,210 MW and equaling roughly 82% of all wind power capacity installed in the United States at the end of

2013. 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 39, the average installed costs of wind power projects declined from the beginning of the U.S. wind industry in California in the 1980s through the early 2000s, before following turbine prices higher through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs appear to have peaked in 2009/2010. That changes in average installed project costs would lag changes in average turbine prices is not surprising and reflects the normal passage of time between when a turbine supply agreement is signed (the time stamp for Figure 38) and when those turbines are actually installed and commissioned (the time stamp for Figure 39).[49]



Source: Berkeley Lab (some data points suppressed to protect confidentiality)

Figure 39. Installed wind power project costs over time

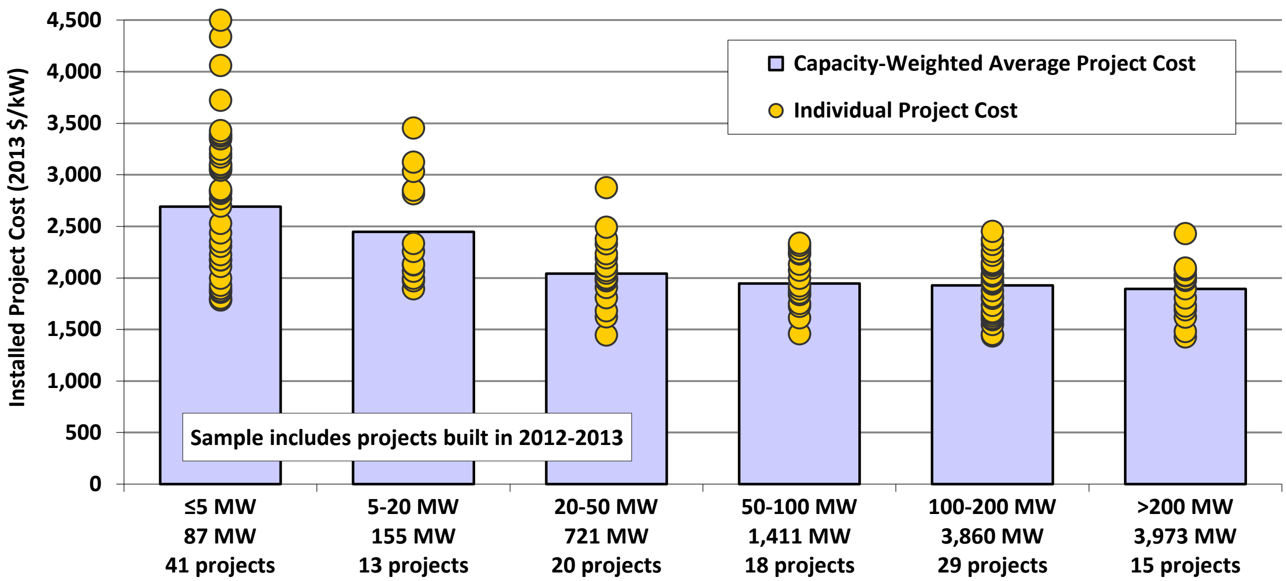
In 2013, the capacity-weighted average installed project cost within our limited sample stood at roughly $1,630/kW, down more than $300/kW from the reported average cost in 2012 and down more than $600/kW from the apparent peak in average reported costs in 2009 and 2010. With just 11 projects totaling 650 MW, however, the 2013 sample size is quite limited, perhaps enabling a few large and low-cost projects to unduly influence the weighted average. Early indications from a larger sample (16 projects totaling more than 2 GW) of projects currently

[49] Since 2009, Figure 39 partly reflects installed cost estimates derived from publicly available data from the Section 1603 cash grant program. In some cases (although exactly which are unknown), the Section 1603 grant data likely reflect the fair market value rather than the installed cost of wind power projects; in such cases, the installed cost estimates shown in Figure 39 will be artificially inflated.

under construction and anticipating completion in 2014 suggest that capacity-weighted average installed costs are closer to $1750/kW—still down significantly from 2012's levels.[50]

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

Average installed wind power project costs exhibit economies of scale, especially at the lower end of the project size range. Figure 40 shows that—among the sample of projects installed in 2012 and 2013—there is a steady drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 20–50 MW range. As project size increases beyond 50 MW, economies of scale appear to be less prevalent.



Source: Berkeley Lab

Figure 40. Installed wind power project costs by project size: 2012–2013 projects

Another way to look for economies of scale is by turbine size (rather than by project size), on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines as opposed to more, smaller turbines. Figure 41 explores this relationship and illustrates that here too some economies of scale are evident as turbine size increases—particularly moving from sub-MW turbines to MW class turbines.[51]

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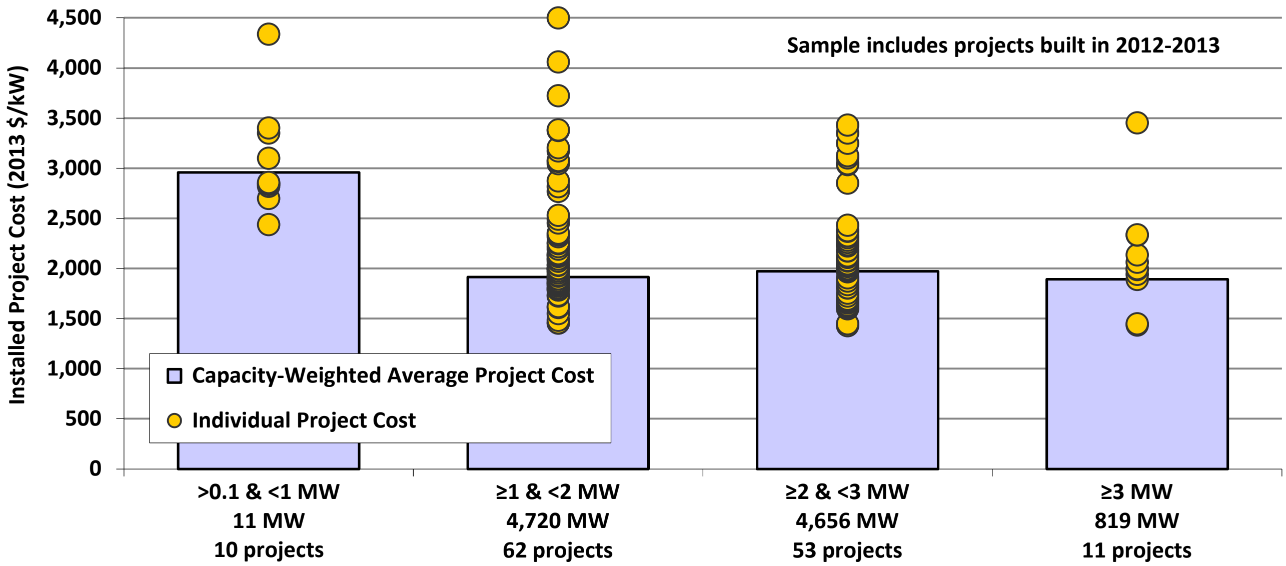
[50] Learning curves have been used extensively to understand past cost trends and to forecast future cost reductions for a variety of energy technologies, including wind energy. Learning curves start with the premise that increases in the cumulative production or installation of a given technology lead to a reduction in its costs. The principal parameter calculated by learning curve studies is the learning rate: for every doubling of cumulative production/installation, the learning rate specifies the associated percentage reduction in costs. Based on the full time series of installed cost data presented in Figure 39 and global cumulative wind power installations, a learning rate can be calculated as follows: 6.9% (using data from 1982 through 2013).

[51] There is likely some correlation between turbine size and project size, at least at the low end of the range of each. In other words, projects of 5 MW or less are more likely than larger projects to use individual turbines of less than 1 MW. As such, Figures 40 and 41—both of which show scale economies at small project or turbine sizes,



Source: Berkeley Lab

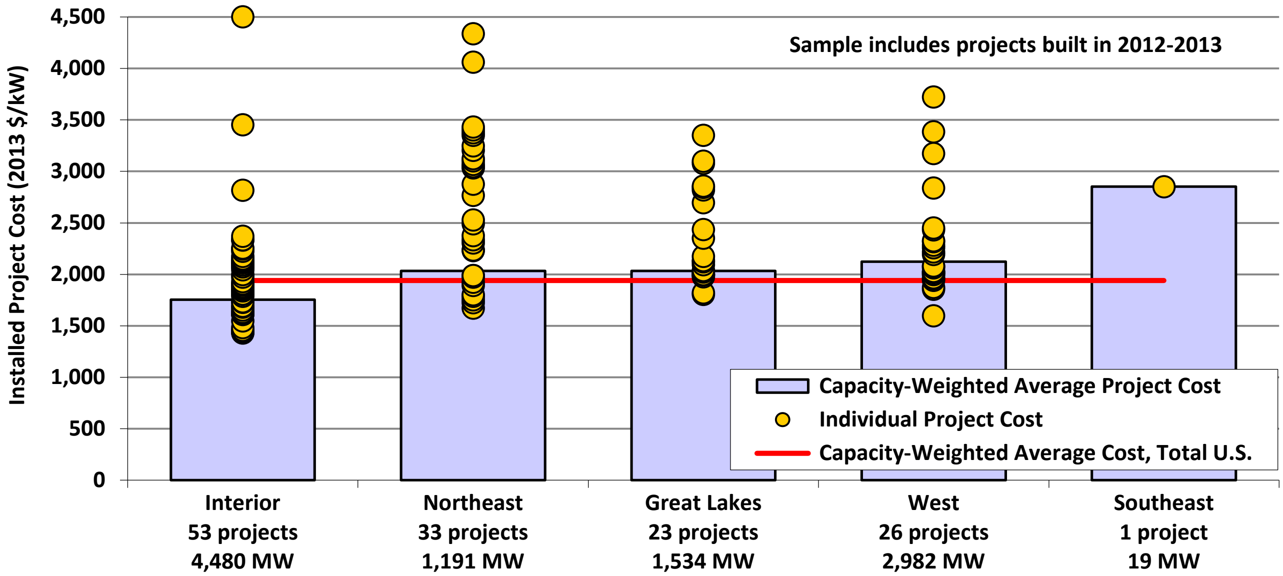
Figure 41. Installed wind power project costs by turbine size: 2012–2013 projects

Regional differences in average project costs are also apparent and may occur due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures as well as variations in the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources). Considering only projects in the sample that were installed in 2012 and 2013, Figure 42 breaks out project costs among the five regions defined in Figure 30.[52] The Interior region—with the largest sample—was the lowest-cost region on average, with average costs of $1,760/kW, while the Southeast was the highest-cost region (although with a sample of just one project); the other three regions all came in relatively close to the nationwide average of roughly $1,940/kW.[53]

diminishing as project or turbine size increases—could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size.

[52] For reference, the 61,110 MW of wind installed in the United States at the end of 2013 is apportioned among the five regions shown in Figure 30 as follows: Interior (35,239 MW), West (13,464 MW), Great Lakes (7,350 MW), Northeast (3,907 MW), and Southeast (735 MW). The remaining installed U.S. wind power capacity is located in Hawaii (206 MW), Puerto Rico (125 MW), and Alaska (62 MW) and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

[53] Graphical presentation of the data in this way should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 42.



Source: Berkeley Lab

Figure 42. Installed wind power project costs by region: 2012–2013 projects

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

Operations and maintenance costs are a significant component of the overall cost of wind energy and can vary substantially among projects. Anecdotal evidence and recent analysis (Lantz 2013) suggest that unscheduled maintenance and premature component failure in particular continue to be key challenges for the wind power industry.

Unfortunately, publicly available market data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades, not least of which has been the up-scaling of turbine size (see Chapter 4). Berkeley Lab has compiled limited O&M cost data for 152 installed wind power projects in the United States, totaling 10,679 MW in capacity, with commercial operation dates of 1982 through 2012. These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M cost data are available for just a subset of years of project operations. Although the data sources do not all clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the facility, as well as rent.[54] Other ongoing

[54] 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.

expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance, are generally not included. As such, the following figures are not representative of *total* operating expenses for wind power projects; the last few paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow may not fully depict the industry's challenges with O&M issues and expenditures; instead, these results should be taken as indicative of potential overall trends. Note finally that the available data are presented in $/MWh terms, as if O&M represents a variable cost; in fact, O&M costs are in part variable and in part fixed. Although not presented here, expressing O&M costs in units of $/kW-year yields qualitatively similar results to those presented in this section.

Figure 43 shows project-level O&M costs by commercial operation date.[55] Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2013, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2012, only year 2013 data are available, and that is what is shown in the figure.[56] Many other projects only have data for a subset of years during the 2000–2013 timeframe, either because they were installed after 2000 or because a full time series is not available, so each data point in the chart may represent a different averaging period within the overall 2000–2013 timeframe. The chart highlights the 59 projects, totaling 6,422 MW, for which 2013 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

The data exhibit considerable spread, demonstrating that O&M costs (and perhaps also how O&M costs are reported by respondents) are far from uniform across projects. However, Figure 43 suggests that projects installed within the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2013 O&M costs for the 24 projects in the sample constructed in the 1980s equal $34/MWh, dropping to $23/MWh for the 37 projects installed in the 1990s, to $10/MWh for the 74 projects installed in the 2000s, and to $9/MWh for the 20 projects installed since 2010.[57] This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as

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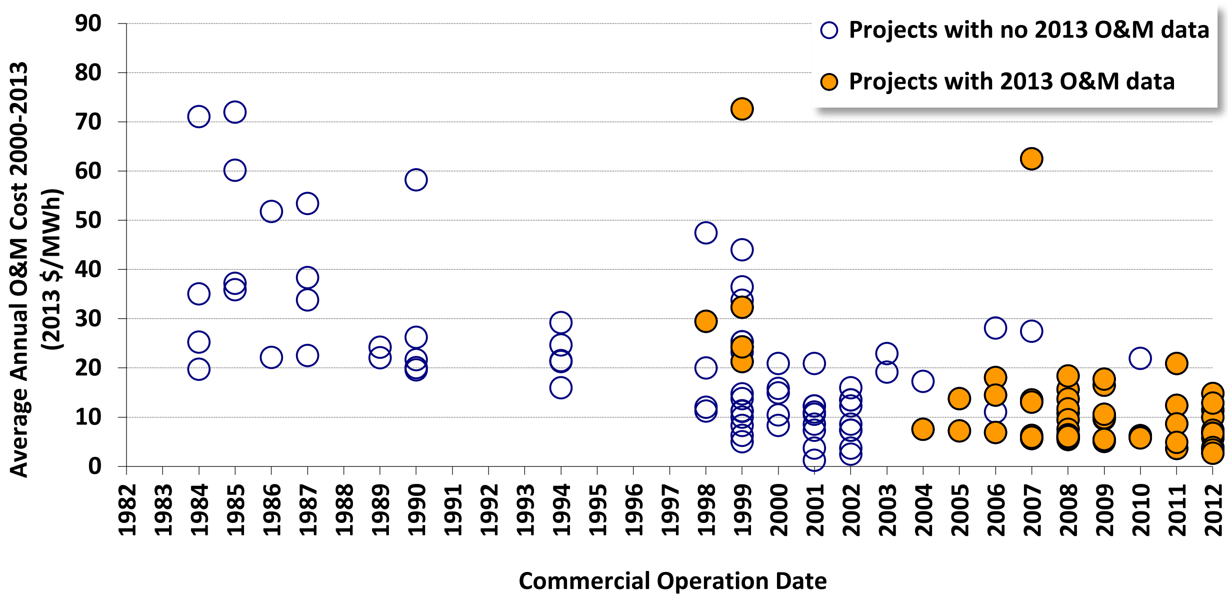
If this occurs, the operating expenses reported in FERC Form 1 and presented in Figures 43 and 44 will not capture total operating costs.

[55] For projects installed in multiple phases, the commercial operation date of the largest phase is used; for re-powered projects, the date at which re-powering was completed is used.

[56] Projects installed in 2013 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2013 would be year 2014 (for which data are not yet available).

[57] If expressed instead in terms of $/kW-year, capacity-weighted average 2000–2013 O&M costs were $66/kW-year for projects in the sample constructed in the 1980s, dropping to $55/kW-year for projects constructed in the 1990s, to $28/kW-year for projects constructed in the 2000s, and to $23/kW-year for projects constructed since 2010. Somewhat consistent with these observed O&M costs, Bloomberg NEF (2014d) reports the cost of a sample of 5-year full-service O&M contracts (most having been included as part of the turbine supply agreement, and therefore pertaining to just the first five years of turbine life) as having declined from $40/kW-year in the 2008–2009 period to $28/kW-year in 2013. An NREL analysis based on data from DNV KEMA and GL Garrad Hassan covering roughly 5 GW of operating wind projects (with only about half that amount having been operable for longer than five years) also shows average levels of expenditure consistent with the Berkeley Lab dataset, at least when focusing on turbine and balance-of-plant O&M costs for projects commissioned in the 2000s (Lantz 2013).

turbines age, component failures become more common, and manufacturer warranties expire;[58] and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a per-MWh basis.



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

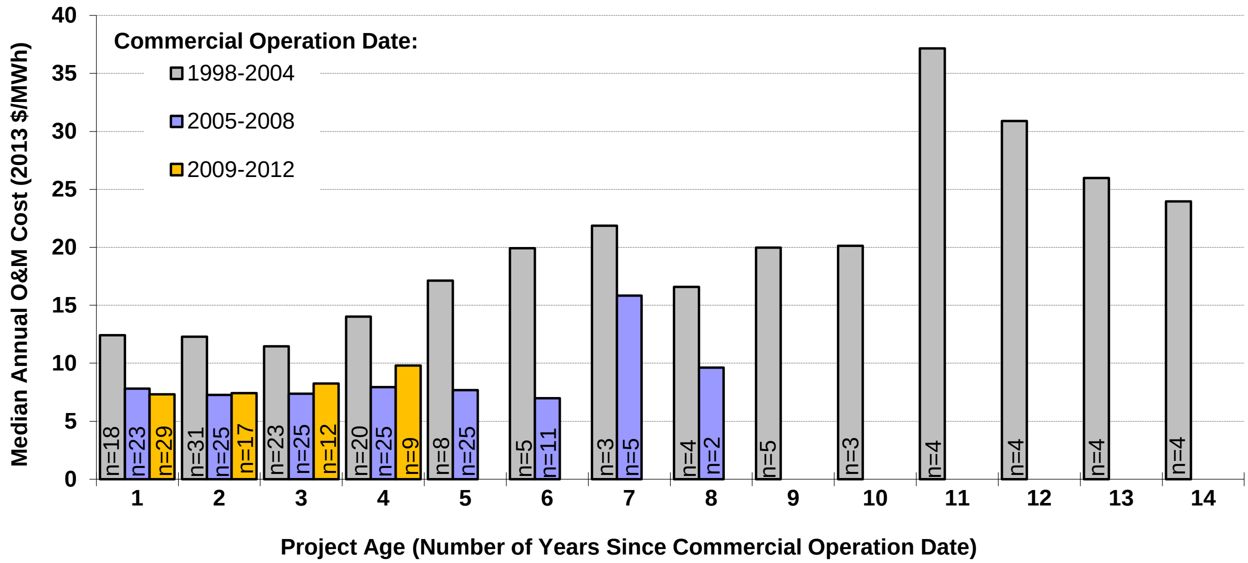
Figure 43. Average O&M costs for available data years from 2000–2013, by commercial operation date

Although limitations in the underlying data do not permit the influence of these two factors to be unambiguously distinguished, to help illustrate key trends, Figure 44 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale. Note that, at each project age increment and for each of the three project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially (from 3 to 31 data points per project-year for projects installed from 1998 through 2004, from 2 to 25 data points per project-year for projects installed from 2005 through 2008, and from 9 to 29 data points per project-year for projects installed from 2009 through 2012).

With these limitations in mind, Figure 44 shows an upward trend in project-level O&M costs as projects age, although the sample size after year 5 is limited. In addition, the figure shows that projects installed more recently (from 2005–2008 and/or 2009-2012) have had, in general, lower O&M costs than those installed in earlier years (from 1998–2004), at least for the first 8 years of operation. Parsing the "recent project" cohort into two sub-periods, however, reveals that this trend towards lower costs has not necessarily continued with the most recent projects in the

[58] Many of the projects installed more recently may still be within their turbine manufacturer warranty period, and/or may have capitalized O&M service contracts within their turbine supply agreement. Projects choosing the Section 1603 cash grant over the PTC may have had a particular incentive to capitalize service contracts (31 projects totaling 44% of the sample capacity installed since 2000 were installed from 2009-2012—i.e., within the period of eligibility for the Section 1603 grant—though only five of these 31 projects actually elected the grant over the PTC). In either case, reported O&M costs will be artificially low.

sample, those installed from 2009-2012 (though cost differences between the 2005-2008 and 2009-12 sample are small and sample size is limited).



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

Figure 44. Median annual O&M costs by project age and commercial operation date

As indicated previously, the data presented in Figures 43 and 44 include only a subset of total operating expenses. In comparison, the financial statements of public companies with sizable U.S. wind project assets indicate markedly higher total operating costs. Specifically, two companies—Infigen and EDP Renováveis (EDPR), which together represented approximately 4,730 MW of installed capacity at the end of 2013 (nearly all of which has been installed since 2000)—report total operating expenses of $24.2/MWh and $23.6/MWh, respectively, for their U.S. wind project portfolios in 2013 (EDPR 2014, 2013, 2012; Infigen 2014, 2013, 2012, 2011).[59] These total operating expenses are more than twice the $10/MWh average O&M cost reported above for the 85 projects in the Berkeley Lab data sample installed since 2000.

This disparity in operating costs between these two project owners and the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, Infigen breaks out its total U.S. operating expense in 2013 ($24.2/MWh) into four categories: asset management and administration ($5.0/MWh), turbine O&M ($11.0/MWh), balance of plant ($2.4/MWh), and other direct costs ($5.8/MWh). Among these four categories, the combination of turbine O&M and balance of plant ($13.4/MWh in total) is likely most comparable to the scope of data reported in the Berkeley Lab sample. Similarly, EDPR breaks out its total U.S. operating costs in 2013 ($23.6/MWh) into three categories: supplies and services, which “includes O&M costs” ($14.7/MWh); personnel costs ($3.7/MWh); and other operating costs, which “mainly includes operating taxes, leases, and rents” ($5.2/MWh). Among these three categories, the $14.7/MWh for supplies and services is probably closest in scope to the Berkeley Lab data. Confirming these basic findings, the recent NREL analysis based on data from DNV

[59] Infigen’s total operating expenses may be higher than indicated here, given that reported costs do not include certain capital expenditures related to the replacement of turbines and/or turbine components.

KEMA on plants commissioned before 2009 shows *total* operating expenditures of $40–$60/kW-year depending on project age, with turbine and balance-of-plant O&M costs representing roughly half of those expenditures (Lantz 2013).

7. Wind Power Price Trends

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

Berkeley Lab collects data on wind PPA prices from the sources listed in the Appendix, resulting in a dataset that currently consists of 343 PPAs totaling 29,632 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation in 2014 or 2015. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs).

Throughout this chapter, PPA prices are expressed on a levelized basis over the full term of each contract and are reported in real 2013 dollars.[60] Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation weighted.[61] Whenever they are broken out by time, the date on (or year in) which the PPA was signed or executed is used, as that date provides the best indication (i.e., better than commercial operation date) of market conditions at the time. Finally, because the PPA prices in the Berkeley Lab sample are reduced by the receipt of state and federal incentives (e.g., the levelized PPA prices reported here would be at least $15/MWh higher without the PTC, ITC, or Treasury Grant), and are also influenced by various local policies and market characteristics, they do not directly represent wind energy generation *costs*.

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to wholesale power prices both nationwide and regionally, and compared to future natural gas prices. In addition, REC prices are presented in a text box on page 63.

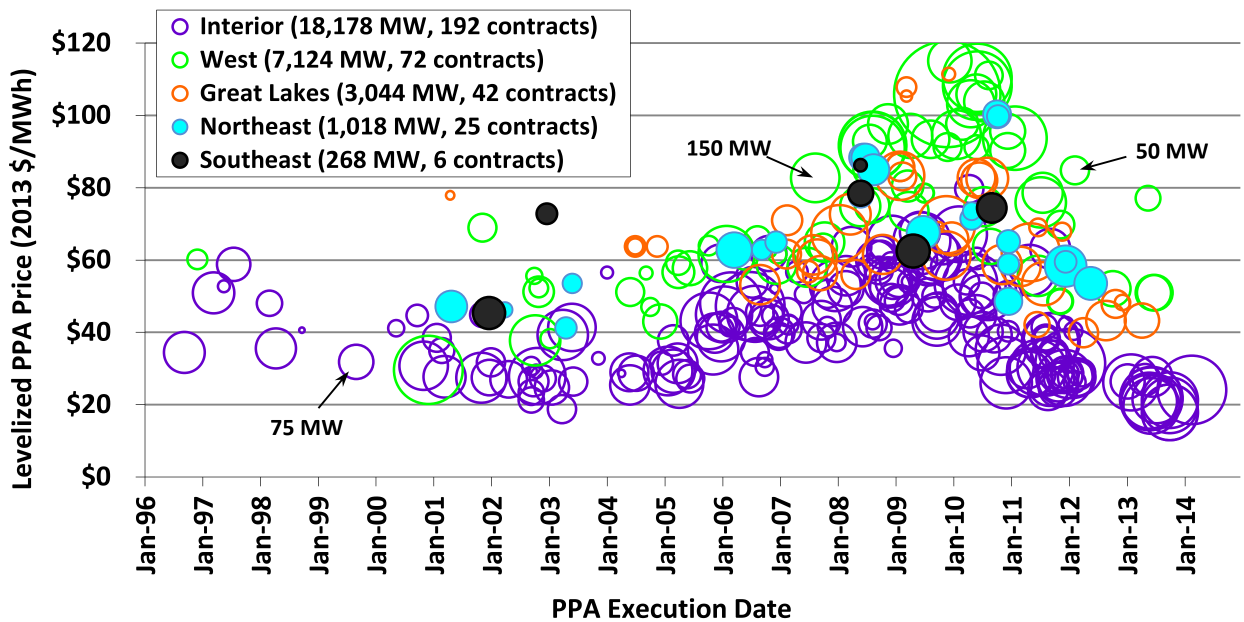
Wind PPA prices have reached all-time lows

Figure 45 plots project-level levelized wind PPA prices by contract execution date, showing a clear downward trend in PPA prices since 2009—both overall and by region (see Figure 30 for

[60] Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 33 years, with 20 years being by far the most common (at 58% of the sample; 89% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 7% real discount rate.

[61] Generation weighting is based on the empirical project-level performance data analyzed in the previous chapter of this report and assumes that historical project performance (in terms of annual capacity factor as well as daily and/or seasonal production patterns where necessary) will hold into the future as well. In cases where there is not enough operational history to establish a "steady-state" pattern of performance, we used discretion in estimating appropriate weights (to be updated in the future as additional empirical data become available).

regional definitions).[62] This trend is particularly evident within the Interior region, which—as a result of its low average project costs and high average capacity factors shown earlier in this report—also tends to be the lowest-priced region over time. Prices generally have been higher in the rest of the United States.[63]



Note: Size of "bubble" is proportional to project nameplate capacity
Source: Berkeley Lab

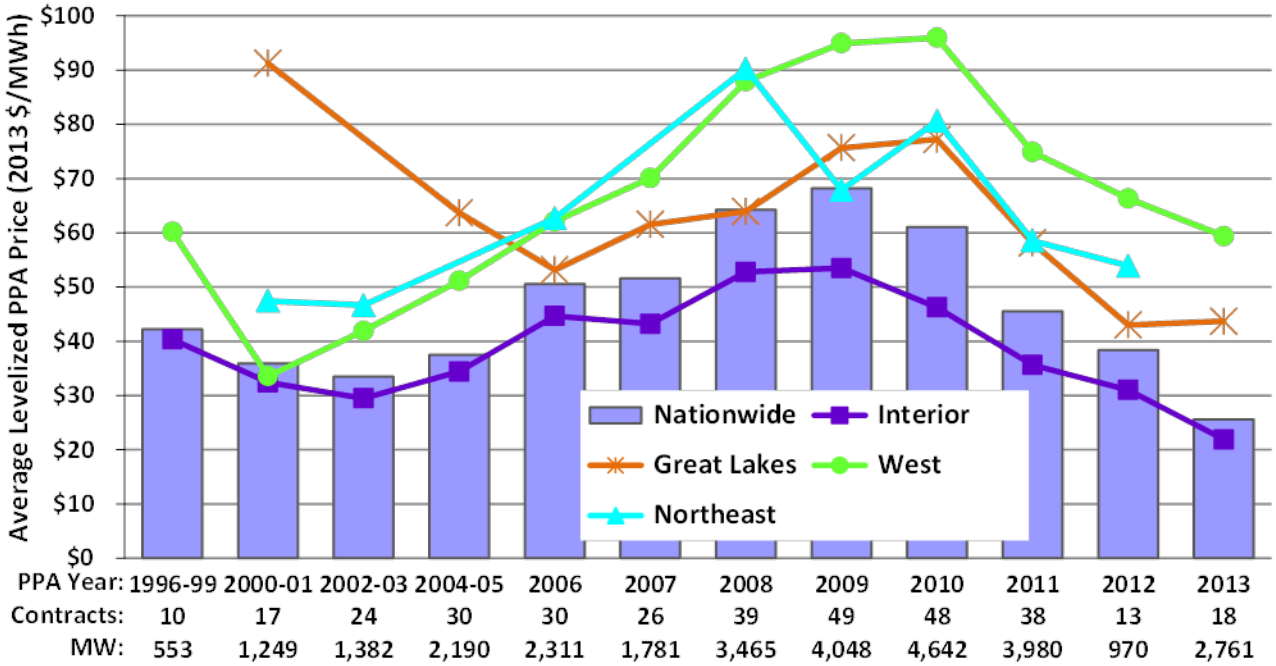
Figure 45. Levelized wind PPA prices by PPA execution date and region

Figure 46 provides a smoother look at the time trend nationwide (the blue bars) by averaging the individual levelized PPA prices shown in Figure 45 by year. After topping out at nearly $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs that were signed in 2013 (and that are within the Berkeley Lab sample) fell to around $25/MWh—the lowest-ever price shown in the figure, but admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country.

While this temporal trend of rising and then falling PPA prices is directionally consistent with the turbine price and installed project cost trends shown in earlier sections, the fact that PPA prices have broken into new lows is nevertheless notable, given that installed project costs have not returned to the low levels from the early 2000s (Figure 39) and that wind projects increasingly have been sited in lower-quality wind resource areas (Figure 33). It would appear

[62] More than 96% of the contracts that are depicted in Figure 45 are from projects that are already online. Only the most recent contracts in the sample (signed in the second half of 2013 or early 2014) are from projects that are not yet online.
[63] Regional differences can affect not only project capacity factors (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region's physical geography, population density, labor rates, or even regulatory processes). It is also possible that regions with higher wholesale electricity prices or with greater demand for renewable energy will, in general, yield higher wind energy contract prices due to market factors.

that the turbine scaling and other improvements to turbine efficiency described in Chapter 4 have more than overcome these headwinds to help drive PPA prices lower.



Source: Berkeley Lab

Figure 46. Generation-weighted average levelized wind PPA prices by PPA execution date and region

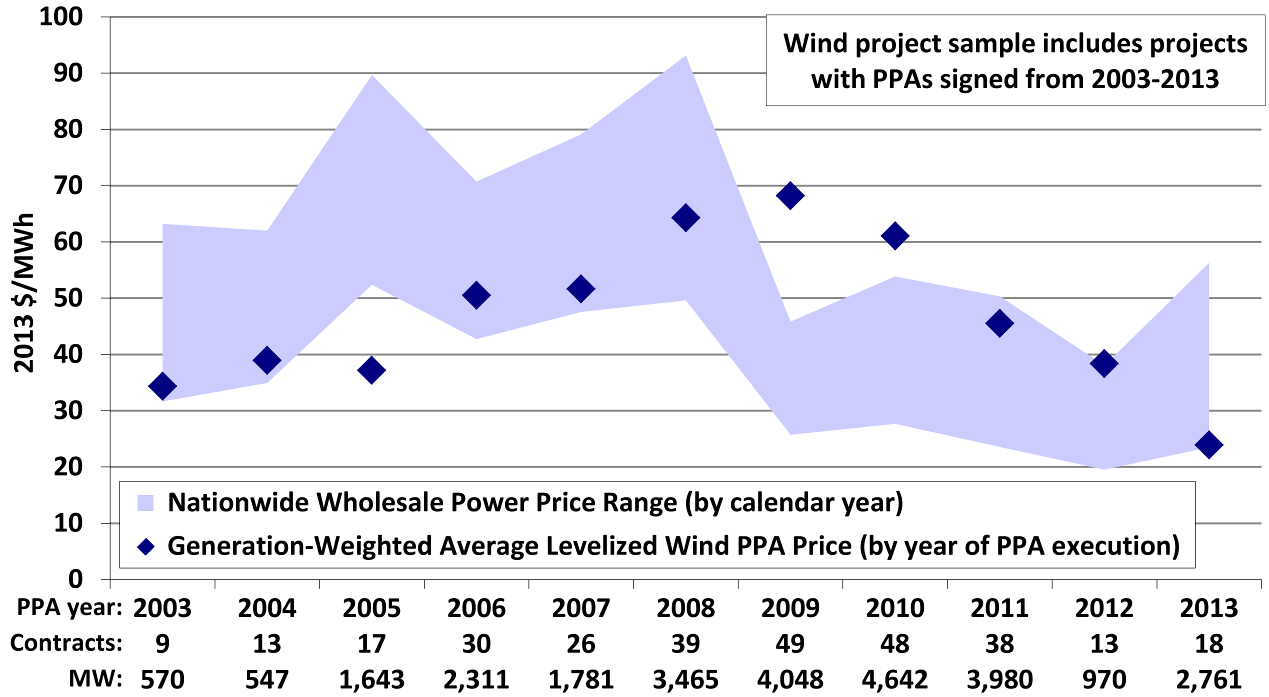
Figure 46 also shows trends in the generation-weighted average levelized PPA price over time among four of the five regions broken out in Figure 30 (the Southeast region is omitted from Figure 46 owing to its small sample size). Figures 45 and 46 both demonstrate that, based on our data sample, PPA prices are generally low in the U.S. Interior, high in the West, and in the middle in the Great Lakes and Northeast regions. The large Interior region, where much of U.S. wind project development occurs, saw average levelized PPA prices of just $22/MWh in 2013.

The relative competitiveness of wind power improved in 2013

Figure 47 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power[64] going back to 2003 at 23 different pricing nodes located throughout the country (refer to the Appendix for the names and approximate locations of the 23 pricing nodes represented by the blue-shaded area). The dark diamonds represent the generation-weighted average levelized wind PPA prices in the years in which contracts were executed (consistent with the nationwide averages presented in Figure 46).

[64] A flat block of power is defined as a constant amount of electricity generated and sold over a specified period. Although wind power projects do not provide a flat block of power, as a common point of comparison a flat block is not an unreasonable starting point. In other words, the time variability of wind energy is often such that its wholesale market value is somewhat lower than, but not too dissimilar from, that of a flat block of (non-firm) power (Fripp and Wiser 2006).

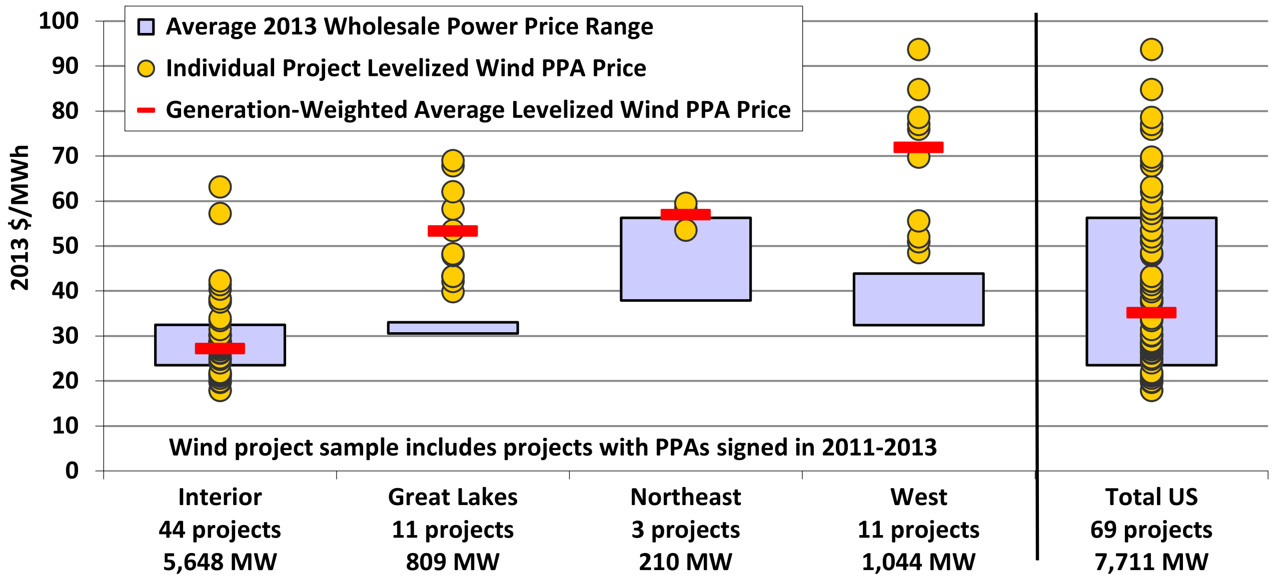
At least within the sample of projects reported here, average long-term wind PPA prices compared favorably to yearly wholesale electricity prices from 2003 through 2008. Starting in 2009, however, the sharp drop in wholesale electricity prices (driven primarily by lower natural gas prices, but also declining electricity demand) squeezed average wind PPA prices out of the wholesale power price range on a nationwide basis. Wind PPA prices have since fallen, however, and in 2011 and 2012 reconnected with the upper end of the wholesale power price range. In 2013, further PPA price declines, along with a bit of a rebound in wholesale prices, put wind back at the bottom of the range once again.



Source: Berkeley Lab, FERC, Ventyx, IntercontinentalExchange

Figure 47. Average levelized long-term wind PPA prices and yearly wholesale electricity prices over time

Although Figure 47 portrays a national comparison, there are clearly regional differences in wholesale electricity prices and in the average price of wind power. Figure 48 focuses just on the sample of wind PPAs signed from 2011 through 2013 and compares those levelized long-term PPA prices to wholesale electricity prices in 2013 by region. The limited wind PPA sample size in some regions must be noted, and the Southeast is excluded altogether from the figure. Nonetheless, based on our sample, wind PPA prices have—in recent years—been most competitive with wholesale power prices in the Interior region.



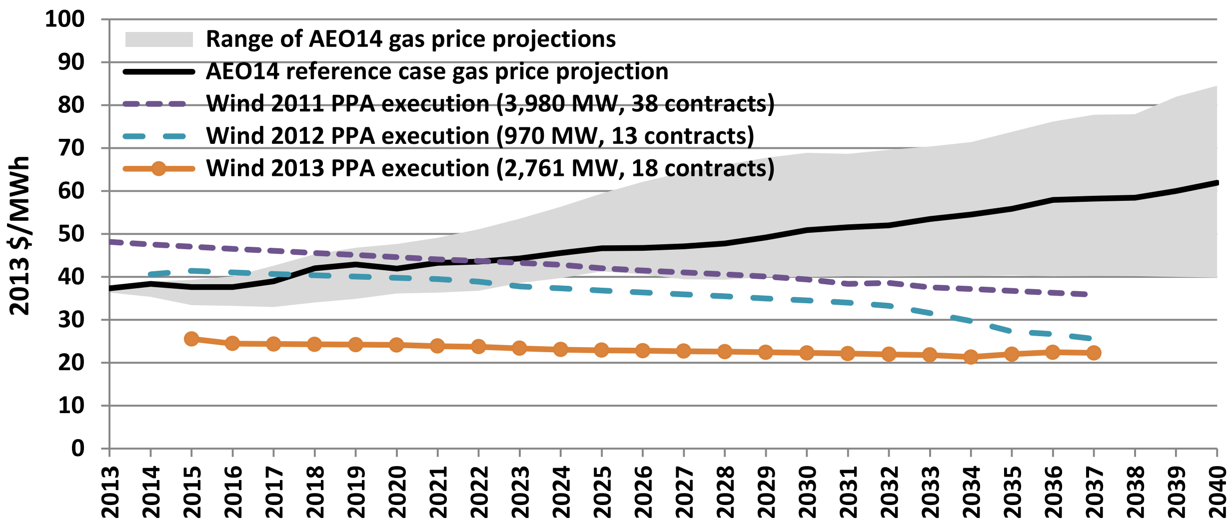
Source: Berkeley Lab, Ventyx, IntercontinentalExchange

Figure 48. Levelized long-term wind PPA prices in 2011-2013 and yearly wholesale electricity prices by region

The comparison between levelized wind PPA and wholesale power prices in Figures 47 and 48 is imperfect for a number of reasons (discussed further below), one of which is that the levelized wind PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale power prices are pertinent to just the single year in question. Figure 48 attempts to remedy this temporal mismatch by presenting an alternative and still simple way of looking at how wind stacks up relative to its competition.

Rather than levelizing the wind PPA prices, Figure 49 plots the future stream of average wind PPA prices from PPAs executed in 2011, 2012, or 2013 against a range of projections of just the fuel costs of natural gas-fired generation.[65] As shown, average wind PPA prices from contracts executed in 2011 and 2012 start out higher than the range of fuel cost projections, but decline (in real 2013$) over time and soon fall within and then eventually below the range. The sample of PPAs executed in 2013 has an average price stream that *begins* below the range of natural gas fuel cost projections, and that remains below even the low-end of gas price forecasts for two decades.

[65] The fuel cost projections come from the Energy Information Administration's *Annual Energy Outlook 2014* publication, and increase from around $4.60/MMBtu in 2013 to $8.65/MMBtu (in 2013 dollars) in 2040 in the reference case. The range around the reference case is bounded by the high and low oil and gas resource cases, and ranges from $5.50/MMBtu to $11.50/MMBtu (again, in 2013 dollars) in 2040. These fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (these start at roughly 8,300 Btu/kWh and gradually decline to around 7,100 Btu/kWh by 2040).



Source: Berkeley Lab, EIA

Figure 49. Average long-term wind PPA prices (by vintage) and natural gas fuel cost projections over time

Figure 49 also hints at the long-term value that wind power can provide as a "hedge" against rising and/or uncertain natural gas prices. The average 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 end up being either slightly lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

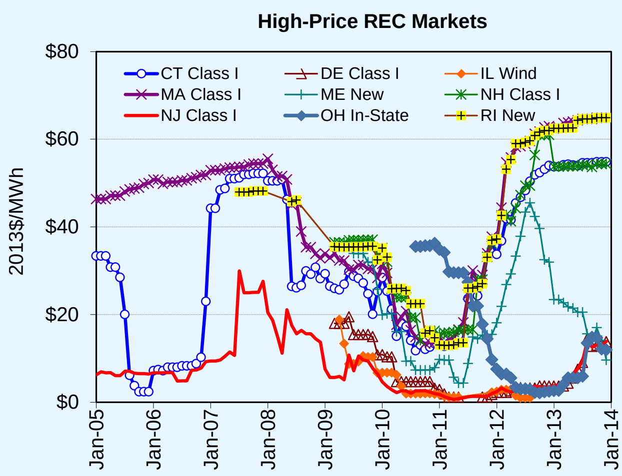
Important Note: Notwithstanding the comparisons made in this section, neither the wind nor wholesale electricity prices (nor fuel cost projections) reflect the full social costs of power generation and delivery. Specifically, the wind PPA prices are reduced by virtue of federal and, in some cases, state tax and financial incentives. Furthermore, these prices do not fully reflect integration, resource adequacy, or transmission costs. At the same time, wholesale electricity prices (or fuel cost projections) do not fully reflect transmission costs, may not fully reflect capital and fixed operating costs, and are reduced by virtue of any financial incentives provided to fossil-fueled generation and its fuel production cycle as well as by not fully accounting for the environmental and social costs of that generation. In addition, wind PPA prices—once established—are fixed and known, whereas wholesale electricity prices are short term and therefore subject to change over time (as shown in Figure 49, EIA and others project natural gas prices to rise, and therefore wholesale electricity prices to also increase, over time). Finally, the location of the wholesale electricity nodes and the assumption of a flat block of power are not perfectly consistent with the location and output profile of the sample of wind power projects.

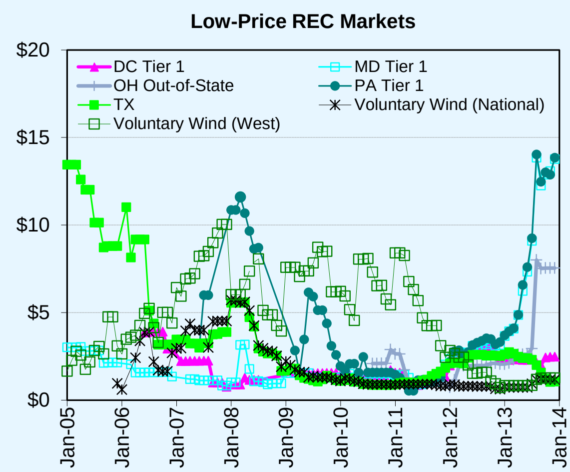
In short, comparing levelized long-term wind PPA prices with either yearly wholesale electricity prices or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to its competition. Nonetheless,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

REC Prices Remain High in the Northeast, Rise Modestly in Mid-Atlantic States

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

The figures below present indicative monthly data of spot-market REC prices in both compliance and voluntary markets, grouped into High-Price and Low-Price markets; data for compliance markets focus on the “Class I” or “Main Tier” of the RPS policies. Clearly, spot REC prices have varied substantially, both across states and over time within individual states, although prices across states within common regions (New England and PJM) are linked to varying degrees. Throughout 2013, REC prices in most Northeastern compliance markets remained relatively high, hovering around each state’s alternative compliance payment rate of $55 to $65/MWh, as supplies in the region continued to be tight. REC pricing in other compliance markets was considerably lower, though for the first time in several years, REC prices rose in PJM states in 2013 (, by year-end, however, those prices had begun to fall and have continued to decline in the first half of 2014). Prices for RECs offered in the voluntary market remained at roughly $1/MWh throughout 2013.





Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last monthly trade (if available) or the mid-point of monthly bid and offer prices, for REC vintages from the current or nearest future year traded in each month.

8. Policy and Market Drivers

Availability of Federal incentives for wind projects built in the near term has helped restart the domestic market, but policy uncertainty persists

Various policy drivers at both the federal and state levels have been important to the expansion of the wind power market in the United States, as have been federal investments wind energy research and development (R&D). In addition to R&D expenditure, at the federal level, the most important policy incentives in recent years have been the PTC (or, if elected, the ITC), accelerated tax depreciation, and an American Recovery and Reinvestment Act of 2009 (Recovery Act) provision that enabled wind power projects to elect, for a limited time, a 30% cash grant in lieu of the PTC. Because projects are no longer eligible for the cash grant, the focus in this section is on the PTC and accelerated depreciation.

- First established in 1992, the PTC provides a 10-year, inflation-adjusted credit that stood at 2.3¢/kWh in 2013. The historical importance of the PTC to the U.S. wind power industry is illustrated by the pronounced lulls in wind power capacity additions in the 4 years (2000, 2002, 2004, 2013) in which the PTC lapsed as well as the increased development activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 1); the spike in wind additions in 2012 is a clear example of this latter effect. In January 2013, the PTC was extended through the American Taxpayer Relief Act, as was the ability to take the 30% ITC in lieu of the PTC. To qualify, wind projects had to begin construction before the end of 2013: as a result of these provisions, significant wind power additions are expected in 2014 and 2015 as projects that began construction in 2013 reach commercial operations.
- Accelerated tax depreciation enables wind project owners to depreciate the vast majority of their investments over a 5- to 6-year period for tax purposes. An even more attractive 50% 1st-year "bonus depreciation" schedule was in place during 2008–2010. Legislation in mid-December 2010 further increased 1st-year bonus depreciation to 100% for those projects placed in service between September 8, 2010 and the end of 2011, after which the 1st-year bonus reverted to 50% for projects placed in service during 2012. The American Taxpayer Relief Act then extended this 50% bonus depreciation for qualifying property placed in service in 2013 (and 2014 for certain long-lived property).

In 2013, little concrete Congressional action occurred on what are seemingly among the wind power industry's two highest priorities—a longer-term extension of federal tax incentives and passage of a federal renewable or clean energy portfolio standard. Additionally, with the PTC now expired, and its renewal uncertain, wind deployment beyond 2015 is somewhat uncertain.

At the same time, the near-term availability of the PTC/ITC for those projects that reached the "under construction" milestone by the end of 2013 has helped restart the domestic wind market and should enable solid growth in capacity additions at least through 2015. Moreover, although the lack of long-term federal incentives for wind energy has been a drag on the industry, the prospective impacts of more-stringent EPA environmental regulations on fossil plant retirements and energy costs may create new markets for wind energy. Of special note are the actions to address carbon emissions that have been initiated at the EPA, which include proposed regulations released in late 2013 that would restrict carbon emissions from new power plants as well as proposed regulations released in June 2014 that would apply carbon restrictions to existing power plants. Finally, R&D investments by the U.S. DOE continue, and hold the prospect of helping to further reduce the cost of wind energy in the future.

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

From 1999 through 2013, 69% of the wind power capacity built in the United States was located in states with RPS policies; in 2013, this proportion was 93%.[66] As of June 2014, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 50).[67] Although no new state RPS policies were passed in 2013, some states strengthened previously established RPS programs. Attempts to weaken RPS policies also have been initiated in a number of states, and in limited cases—including in Ohio, in 2014—have led to meaningful changes in RPS design.

In aggregate, existing state RPS policies require that by 2025 (at which point most state RPS requirements will have reached their maximum percentage targets) at least 9% of total U.S. generation supply will be met with *RPS-eligible* forms of renewable electricity, equivalent to roughly 106 GW of renewable generation capacity.[68] Incremental growth in RPS requirements through 2025 represents 40% of projected growth in total U.S. electricity generation over that timeframe, although some portion of the growth in RPS requirements may be met with existing capacity (e.g., in regions that are currently over-supplied relative to their RPS targets).

Given the size of RPS targets and the amount of new renewable energy capacity that has been built since enactment of those policies, Berkeley Lab projects that existing state RPS programs require average annual renewable energy additions of roughly 3–4 GW/year through 2025, not all of which will be wind.[69] This is below the average of 7 GW of wind power capacity added in each year over the 2007–2013 period, and even further below the 9 GW per year of total renewable generation capacity added during that time frame, demonstrating the limitations of relying exclusively on state RPS demand to drive future wind power development.

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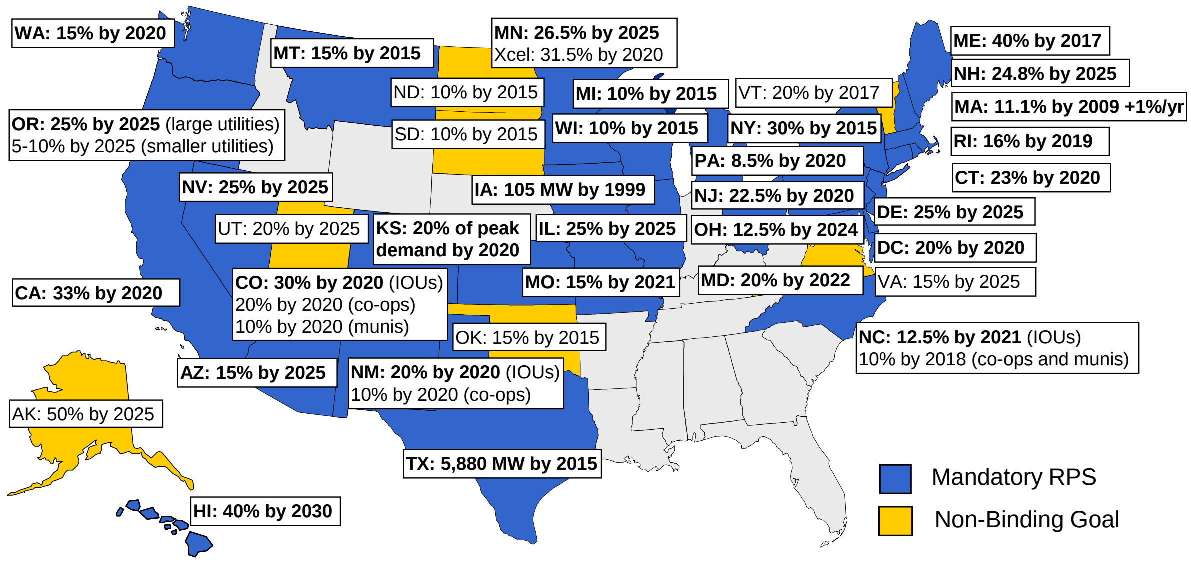
[66] Such statistics provide only a rough indication of the impact of RPS policies on wind power development and could either overstate or understate the actual policy effect to date.

[67] Mandatory RPS policies and non-binding renewable energy goals also exist in a number of U.S. territories, but are not shown in Figure 50.

[68] Berkeley Lab's projections of new renewable capacity required to meet each state's RPS requirements assume different combinations of renewable resource types for each RPS state, although they do not assume any biomass co-firing at existing thermal plants. To the extent that RPS requirements are met with a larger proportion of high-capacity-factor resources than assumed in this analysis or with biomass co-firing at existing thermal plants, the required new renewable capacity would be lower than the projected amount presented here.

[69] Again, varying combinations of renewable resource types for each RPS state were assumed in estimating the 3–4 GW/year of average annual renewable capacity additions required to meet RPS obligations through 2025. As a point of comparison, AWEA (2013) forecasts roughly 2.4 GW/year of wind additions from 2013 through 2025 as a result of state RPS requirements.



Source: Berkeley Lab

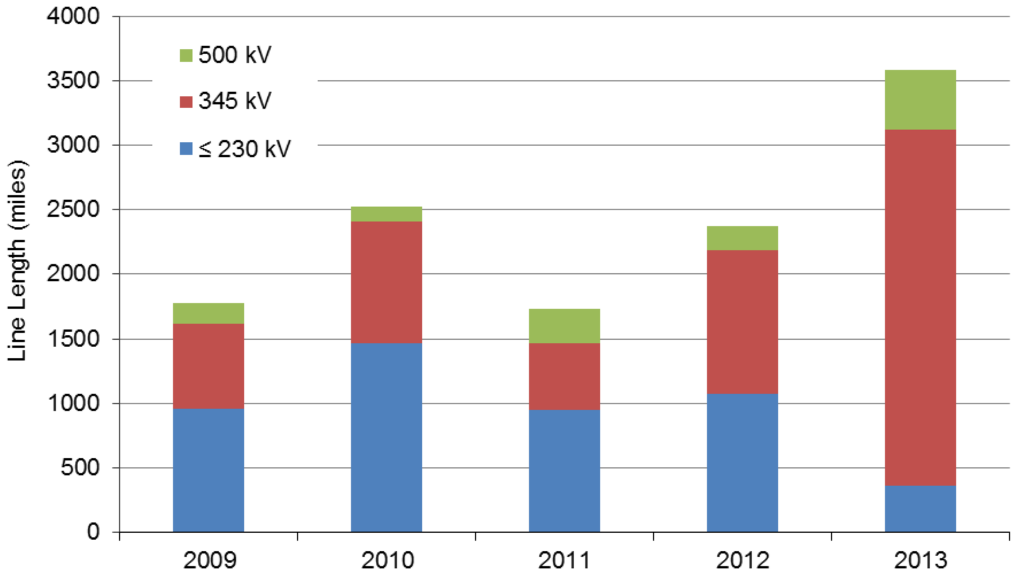
Note: The figure does not include West Virginia's mandatory "alternative and renewable energy portfolio standard" or Indiana's voluntary "clean energy standard." Under these two states' policies, both renewable and non-renewable energy resources may qualify, but neither state specifies any minimum contribution from renewables. Thus, for the purposes of the present report, these two states are not considered to have enacted mandatory RPS policies or non-binding renewable energy goals. Also not included in the figure are the mandatory RPS and non-binding renewable energy goals established in U.S. territories. Finally, note that many states have multiple "tiers" within their RPS policies: these details are not summarized in the figure.

Figure 50. State RPS policies and non-binding renewable energy goals (as of August 2014)

In addition to state RPS policies, utility resource planning requirements, principally in Western and Midwestern states, have also helped spur wind power additions in recent years, as has voluntary customer demand for "green" power. State renewable energy funds provide support for wind power projects (both financial and technical) in some jurisdictions, as do a variety of state tax incentives. Finally, concerns about the possible impacts of global climate change continue to fuel interest in some states and regions to implement and enforce carbon-reduction policies. The Northeast's Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy, for example, has been operational for several years, and California's greenhouse gas cap-and-trade program commenced operation in 2012, although carbon pricing seen to date has been too low to drive significant wind energy growth. At the same time, other states have expressed some skepticism about these efforts, and a number of states have withdrawn, or undertaken steps toward withdrawal, from regional greenhouse gas reduction initiatives. How these dynamics will evolve as the EPA steps in to regulate power sector carbon emissions remains unclear.

Solid progress on overcoming transmission barriers continued

Transmission development has gained traction in recent years. FERC reports that over 3,500 miles of transmission lines came on-line in 2013, a significant increase from recent years (Figure 51). Another 15,000 miles of transmission lines are in various stages of development with a proposed on-line date of 2016 or earlier, with about one-third of those lines having a high probability completion (FERC 2014). According to the Edison Electric Institute (EEI), total transmission investment by investor-owned utilities reached $17.5 billion in 2013. EEI forecasts a decrease in investment in 2014 and 2015, primarily attributable to recent economic conditions and the continuance of low electric demand growth. Nonetheless, EEI identified over 170 transmission projects in development representing more than $60 billion in possible investment, 76% of which would—at least in part—support the integration of renewable energy (EEI 2014).



Source: FERC monthly infrastructure reports

Figure 51. Miles of transmission projects completed, by year and voltage

Lack of transmission can be a barrier to new wind power development, and insufficient transmission capacity in areas where wind projects are already built can lead to curtailment, as illustrated earlier. New transmission is particularly important for wind energy because wind power projects are constrained to areas with adequate wind speeds, which are often located at a distance from load centers. There is also a mismatch between the relatively short timeframe often needed to develop a wind power project compared to the longer timeframe typically required to build new transmission. Uncertainty over transmission siting and cost allocation, particularly for multi-state transmission lines, further complicates transmission development.

One of the most significant transmission undertakings devoted to wind power, the Competitive Renewable Energy Zones (CREZ) project in Texas, was largely finished by the end of 2013. The CREZ includes almost 3,600 circuit miles of transmission lines and was designed to accommodate up to 18,500 MW of total wind power capacity, 11,500 MW of which is additional to what existed when the lines were planned in 2008.[70] The $6.8 billion cost of CREZ was $2 billion higher than first estimated, in part because over 600 circuit miles of additional transmission lines were needed to accommodate requested changes in routing from landowners. Because of CREZ, ERCOT reports that wind-related congestion between West Texas and other zones has largely disappeared. Moreover, ERCOT predicts that over 7,000 MW of new wind capacity will be installed in Texas by the end of 2015, with another 1,300 MW projected to come online in 2016. ERCOT recently issued a report stating that projected wind development in the

[70] The total wind capacity that can be accommodated in ERCOT with CREZ is likely to significantly exceed 18,500 MW, in part because many projects have been or will be built in locations that are not dependent on the CREZ lines.

Texas Panhandle is exceeding expectations, and additional transmission, reactive power and synchronous condensers will need to be added (ERCOT 2014). Partly in response, the Texas PUC has opened a staff investigation on whether any such costs should be assigned to renewable energy generators rather than to all customers, as is currently the case (Texas PUC 2014).

Elsewhere, NV Energy and Great Basin Transmission South, an affiliate of LS Power, completed the 236 mile, 500-kV, One Nevada transmission project that connects NV Energy and Sierra Pacific Power. LS Power is also developing two other transmission projects: the 500-kV Southern Nevada Intertie Project and the 500-kV Southwest Intertie Project North, both of which in combination with the ON Line could transmit over 2,000 MW. Two other transmission projects of importance to wind that were completed in 2013 include: (1) the Montana-Alberta Tie Line, a 230-kV merchant transmission line capable of transmitting 300 MW that connects Alberta to Northwestern Energy in Montana; and (2) the Pawnee-Smoky Hill double-circuit, 345-kV transmission line between the cities of Brush and Aurora in Colorado, which can transmit 300 to 500 MW of generation. Finally, in Maine, Emera Maine and Central Maine Power entered into a memorandum of understanding to study and perhaps develop transmission projects to support 2,100 MW of wind.

AWEA (2014a) has identified 15 near-term transmission projects that—if all were completed—could carry almost 60 GW of additional wind power capacity. These transmission projects are summarized in Table 6. Because AWEA focused on near-term transmission projects, longer-term transmission projects, such as the Tres Amigas project in New Mexico that, if developed, would tie the Western, Eastern and Texas grids together, are not included in the table.

Table 6. Planned near-term transmission projects and potential wind capacity

Transmission Project Name (State)	Voltage (kilovolts)	Estimated In-service Date	Estimated Potential Wind Capacity, MW
CapX (MN, SD, ND, WI)	345, one 230 line	2014	5,000
BPA Open Season (OR, WA)	500	2014	4,200
Tehachapi Phases 2-3 (CA)	500	2015	3,800
Maine Power Reliability Program (ME)	345, 115	2015	1,500
Lower Rio Grande Valley (TX)	345	2016	1,500
CO-WY Intertie (CO, WY)	345	2016	900
SPP Priority Projects (TX, OK, KS, MO)	345	2013-2017	3,200
Midwest ISO Multi-Value Projects (ND, SD, IA, MN, WI, IL, MO, MI)	345, one 765 line	2015-2020	14,000
Colstrip Upgrade Project (MT)	500	2016	480
Transwest Express (WY)	600 DC	2016	3,000
Sunzia (NM, AZ)	500	2016	3,000
Clean Line Projects (KS, OK, TX, NM, IA)	600 DC	2017-2018	14,000
Gateway West (WY, ID)	500	2018	3,000
Gateway South (WY, UT)	500	2018	1,500
Boardman-Hemingway (OR, ID)	500	2018	1,000
Total Potential New Transmission Capacity			**~60,000**

Source: AWEA (2014a)

FERC continued to implement Order 1000 in 2013, which requires public utility transmission providers to improve intra- and inter-regional transmission planning processes and to determine cost allocation methodologies for new transmission facilities. The transmission planning requirements established in Order 1000 include the development of regional transmission plans, mandatory participation in regional transmission planning, consideration of transmission needs driven by state and federal policy requirements (such as state RPS policies), and transmission planning coordination between neighboring balancing authorities (FERC 2011). FERC issued more than 40 orders in 2013 concerning the initial compliance filings under Order 1000, which described how FERC-regulated transmission providers would comply with the regional transmission planning and regional cost allocation requirements. FERC also received a second set of compliance filings in July 2013 concerning the inter-regional planning coordination and inter-regional cost allocation requirements of Order 1000. FERC has not yet issued any orders for these second set of compliance filings. Separately, the U.S. District of Columbia Circuit Court of Appeals is deliberating over a petition by the American Public Power Association, the National Association of Regulatory Utility Commissioners, and several electric utilities over whether FERC has the statutory authority to issue and implement Order 1000.

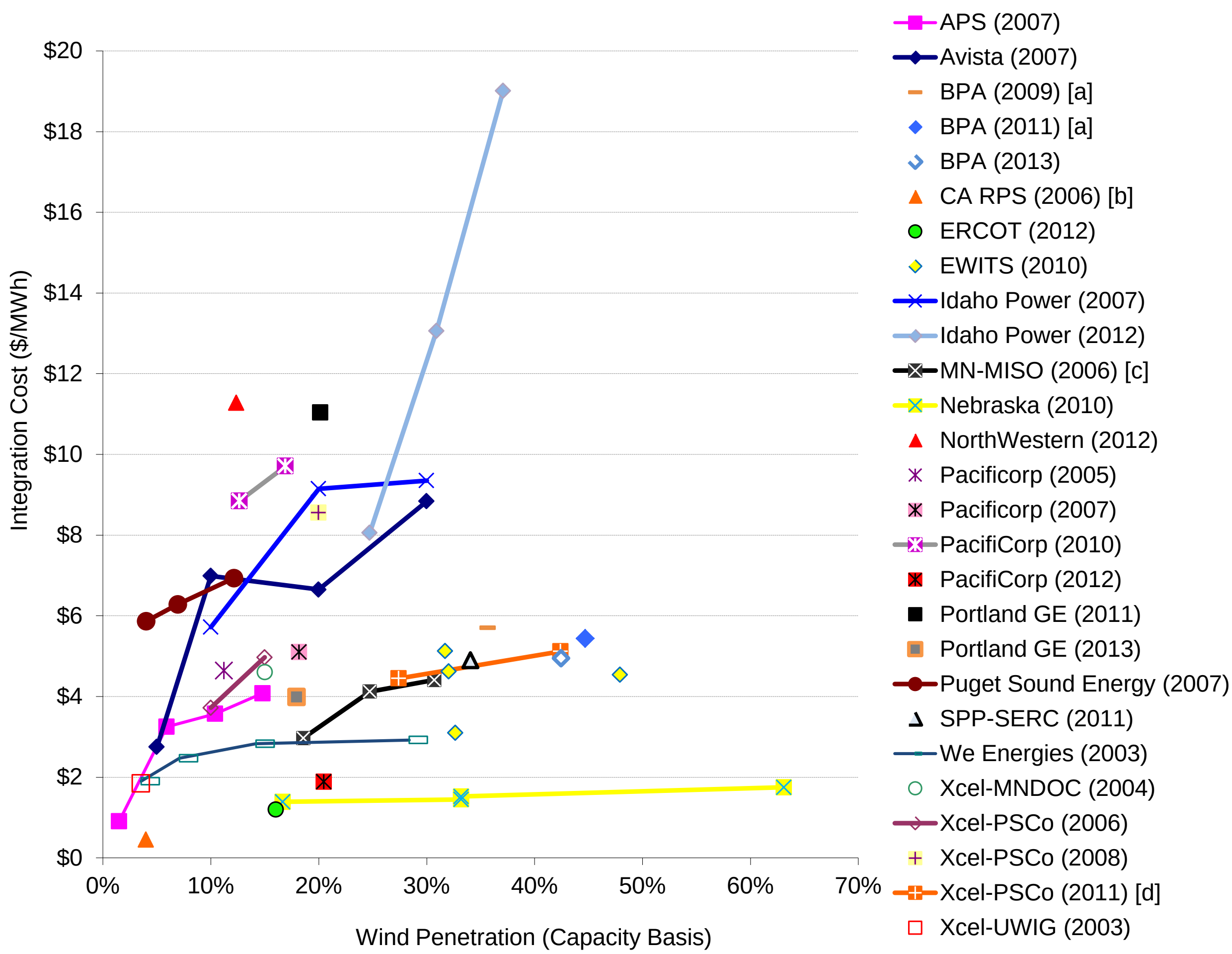
System operators are implementing methods to accommodate increased penetration of wind energy

Due to the variable nature of wind, considerable attention is paid to the potential impacts of wind energy on power systems. Concerns about, and solutions to, these issues have affected, and continue to impact, the pace of wind power deployment in the United States. Experience in operating power systems with wind energy is also increasing worldwide, leading to an emerging set of best practices (Exeter and GE 2012, WGA 2012).

Figure 52 provides a selective listing of estimated wind integration costs associated with increased wind energy from integration studies completed from 2003 through 2013 at various levels of wind power capacity penetration. With one exception, wind integration costs estimated by the studies reviewed are below $12/MWh—and often below $5/MWh—for wind power capacity penetrations up to and even exceeding 40% of the peak load of the system in which the wind power is delivered. Variations in estimated costs across studies are due, in part, to differences in methodologies, definitions of integration costs, power system and market characteristics, wind energy penetration levels, fuel price assumptions, and the degree to which thermal power plant cycling costs are included.

Because methods vary and a consistent set of operational impacts has not been included in each study, results from the different analyses of integration costs are not fully comparable. Porter et al. (2013) provide additional details summarizing many of the studies included here. Note also that the rigor with which the various studies have been conducted varies, as does the degree of peer review. Finally, there has been some recent literature questioning the methods used to estimate wind integration costs and the ability to disentangle those costs explicitly, while also highlighting the fact that other generating options also impose integration challenges and costs to electricity systems (Milligan et al. 2011).

Two new integration costs studies were completed in 2013, both by organizations that had previously completed studies already included in this review: Portland General Electric (PGE) and BPA. In both cases, the new wind integration cost estimate was lower than in the previous study by the same entity. In the case of PGE, the substantial reduction (from over $11/MWh to less than $4/MWh) was attributed to the addition of flexible balancing resources and increased wind diversity (PGE 2014).



[a] Costs in $/MWh assume 31% capacity factor.
[b] Costs represent 3-year average.
[c] Highest over 3-year evaluation period.
[d] Cost includes the coal cycling costs found in Xcel Energy (2011).

Figure 52. Integration costs at various levels of wind power capacity penetration[71]

In addition to wind integration costs, a number of studies examine the impact of changes to existing practices in power system operations, the role of forecasting, and the capability of supply- and demand-side technologies in providing the needed flexibility to integrate wind power. Conclusions from recent integration studies include the following:

[71] References for studies conducted prior to 2013 can be found in previous versions of the Wind Technology Market Report. Sources for new studies include: BPA (2013) and PGE (2014).

- The PJM Renewable Integration Study (GE 2014) found no significant operational issues with up to 30% of PJM's energy coming from wind and solar, given adequate transmission expansion and additional regulating reserves.
- The Western Wind and Solar Integration Study Phase II (Lew et al. 2013) and the PJM study (GE 2014), among other studies, include an assessment of cycling costs. In both studies, cycling was found to increase with more renewables, though the associated costs were modest. In the West, accounting for cycling costs was found to reduce the benefits of wind and solar by $0.14-0.67/MWh. In PJM, the increased cycling costs did not significantly affect the overall economic impact of the renewable generation. Both studies found the reduction in wind's emissions savings from cycling impacts to be relatively small.
- The Manitoba Hydro Wind Synergy Study (Bakke et al. 2013) found significant benefits associated with adding a 500 kV transmission line from hydro-rich Manitoba to MISO. The benefits include reduced wind curtailment in the northern MISO, a reduction in cost for MISO, and expanded revenue for Manitoba Hydro.
- The Eastern Frequency Response Study (Miller et al. 2013) examined frequency response in the Eastern Interconnection in cases with up to 24% of power being generated by wind in the interconnection. It found no evidence that adding wind generation will inevitably degrade frequency response, and highlights existing technical options to maintain adequate frequency response. NREL also released a study on the capabilities of wind to provide active power control in the form of primary frequency response, inertial response, and regulation through automatic-generation control, finding that active power control from wind can be used to support power system reliability (Ela et al. 2014).

In addition to studies, system operators continue to implement methods to accommodate increased penetration of wind energy:

- Centralized wind energy forecasting systems are currently in place in all ISO/RTO areas, and are also in use by a growing number of electric utilities (Exeter and GE 2012). A number of utilities in the West view forecasts as vital for meeting reliability requirements and efficient scheduling of resources (Widiss and Porter 2014).
- ISOs continue to refine scheduling and commitment processes, including updates like the MISO look-ahead commitment, the incorporation of wind into dispatch at MISO, the flexible ramping constraint at the CAISO, and sub-hourly exchange between markets.
- FERC conditionally approved the CAISO and PacifiCorp's proposal to implement an Energy Imbalance Market (EIM), which is expected to come online in October 2014. NVEnergy filed requests with the Nevada Public Utilities Commission and FERC to join the EIM by October 2015. Economic studies indicate that the benefits to PacifiCorp and NVEnergy of joining the EIM will exceed the costs (E3 2013, 2014).

Some utilities continue to charge wind projects directly for balancing services. BPA, Nebraska Public Power District, Puget Sound Energy, and Westar Energy all differentiate balancing charges for variable energy renewables, including wind.[72] FERC rejected a proposal by PacifiCorp for a new wind integration charge, in part due to PacifiCorp's failure to include the FERC Order 764 reforms (namely, the requirement for 15-min scheduling). Xcel Energy (Colorado) filed a proposal for a new wind integration charge with FERC in May 2014. Similar charges to recover costs associated with regulation reserves will continue to be evaluated on a case-by-case basis by FERC according to Order 764 (FERC 2012). As of April 2014, 36 public utilities outside of RTO markets and six RTOs had filed compliance plans at FERC for Order 764. The majority of public utilities rely on the pro-forma tariff language of Order 764, while the RTOs have filed more complex compliance plans due to the need to integrate reforms with their particular market structures.

[72] In addition, Idaho Power, Avista, and PacifiCorp all discount their published avoided cost payments for qualifying wind power projects in Idaho by an integration rate that ranges from 7-9% of the avoided cost rate, up to $6.50/MWh. Idaho Power recently proposed to update its wind integration rate to be consistent with its most recent wind integration study, resulting in integration costs in the range of $6.83 to $34.7/MWh depending on the amount of wind deployment and whether higher integration costs are allocated to all wind contracts or only to new wind contracts (Idaho Power 2013)

9. Future Outlook

The meager 1,087 MW of wind capacity additions in 2013 was below all forecasts presented in last year's edition of the *Wind Technologies Market Report*. A key factor driving this outcome was the limited motivation for projects to achieve commercial operations by year-end 2013 as a result of a late extension of the PTC in January 2013 that also altered PTC-eligibility guidelines to only require construction to have begun by the end of that year.

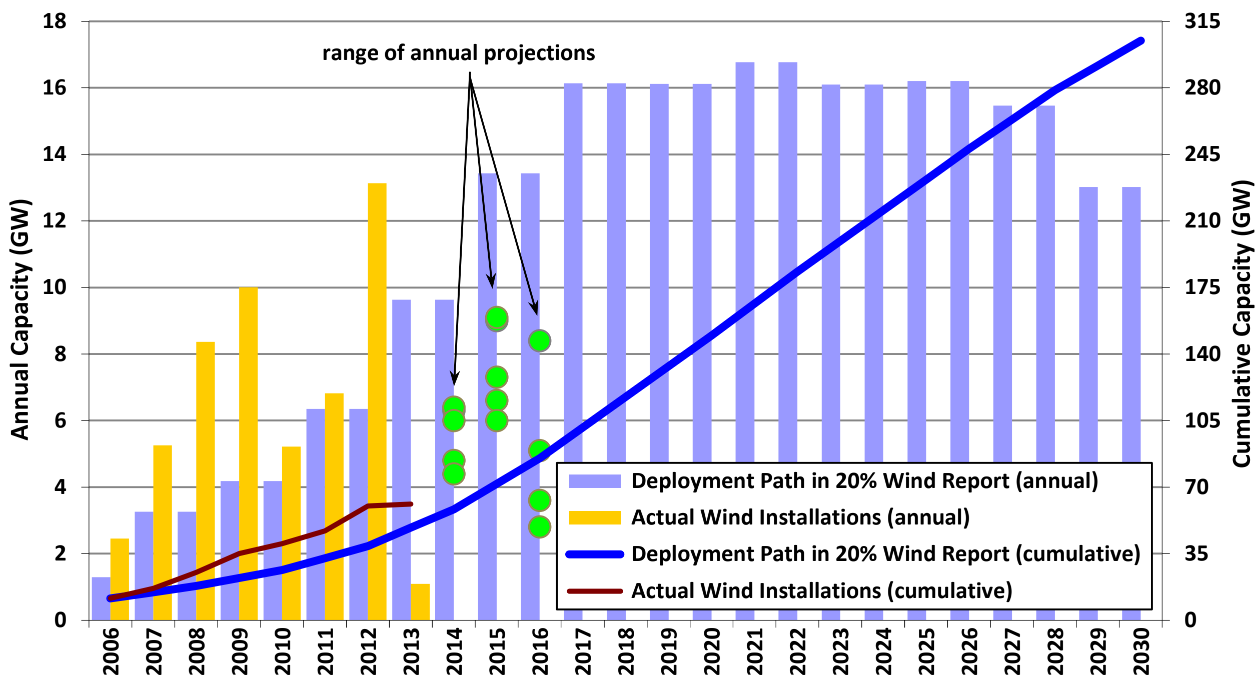
Because federal tax incentives are available for projects that initiated construction by the end of 2013, significant new builds are anticipated in 2014 and 2015 as those projects are commissioned. Near-term wind additions will also be driven by the recent improvements in the cost and performance of wind power technologies, leading to the lowest power sales prices yet seen in the U.S. wind sector. Among the forecasts for the domestic market presented in Table 7, expected capacity additions range from 4,400 to 6,400 MW in 2014, and from 6,000 to 9,100 in 2015. With AWEA (2014b) reporting that more than 13,000 MW of wind power was under construction at the end of the first quarter of 2014, the industry appears to be on track to meet these expectations. Still, the upper end of the forecast range for 2014 and for 2015 does not approach the record build level achieved in 2012.

Table 7. Forecasts for annual U.S. wind capacity additions (MW)

Source	2014	2015	2016	Notes
Bloomberg NEF (2014c)	6,000	9,000	3,600	Assumes no PTC extension beyond current law
IHS EER (2014)	4,800	7,300	8,400	Assumes one PTC extension for 2016
Navigant (2014)	6,300	6,000	2,800	Assumes no PTC in 2016
MAKE Consulting (2014)	6,400	6,600	5,100	Assumes one PTC extension for 2016
EIA (2014b)	4,400	9,100	na	Assumes no PTC extension beyond current law

Projections for 2016 and beyond are much less certain. The PTC has expired, and its renewal remains in question. Expectations for continued low natural gas prices, modest electricity demand growth, and limited near-term renewable energy demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and growing competition from solar energy in certain regions of the country. Industry hopes for a federal renewable or clean energy standard, or climate legislation, have also dimmed in the near term. At the same time, recent declines in the price of wind energy have been substantial, helping to improve the economic position of wind even in the face of relatively low natural gas prices and boosting the prospects for future growth even if state and federal incentives decline. The potential for continued technological advancements and cost reductions through public and private R&D further enhance the prospects for longer-term growth. Additionally, new and proposed EPA regulations, and the impact of those regulations on fossil plant retirements and demand for low-carbon energy sources, may create new markets for wind energy. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse uncertainties, it is no surprise that the forecasts for market growth in 2016 reported in Table 7 span a wide range, from 2,800 MW to 8,400 MW.

Regardless of future uncertainties, and despite the poor showing in 2013, wind power capacity additions in recent years have put the United States on an early trajectory that may lead to 20% of the nation's electricity demand coming from wind energy by 2030 (Figure 53). In 2008, DOE published a report that analyzed the technical and economic feasibility of achieving 20% wind energy penetration by 2030 (DOE 2008). The 2008 study found no insurmountable barriers to reaching 20% wind energy penetration, and laid out a potential wind power deployment path that started at 3.3 GW/year in 2007, increasing to 4.2 GW/year by 2009, 6.4 GW/year by 2011, 9.6 GW/year by 2013, 13.4 GW/year by 2015, and roughly 16 GW/year by 2017 and thereafter, yielding cumulative wind power capacity of 305 GW by 2030. Historical growth over the last eight years puts the United States on a trajectory exceeding this deployment path. Nonetheless, annual wind additions in 2013 fell well short of the pathway envisioned in the 2008 DOE report, and projections for additions in 2014 through 2016 similarly fall short of the growth envisioned in the 2008 report for those years. These developments suggest that achieving 20% wind energy by 2030 may require efforts and investment that go beyond business as usual expectations. A revised *Wind Vision* analysis from the DOE is underway, to be released in the upcoming months: it will describe the impacts, costs, and benefits of maintaining strong near- and long-term growth in U.S. wind power additions, and will also provide a roadmap of actions to reduce wind energy costs and increase wind deployment.



Source: DOE 2008 (20% wind scenario), AWEA (historical additions), Table 7 (projected additions)

Figure 53. Wind power capacity growth: 20% wind report, actual installations, projected growth

Appendix: Sources of Data Presented in this Report

Installation Trends

Data on wind power additions in the United States (as well as certain details on the underlying wind power projects) come from AWEA, although methodological differences noted throughout this report result in some discrepancies in the data presented here relative to AWEA (2014a). We thank AWEA for the use of their comprehensive wind project database. Annual wind power capital investment estimates derive from multiplying these wind power capacity data by weighted-average capital cost data, provided elsewhere in the report. Data on non-wind electric capacity additions come primarily from EIA (for years prior to 2013) and Ventyx's Velocity database (for 2013), except that solar data come from the Interstate Renewable Energy Council and Solar Energy Industries Association (SEIA)/GTM Research. Information on offshore wind power development activity in the United States was compiled by Navigant.

Global cumulative (and 2013 annual) wind power capacity data come from Navigant (2014) but are revised to include the U.S. wind power capacity used in the present report. Wind energy as a percentage of country-specific electricity consumption is based on year-end wind power capacity data and country-specific assumed capacity factors that come from Navigant (2014), as revised based on a review of EIA country-specific wind power data. For the United States, the performance data presented in this report are used to estimate wind energy production. Country-specific projected wind generation is then divided by country-specific electricity consumption; the latter is estimated based on actual past consumption as well as forecasts for future consumption based on recent growth trends (these data come from EIA).

The wind power project installation map was created by NREL, based in part on AWEA's database of projects and in part on data from Ventyx's Velocity database on the location of individual projects. Wind energy as a percentage contribution to statewide electricity generation is based exclusively on wind generation data divided by in-state total electricity generation in 2013, using EIA data.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO, RTO, or utility. Only projects that were active in the queue at the end of 2013, but that had not yet been built, are included. Suspended projects are not included in these listings. Data on projects that are in the nearer-term development pipeline come from Ventyx (2014) and AWEA (2014b).

Industry Trends

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

Information on wind turbine and component manufacturing comes from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. Data on U.S. nacelle assembly capability come from Bloomberg NEF (2014a), while U.S. tower and blade manufacturing capability come from AWEA (2014a). The listings of manufacturing and supply-chain facilities are not intended to be exhaustive. OEM profitability data come from a Berkeley Lab review of turbine OEM annual reports.

Data on U.S. imports and exports of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. International Trade Commission (USITC), and can be obtained from the USITC's DataWeb (http://dataweb.usitc.gov/). Additional data and information were provided by GLWN, under contract to Berkeley Lab. The analysis of USITC trade data relies on the "customs value" of imports as opposed to the "landed value" and hence does not include costs relating to shipping or duties. The table below lists the specific trade codes used in the analysis presented in this report. For more information on the USITC data and their application to wind energy, see David (2009, 2010, 2011).

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	2006-2013	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 and lattice masts - tubular	2011-2013	virtually all for wind turbines
8501.64.0020	AC generators (alternators) from 750 to 10,000 kVA	2006-2011	not exclusive to wind turbine components
8501.64.0021	AC generators (alternators) from 750 to 10,000 kVA for Wind-powered Generating sets	2012–2013	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	2012–2013	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	2012–2013	exclusive to wind turbine components
8483.40.5010	fixed ratio speed changers	2006-2013	not exclusive to wind turbine components
8483.40.5050	multiple and variable ratio speed changers	2006-2013	not exclusive to wind turbine components

As shown in the table above, some trade codes are exclusive to wind, whereas others are not. As such, assumptions are made for the proportion of wind-related equipment in each of the larger non-wind-specific HTS trade categories. These assumptions are based on: an analysis of recent trade data where separate, wind-specific trade categories exist; a review of the countries of origin for the imports; personal communications with USITC and AWEA staff; USITC trade cases (ITC 2012, ITC 2013); and import patterns in the larger HTS trade categories. The assumptions generally reflect the rapidly increasing imports of wind equipment from 2006–2008, the subsequent decline in imports from 2008–2010, the slight increase from 2010–2012, and again the dramatic decline in 2013. To reflect uncertainty in these proportions, a ±10% variation is applied to the larger trade categories that include wind turbine components other than gearboxes, a ±20% variation is applied to the categories that include gearboxes prior to 2013 (the larger uncertainty for gearboxes reflects the relative paucity of data that can be used to estimate a more precise point estimate for wind-related imports), and a ±10% variation is applied to the categories that include gearboxes in 2013 (to account for modest wind deployment that year). Information on wind power financing trends was compiled by Berkeley Lab. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of the AWEA project database.

Wind Turbine Technology Trends

Information on turbine hub heights, rotor diameters, specific power, and IEC Class was compiled by Berkeley Lab based on information provided by AWEA, turbine manufacturers, standard turbine specifications, Federal Aviation Administration data, web searches, and other sources. Some turbines—especially in recent years—have not been rated within a numerical IEC Class, but are instead designated as Class "S", for special. In such instances, we assigned turbines to the numerical IEC Class that best matched the specific power of the turbine, sometimes in consultation with the OEM.

Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

Performance, Cost, and Pricing Trends

Wind project performance data are compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment of Berkeley Lab staff. Data on curtailment are from ERCOT (for Texas), MISO (for the Midwest), Xcel Energy (for its Northern States Power Company, Public Service Company of Colorado, and Southwestern Public Service Company subsidiaries), PJM, NYISO, and BPA (for the Northwest).

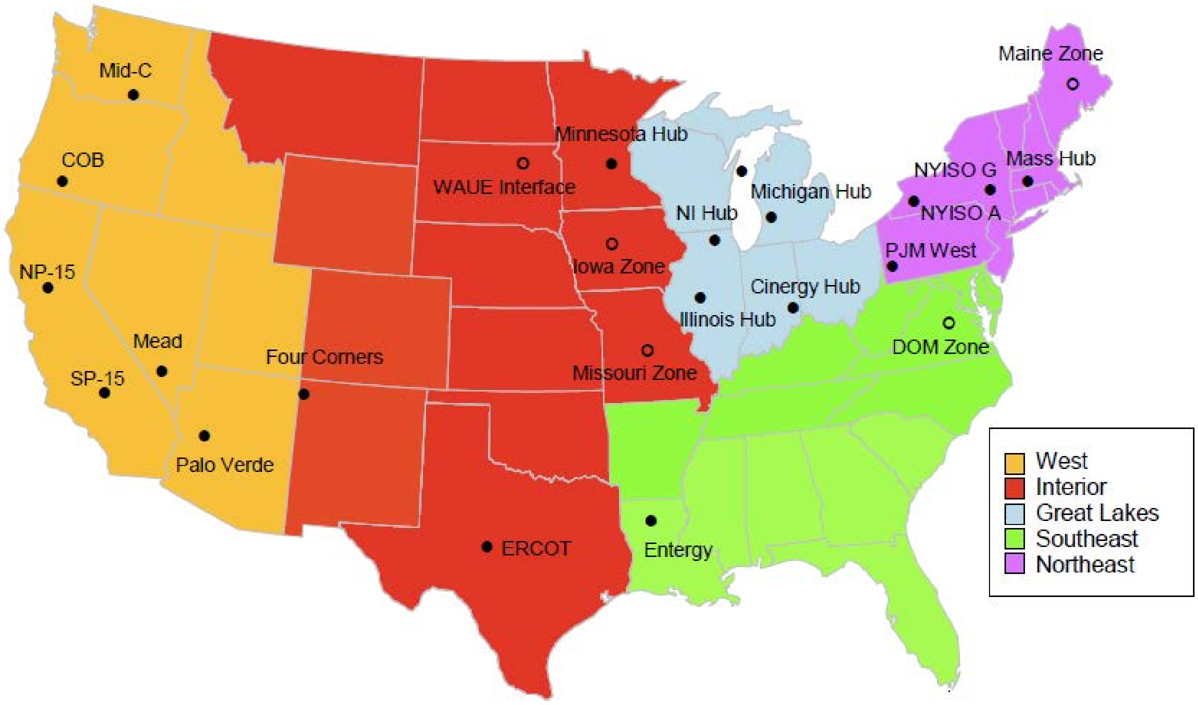
The following procedure was used to estimate the quality of the wind resource in which wind projects are located. First, the location of individual wind turbines and the year in which those turbines were installed were identified using Federal Aviation Administration Digital Obstacle (i.e., obstruction) files (accessed via Ventyx' Intelligent Map) and Berkeley Lab data on individual wind projects. Second, NREL used data from AWS Truepower—specifically, gross capacity factor estimates with a 200-meter resolution—to estimate the quality of the local wind resource at an 80-meter height for each of those turbines. These gross capacity factors are derived from average mapped 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). To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100% assigned in that period. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998-1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the "lower" category includes all projects or turbines with an estimated gross capacity factor of less than 35%, the "medium" category corresponds to ≥35%–42.5%, the "higher" category corresponds to ≥42.5%–50%, and the "highest" category corresponds to ≥50%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 33,553 turbines representing 57,384

MW of capacity installed from 1998 through 2013, or 96% of all wind power capacity installed in the continental United States over that period.
Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission and other regulatory filings. In part because wind turbine transactions vary in the turbines and services offered, a good deal of intra-year variability in the cost data is apparent.

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 power projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, FERC Form 1, various Securities and Exchange Commission filings, various 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. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not equally credible, little emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer insight. Only wind power 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 2001–2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. Some data points are suppressed in the figures to protect data confidentiality.

Wind PPA price data are based on multiple sources, including prices reported in FERC's *Electronic Quarterly Reports*, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs. Wholesale electricity price data were compiled by Berkeley Lab from the IntercontinentalExchange (ICE) as well as Ventyx's Velocity database (which itself derives wholesale price data from the ICE and the various ISOs). Earlier years' wholesale electricity price data come from FERC (2007, 2005). Pricing hubs included in the analysis, and within each region, are identified in the map below. To compare the price of wind to the cost of future natural gas-fired generation, a range of fuel cost projections from the Energy Information Administration's *Annual Energy Outlook 2014* publication are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (these heat rates start at roughly 8,300 Btu/kWh and gradually decline to around 7,100 Btu/kWh by 2040). REC price data were compiled by Berkeley Lab based on information provided by Evolution Markets and Spectron.



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

Map of regions and wholesale electricity price hubs used in analysis

Policy and Market Drivers

The wind energy integration, transmission, and policy sections were written by staff at Berkeley Lab and Exeter Associates, based on publicly available information.

Future Outlook

This chapter was written by staff at Berkeley Lab, based largely on publicly available information.

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wind.energy.gov

Lawrence Berkeley National Laboratory
emp.lbl.gov/research-areas/renewable-energy

National Renewable Energy Laboratory
www.nrel.gov/wind

Sandia National Laboratories
sandia.gov/wind

Pacific Northwest National Laboratory
energyenvironment.pnnl.gov/eere/

Lawrence Livermore National Laboratory
missions.llnl.gov/energy/technologies/wind-forecasting

Oak Ridge National Laboratory
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Argonne National Laboratory
www.anl.gov/energy/renewable-energy

Idaho National Laboratory
inlportal.inl.gov/portal/server.pt/community/energy_and_environment/278

Savannah River National Laboratory
srnl.doe.gov/energy-secure.htm

American Wind Energy Association
awea.org

Database of State Incentives for Renewables & Efficiency
dsireusa.org

International Energy Agency – Wind Agreement
ieawind.org

National Wind Coordinating Collaborative
nationalwind.org

Utility Variable-Generation Integration Group
variablegen.org/newsroom/

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On the Cover

Pete Johnson of Gemini Rope Access Solutions, inspects the blades of a 3MW Alstom wind turbine by repelling down the blades. The turbine is undergoing testing at NREL's National Wind Technology Center (NWTC) in Boulder, Colorado.

Photo from Dennis Schroeder, NREL 27196

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