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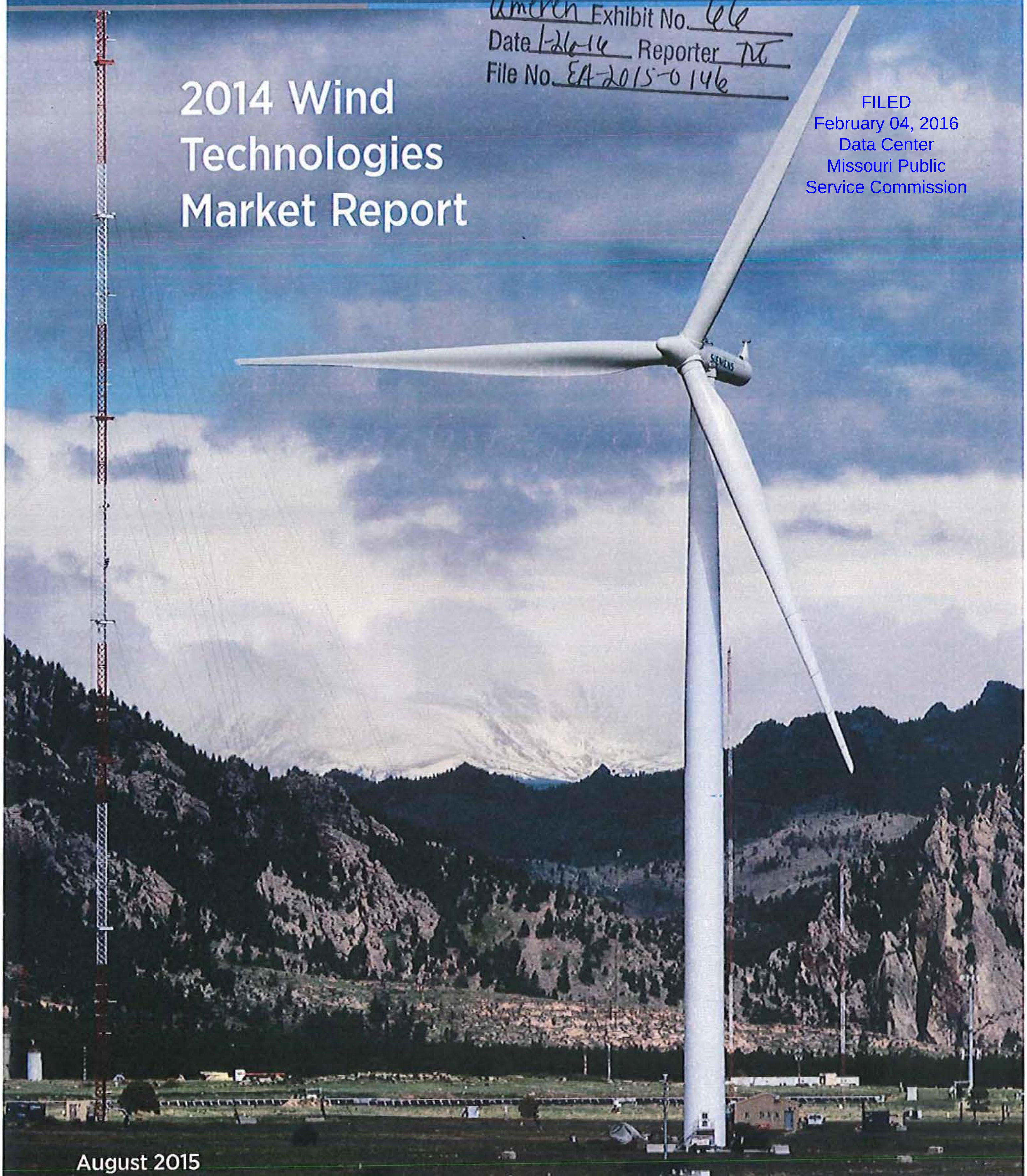
2014 Wind Technologies Market Report



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2014 Wind Technologies Market Report

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Acronyms and Abbreviations

AWEA	American Wind Energy Association
Bloomberg NEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
BOEM	Bureau of Ocean Energy Management
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
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
NYISO	New York Independent System Operator
O&M	operations and maintenance
OEM	original equipment manufacturer
PJM	PJM Interconnection
POU	publicly owned utility
PPA	power purchase agreement
PTC	production tax credit
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative

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

Executive Summary

Wind power capacity additions in the United States rebounded in 2014, and continued growth through 2016 is anticipated. Recent and projected near-term growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—which is available for projects that began construction by the end of 2014. Wind additions are also being driven by recent improvements in the cost and performance of wind power technologies, which have resulted in the lowest power sales prices ever seen in the U.S. wind sector. Growing corporate demand for wind energy and state-level policies play important roles as well. Expectations for continued technological advancements and cost reductions may further boost future growth. At the same time, the prospects for growth beyond 2016 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 growth expectations. These trends, in combination with increasingly global supply chains, have limited the growth of 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.

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

Installation Trends

- **Wind power additions rebounded in 2014, with 4,854 MW of new capacity added in the United States and $8.3 billion invested.** After a lackluster year in 2013, cumulative wind power capacity grew by nearly 8%, bringing the total to 65,877 MW.
- **Wind power represented 24% of electric-generating capacity additions in 2014.** Wind power was the third-largest source of new generation capacity in 2014, after natural gas and solar. 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 (49%) regions. Its contribution to generation capacity growth over that period is somewhat smaller in the Northeast (27%) and West (26%), and considerably less in the Southeast (2%).
- **The United States ranked third in annual wind additions in 2014, but was well behind the market leaders in wind energy penetration.** Global wind additions reached a new high in 2014, with cumulative capacity standing at 372,000 MW. The United States remained the second leading market in terms of cumulative capacity, but was the leading country in terms of wind power production. A number of countries have achieved high levels of wind penetration: end-of-2014 wind power is estimated to supply the equivalent of roughly 39% of Denmark's electricity demand and more than 20% of Ireland, Portugal, and Spain's demand. In the United States, the wind power capacity installed by the end of 2014 is estimated, in an average year, to equate to 4.9% of electricity demand.
- **Texas installed the most capacity in 2014 with 1,811 MW, while nine states exceed 12% wind energy penetration.** New utility-scale wind turbines were installed in nineteen states in 2014. On a cumulative basis, Texas remained the clear leader, with more than 14,000 MW installed. Notably, the wind power capacity installed in Iowa and South Dakota supplied more than 28% and 25%, respectively, of all in-state electricity generation in 2014, with

Kansas close behind at nearly 22%. In six other states wind supplied between 13% and 18% of all in-state electricity generation in 2014.

- **No commercial offshore turbines have been commissioned in the United States, but progress toward the first U.S. offshore wind project in Rhode Island continued in 2015 amid mixed market signals.** At the end of 2014, global offshore wind capacity stood at roughly 7.7 GW. Though no commercial offshore projects have been installed in the United States, a project in Rhode Island started construction in 2015. Projects in Massachusetts, New Jersey, and Virginia, meanwhile, all experienced set-backs. Strides continued to be made in the federal arena in 2014, both through the U.S. Department of the Interior's responsibilities in granting offshore leases and the U.S. Department of Energy's (DOE's) funding for demonstration projects. A total of 18 offshore wind projects (15 GW) are in various stages of development in the continental United States.
- **Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration.** At the end of 2014, there were 96 GW of wind power capacity within the transmission interconnection queues reviewed for this report, representing 30% of all generating capacity within these queues – higher than all other generating sources except natural gas. In 2014, 29 GW of gross wind power capacity entered the interconnection queues, compared to 65 GW of natural gas and 20 GW of solar.

Industry Trends

- **GE, Siemens, and Vestas captured 98% of the U.S. market in 2014.** Continuing the recent dominance of the three largest turbine suppliers to the U.S. market, in 2014 GE captured 60% of the market, followed by Siemens (26%) and Vestas (12%). Globally, Vestas remained the top supplier, followed by Siemens, GE, and Goldwind. 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 in China.
- **The manufacturing supply chain continued to adjust to swings in domestic demand for wind equipment.** With near-term growth in the U.S. market, wind sector employment increased from 50,500 in 2013 to 73,000 in 2014. Moreover, the profitability of turbine suppliers has generally rebounded over the last two years, after a number of years in decline. Although there have been a number of recent closures, four major turbine manufacturers had one or more domestic manufacturing facilities operating at the end of 2014. Domestic nacelle assembly capability stood at roughly 9 GW in 2014, and the United States also had the capability to produce approximately 7 GW of blades and 7 GW of towers annually. Despite the significant growth in the domestic supply chain over the last decade, however, prospects for further expansion have dimmed. Far more domestic manufacturing facilities closed in 2014 than opened. With an uncertain domestic market after 2016, some manufacturers have been hesitant to commit additional long-term resources to the U.S. market.
- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports.** The U.S. wind sector is reliant on imports of wind equipment from a wide array of countries, with the level of dependence varying by component. Domestic content is highest for nacelle assembly (>90%), towers (70-80%), and blades and hubs (45-65%), but is much lower (<20%) for most components internal to the

nacelle. Exports of wind-powered generating sets from the United rose from $16 million in 2007 to $488 million in 2014; tower exports equaled $116 million in 2014.

- **The project finance environment remained strong in 2014.** Spurred on by the 2015 expiration (later extended through 2016) of the PTC safe harbor guidance provided by the IRS in late 2013, the U.S. wind market raised $5.8 billion of new tax equity in 2014—the largest single-year amount on record. Debt finance increased slightly to $2.7 billion, with plenty of additional availability. Tax equity yields held steady at around 8% (in unlevered, after-tax terms), while the cost of term debt fell by roughly 100 basis points (i.e., an absolute decrease of 1%). Looking ahead, 2015 should be another busy year, given the extension of the safe harbor guidance through 2016.
- **Utility ownership of wind assets rebounded somewhat in 2014.** Utilities own 26% of all new wind capacity installed in 2014, up from just 4% in 2013 and 10% in 2012, and just edging out the previous high of 25% in 2011. Independent power producers (IPPs) own the remaining 74% of new 2014 capacity. On a cumulative basis through 2014, IPPs own 82% and utilities own 16% of U.S. wind capacity, with the remaining 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 continued to expand, at least in Texas.** Electric utilities continued to be the dominant off-takers of wind power in 2014, either owning (26%) or buying (40%) power from 66% of the new capacity installed last year. Merchant/quasi-merchant projects accounted for another 33%. On a cumulative basis, utilities own (16%) or buy (53%) power from 69% of all wind power capacity in the United States, with merchant/quasi-merchant projects accounting for 23% and competitive power marketers (defined here as intermediaries that purchase power under contract and then resell that power to others, but also including corporate wind purchasers) accounting for 7%. Looking ahead, the latter segment should grow in response to a surge (~2 GW) of recently announced corporate wind power purchases from projects that will be built in the next few years.

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 2014 was 1.9 MW, up 172% since 1998–1999. The average hub height in 2014 was 82.7 meters, up 48% since 1998-1999, while the average rotor diameter was 99.4 meters, up 108% 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 stabilization of the long-term trend in recent years. In 2008, no turbines employed rotors that were 100 meters in diameter or larger; by 2014, that percentage was 80%.
- **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) over time, from 394 W/m^2 among projects installed in 1998–1999 to 249 W/m^2 among projects installed in 2014. 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 2014, 94% of new installations used IEC Class 3 and Class 2/3 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 the Great Lakes and Northeast.** Low specific power and IEC Class 3 and 2/3 turbines are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites. In parts of the Interior region, in particular, relatively low wind turbulence has allowed turbines designed for lower 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 the Great Lakes and Northeastern regions, in lower wind speed sites, with specific location decisions likely driven by the wind shear of the site.

Performance Trends

- **Sample-wide capacity factors have increased, but have been impacted by curtailment and inter-year wind resource variability.** Wind project capacity factors have generally been higher on average in more recent years (e.g., 32.9% between 2011 and 2014 versus 31.8% between 2006 and 2010 versus 30.3% between 2000 and 2005), but time-varying influences—such as inter-year variations in the strength of the wind resource or changes in the amount of wind energy curtailment—have tended to mask the positive influence of turbine scaling on capacity factors. Positively, the degree of wind curtailment has declined recently in what historically have been the most problematic areas. For example, only 0.5% of all wind generation within ERCOT was curtailed in 2014, 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 32% to 35% nationwide.** When controlling for time-varying influences by focusing only on capacity factors in 2014 (parsed by project vintage), it is difficult to discern any improvement in *average* capacity factors among projects built after 2005 (although the *maximum* 2014 capacity factors achieved by individual projects within each vintage have generally increased in the past six years). This is partially attributable to the fact that the average quality of the wind resource in which new projects are located has declined; this decrease was particularly sharp—at 10-15%—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 or 2013, average capacity factors in 2014 were the highest in the Interior (41%) and the lowest in the West (27%). Not surprisingly, these regional rankings are roughly consistent

[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.

with the relative quality of the wind resource in each region, but also reflect the degree to which each region has adopted new turbine design enhancements (e.g., turbines with a lower specific power, or taller towers) that can boost project capacity factors. For example, the Great Lakes (which ranks second among regions in terms of 2014 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 increases in hub heights and especially rotor diameters. Recently announced transactions feature pricing in the \$850–\$1,250/kW range. These price reductions, coupled with improved turbine technology, have exerted downward pressure on project costs and wind power prices.
- **Lower turbine prices have driven reductions in reported installed project costs.** The capacity-weighted average installed project cost within our 2014 sample stood at roughly \$1,710/kW—down \$580/kW from the apparent peak in average reported costs in 2009 and 2010. Early indications from a preliminary sample of 17 projects totaling more than 2 GW that are currently under construction and anticipating completion in 2015 suggest no material change in installed costs in 2015.
- **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 2014, the windy Interior region of the country was the lowest-cost region, with a capacity-weighted average cost of \$1,640/kW.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, it appears that projects installed over the past decade have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first several years of operation, 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 2014 (and that are within the Berkeley Lab sample) fell to around \$23.5/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 have, in recent years, been sited in somewhat lower-quality resource areas.
- **The relative economic competitiveness of wind power improved in 2014.** The continued decline in average levelized wind PPA prices, along with a continued rebound in wholesale power prices, left average wind PPA prices signed in 2014 below the bottom of the range of nationwide wholesale power prices. 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 or 2014 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 is leading to a resurgent domestic market, but a possible policy cliff awaits.** In December 2014, the PTC was extended, as was the ability to take the 30% investment tax credit (ITC) in lieu of the PTC. To qualify, projects had to begin construction before the end of 2014. These provisions are expected to spur solid growth in wind capacity additions in both 2015 and 2016. With the PTC now expired and its renewal uncertain, however, wind deployment beyond 2016 is also uncertain. On the other hand, the prospective impacts of EPA's proposed regulations on power-sector carbon emissions 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 2015, RPS policies existed in 29 states and Washington D.C. Of all wind capacity built in the United States from 1998 through 2014, roughly 54% is delivered to load serving entities with RPS obligations; in 2014, this proportion was 31%. Existing RPS programs are projected to require average annual renewable energy additions of 4–5 GW/year through 2025, only a portion of which will come from wind. These additions are well below the average growth rate in wind power capacity in recent years, demonstrating the limitations of relying exclusively on RPS programs to drive future deployment.
- **Solid progress on overcoming transmission barriers continued.** About 2,000 miles of transmission lines came on-line in 2014—substantially lower than 2013 but consistent with the 2009-2012 time period. The wind industry has identified 18 near-term transmission projects that—if all were completed—could carry 55-60 GW of additional wind capacity. The Federal Energy Regulatory Commission continues to implement Order 1000, which was intended to improve transmission planning and cost allocation. Despite this progress, planning, siting, and cost-allocation remain key barriers to transmission investment.
- **System operators are implementing methods to accommodate increased penetrations of wind energy.** Studies show that wind energy integration costs are almost always below $12/MWh—and often below $5/MWh—for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. System operators continue to implement a range of methods to accommodate increased wind energy penetrations, including: centralized wind forecasting, treating wind as dispatchable, shorter scheduling intervals, and balancing areas consolidation and coordination.

Because federal tax incentives are available for projects that initiated construction by the end of 2014, a further resurgence in new builds is anticipated in both 2015 and 2016. Near-term wind additions will also be driven by the recent improvements in the cost and performance of wind power technologies, which have led to the lowest power sales prices yet seen in the U.S. wind sector. Projections for 2017 and beyond are much less certain. Despite the low price of wind energy and the potential for further cost reductions, analysts note that 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 rebounded in 2014, and continued growth through 2016 is anticipated. Recent and projected near-term growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—which is available for projects that began construction by the end of 2014. Wind additions are also being driven by recent improvements in the cost and performance of wind power technologies, which have resulted in the lowest power sales prices ever seen in the U.S. wind sector. Growing corporate demand for wind energy and state-level policies play important roles as well. Expectations for continued technological advancements and cost reductions may further boost future growth. At the same time, the prospects for growth beyond 2016 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. What these trends 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.

This annual report—now in its ninth year—provides a detailed overview of developments and trends in the U.S. wind power market, with a particular focus on 2014. The report begins with an overview of key installation-related trends: trends in U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual states; 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, and 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 2014. New to this edition are the following: refinement of the manufacturing, supply chain, and domestic content assessments; discussion of the burgeoning trend of commercial wind energy purchases; and a comparison of recent and forecasted wind capacity growth with the trajectory analyzed in the DOE's *Wind Vision* report released in 2015. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[1] The U.S. wind power sector is multifaceted,

[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

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 *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.

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 (2015a) 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 2014; with some limited exceptions (including the final section of the report), the report does not seek to forecast future trends.

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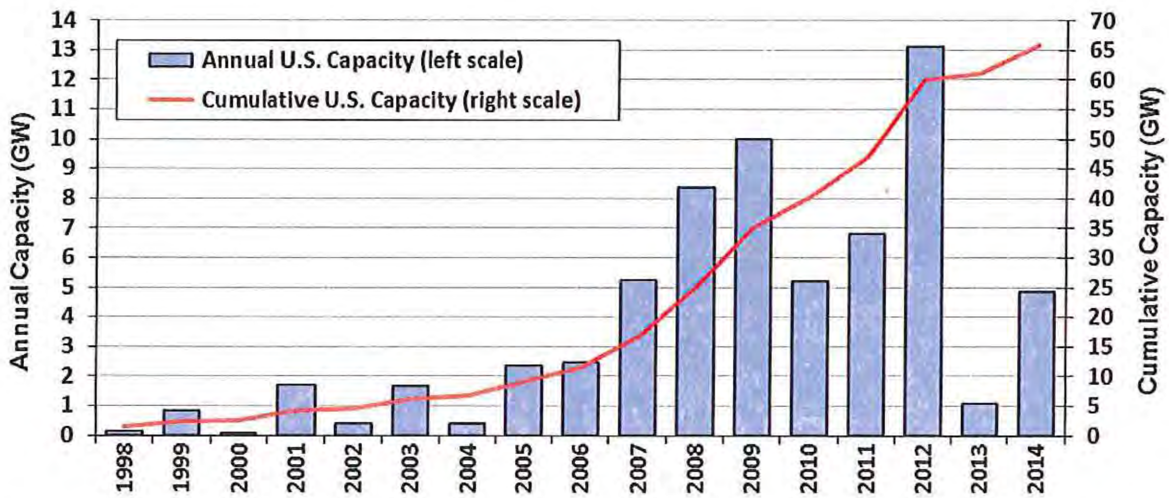
distinction. In years prior to 2011, different cut-offs are used to better match AWEA's reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.

[2] As used by the 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). See, for example, Orrell and Foster (2015).

2. Installation Trends

Wind power additions rebounded in 2014, with 4,854 MW of new capacity added in the United States and $8.3 billion invested

The U.S. wind power market rebounded in 2014, after lackluster growth in 2013, with 4,854 MW of new capacity added, bringing the cumulative total to 65,877 MW (Figure 1).[3] This growth required $8.3 billion of investment in wind power project installations in 2014, for a cumulative investment total of $135 billion since the beginning of the 1980s (all cost and price data are reported in real 2014$).[4] Nonetheless, wind power installations in 2014 were well off peak-year additions, falling below the yearly totals in each year during the 2007 to 2012 period. Cumulative wind power capacity grew by nearly 8% in 2014.



Source: AWEA project database

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

Recent improvements in the cost and performance of wind power technologies helped underpin growth in 2014. State renewables portfolio standards (RPS) and increased corporate demand for wind power also played a role. A key additional factor was the PTC which, in December 2014, was extended to projects that had begun construction by the end of 2014. In part as a result, growth in wind power capacity additions is anticipated to continue in 2015 and 2016.

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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, utility-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 2014. As shown, 3.7 MW of small wind turbines were sold in the United States in 2014, with 82% of that capacity coming from U.S. suppliers (Orrell and Foster 2015). The small wind turbine market continued to struggle in 2014 after achieving record sales in 2008 through 2012. Small wind turbine deployments were spread primarily across Alaska, Iowa, Kansas, Minnesota, Nevada, New York, and Texas in 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
2014	3.7 MW	1,600

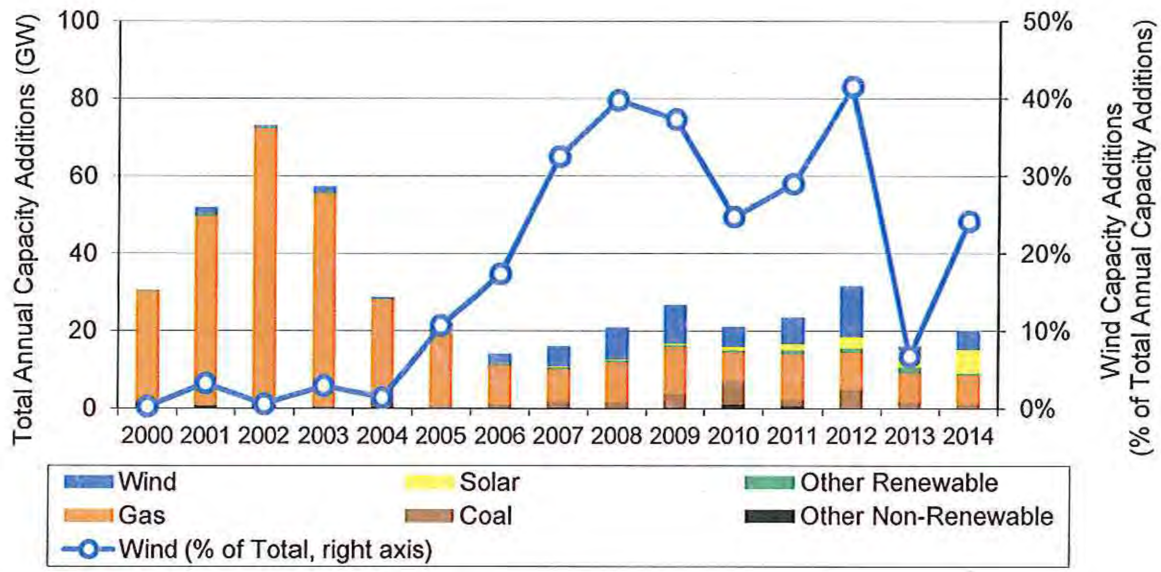
Source: Orrell and Foster (2015)

Sales in this sector historically have been motivated—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); in early 2014, the IRS established performance and quality standards that small wind turbines must meet to obtain this incentive. The now-expired Section 1603 Treasury Grant Program and programs administered by the U.S. Department of Agriculture have also played a role in the sector. Challenges continue to be competition from solar systems, suspended state incentives, and high soft costs such as permitting.

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: *2014 Distributed Wind Market Report.*

Wind power represented 24% of electric-generating capacity additions in 2014

Wind power has comprised a sizable share of generation capacity additions in recent years, especially since 2007. Wind power's share of total U.S. electric generation capacity additions in 2014 was 24%, up substantially from the prior year though still below levels achieved in other recent years (Figure 2).[5] Overall, wind power ranked third in 2014 as a source of new generation capacity, behind natural gas (38% of total U.S. capacity additions) and solar (30%).

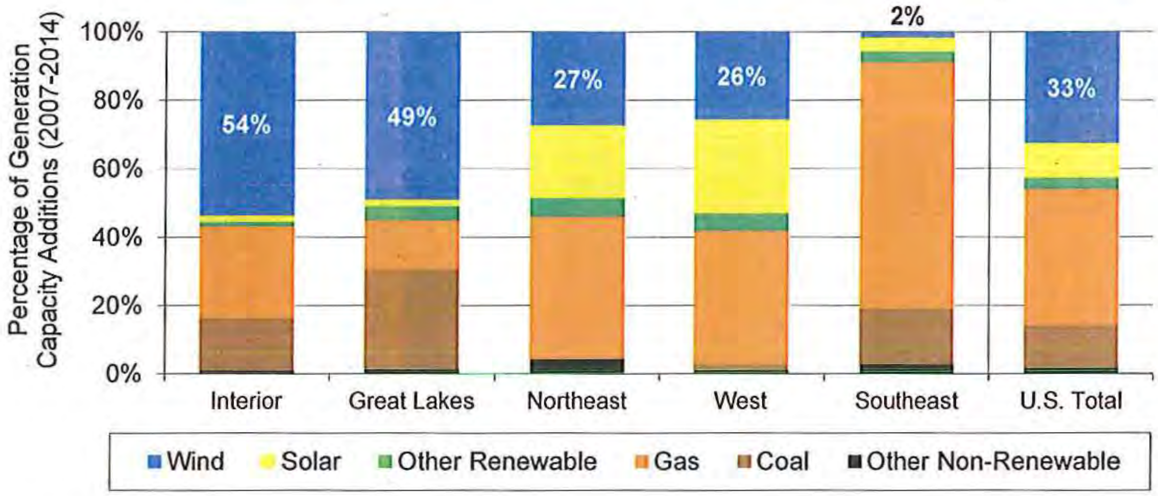


Source: Ventyx, AWEA, GTM Research, Berkeley Lab

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

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 (49%) regions (Figure 3; see Figure 29, later, for regional definitions). Its contribution to generation capacity growth over that period is somewhat smaller—but still significant—in the Northeast (27%) and West (26%), 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: Ventyx, AWEA, GTM Research, Berkeley Lab

Figure 3. Generation capacity additions by region (2007–2014)

EIA's (2015a) reference-case forecast projects that total U.S. electricity generation will increase at an average pace of roughly 0.8% per year over the next decade. Growth in wind power capacity over the 2007–2014 period averaged 6.8 GW per year. If wind power capacity additions continued over the next decade at this same pace, and operate at similar capacity factors to historical levels, then more than 55% of the nation's projected increase in electricity generation over the next decade would be met with wind electricity.

The United States ranked third in annual wind additions in 2014, but was well behind the market leaders in wind energy penetration

Global wind additions reached a new high in 2014 of more than 51,000 MW, 14% above the previous record of roughly 45,000 MW added in 2012. Cumulative global capacity stood at approximately 372,000 MW at the end of the year (Navigant 2015; Table 1).[6] The United States ended 2014 with 18% of total global wind power capacity, a distant second to China by this metric (Table 1).[7] On the basis of wind power production, however, the United States remained the leading country globally in 2014 (AWEA 2015a). Annual growth in cumulative capacity in 2014 was 8% for the United States and 16% 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, the United States dropped precipitously to 6th place in annual wind

[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 (2015) 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 2014, 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.

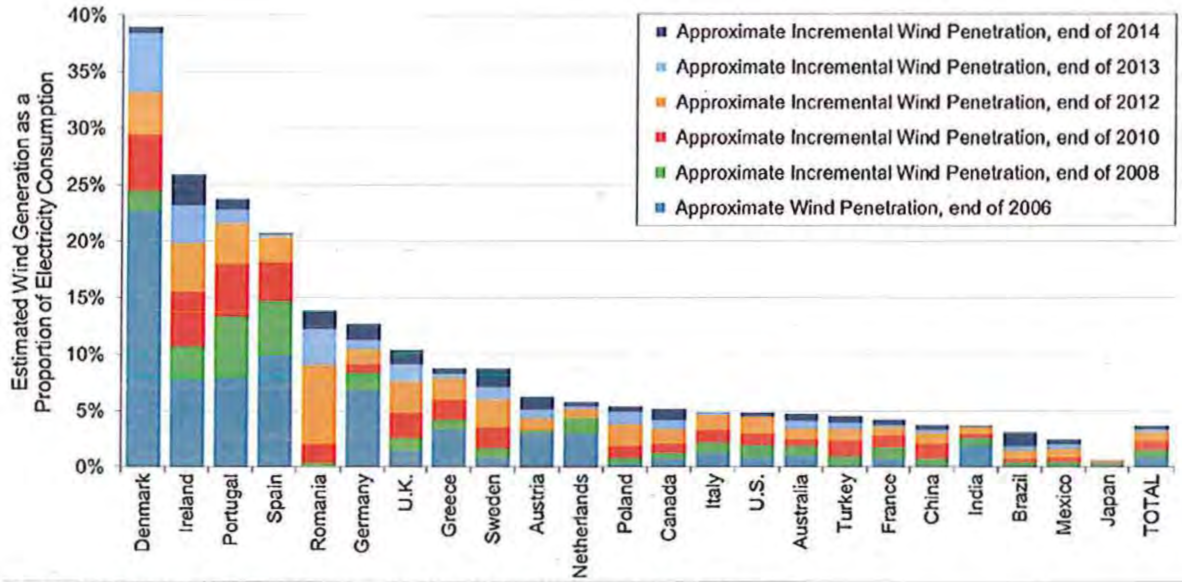
additions, but then regained some ground in 2014, rising to 3rd place behind China and Germany (Table 1). The U.S. wind power market represented over 9% of global installed capacity in 2014.

Table 1. International Rankings of Wind Power Capacity

Annual Capacity (2014, MW)		Cumulative Capacity (end of 2014, MW)	
China	23,300	China	114,760
Germany	5,119	United States	65,877
United States	4,854	Germany	39,223
Brazil	2,783	India	22,904
India	2,315	Spain	22,665
Canada	1,871	United Kingdom	12,413
United Kingdom	1,467	Canada	9,684
Sweden	1,050	France	9,170
France	1,042	Italy	8,556
Turkey	804	Brazil	6,652
Rest of World	6,625	*Rest of World*	60,208
TOTAL	51,230	TOTAL	372,112

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-2014 (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 2015 (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-2014 installed wind power is estimated to supply the equivalent of roughly 39% of Denmark's electricity demand and more than 20% of Ireland, Portugal, and Spain's demand. In the United States, the cumulative wind power capacity installed at the end of 2014 is estimated, in an average year, to equate to 4.9% of the nation's electricity demand. On a global basis, wind energy's contribution is estimated to be approximately 3.7%.



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

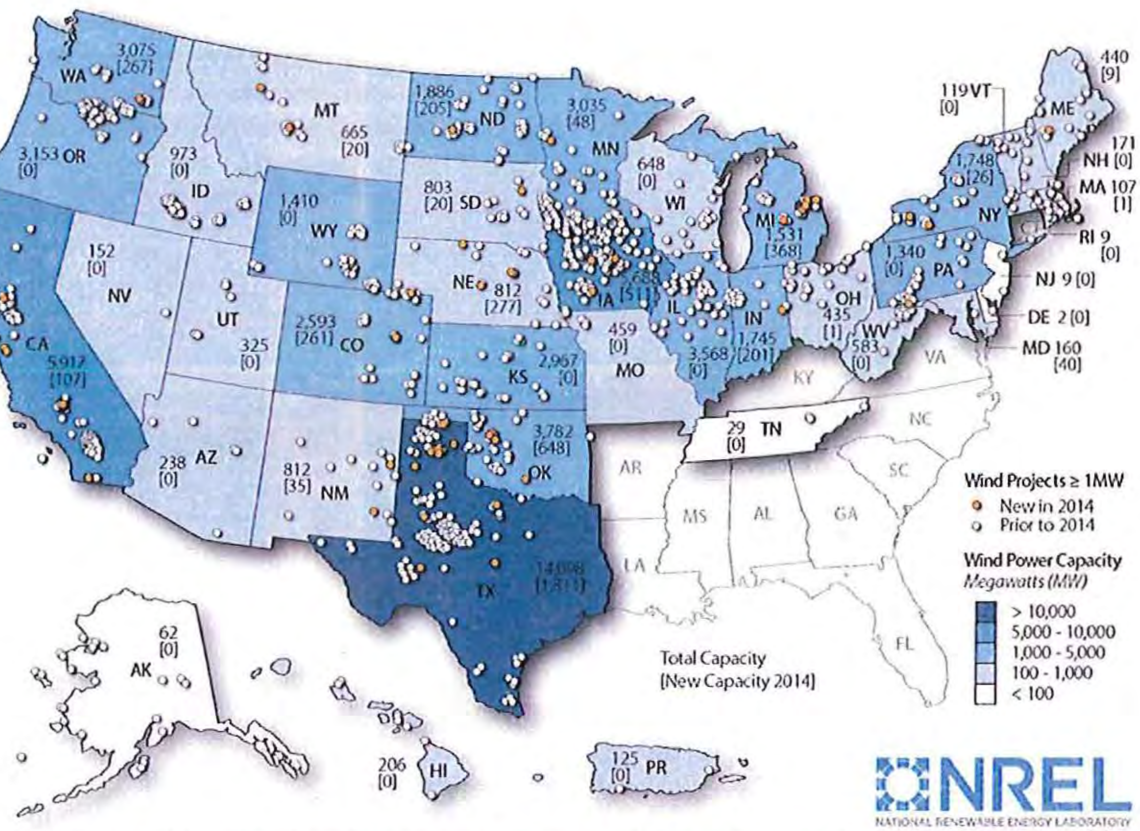
Figure 4. Approximate wind energy penetration in the countries with the greatest installed wind power capacity

Texas installed the most capacity in 2014 with 1,811 MW, while nine states exceed 12% wind energy penetration

New utility-scale[8] wind turbines were installed in 19 states in 2014. Texas installed the most new wind capacity of any state in 2014, with 1,811 MW. As shown in Figure 5 and Table 2, other leading states in terms of new capacity included Oklahoma (648 MW), Iowa (511 MW) Michigan (368 MW), and Nebraska (277 MW).

On a cumulative basis, Texas remained the clear leader among states, with 14,098 MW installed at the end of 2014—*more than twice as much as the next-highest state* (California, with 5,917 MW). In fact, Texas has more wind capacity than all but five countries (including the United States) worldwide. States (distantly) following Texas in cumulative installed capacity include California, Iowa, Oklahoma, Illinois, Oregon, Washington, and Minnesota—all with more than 3,000 MW. Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2014, 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 2014, as discussed in the next section.

[8] "Utility-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 2014.

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

Some states have realized high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2014 divided by total in-state electricity generation in 2014.[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 2014, Table 2 does not fully capture the impact of new wind power capacity added during 2014 (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 (2014)		Cumulative (end of 2014)		Actual (2014)*	
Texas	1,811	Texas	14,098	Iowa	28.5%
Oklahoma	648	California	5,917	South Dakota	25.3%
Iowa	511	Iowa	5,688	Kansas	21.7%
Michigan	368	Oklahoma	3,782	Idaho	18.3%
Nebraska	277	Illinois	3,568	North Dakota	17.6%
Washington	267	Oregon	3,153	Oklahoma	16.9%
Colorado	261	Washington	3,075	Minnesota	15.9%
North Dakota	205	Minnesota	3,035	Colorado	13.6%
Indiana	201	Kansas	2,967	Oregon	12.7%
California	107	Colorado	2,593	Texas	9.0%
Minnesota	48	North Dakota	1,886	Wyoming	8.9%
Maryland	40	New York	1,748	Maine	8.3%
New Mexico	35	Indiana	1,745	New Mexico	7.0%
New York	26	Michigan	1,531	California	7.0%
Montana	20	Wyoming	1,410	Nebraska	6.9%
South Dakota	20	Pennsylvania	1,340	Montana	6.5%
Maine	9	Idaho	973	Washington	6.3%
Ohio	0.9	New Mexico	812	Hawaii	5.9%
Massachusetts	0.6	Nebraska	812	Illinois	5.0%
		South Dakota	803	Vermont	4.4%
Rest of U.S.	0	*Rest of U.S.*	4,941	*Rest of U.S.*	0.9%
TOTAL	4,854	TOTAL	65,877	TOTAL	4.4%

* Based on 2014 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 progress toward the first U.S. offshore wind project in Rhode Island continued in 2015 amid mixed market signals

At the end of 2014, global cumulative offshore wind power capacity stood at roughly 7,700 MW (Navigant 2015), with Europe being the primary center of activity. Navigant (2015) reports that 852 MW of new offshore wind capacity was commissioned in 2014, down from 1,734 MW in 2013, and projects that 2015 will be a watershed year, with 4,700 MW of new offshore capacity likely to be commissioned.[10]

No commercial offshore projects have been installed in the United States, however, the 30 MW Block Island project started construction in 2015. The project is expected to be commissioned by the fall of 2016. A number of other high-profile projects have run into legal and political headwinds:

[10] Various data sources report different figures, in part due to differing perspectives on when to consider a project "completed."

- National Grid and NSTAR canceled their power purchase agreements (PPA) with the 468 MW Cape Wind project after it failed to meet a December 31, 2014 deadline to obtain financing, start construction, or put up financial collateral. Cape Wind believes that the milestone should have been extended, and is expected to challenge the decision.
- The New Jersey Board of Public Utilities once again rejected the 25 MW Fishermen's Energy Atlantic City application for the state's Offshore Renewable Energy Credit program, citing concerns about the net economic benefits to the state. Fishermen's Energy lost its first appeal in May 2015 but has announced that it will further appeal to the State Supreme Court.
- Dominion Virginia Power announced that it would delay the 12 MW Virginia Offshore Wind Technology Advancement Project after initial bids for construction came in at more than 60% above initial estimates. Dominion is working with its partners to evaluate potential approaches for reducing the cost of the project.

The most pressing challenge the industry faces is the cost of offshore wind, and the related lack of available power purchase agreements and/or state and federal policies to support those high costs. NREL estimates that, in 2013, the levelized cost of offshore wind energy was $215/MWh (Moné et al. 2015). Recent data suggest that costs have stabilized, and many expect decreases through 2020. As evidence, recent winning bids for competitive subsidies in Denmark and the United Kingdom ranged from $137/MWh to $197/MWh.[11] These three projects, totaling 1,560 MW, are expected to be commissioned between 2017 and 2019.

Another key challenge for the U.S. offshore wind industry is the complexity of the regulatory environment. The mechanisms for planning, siting, and permitting offshore wind projects are highly decentralized, and this decentralization requires developers to engage with multiple local, state, and federal agencies and stakeholders. Further, regulatory processes to secure site control and construction authorization are largely decoupled from offtake agreements that could support the economics of an offshore wind project. This creates uncertainty relative to European markets, in that U.S. developers who win competitive lease auctions must then separately negotiate PPAs, which (due to lack of policy to cover the cost of offshore wind in most states) are largely unavailable and subject to approval by state regulatory bodies.

Despite these challenges, there remains interest in developing offshore wind projects in the United States. Driving this interest is the close proximity of offshore wind resources to population centers, which could address transmission congestion; the potential for local economic development benefits; and superior capacity factors compared to developable land-based wind resources in some coastal regions. Progress in the federal arena is supporting commercial interest, through regulatory approvals and technology investment. The Bureau of Ocean Energy Management (BOEM), under the U.S. Department of the Interior, has granted five competitive leases for sites in Rhode Island, Massachusetts, Maryland, and Virginia. DOE has also made significant investments in offshore wind energy research and development, including funding for seven advanced technology demonstration partnerships; three of these were selected

[11] Converted to U.S. Dollars at 2014 annual average exchange rates, despite auctions being held in 2015; figures in U.S. dollars range between $116/MWh and $178/MWh if using 2015 exchange rates. Note that these contract values cannot be directly compared to levelized cost of energy figures, or with each other, in part because contract lengths vary and developers in Denmark do not have to pay for offshore grid connection.

in May 2014 to receive an additional $46.7 million each for deployment, with two others receiving $3 million each to complete engineering designs of innovative technology concepts.

Figure 6 identifies 18 proposed offshore wind power projects in the continental United States, which are in various stages of development, based on data from NREL. These projects total more than 15 GW of potential capacity, of which approximately 6 GW have obtained site control through leases or determinations of no competitive interest. The projects are primarily located in the Northeast and Mid-Atlantic, with one project each in the Great Lakes and the Pacific Northwest. Not shown on the map are two 408 MW floating projects proposed in Hawaii, where the developer filed unsolicited lease requests to BOEM in early 2015.

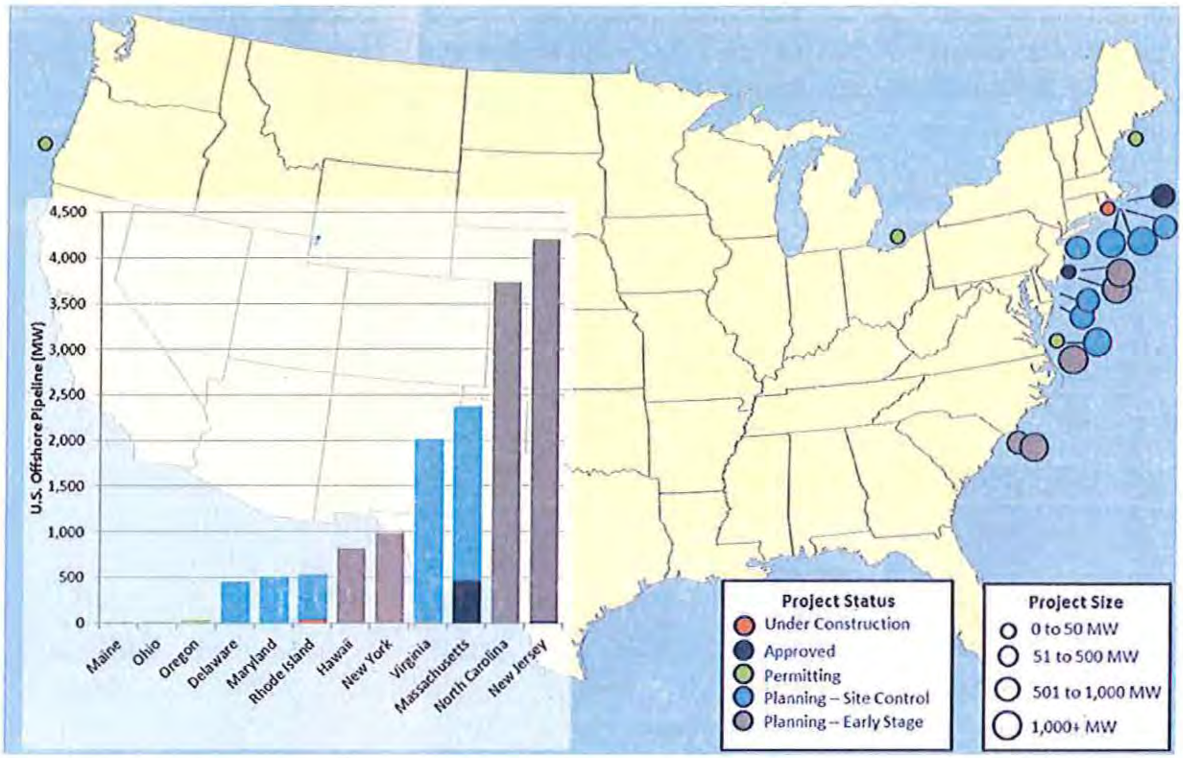
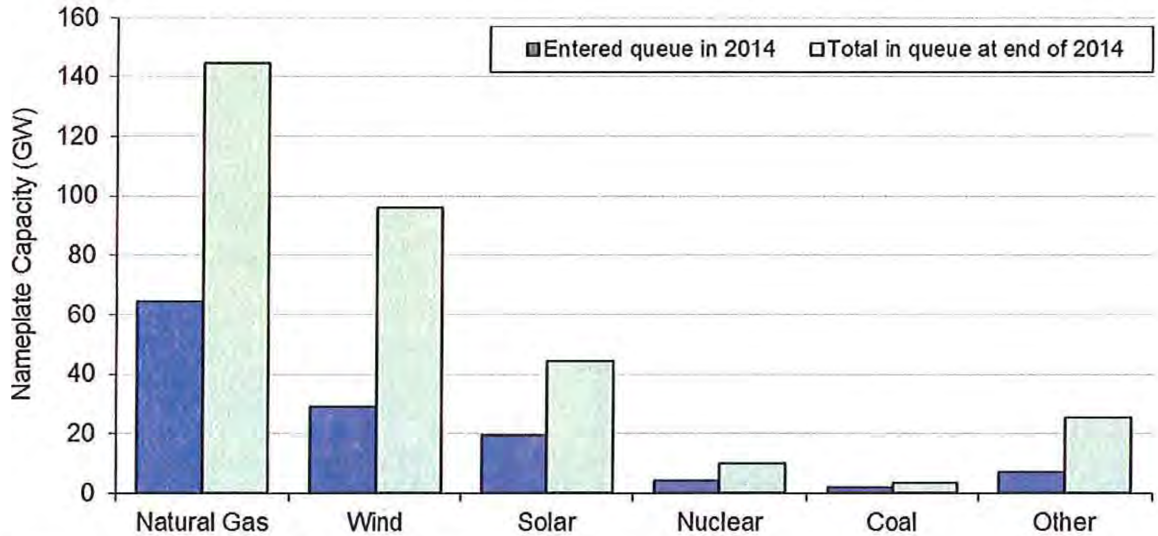


Figure 6. Offshore wind power projects under development in the United States

Of the projects identified in Figure 6, Deepwater Wind's Block Island project (Rhode Island) is the only one that currently has a PPA; achievement of this milestone enabled the project to close financing and to begin construction in Spring 2015. Cape Wind was originally scheduled to start construction by May 2015, but filed a request with the Massachusetts Energy Facilities Siting Board to extend the deadline by two years as a result of uncertainty about the status of its PPAs. As noted earlier, DOE selected three innovative projects for additional federal funding: Dominion Virginia Power (12 MW, Virginia), Principle Power (up to 30 MW, Oregon), and Fishermen's Energy (at least 20 MW, New Jersey). These projects are working with regulators to finalize design, secure permits, and establish power sales agreements. The recent challenges highlighted above suggest that the schedules for these projects are subject to uncertainty.

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

One testament to the continued interest in land-based wind energy is the amount of wind power capacity currently working its way through the major transmission interconnection queues across the country. Figure 7 provides this information for wind power and other resources aggregated across 35 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.[12] These data should be interpreted with caution: 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 past 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.



Source: Exeter Associates review of interconnection queues

Figure 7. Nameplate resource capacity in 35 selected interconnection queues

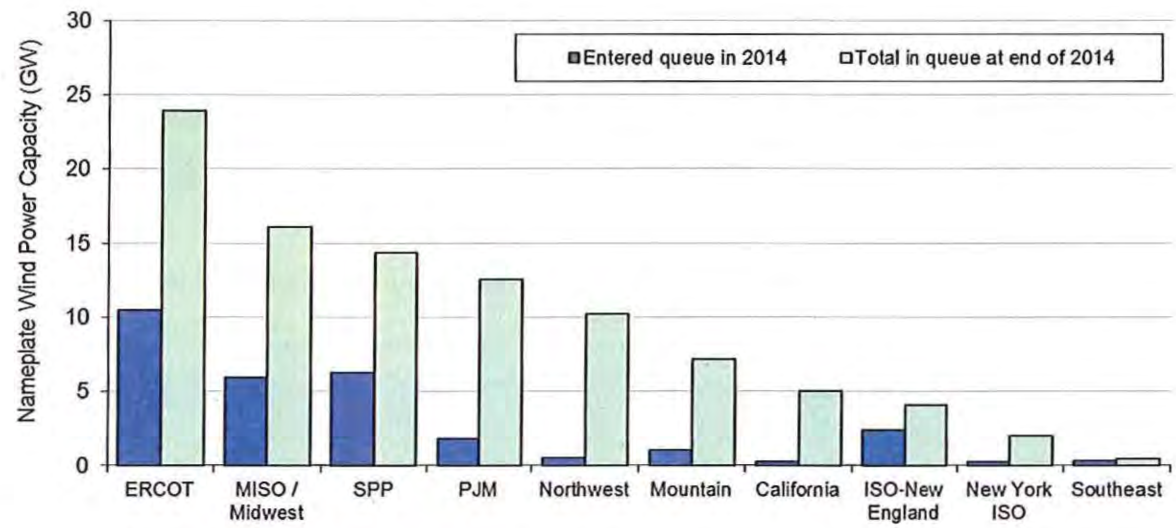
Even with this important caveat, the amount of wind capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2014, there were 96 GW of wind power capacity within the interconnection queues reviewed for this report—almost one-and-a-half times the installed wind power capacity in the United States. This 96 GW represented 30% of all generating capacity within these selected queues at

[12] The queues surveyed include PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), New York ISO (NYISO), ISO-New England (ISO-NE), California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and 25 other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of about 86% of the U.S. total. Figures 7 and 8 only include projects that were active in the queue at the end of 2014 but that had not yet been built; suspended projects are not included.

that time, higher than all other generating sources except for natural gas. In 2014, 29 GW of gross wind power capacity entered the interconnection queues, compared to 65 GW of natural gas and 20 GW of solar.

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 or held steady. Since 2009, for example, the amount of wind power capacity has dropped by 68%, coal by 88%, and nuclear by 65%, whereas solar capacity has increased by 32% and natural gas by 31%.

The wind capacity in the interconnection queues is spread across the United States, as shown in Figure 8, with larger amounts in ERCOT (25%), the Midwest (17%), Southwest Power Pool (SPP) (15%), PJM Interconnection (13%), and the Northwest (11%). Somewhat smaller amounts are found in the Mountain region (7%), California (5%), ISO-New England (4%), New York ISO (2%), and the Southeast (0.5%).



Source: Exeter Associates review of interconnection queues

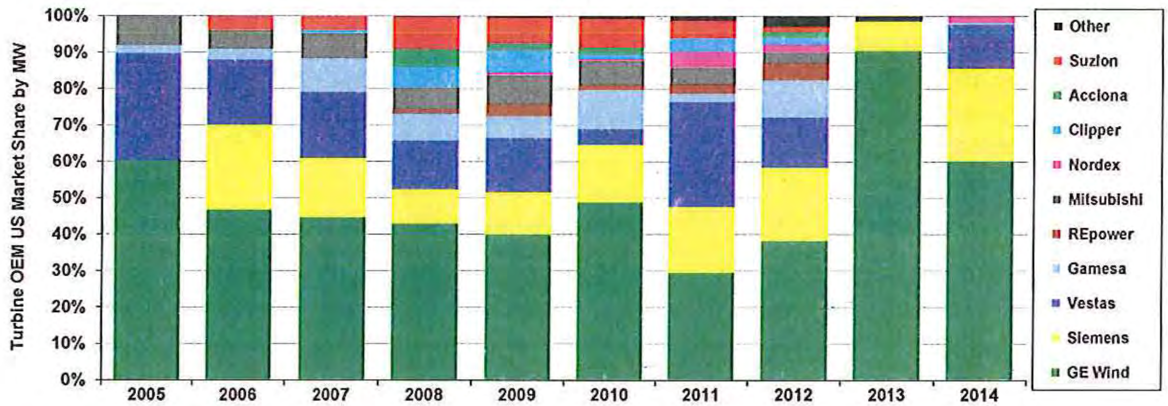
Figure 8. Wind power capacity in 35 selected interconnection queues

As a measure of the near-term development pipeline, Ventyx (2015) estimates that—as of June 2015—approximately 35 GW of wind power capacity was either: (a) under construction or in site preparation (13 GW), (b) in development and permitted (13 GW), or (c) in development with a pending permit and/or regulatory applications (9 GW). These totals are similar to last year at approximately the same time (June 2014), indicating that the development pipeline remains strong. AWEA (2015b), meanwhile, reports that 13.6 GW of wind power capacity was under construction at the end of the first quarter of 2015. Confirming these figures, the EIA (2015c) identifies 17.1 GW of planned wind power additions for 2015 and 2016.

3. Industry Trends

GE, Siemens, and Vestas captured 98% of the U.S. market in 2014

Continuing the recent dominance of the three largest turbine suppliers to the U.S. market, of the 4,854 MW of new U.S. wind capacity installed in 2014, 60% (2,912 MW) deployed turbines from GE Wind, with Siemens coming in second (1,241 MW, 26% market share), followed by Vestas (584 MW, 12% market share) (Figure 9 and Table 3).[13] Other suppliers included Nordex (90 MW), Gamesa (23 MW), PowerWind (0.9 MW), and RRB (0.6 MW).



Source: AWEA project database

Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2014

Table 3. Annual U.S. Turbine Installation Capacity by Manufacturer

Manufacturer	Turbine Installations (MW)									
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
GE Wind	1,431	1,146	2,342	3,585	3,995	2,543	2,006	5,016	984	2,912
Siemens	0	573	863	791	1,162	828	1,233	2,638	87	1,241
Vestas	699	439	948	1,120	1,489	221	1,969	1,818	4	584
Gamesa	50	74	494	616	600	566	154	1,341	0	23
REpower	0	0	0	94	330	68	172	595	0	0
Mitsubishi	190	128	356	516	814	350	320	420	0	0
Nordex	0	0	3	0	63	20	288	275	0	90
Clipper	3	0	48	470	605	70	258	250	0	0
Acciona	0	0	0	410	204	99	0	195	0	0
Suzlon	0	92	198	738	702	413	334	187	0	0
Other	2	2	2	23	43	41	86	398	12	2
TOTAL	2,374	2,453	5,253	8,362	10,005	5,220	6,819	13,133	1,087	4,854

Source: AWEA project database

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

Vestas remained the top supplier of turbines worldwide in 2014 (Navigant 2015). Siemens, GE, and Goldwind followed. 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, however, the growth of Chinese turbine manufacturers has been based almost entirely on sales to the Chinese market. Other than GE, no other U.S.-owned turbine manufacturer plays a meaningful role in global or U.S. large-wind-turbine supply.[14]

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

The wind industry's domestic supply chain continues to deal with conflicting pressures: an upswing in near-term expected growth, and then possible market realignment after 2016. As the cumulative capacity of U.S. 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 and growing global competition, expectations for further supply-chain expansion have become more pessimistic. As a result, though many manufacturers increased the size of their U.S. workforce 2014 to meet near-term demand, market consolidation and restructuring were also major trends.

Figure 10 presents a non-exhaustive list of the more-than 130 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2014, focusing on the utility-scale wind market.[15] Figure 11 segments those facilities by major component.

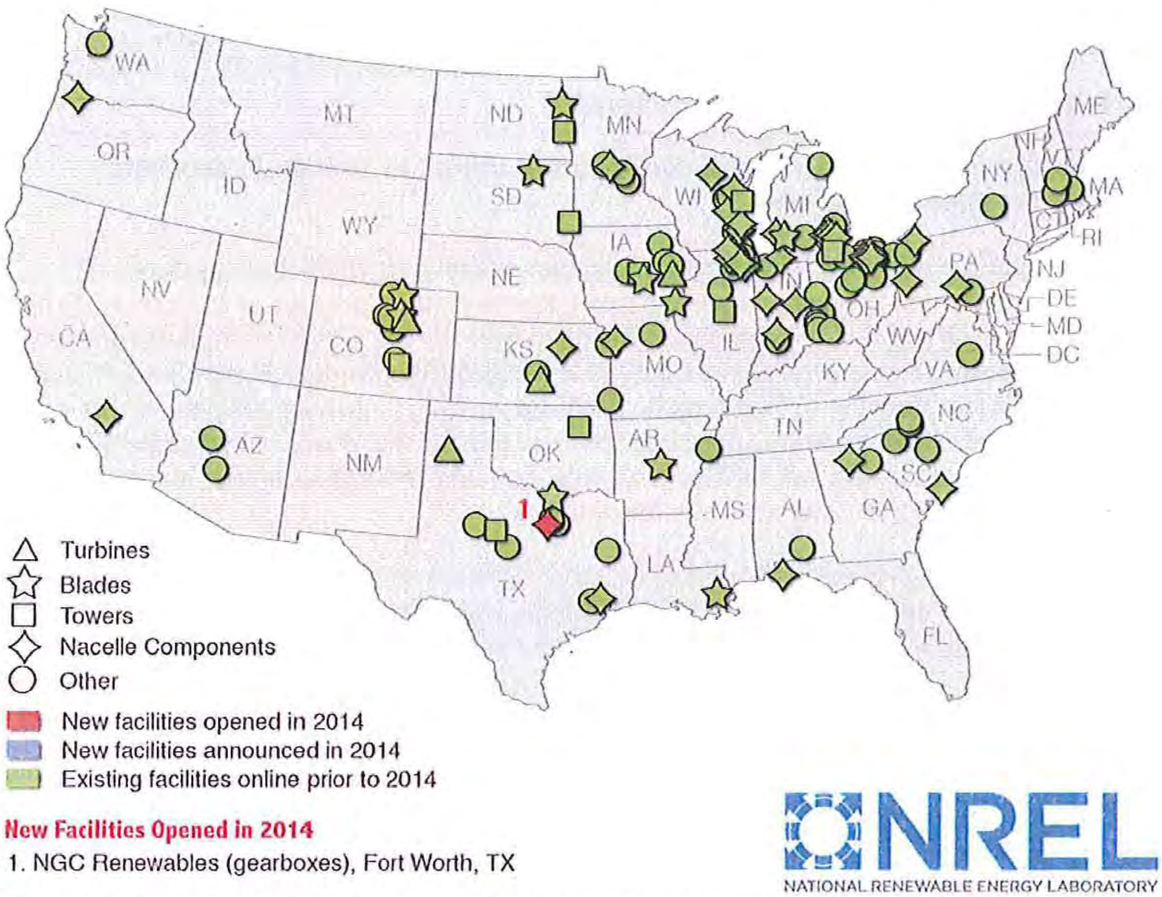
Due in part to future demand uncertainty, but also to growing international competition, only one new wind-related manufacturing facility opened in 2014: NGC Renewables, a gearbox manufacturer. Located in Fort Worth, Texas, the plant may support 150 jobs when fully operational. At the same time, at least 12 existing wind turbine or component manufacturing facilities were consolidated, closed, or stopped serving the industry in 2014. Also, for a second consecutive year, no major new announcements were made in 2014 about prospective future wind turbine and component manufacturing and assembly facilities.

Notwithstanding the recent supply chain consolidation, there remain a large number of domestic manufacturing facilities, and many manufacturers either expanded their workforce in 2014 to meet demand (e.g., Vestas, Siemens), remodeled facilities to meet industry standards (e.g., LM Windpower), or relocated to new, larger facilities (e.g., Creative Foam). Moreover, as also shown in Figure 10, turbine and component manufacturing facilities are spread across the country. Many manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers (OEMs). However, even states that are relatively far from major wind power markets have manufacturing facilities. Most states in the Southeast, for example, have wind manufacturing facilities despite the fact that there are few wind power projects in that region. Workforce considerations,

[14] U.S. manufacturers are major players in the global market for smaller-scale turbines.

[15] The data on existing, new, and announced manufacturing facilities presented here differ from those presented in AWEA (2015a) due, in part, to methodological differences. For example, AWEA (2015a) 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, or materials suppliers. As a result, AWEA (2015a) reports a much larger number of wind-related manufacturing facilities, over 500 in total.

transportation costs, and state and local incentives are among the factors that typically drive location decisions.

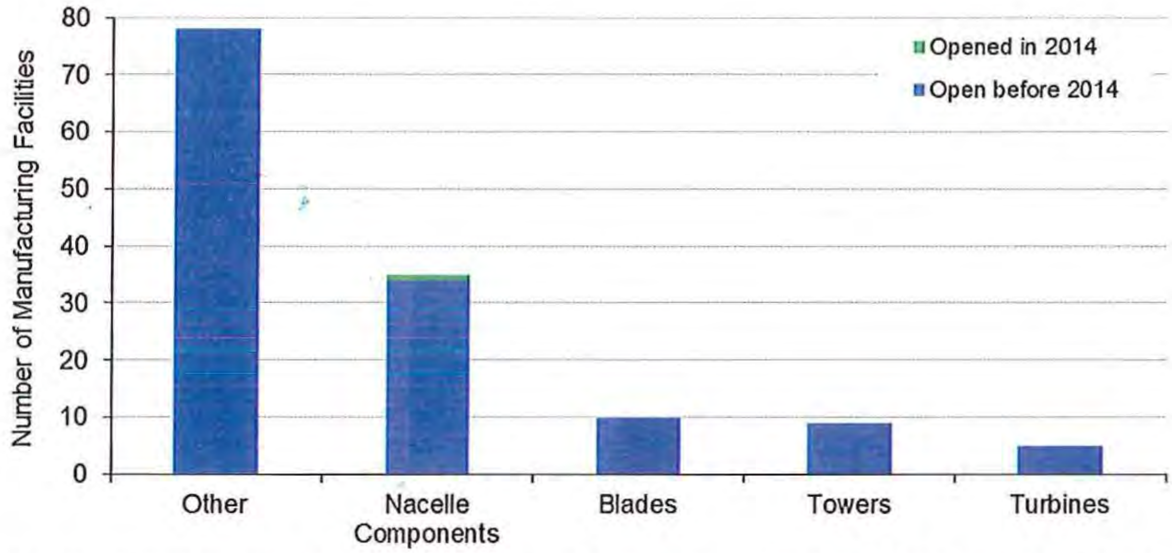


Note: Figure includes turbine and component manufacturing facilities, as well as other supply chain facilities, but excludes corporate headquarters and service-oriented facilities. The facilities shown are not intended to be exhaustive. Those facilities designated as "Turbines" may include nacelle assembly as well as, in some cases, the manufacturing of towers, blades, and nacelle components.

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

Among the many other facets of the domestic supply chain, in 2010, 9 of the 11 wind turbine OEMs with the largest shares of the U.S. market owned at least one domestic manufacturing facility (Acciona, Clipper, DeWind, Gamesa, GE, Nordex, Siemens, Suzlon, and Vestas).[16] Since that time, a number of these facilities have been closed, in part reflecting the increased concentration of the U.S. wind industry among the three top OEMs and in part reflecting an increased desire to consolidate production at centralized facilities overseas in order to gain economies of scale. For example, Gamesa closed its sole remaining U.S. plant in 2014. Nonetheless, four major OEMs (GE, Vestas, Siemens, Acciona) still had one or more operating manufacturing facilities in the United States at the end of 2014, including all three of the primary suppliers to the U.S. market. In contrast, a decade earlier (2004), there was only one active utility-scale wind energy OEM assembling nacelles in the United States (GE).

[16] 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.

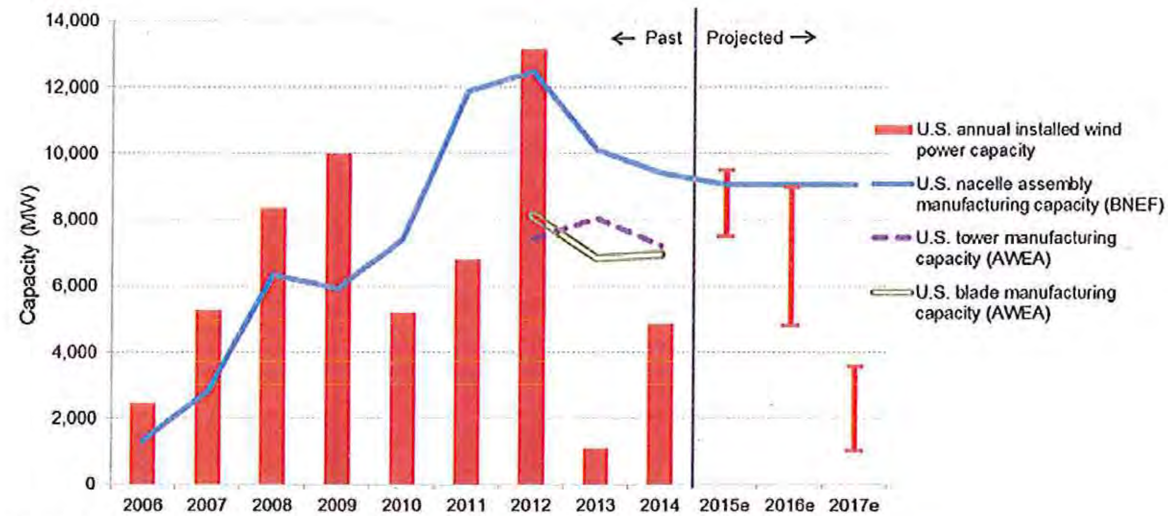


Note: Manufacturing facilities that produce multiple components are included in multiple bars. "Other" includes facilities that produce items such as: enclosures, power converters, slip-rings, inverters, electrical components, tower internals, climbing devices, couplings, castings, rotor hubs, plates,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

Source: National Renewable Energy Laboratory

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

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 9 GW in 2014 (Figure 12; Bloomberg NEF 2015a). In addition, AWEA (2015a) reports that U.S. manufacturing facilities have the capability to produce more than 10,000 individual blades (~7 GW) and 3,700 towers (~7 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 anticipated market demand in 2015 and 2016, but well exceeds expected demand in 2017. Such comparisons should be made with care, however, because 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).

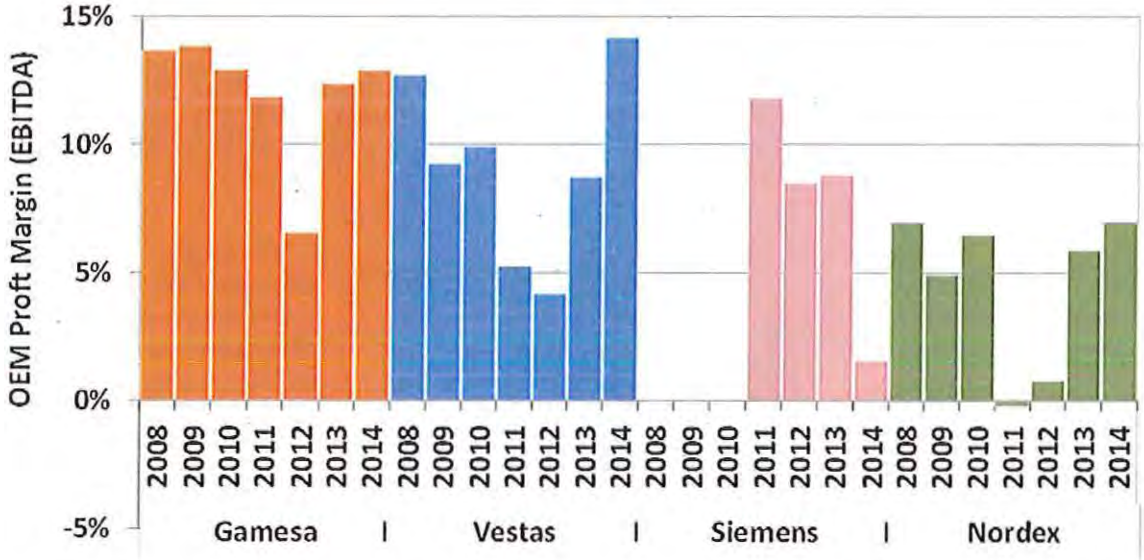


Source: AWEA, Bloomberg NEF, EIA, FTI, IHS, Navigant, MAKE, Berkeley Lab

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

Fierce competition throughout the supply chain has caused many manufacturers to execute corporate realignments and other cost-cutting strategies globally and domestically; the divestment of non-core assets and lower levels of vertical integration have been common elements of these responses. In part as a result, the profitability of turbine OEMs has generally rebounded over the last two years, after a number of years in decline (Figure 13). Moreover, with significant domestic wind installations expected in 2015 and 2016, turbine OEMs and component manufacturers—in many cases—increased their workforce in 2014. AWEA (2015a) estimates that the wind industry employed 73,000 full-time[17] workers in the United States at the end of 2014—up from the 50,500 jobs reported for 2013 due to surging demand, but still below the levels seen from 2008 through 2012. The 73,000 jobs include, among others, those in manufacturing and supply chain (~19,200); construction, development, and transportation (~26,700); and plant operations (~17,000). With an uncertain domestic market after 2016, however, some manufacturers have been hesitant to commit additional long-term resources to the U.S. market.

[17] 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

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

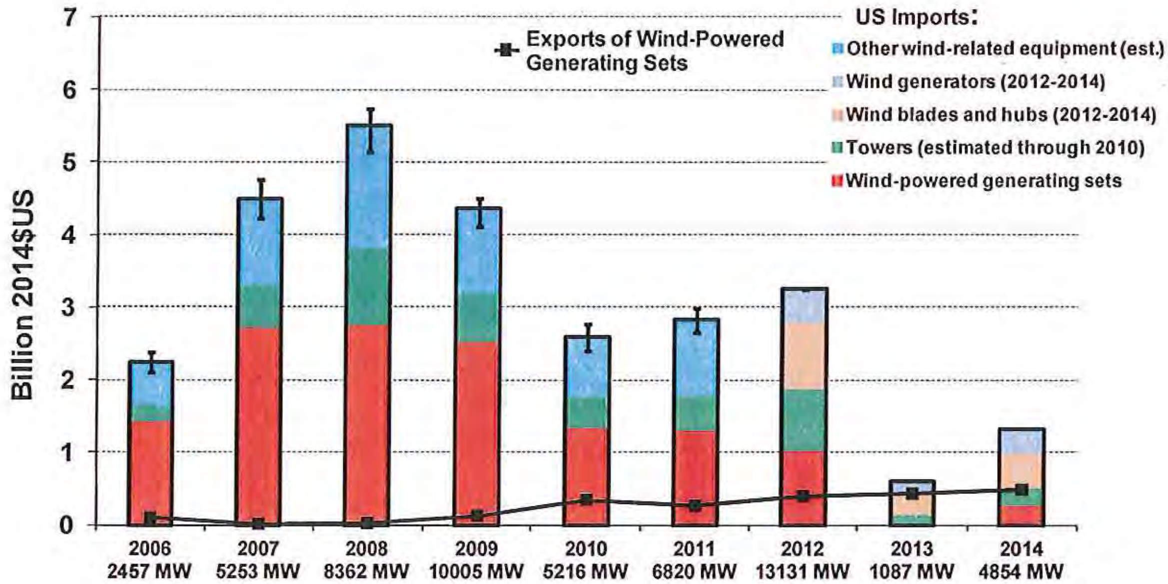
The U.S. wind sector is reliant on imports of wind equipment, though the level of dependence varies by component: some components have witnessed an increasing and relatively high domestic share, whereas other components remain largely imported. These trends are revealed, in part, by data on wind power equipment trade from the U.S. Department of Commerce.[18]

Figure 14 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating 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.[19] The selected wind turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (and generator parts), and blades and hubs. 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 likely to be represented by wind turbine components (see the appendix for details); the error bars in the figure account for uncertainty in these assumed fractions. By 2012, however, all of the trade

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

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

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, in 2012 and after, no error bars are included as all of the tracked imports are known to be wind-related. 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.



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

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

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 dropping sharply in 2013 with the simultaneous drop in U.S. wind installations. In 2014, as U.S. wind installations bounced back, so did imports of wind-related turbine equipment. These overall trends are driven by a combination of factors: changes in the share of domestically manufactured wind turbines and components (versus imports), changes in the annual rate of wind 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 just $16 million in 2007 to $350 million in 2010 and then to $488 million in 2014. The largest destination markets for these exports over the entire 2006–2014 timeframe were Canada (59%) and Brazil (28%), while 2014 exports were also dominated by Canada (58%) and Brazil (34%). U.S. exports of 'towers and lattice masts' in 2014 totaled $116 million, with over half of these exports going to Canada. 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 2011–2014 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 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 2014, by country of origin, as well as the main "ports of entry"[20]: 42% of the import value in 2014 came from Asia (led by China), 39% from Europe (led by Spain), and 20% from the Americas (led by Brazil). The principal ports of entry for this wind equipment were Houston-Galveston, TX (36%), Savannah, GA (14%), and Great Falls, MT (11%).

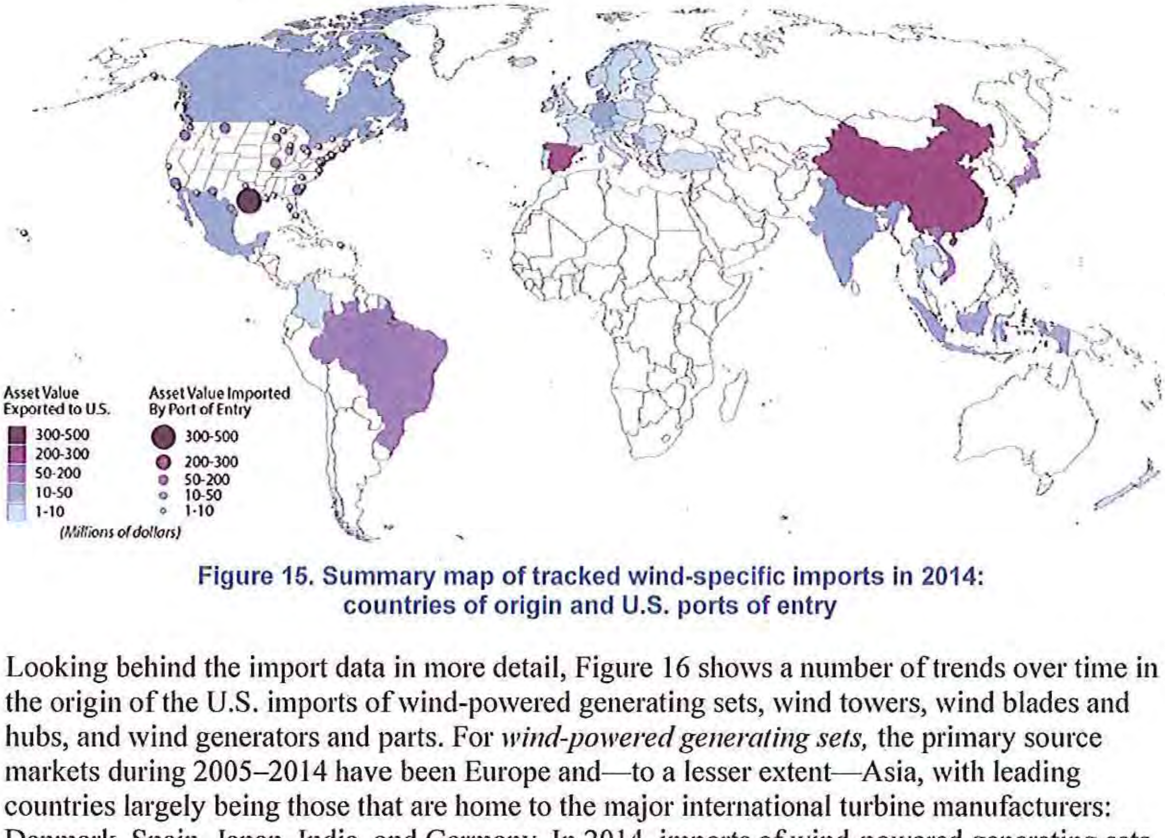
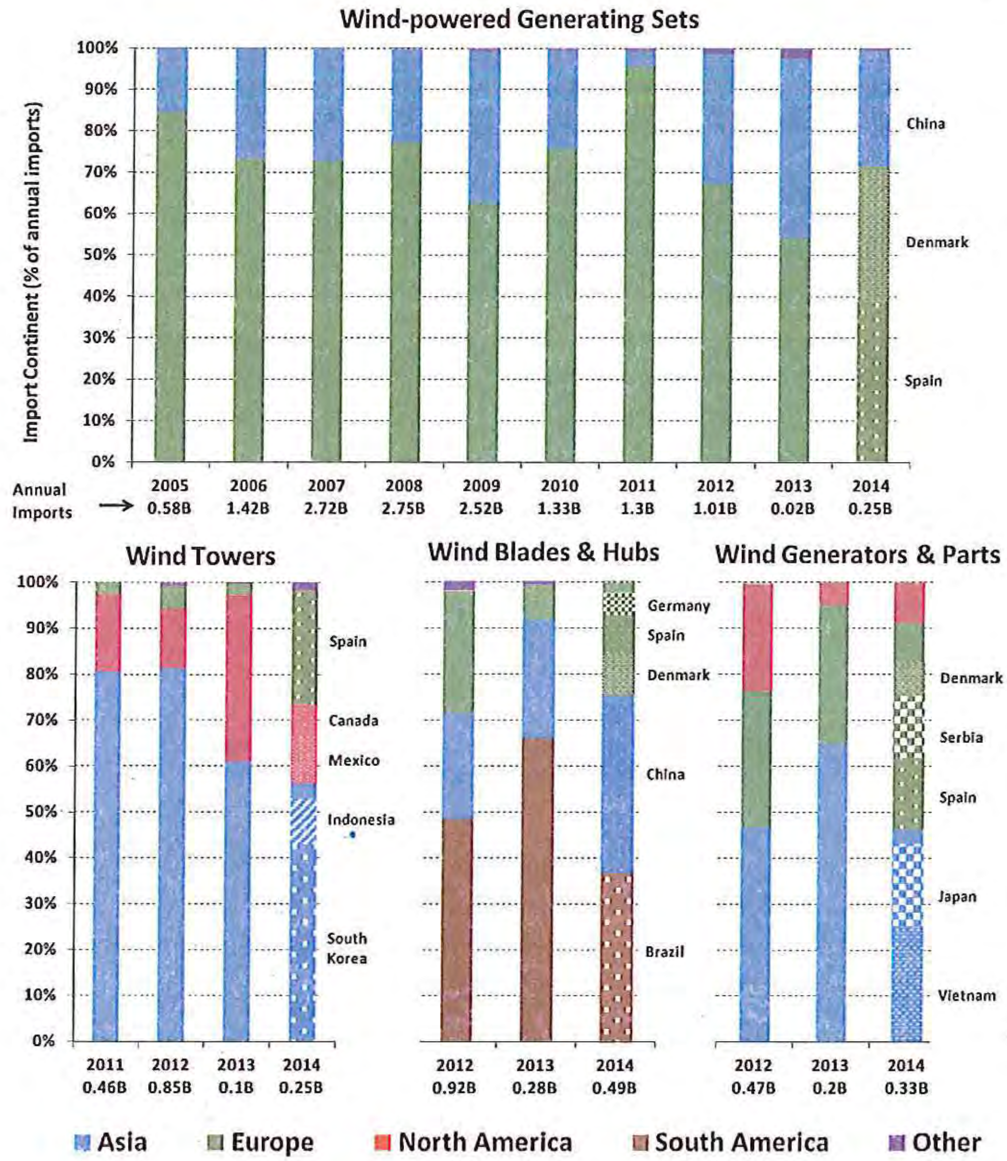


Figure 15. Summary map of tracked wind-specific imports in 2014: countries of origin and U.S. ports of entry

Looking behind the import data in more detail, Figure 16 shows a number of trends over time in the origin of the U.S. imports of wind-powered generating sets, wind towers, wind blades and hubs, and wind generators and parts. For *wind-powered generating sets,* the primary source markets during 2005–2014 have been Europe and—to a lesser extent—Asia, with leading countries largely being those that are home to the major international turbine manufacturers: Denmark, Spain, Japan, India, and Germany. In 2014, imports of wind-powered generating sets were dominated by Spain, Denmark, and China, though the total import value was relatively low. 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 and 2014, not only did the total import value decline, but there were almost no imports from China and Vietnam,

[20] The trade categories included here are the same as in Figure 14. As noted earlier, imports of many wind turbine component parts occur in broad trade categories not captured by those included in this analysis. As such, the data presented in the figure understate the aggregate amount of wind equipment imports into the United States. Note that "ports of entry" as used here refers to, in some cases, multiple ports located in the same geographic region; note also that goods may arrive at ports of entry by land, air, or sea.

likely a result of the tariff measures that were imposed on wind tower manufacturers from each of these countries. Tower imports in 2014 came from a mix of countries from Asia (e.g., South Korea and Indonesia), Europe (e.g., Spain), and North America (e.g., Mexico and Canada). With regards to *wind blades and hubs*, Brazil and China dominate as source markets (various European countries play a somewhat lesser role), with China steadily increasing its market share over time. Finally, the import origins for *wind-related generators and generator parts* were distributed across a number of largely Asian and European countries from 2012 through 2014.



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

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

Because trade data do not track all imports of wind equipment, it is not possible to use those data to establish a clear overall distinction between import and domestic content. The trade data also do not allow for a precise estimate of the domestic content of specific wind turbine components. Nonetheless, based on those data and a variety of assumptions, Table 4 presents rough estimates of the domestic content for some major wind turbine components used in U.S. wind power projects in the 2013-2014 period. On a component-by-component basis, domestic content varies widely, with domestic content the strongest for large, transportation-intensive components.

Table 4. Approximate Domestic Content of Major Components in 2013–2014

Generators	Towers	Blades & Hubs	Wind-Powered Generating Sets
< 15%	70-80%	45-65%	> 90% 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).[21] 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; when considering balance-of-plant costs as well, overall project-level domestic content in 2012 reached roughly 60%. These interviews further revealed that domestic content is relatively high for blades, towers, nacelle assembly and nacelle covers, supporting the more-recent 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, typically well below 20%.[22]

The project finance environment remained strong in 2014

With the PTC's "start of construction" safe harbor in place,[23] 2014 was a big year for wind project finance. This was particularly true in the tax equity market, where project sponsors raised $5.8 billion of new tax equity in 2014—up from $3.1 billion in 2013 and the largest single-year amount on record—to help finance 5,200 MW of wind capacity (AWEA 2015a; Chadbourne & Parke 2015). On the debt side, AWEA (2015a) reports that 2,715 MW of new and existing wind capacity raised $2.7 billion in debt in 2014—up slightly from the $2.4 billion raised in 2013, but well below the higher levels seen in previous years when the Section 1603 grant was available.[24] Most of the projects financed in 2014 will achieve commercial operations in 2015.

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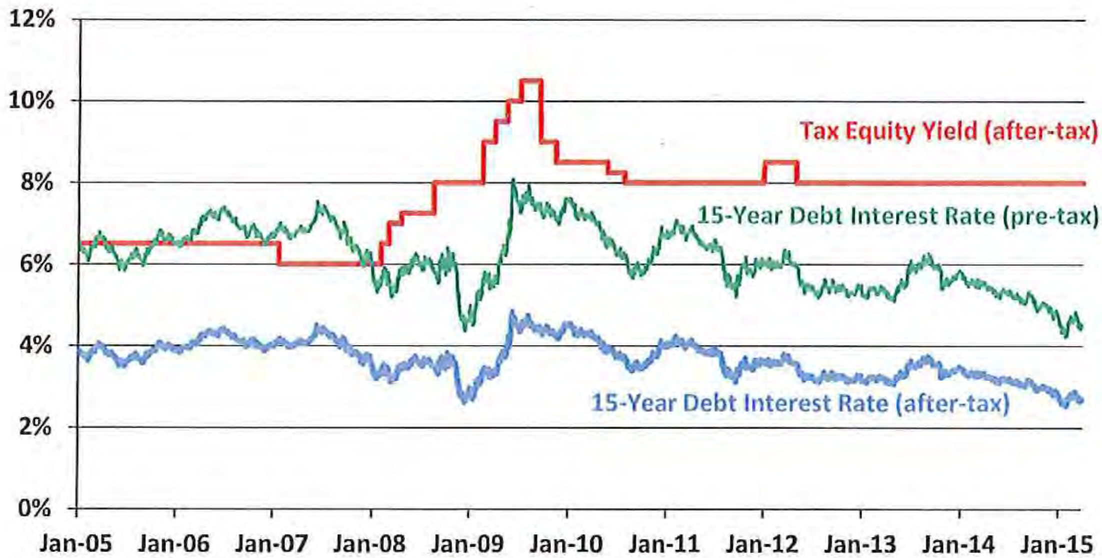
[21] On the other hand, this analysis also assumes that all components imported into the United States are used for the domestic market and not used to assemble wind-powered generating sets that are exported from the United States. If this were not the case, the resulting domestic fraction would be higher than that presented here.

[22] The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab.

[23] For most of 2014, the market operated under the assumption that 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. In December 2014, however, the PTC was extended for projects that began construction by the end of 2014, leading the IRS to eventually (in March 2015) extend the safe harbor timeline by one year as well, through 2016.

[24] 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 and foregoing tax equity altogether. 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

As shown in Figure 17, tax equity yields held steady in 2014, continuing to hover around 8% on an after-tax unlevered basis. In contrast, debt interest rates trended lower by roughly 100 basis points (i.e., an absolute decrease of 1%) throughout 2014 as debt availability remained high, with the 15-year benchmark fixed interest rate ending the year around 4.75% on a pre-tax basis (~2.9% on a post-tax basis).[25] As a result, the spread between tax equity yields and 15-year term debt (on a post-tax basis) ended the year at around 5%—its highest level since 2009. Partnership flip structures[26] remained the dominant tax equity vehicle, while banks continued to focus more on shorter-duration loans (7–10 year mini-perms remained the norm[27]), leaving longer-duration, fully amortizing loans to institutional lenders (Chadbourne & Parke 2015).



Source: Adapted from Bloomberg NEF (2015a)

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

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losses and credits. Because most tax equity investors will not allow leverage on projects in which they invest (Chadbourne & Parke 2015), the expiration of the Section 1603 grant for wind and the correspondingly greater reliance on the PTC could be a contributor to the decline in debt raised by new wind projects in 2013 and 2014.

[25] The returns of equity investors in renewable projects are 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 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%.

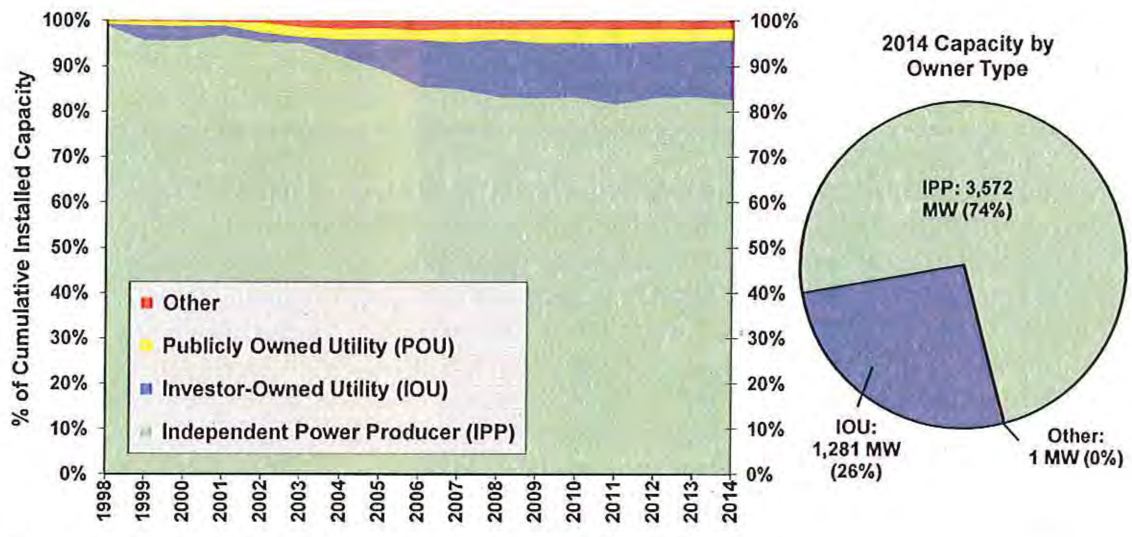
[26] A "partnership flip" is a project finance structure in which the developer or project sponsor partners with a third-party tax equity investor to jointly invest in and own the project. Initially, allocations of cash revenue and tax benefits are skewed heavily in favor the tax equity partner (which is able to efficiently monetize the tax benefits), but eventually "flip" in favor of the project sponsor partner once the tax benefits have been largely exhausted.

[27] 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).

Looking ahead to the remainder of 2015, financing activity in both the tax equity and debt markets is likely to remain strong given the extension of the PTC safe harbor guidance through 2016. Despite increasing competition for tax equity from solar in 2015 and 2016 (as the Section 48 commercial ITC is scheduled to revert from 30% to 10% in 2017), tax equity investors seem confident that there will be enough capital to meet the market's needs (Chadbourne & Parke 2015). Ongoing investment demand from YieldCos (e.g., NextEra Energy Partners, Pattern Energy Group, TerraForm Power, NRG Yield, etc.) should help in this regard by supplementing the capital stack with low-cost equity. Debt is also expected to remain plentiful.

Utility ownership of wind assets rebounded somewhat in 2014

Independent power producers (IPPs) own 3,572 MW, or 74%, of the 4,854 MW of new wind capacity installed in the United States in 2014 (Figure 18). Nearly all of the remaining 26% is owned by investor-owned utilities (IOUs), led by MidAmerican Energy (3 projects totaling 511 MW), Portland General Electric (267 MW), Minnesota Power (205 MW), Detroit Edison (2 projects totaling 187 MW), and Consumers Energy (111 MW). Finally, one 600 kW turbine falls into the "other" category of projects owned by neither IPPs nor utilities (e.g., towns, schools, commercial customers, farmers),[28] while publicly owned utilities (POUs) do not own any of the new wind power capacity brought online in 2014. Of the *cumulative* installed wind power capacity at the end of 2014, IPPs own 82% and utilities own 16% (13.3% IOU and 2.5% POU), with the remaining 2% falling into the "other" category.



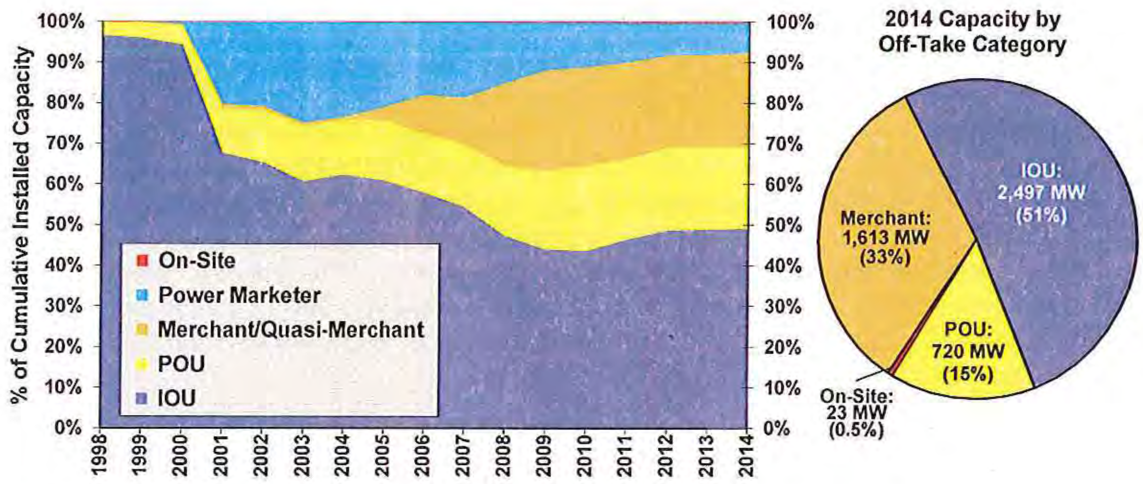
Source: Berkeley Lab estimates based on AWEA project database

Figure 18. Cumulative and 2014 wind power capacity categorized by owner type

[28] Most of the "other" projects, along with some IPP- and POU-owned projects, might also be considered "community wind" projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project. According to AWEA (2015a), 2.5% of 2014 wind capacity additions qualified as community wind projects.

Long-term contracted sales to utilities remained the most common off-take arrangement, but merchant projects continued to expand, at least in Texas

Electric utilities continued to be the dominant off-takers of wind power in 2014 (Figure 19), either owning (26%) or buying (40%) power from 66% of the new capacity installed last year (with the 66% split between 51% IOU and 15% POU). On a cumulative basis, utilities own (16%) or buy (53%) 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.



Source: Berkeley Lab estimates based on AWEA project database

Figure 19. Cumulative and 2014 wind power capacity categorized by power off-take arrangement

Merchant/quasi-merchant projects continued to rebound in 2014, accounting for 33% of all new capacity (compared to 25% in 2013 and ~20% in each of the three years from 2010-2012) 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[29]) rather than being locked in through a long-term PPA. Of the merchant capacity built in 2014, 96% is located in Texas, with the small remainder located in PJM and NY-ISO. 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.

[29] 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.

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, but also including corporate wind power purchasers[30]—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 2014 is selling to power marketers, while just 7% of cumulative wind power capacity does so (down from more than 20% in the early 2000s). Looking ahead, however, this segment should grow in response to a surge of recently announced corporate wind power purchases from projects that will be built in the next few years (see Text Box in Chapter 8).

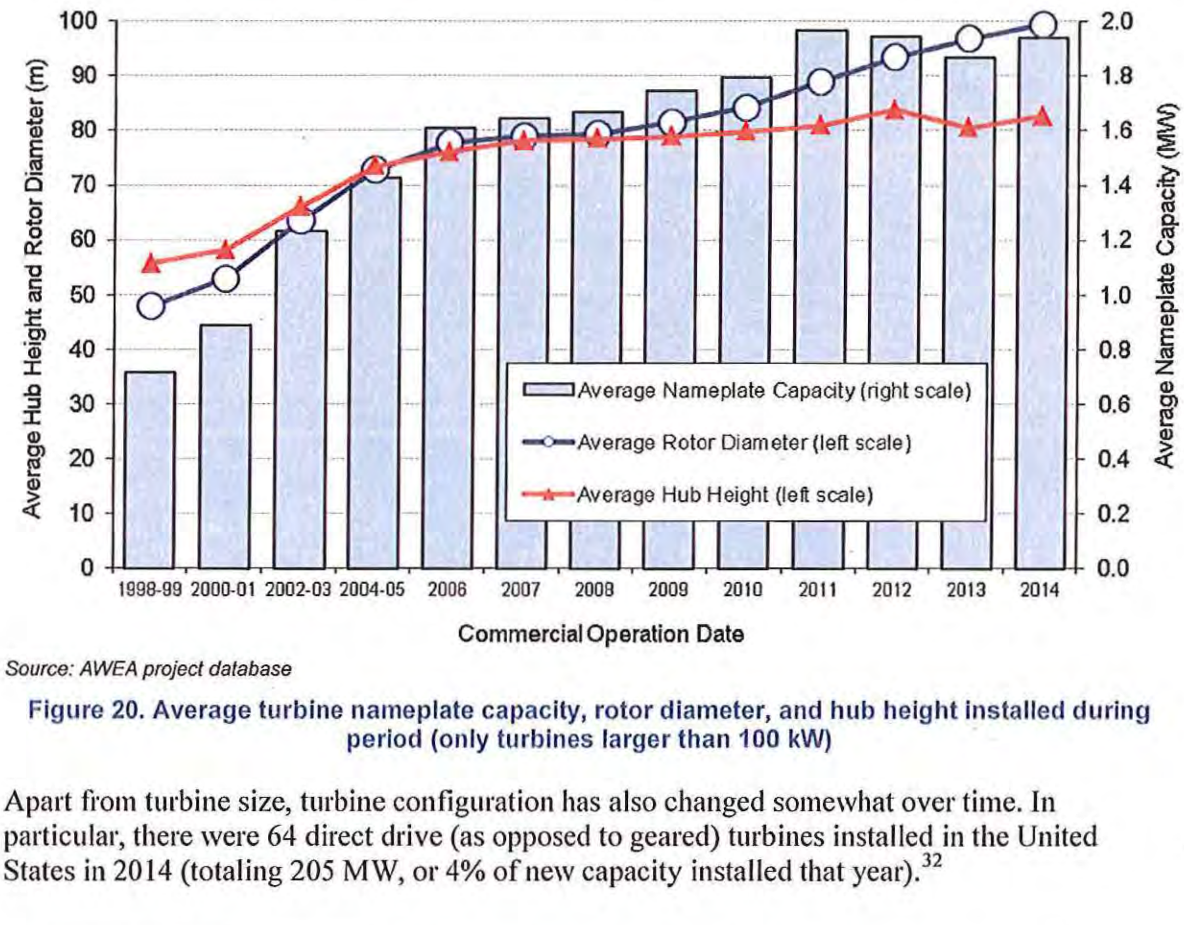
Finally, 23 MW (0.5%) of the wind power additions in 2014 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.

[30] 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 cases the end user is effectively acting as a power marketer.

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 newly installed wind turbines in the United States in 2014 was over 1.9 MW, up 172% since 1998–1999 (Figure 20).[31] The average hub height of turbines installed in 2014 was 82.7 meters, up 48% since 1998–1999. Average rotor diameters have increased at a more rapid pace than hub heights, especially recently; the average rotor diameter of wind turbines installed in 2014 was 99.4 meters, up 108% since 1998–1999, which translates into a 333% 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 20. Average turbine nameplate capacity, rotor diameter, and hub height installed during period (only turbines larger than 100 kW)

Apart from turbine size, turbine configuration has also changed somewhat over time. In particular, there were 64 direct drive (as opposed to geared) turbines installed in the United States in 2014 (totaling 205 MW, or 4% of new capacity installed that year).[32]

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

[32] Direct drive technology has been relatively slow to enter the U.S. market in comparison to global trends—e.g., Navigant (2015) reports that 27% of *global* wind turbine supply in 2014 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.

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

As indicated in Figure 20, and as detailed in Figures 21–23, rotor diameter scaling has been especially significant over the last five years, and more so than increases in nameplate capacity and hub heights, both of which have seen a stabilization of the long-term trend in recent years.

Starting with turbine nameplate capacity, Figure 21 presents not only the trend in *average* nameplate capacity (as also shown earlier, in Figure 20) but also how the prevalence of different turbine capacity ratings has changed over time. The average nameplate capacity of newly installed wind turbines has largely held steady since 2011, and the longer-term pace of growth started to slow after 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. Moreover, both 2013 and 2014 showed some reversal of this trend, with a majority share of sub-2 MW machines.

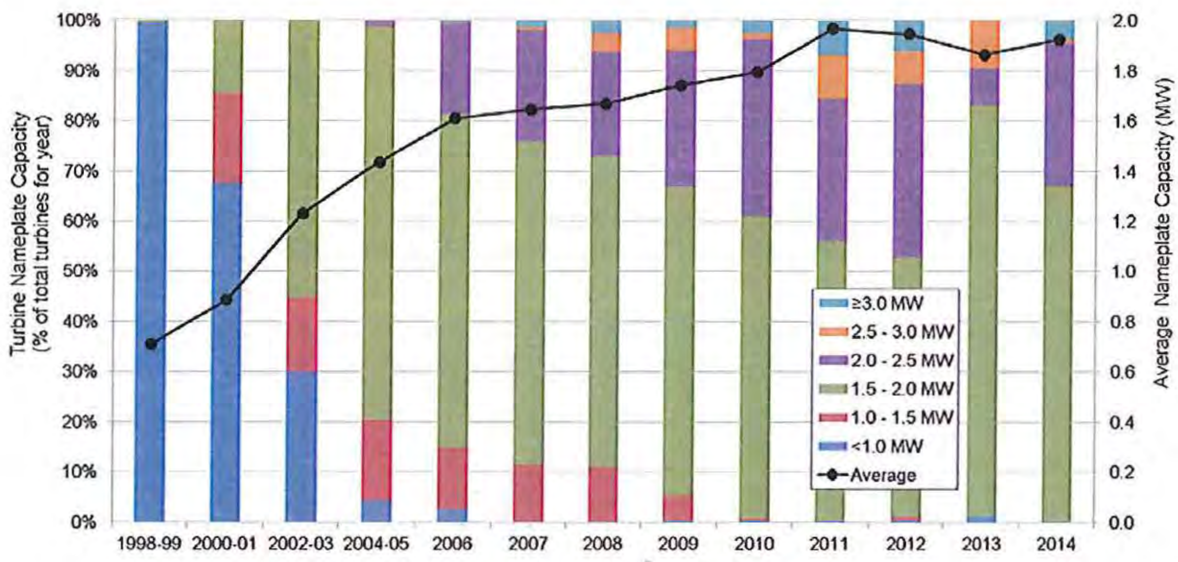


Figure 21. Trends in turbine nameplate capacity

As with nameplate capacity, the average hub height of wind turbines has held steady since 2011 (Figure 22). More generally, growth in average hub height has been slow since 2005, with 80 meter towers dominating the overall market. Towers that are 90 meters and taller started to penetrate the market in 2011, however, a trend that has continued into 2014.

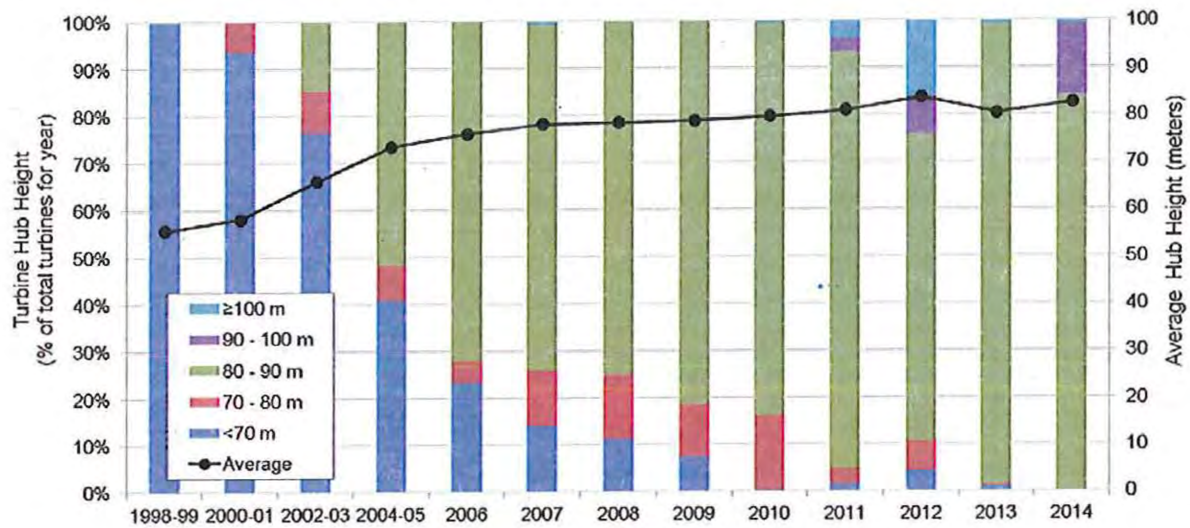


Figure 22. Trends in turbine hub height

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 23, this recent increase has been especially apparent since 2009. In 2008, no turbines employed rotors that were 100 m in diameter or larger. By 2012, 47% of newly installed turbines featured rotors of that length and, in 2014 the percentage grew to 80%. Rotor diameters of 110 m or larger, meanwhile, started penetrating the market in 2012; in 2014, 5% of the installed turbines featured rotors of that size.

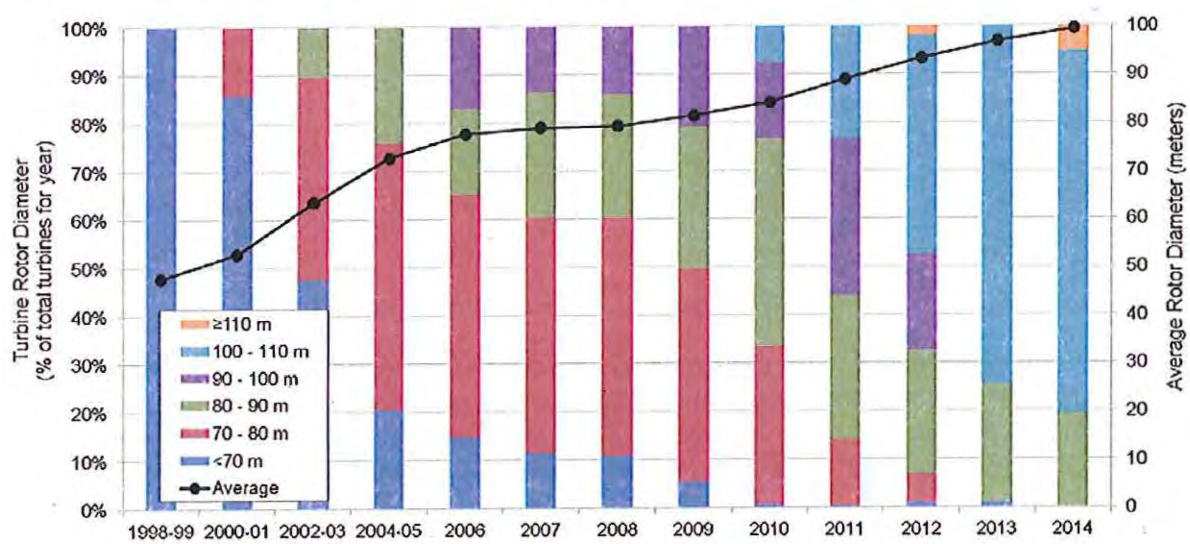


Figure 23. Trends in turbine rotor diameter

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 394 W/m^2 among projects installed in 1998–1999 to 249 W/m^2 among projects installed in 2014 (Figure 24). The decline in specific power was especially rapid from 2001 to 2005 and, more recently, from 2011 to 2014.

All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity, 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: 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 physical stress. As suggested in Figure 24 and as detailed in the next section, however, such turbines are now in widespread use in the United States—even in sites with high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.

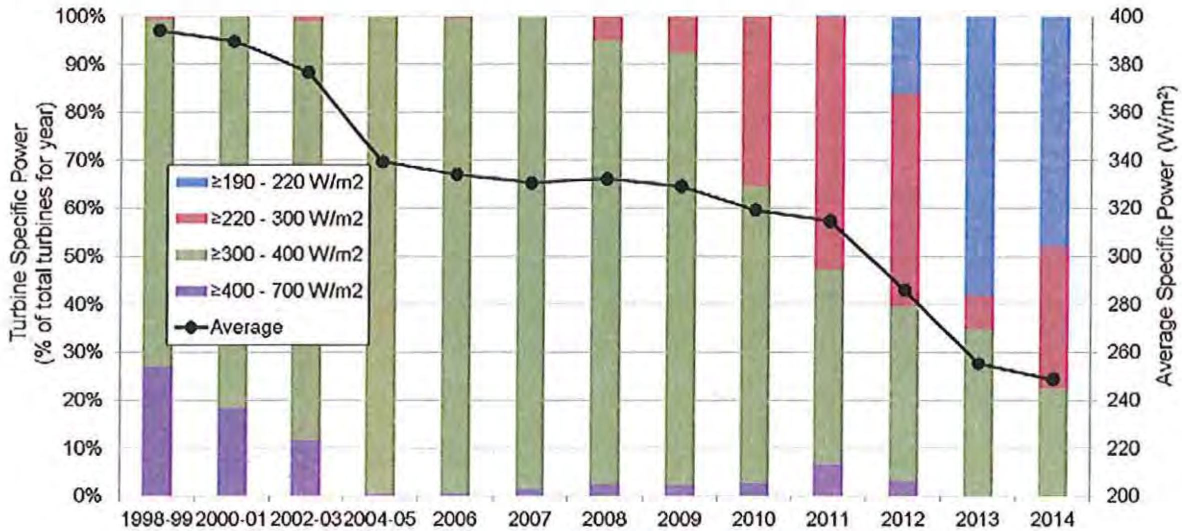


Figure 24. Trends in turbine specific power

Another indication of the increasing prevalence of machines designed for lower wind speeds is revealed in Figure 25, which presents trends in wind turbine installations by IEC Class. The IEC classification system considers multiple site characteristics, including wind speed, gusts, and turbulence. Class 3 turbines are generally designed for lower wind speed sites (7.5 m/s and below), Class 2 turbines for medium wind speed sites (up to 8.5 m/s), and Class 1 turbines for higher wind speed sites (up to 10 m/s). Some turbines are designed at the margins of two classifications, and are labeled as such (e.g., Class 2/3).

As shown, the U.S. wind market has become increasingly dominated by IEC Class 3 turbines in recent years. In 2000–2001, Class 1 machines were prevalent. From 2002 through 2009, Class 2 machines penetrated the market substantially. Since 2009, there has been a substantial decline in the use of Class 2 turbines, and a concomitant increasing market share of Class 3 and Class 2/3 turbines. In 2014, 68% of the newly installed turbines were Class 3 machines, with another 27% Class 2/3 machines; only 6% of turbines were Class 2 or lower.

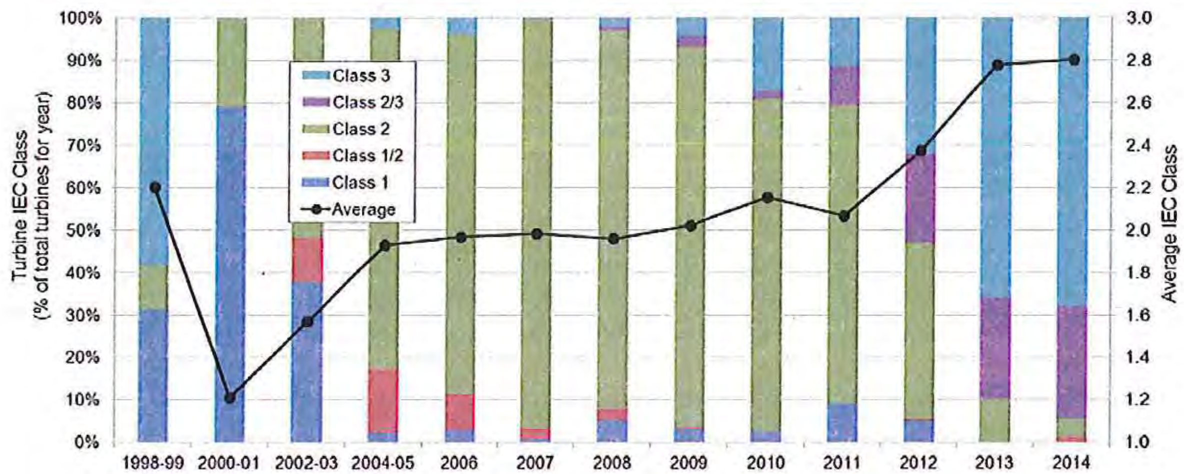
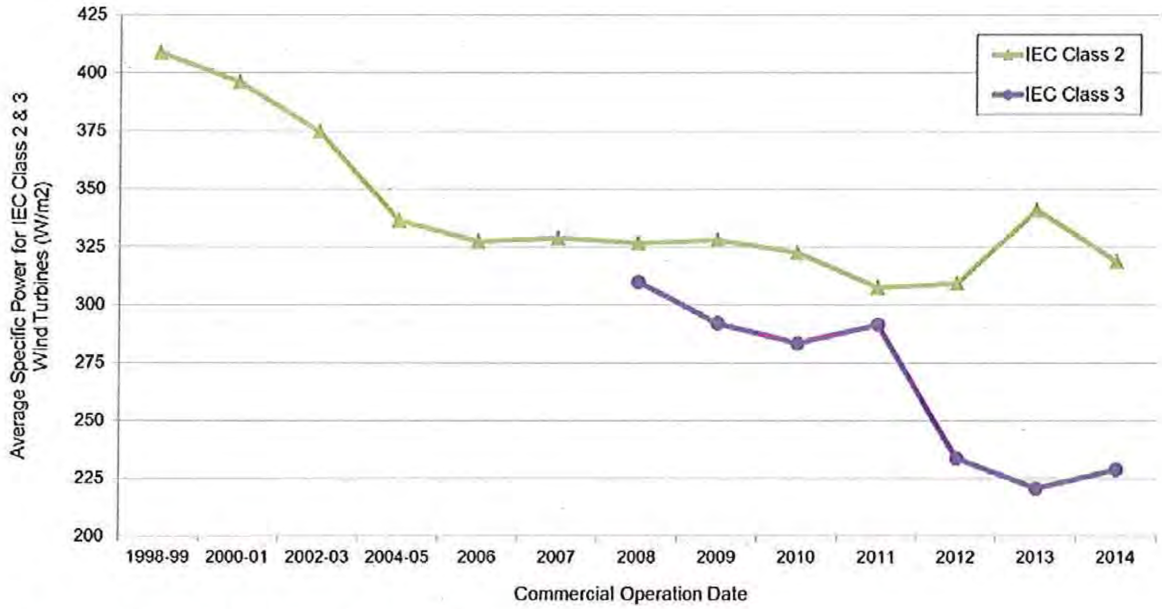


Figure 25. Trends in turbine IEC class

Moreover, Class 2 and 3 turbine technology has not remained stagnant, namely through expanded rotors that drive even-lower specific power ratings. Whereas Figure 24 shows the trend in average specific power across all turbines installed in each year (regardless of IEC Class), Figure 26 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 generally dropped with time. As such, not only has the average specific power declined across all wind turbine installations (Figure 24), but the marked shift to Class 2 and then to Class 3 turbines shown in Figure 25 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 40 turbines

Figure 26. 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 the Great Lakes and Northeast

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 historically (see Chapter 5), it is clear in Figures 27 and 28 that turbines originally designed for lower wind speeds are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites.

Figure 27 presents the percentage of turbines installed in four distinct regions of the United States[33] (see Figure 29 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 2012–2014 time period. Figure 28 presents similar information, but segments the data by the wind resource quality of the site rather than by the region in which the turbines are located.

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

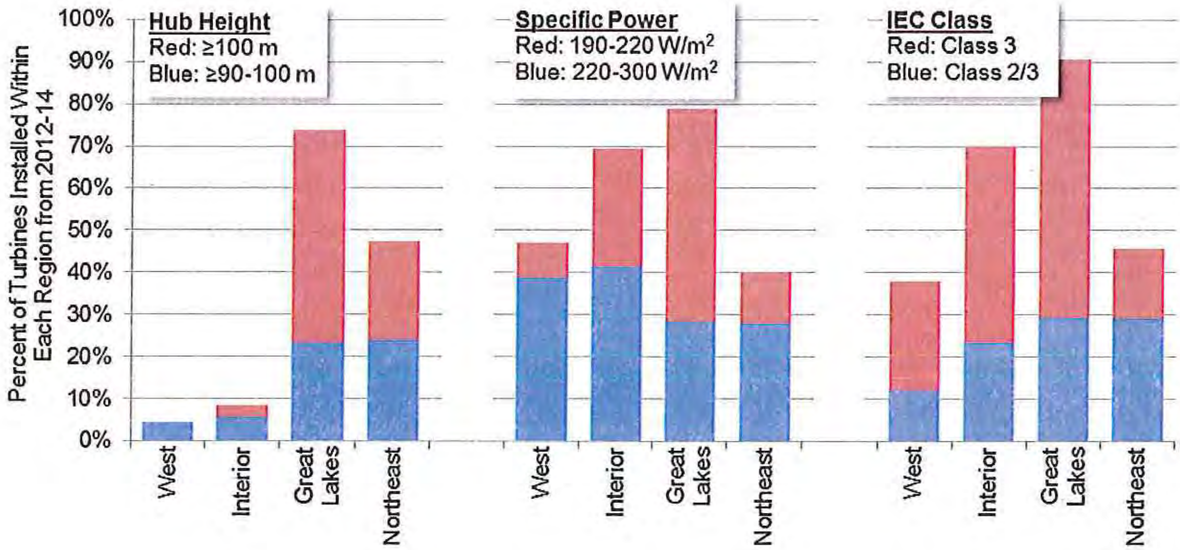
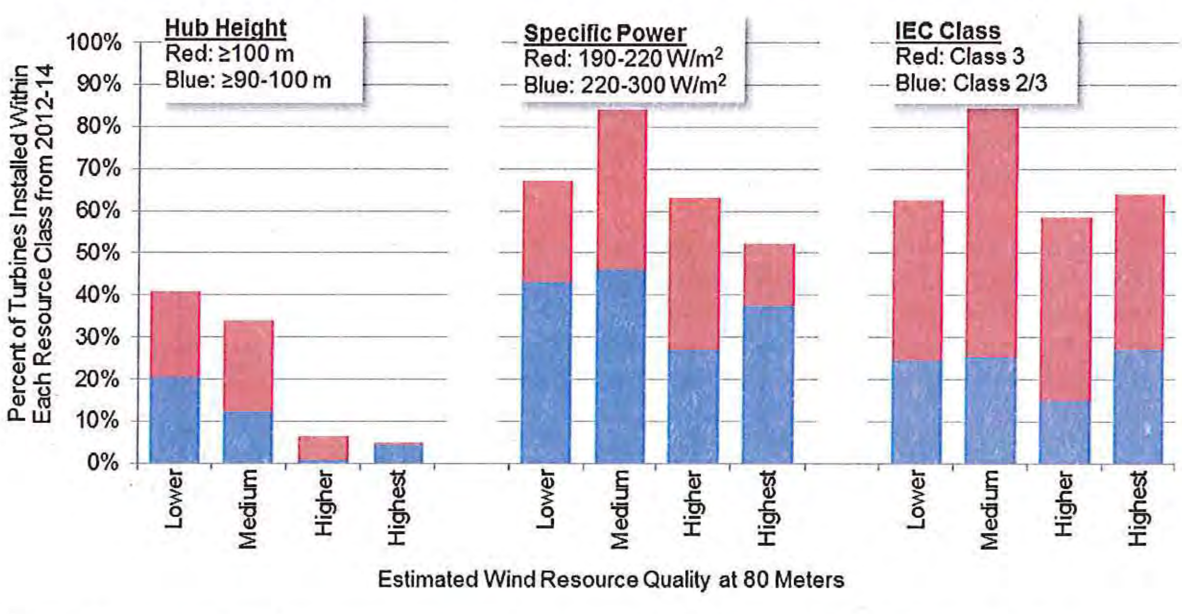


Figure 27. Deployment of turbines originally designed for lower wind speed sites, by region



Note: Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The "lower" category includes all projects with an estimated gross capacity factor of <40%, the "medium" category corresponds to 40%–45%, the "higher" category corresponds to 45%-50%, and the "highest" category includes any project at or exceeding 50%.

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

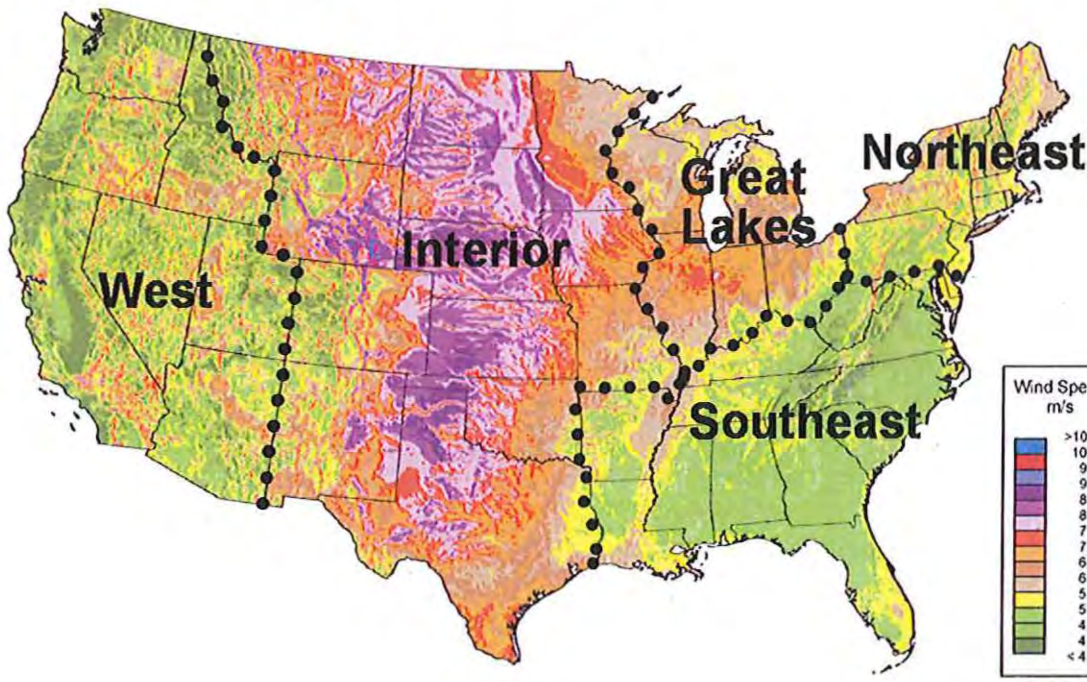
Low specific power machines installed over this three-year period have been regularly deployed in all regions of the country, though their market share in the Great Lakes (79%) and Interior (70%) exceeds that in the West (47%) and Northeast (40%). Similarly, these turbines have been commonly used in all resource regimes, as shown in Figure 28, including at sites with very high wind speeds. At the same time, turbines with the lowest specific power ratings (190–220 W/m^2)

have been installed in greater proportions in lower, medium, and higher wind speed sites than in the highest wind speed sites, and are relatively more prevalent in 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 (91%) and Interior (70%) regions, but have also gained significant market in the Northeast (46%) and West (38%). Moreover, these turbines have been regularly deployed in both lower- and higher-quality resources sites.

Finally, taller towers have seen higher market share in the Great Lakes (74%) and Northeast (47%) than in the Interior (8%) and West (4%), often in sites with lower wind speeds. This is largely due to the fact that such towers are most commonly used in sites with higher-than-average wind shear (i.e., greater increases in wind speed with height) to access the better wind speeds that are typically higher up. Sites with higher wind shear are prevalent in the Great Lakes and Northeast regions.

In combination, these findings demonstrate that turbines originally designed for lower wind speed sites are, in fact, being deployed in such sites. More interesting, however, is that 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.



Source: AWS Truepower, National Renewable Energy Laboratory

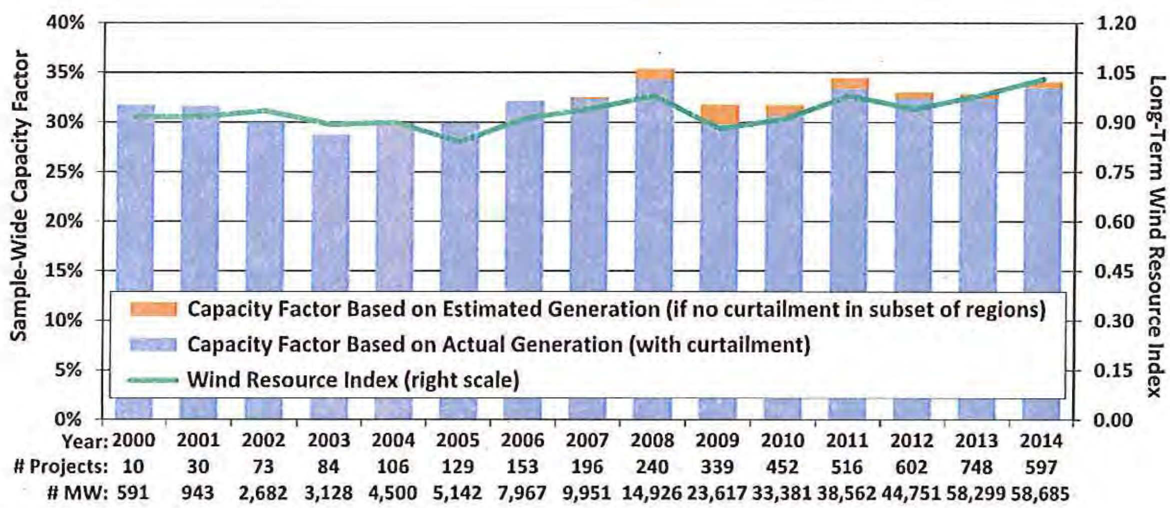
Figure 29. Regional boundaries overlaid on a map of average annual wind speed at 80 meters

5. Performance Trends

Following the previous discussion of technology trends, this chapter presents data from a Berkeley Lab compilation of project-level capacity factors. The full data sample consists of 597 wind projects built between 1998 and 2013 and totaling 58,685 MW (96% of nationwide installed wind capacity at the end of 2013).[34] The discussion is divided into three subsections: the first analyzes trends in sample-wide capacity factors over time, the second looks at variations in capacity factors by project vintage, and the third focuses on regional variations.

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

The blue bars in Figure 30 show the average sample-wide capacity factor of wind projects in each calendar year among a progressively larger cumulative sample in each year.[35] Viewed this way—on a cumulative, sample-wide basis—one might expect to see a gradual improvement in capacity factor over time, as newer turbines are added to the fleet. Although capacity factors have generally been higher on average in more recent years (e.g., 32.9% between 2011 and 2014 versus 31.8% between 2006 and 2010 versus 30.3% between 2000 and 2005), the trend is not as significant as expected. Two factors that influence these trends are discussed below: wind energy curtailment and inter-year variability in the strength of the wind resource. A third factor, the average quality of the resource in which projects are located, is discussed in the next section.



Source: Berkeley Lab

Figure 30. Average cumulative sample-wide capacity factors by calendar year

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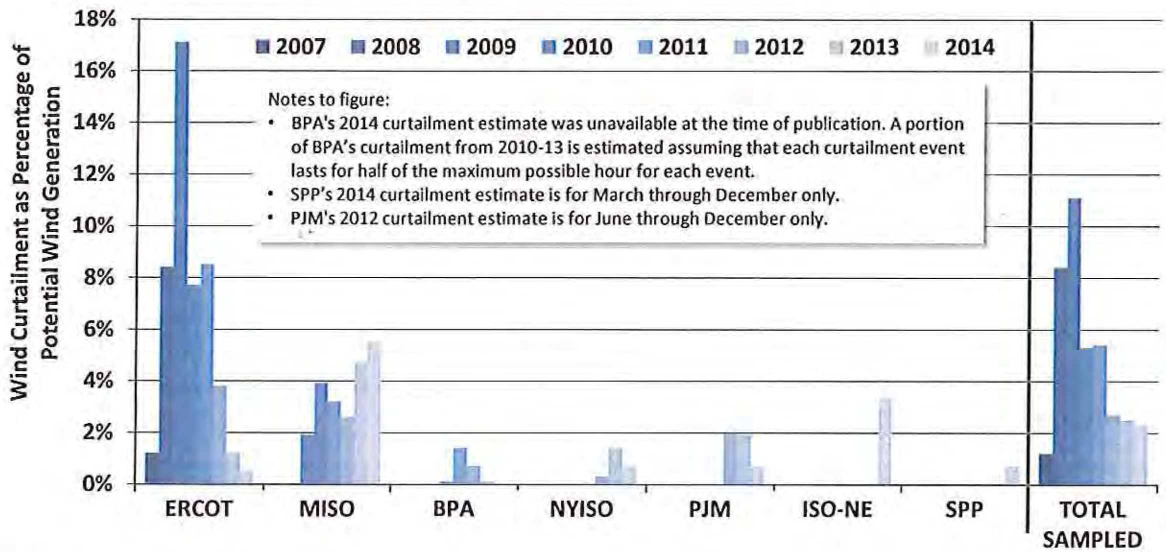
[34] Although some performance data for wind power projects installed in 2014 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on projects with commercial operation dates from 1998 through 2013.

[35] There are fewer individual projects—although more capacity—in the 2014 cumulative sample than there are in 2013. 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 2015 before EIA reports 2014 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.

Wind Power Curtailment. Curtailment of wind project output can occur due to transmission inadequacy, minimum generation limits, other forms of grid inflexibility, and/or environmental restrictions, and might be expected to increase as wind energy penetrations rise. That said, in areas where curtailment has been particularly problematic in the past—principally in Texas—steps taken to address the issue have significantly mitigated the concern. For example, Figure 31 shows that only 0.5% of potential wind energy generation within ERCOT was curtailed in 2014, down sharply from 17% in 2009, roughly 8% in both 2010 and 2011, nearly 4% in 2012, and 1.2% in 2013. 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.



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

Figure 31. Estimated wind curtailment by region as a percentage of potential wind generation

Elsewhere, the only regions shown in Figure 31 in which wind curtailment exceeded 1% in 2014 were MISO at 5.5% (as much of the new wind buildout continues to be located within this ISO) and ISO-NE at 3.3% (a rough estimate that the grid operator suspects is understated). Both ISO-NE and SPP are newcomers to this section this year, as both ISOs/RTOs have only recently implemented methods—still being refined—by which to track wind power curtailment. Except for BPA, all of the regions shown in Figure 31 track both "forced" (i.e., required by the grid operator for reliability reasons) and "economic" (i.e., voluntary as a result of wholesale market prices) curtailment. BPA (which did not report in 2014) tracks only forced curtailment, which means that its modest curtailment estimates for 2010–2013 may understate the true level of curtailment experienced by wind power projects in the region.

In aggregate, assuming a 33% average capacity factor, the total amount of curtailed wind generation tracked in Figure 31 for 2014 equates to the annual output of roughly 980 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 30 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 seven territories shown in Figure 31, 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 2014 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.[36]

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 30 shows that 2014 was a generally good wind year, at least in terms of the national average wind energy resource as measured by one large project sponsor.[37] 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 32% to 35% nationwide

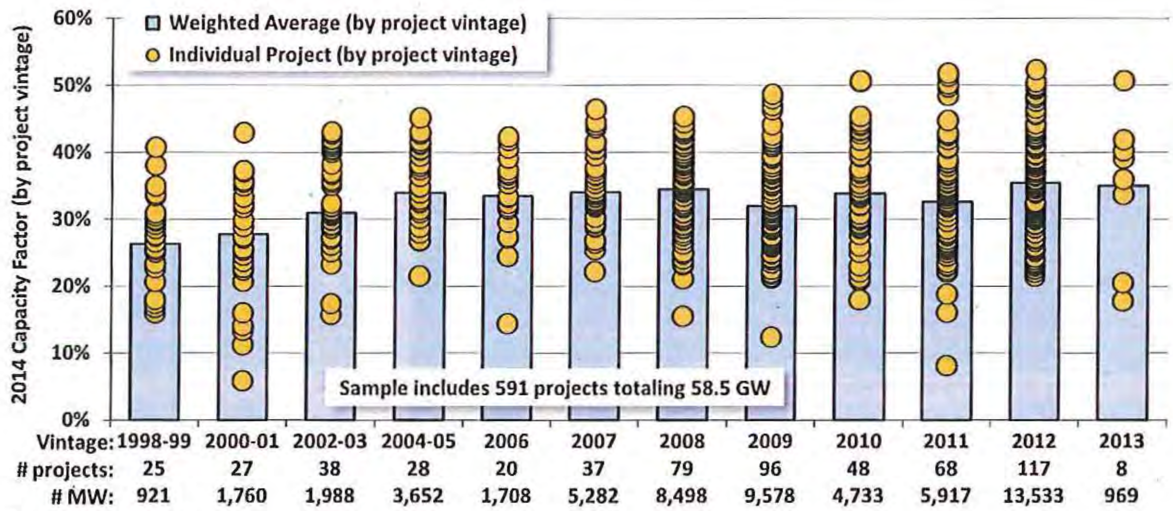
One way to control for the time-varying influences described in the previous section (e.g., annual wind resource variations or changes in the amount of wind curtailment) is to focus exclusively on capacity factors in a single year, such as 2014.[38] As such, whereas Figure 30 presents capacity factors in each calendar year, Figure 32 instead shows only capacity factors in 2014, broken out by project vintage. Wind power projects built in 2014 are again not included, as full-year performance data are not yet available for those projects.

Figure 32 shows an increase in weighted average 2014 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* 2014 capacity factor attained by any individual project. Somewhat surprisingly, however, weighted average 2014 capacity factors *do not* show an increasing trend among post-2005 project vintages, despite the significant scaling in turbine size in recent years (reported earlier in Chapter 4, and especially related to rotor diameter scaling and the resultant decline in specific power).

[36] The seven regions included in Figure 31 collectively contributed more than 70% of total U.S. wind generation in 2014.

[37] The green line in Figure 30 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.

[38] Although focusing just on 2014 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 2014 was not a representative year in terms of the strength of the wind resource or wind power curtailment.

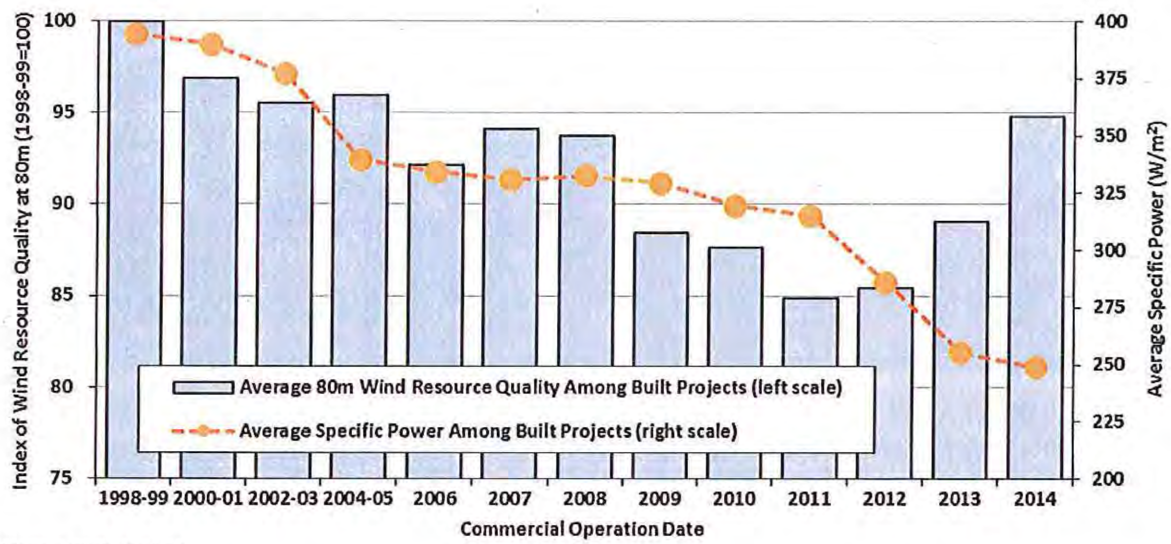


Source: Berkeley Lab

Figure 32. Calendar year 2014 capacity factors by project vintage

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 24 and 26), 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

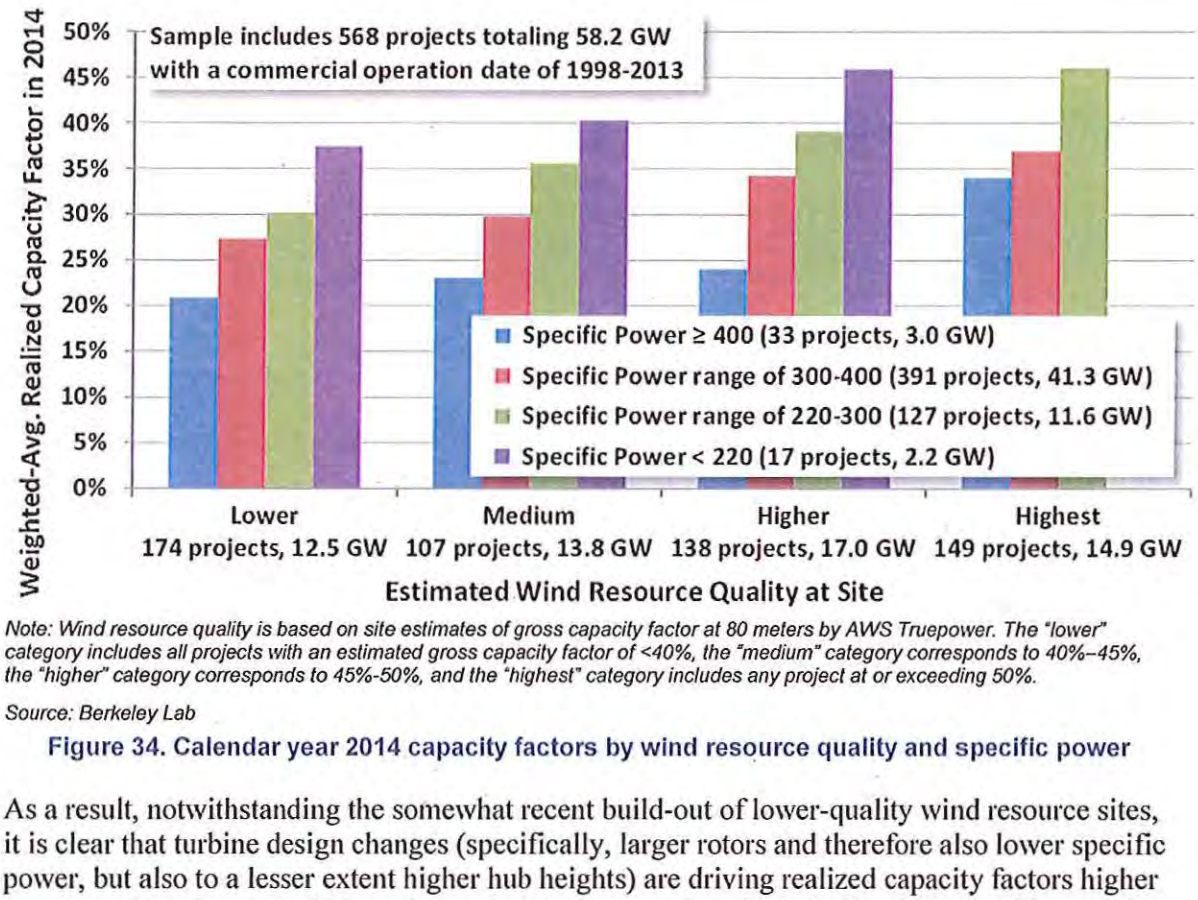
Counterbalancing the decline in specific power, however, has been a tendency to build new wind projects in lower-quality wind resource areas; this is especially the case among projects installed from 2009 through 2012. Figure 33 shows that the average estimated quality of the wind resource at 80 meters among projects built in 2011 and 2012 is roughly 15% lower than it is among projects built back in 1998–1999 and that the decline has been particularly sharp since 2008.[39] Although there was a rebound in 2013 (the most recent project vintage in our capacity factor sample included in Figure 32) and 2014 (which will impact our capacity factor sample in future years), the buildout of wind power projects in 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, as evidenced in part by the increased development in 2013 and 2014 in those higher-quality wind resource areas. Several factors could have driven this trend, especially in the 2009 to 2012 period:

- **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 over this period (or other siting constraints, or even just regionally differentiated wholesale electricity prices) by focusing on those projects in their pipeline that may not be located in the best wind resource areas but that do have access to transmission (or higher-priced markets, or readily available sites without long permitting times).
- **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

[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.

(or ITC) was not dependent on how much electricity a project generates, it is possible that developers seized this limited opportunity to build out the less-energetic sites in their development pipelines. 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, depending on the wind resource quality estimated for each site. Within each wind resource category, projects are further differentiated by their specific power. As one would expect, projects sited in higher-wind-speed areas generally realized higher 2014 capacity factors than those in lower-wind-speed areas, regardless of specific power. Likewise, within each of the four wind resource categories along the x-axis, projects that fall into a lower specific power range realized significantly higher 2014 capacity factors than those in a higher specific power range.

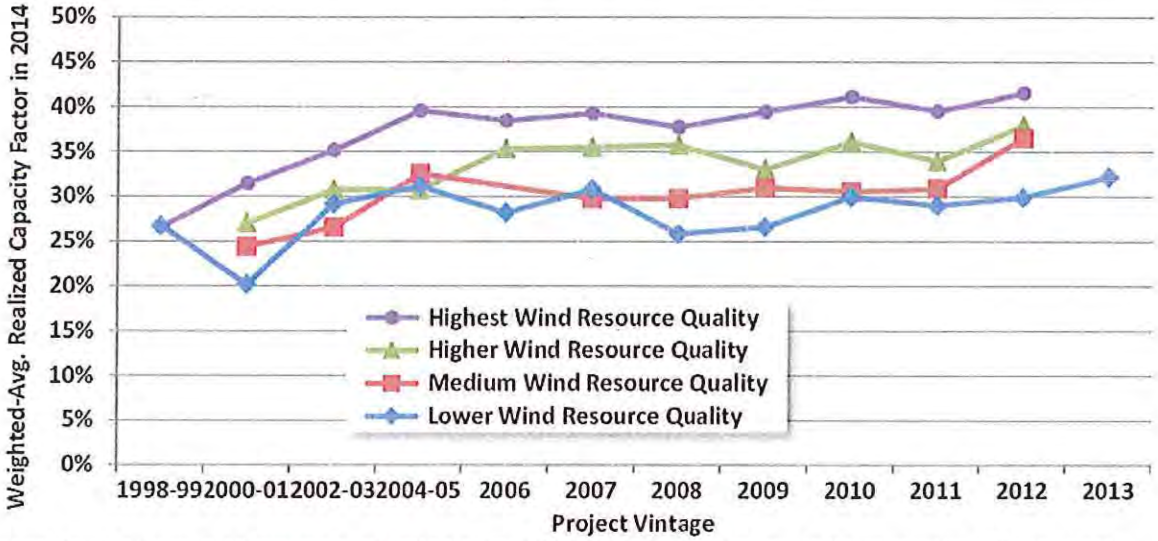


Note: Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The "lower" category includes all projects with an estimated gross capacity factor of <40%, the "medium" category corresponds to 40%–45%, the "higher" category corresponds to 45%-50%, and the "highest" category includes any project at or exceeding 50%.

Source: Berkeley Lab

Figure 34. Calendar year 2014 capacity factors by wind resource quality and specific power

As a result, notwithstanding the somewhat 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 realized 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 the same four different categories of wind resource quality, and then reports average realized 2014 capacity factors by commercial operation date within each category.[40] As before, projects sited in higher-wind-speed areas have, on average, higher realized capacity factors. More importantly, although there is some variability in the year-to-year trends, it is clear that within each of the four wind resource categories there has been an improvement in realized capacity factors over time, by commercial operation date.



Notes: Only the "lower" wind resource quality data are shown for 2013 vintage projects due to low sample size in the other three categories (see footnote 40). Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The "lower" category includes all projects with an estimated gross capacity factor of <40%, the "medium" category corresponds to 40%–45%, the "higher" category corresponds to 45%-50%, and the "highest" category includes any project at or exceeding 50%.

Source: Berkeley Lab

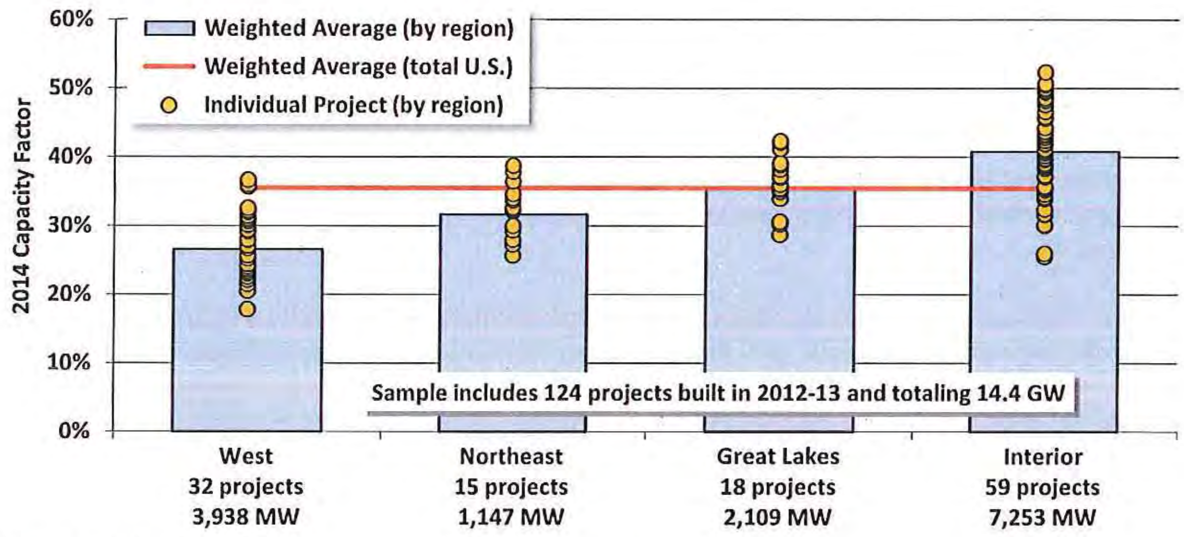
Figure 35. Calendar year 2014 capacity factors by project vintage and wind resource quality

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 2014 capacity factors ranging from a minimum of 18% to a maximum of 51% among the small number of projects built in 2013. Some of the spread in project-level capacity factors—for projects built in 2013 and before—is attributable to regional variations in average wind resource quality.

Figure 36 shows the regional variation in 2014 capacity factors (using the regional definitions shown in Figure 29, earlier) based on a sample of wind power projects built in 2012 or 2013; 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 (41%) and the lowest in the West (27%).[41] Even within each region, however, there is still considerable spread—e.g., 2014 capacity factors range from 26% up to 52% for projects installed in the Interior region in 2012 or 2013.

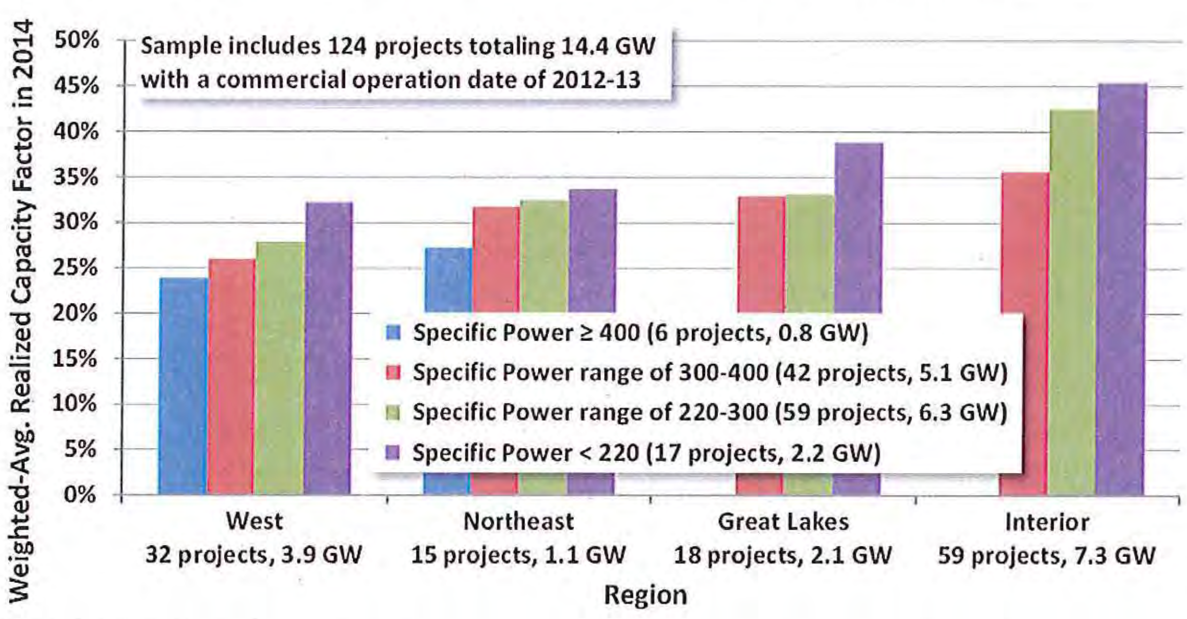
[40] The figure only includes those data-points representing at least three projects in any single resource-year pair. Among 2013 vintage projects, only the "lower" wind resource quality grouping meets this sample size threshold.
[41] Given the relatively small sample size in some regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2014, care should be taken in extrapolating these results.



Source: Berkeley Lab

Figure 36. Calendar year 2014 capacity factors by region: 2012-2013 vintage 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 realized capacity factors than those in a higher specific power range.



Source: Berkeley Lab

Figure 37. Calendar year 2014 capacity factors by region and specific power

As shown earlier in Chapter 4 ("Technology Trends"), the rate of adoption of turbines with lower specific power ratings has varied by region. For example, Figure 27 (earlier) shows that 50% of all turbines installed in the Great Lakes region from 2012–2014 have a specific power rating of less than 220 W/m^2, while the comparable number in the West is 8%. Similarly, more than 70% of all turbines installed in the Great Lakes region from 2012–2014 have tower heights of at least 90 meters, compared to 4% 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 30–37 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.

Wind turbine prices remained well below levels seen several years ago

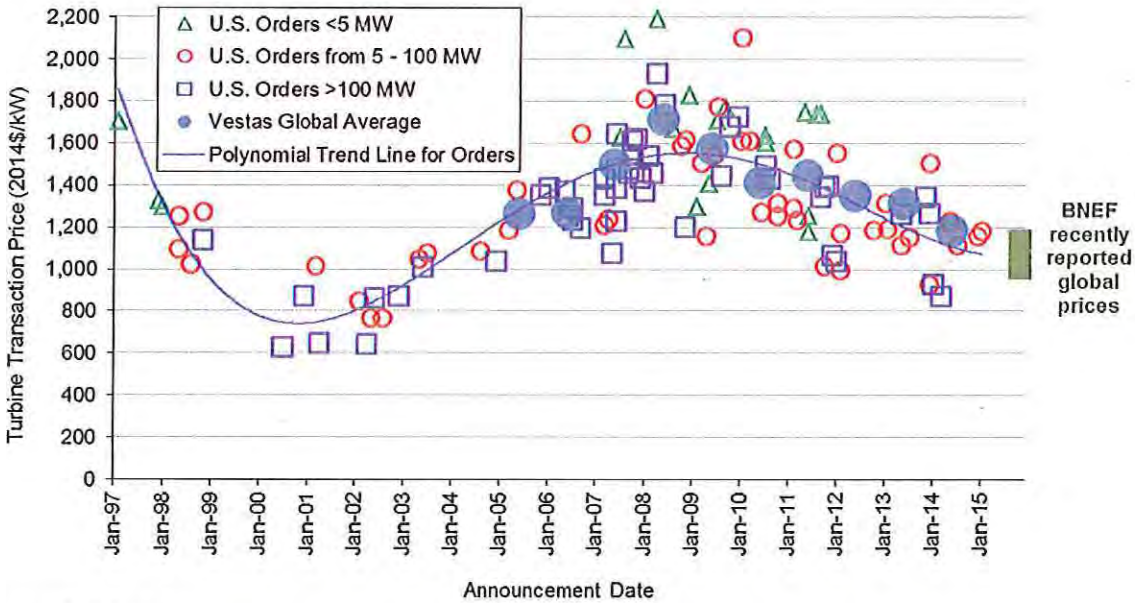
Wind turbine prices have dropped substantially in recent years, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Prices maintained their low levels in 2014, partly a result of continued stiff competition among turbine OEMs and equipment suppliers and related cost-cutting measures.

Berkeley Lab has gathered price data for 117 U.S. wind turbine transactions totaling 29,740 MW announced from 1997 through the beginning of 2015, but including only six transactions (863 MW) announced in 2014/15. 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.[42] 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 2014, as reported in Vestas' financial reports; and (2) a range of recent global average wind turbine prices, as reported by Bloomberg NEF (2015b).

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).

[42] 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

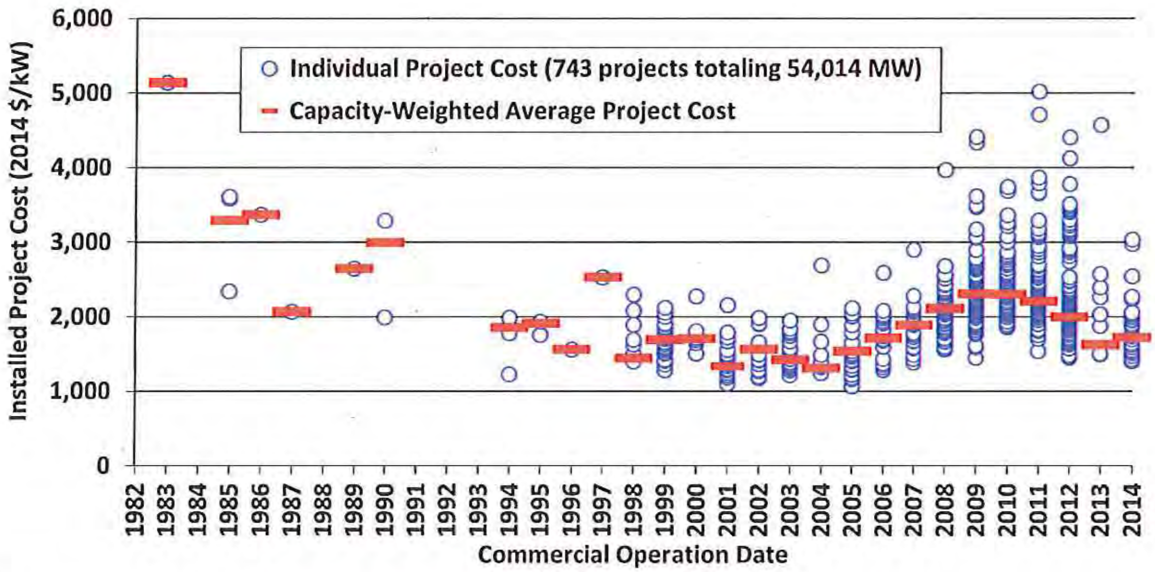
Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 38, our limited sample of recently announced U.S. turbine transactions shows pricing in the \$850–\$1,250/kW range. Bloomberg NEF (2015b) reports global average pricing for recent contracts of \$950-1,200/kW. Data from Vestas largely confirm these pricing points, with average global prices dropping to roughly \$1,175/kW in 2014.

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.

Lower turbine prices have driven reductions in reported installed project costs

Berkeley Lab compiles data on the total installed cost of wind power projects in the United States, including data on 36 projects completed in 2014 totaling 3,888 MW, or 80% of the wind power capacity installed in that year. In aggregate, the dataset (through 2014) includes 743 completed wind power projects in the continental United States totaling 54,014 MW and equaling roughly 82% of all wind power capacity installed in the United States at the end of 2014. 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, and then increased—reflecting turbine price changes—through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs appear to have peaked in 2009/2010, with substantial declines since that time. 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).[43]



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

Figure 39. Installed wind power project costs over time

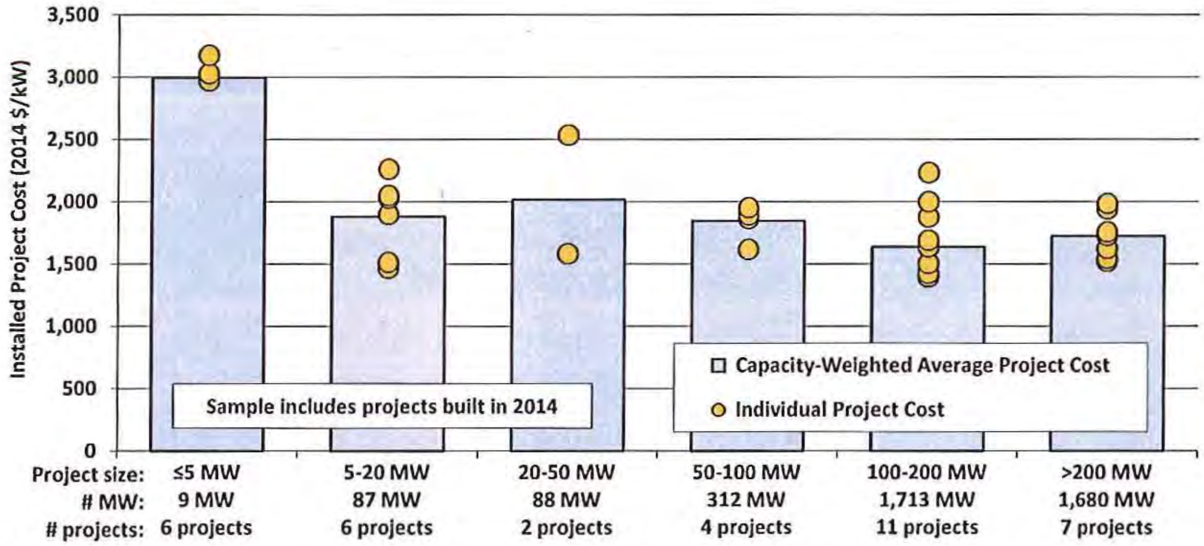
In 2014, the capacity-weighted average installed project cost within our sample stood at roughly \$1,710/kW – approximately \$100/kW higher than the reported average cost from a very small sample in 2013, but down \$580/kW from the apparent peak in average reported costs in 2009 and 2010. Early indications from a limited sample of 17 projects (totaling more than 2 GW) currently under construction and anticipating completion in 2015 suggest no material change in capacity-weighted average installed costs in 2015.[44]

[43] For projects placed in service from 2009 through 2012, 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.

[44] 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

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 restricted sample of projects installed in 2014, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 5–20 MW range. As project size increases further, however, economies of scale appear to be somewhat less prevalent.



Source: Berkeley Lab

Figure 40. Installed wind power project costs by project size: 2014 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.[45]

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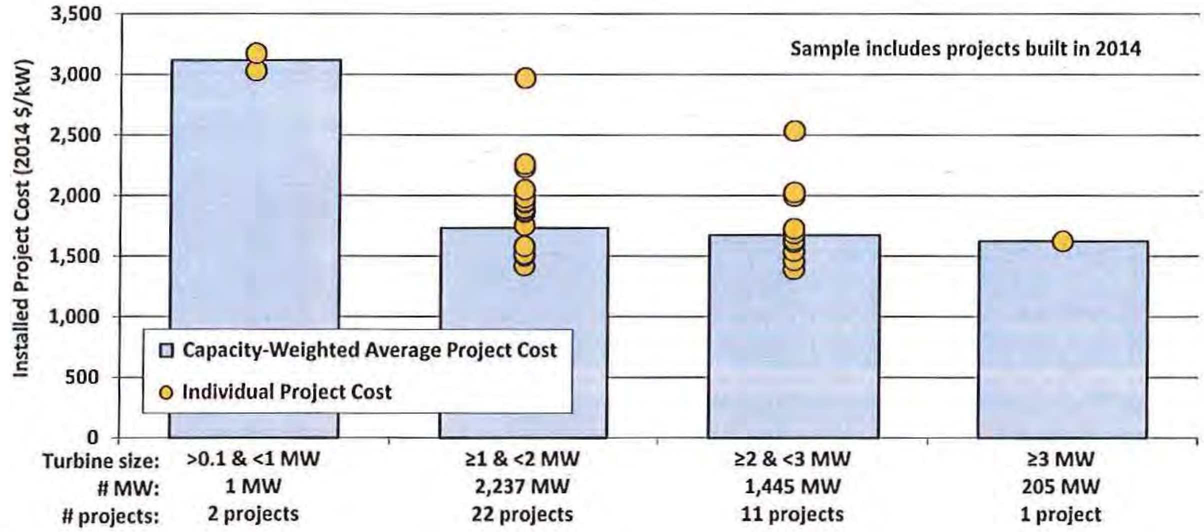
parameter calculated by learning curve studies is the learning rate: for every doubling of cumulative production/installation, the learning rate specifies the associated percentage reduction in costs. Considering the full time series of installed cost data presented in Figure 39 (from 1982 through 2014) in conjunction with global cumulative wind power installations over that same period results in a learning rate of 6.7%.

[45] 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, 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.



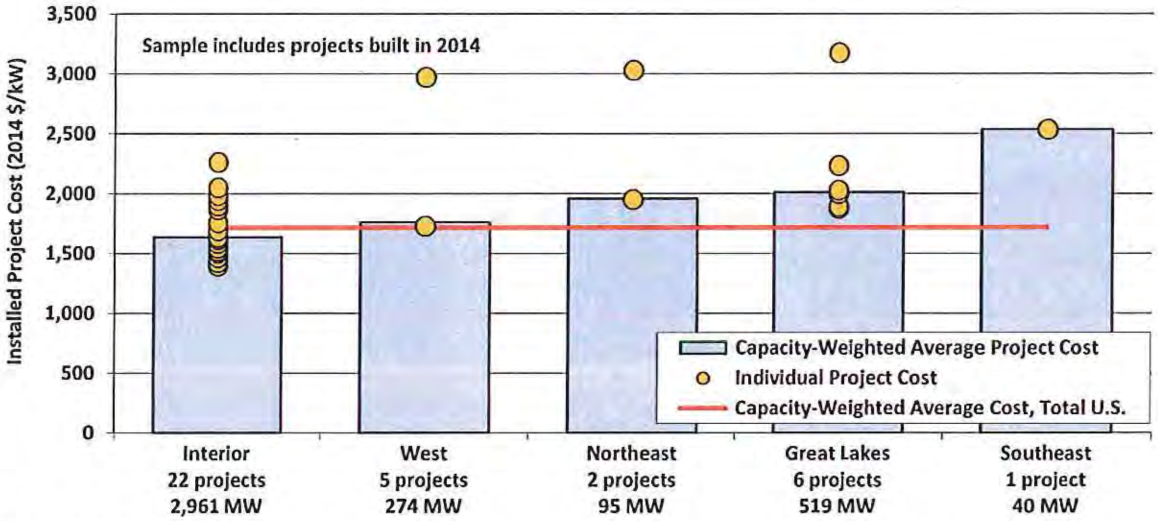
Source: Berkeley Lab

Figure 41. Installed wind power project costs by turbine size: 2014 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 2014, Figure 42 breaks out project costs among the five regions defined in Figure 29.[46] The Interior region—with by far the largest sample—was the lowest-cost region on average, with average costs of $1,640/kW, while the Southeast was the highest-cost region (although with a sample of just one project).[47]

[46] For reference, the 65,877 MW of wind installed in the United States at the end of 2014 is apportioned among the five regions shown in Figure 29 as follows: Interior (39,006 MW), West (13,817 MW), Great Lakes (7,920 MW), Northeast (3,943 MW), and Southeast (775 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.

[47] 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: 2014 projects

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

Operations and maintenance costs are an important component of the overall cost of wind energy and can vary substantially among projects. 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 147 installed wind power projects in the United States, totaling 10,350 MW in capacity, with commercial operation dates of 1982 through 2013. 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.[48] Other ongoing 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

[48] 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.

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.[49] Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2014, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2013, only year 2014 data are available, and that is what is shown in the figure.[50] Many other projects only have data for a subset of years during the 2000–2014 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 2000–2014 timeframe. The chart highlights the 64 projects, totaling 6,735 MW, for which 2014 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 also suggests that projects installed within the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2014 O&M costs for the 24 projects in the sample constructed in the 1980s equal $34/MWh, dropping to $24/MWh for the 37 projects installed in the 1990s, to $10/MWh for the 66 projects installed in the 2000s, and to $9/MWh for the 20 projects installed since 2010.[51] This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as turbines age, component failures become more common, and manufacturer warranties expire;[52]

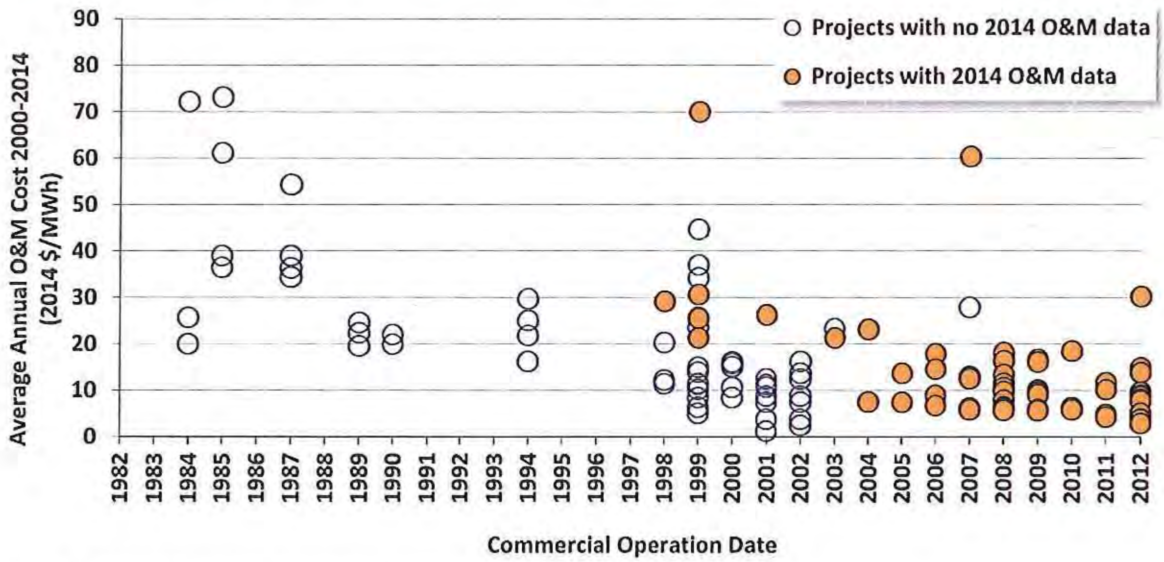
[49] For projects installed in multiple phases, the commercial operation date of the largest phase is used; for re-powered projects, the date at which re-powering was completed is used.

[50] Projects installed in 2014 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 2014 would be year 2015 (for which data are not yet available).

[51] If expressed instead in terms of $/kW-year, capacity-weighted average 2000–2014 O&M costs were $67/kW-year for projects in the sample constructed in the 1980s, dropping to $56/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 (2015d) shows a reduction in the cost of a sample of full-service O&M contracts (pertaining to the first years of turbine life) since 2008 (though with increases since the low in 2012), reaching 26.7 Euro/kW-year in 2014 (~$29/kW-year). An NREL analysis based on data from DNV KEMA and GL Garrad Hassan covering roughly 5 GW of operating wind projects (with only about half that amount having been operable for longer than five years) also shows average levels of expenditure consistent with the Berkeley Lab dataset, at least when focusing on turbine and balance-of-plant O&M costs for projects commissioned in the 2000s (Lantz 2013).

[52] 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 45% 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.

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.

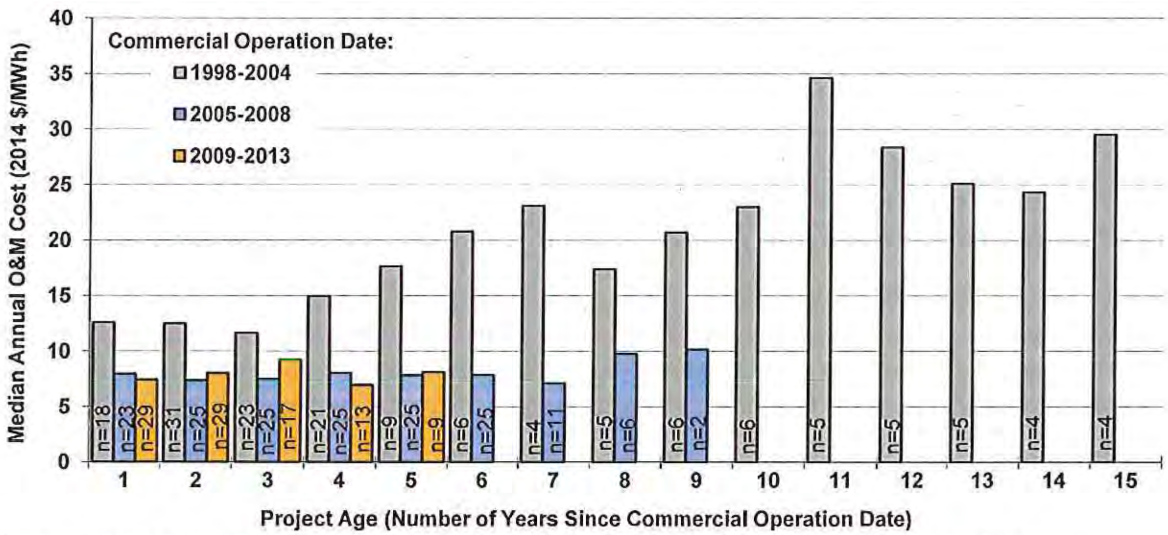


Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure 43. Average O&M costs for available data years from 2000–2014, 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.

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 6 is limited. In addition, the figure shows that projects installed more recently (from 2005–2008 and/or 2009-2013) have had, in general, lower O&M costs than those installed in earlier years (from 1998–2004), at least for the first 9 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 sample: cost differences between the 2005-2008 and 2009-2013 project samples are small, with no consistent trend as projects age.



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 4,864 MW of installed capacity at the end of 2014 (nearly all of which has been installed since 2000)—report total operating expenses of $25.1/MWh and $21.4/MWh, respectively, for their U.S. wind project portfolios in 2014 (EDPR 2015; Infigen 2015, 2014).[53] These total operating expenses are more than twice the ~$10/MWh average O&M cost reported above for the 86 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 2014 ($25.1/MWh) into four categories: asset management and administration ($4.9/MWh), turbine O&M ($11.8/MWh), balance-of-plant ($2.8/MWh), and other direct costs ($5.7/MWh). Among these four categories, the combination of turbine O&M and balance of plant ($14.5/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 2014 ($21.4/MWh) into three categories: supplies and services, which "includes O&M costs" ($14.2/MWh); personnel costs ($3.6/MWh); and other operating costs, which "mainly includes operating taxes, leases, and rents" ($3.5/MWh). Among these three categories, the $14.2/MWh for supplies and services is probably closest in scope to the Berkeley Lab data. Confirming these basic findings (i.e., that turbine and balance-of-plant O&M costs make up only about half of total operating costs), NREL analysis based on data from DNV 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).

[53] 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.

7. Wind Power Price Trends

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

Berkeley Lab collects data on wind PPA prices from the sources listed in the Appendix, resulting in a dataset that currently consists of 363 PPAs totaling 32,641 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation in 2015 or 2016. 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 2014 dollars.[54] Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.[55] 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 62.

Wind PPA prices have reached all-time lows

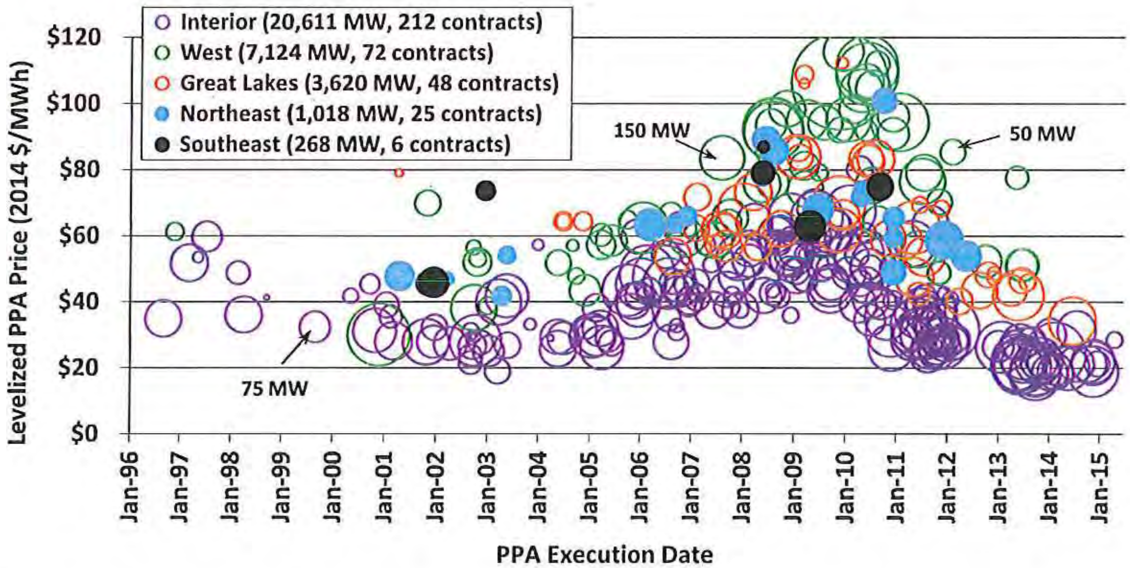
Figure 45 plots project-level levelized wind PPA prices by contract execution date, showing a clear downward trend in PPA prices since 2009 and 2010—both overall and by region (see Figure 29 for regional definitions).[56] This trend is particularly evident within the Interior region, which—as a result of its low average project costs and high average capacity factors shown

[54] 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 59% 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.

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

[56] Roughly 95% of the contracts that are depicted in Figure 45 are from projects that are already online. For the most part, only the most recent contracts in the sample are from projects that are not yet online.

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.[57]



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

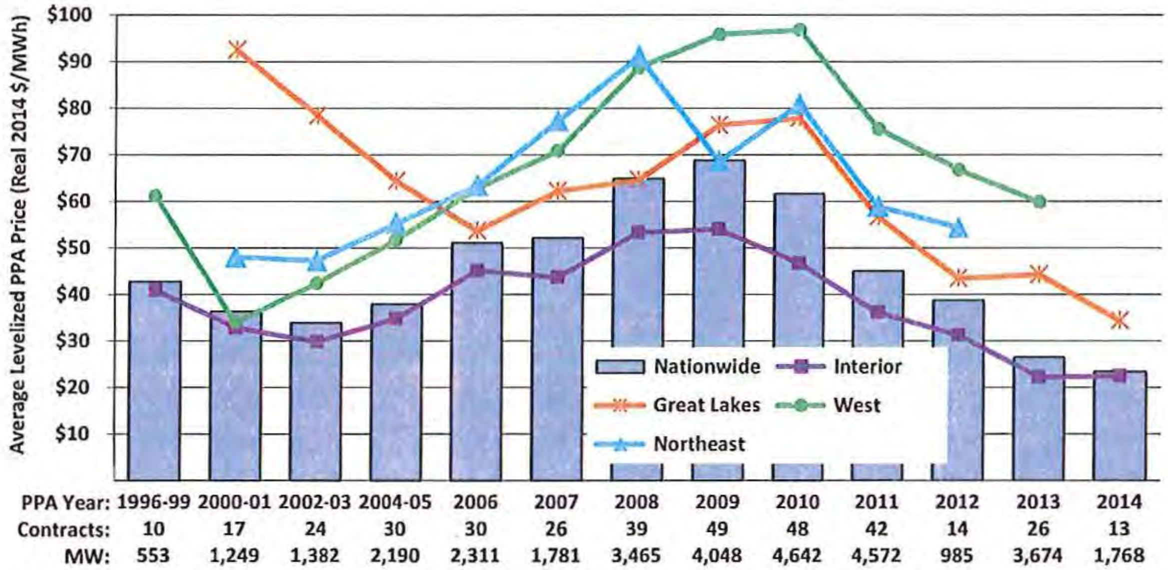
Source: Berkeley Lab

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 2014 (and that are within the Berkeley Lab sample) fell to $23.5/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.

This trend of rising PPA prices from 2003 to 2009 and then falling prices since then is directionally consistent with the turbine price and installed project cost trends shown in earlier sections. Moreover, the fact that PPA prices have broken into new lows is notable, given that installed project costs have not returned to the low levels from the early 2000s (Figure 39) and that wind projects have, in recent years, been sited in lower-quality wind resource areas albeit with some reversal of this trend in 2013 and 2014 (Figure 33). It would appear 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.

[57] 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.



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 29 (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 somewhere in between 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 (among the Berkeley Lab contract sample) of just $22.4/MWh in 2014.

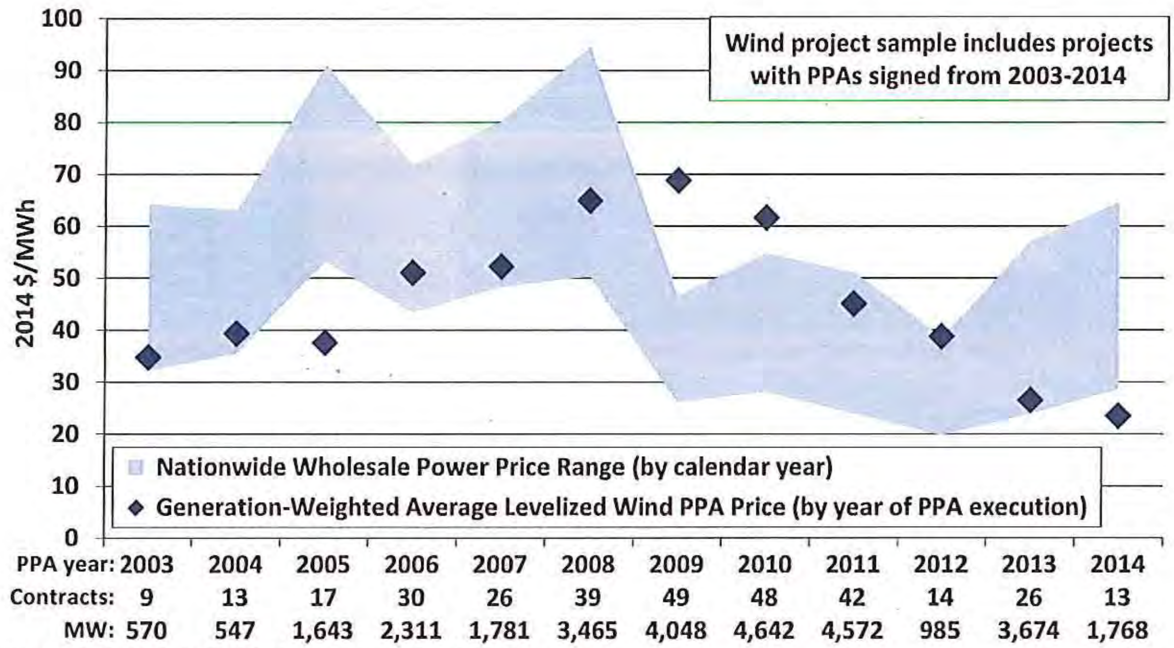
The relative economic competitiveness of wind power improved in 2014

Figure 47 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power[58] 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).

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

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

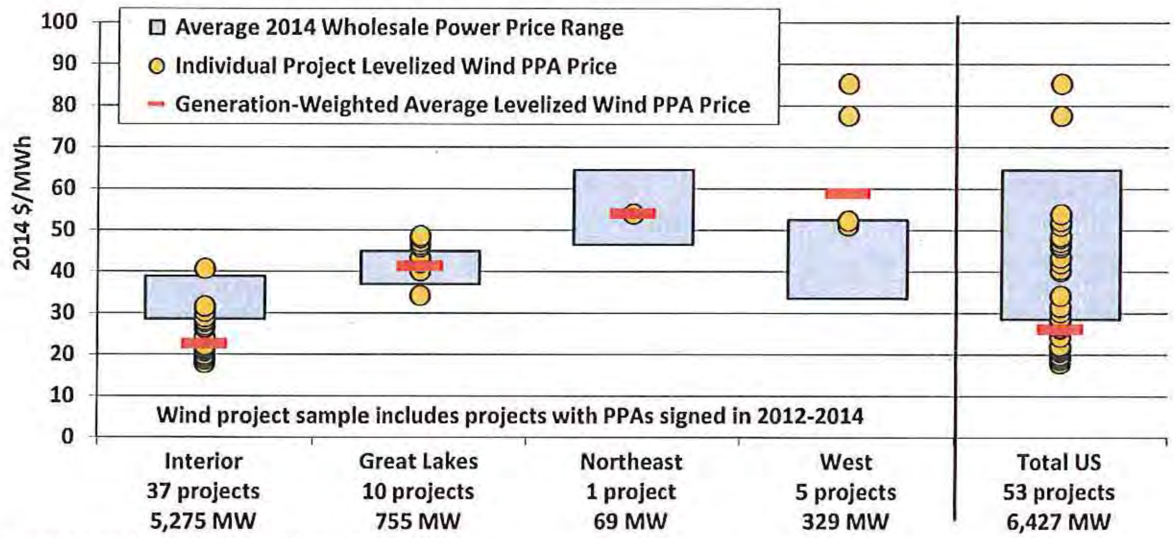
gas prices, but also declining electricity demand) squeezed average wind PPA prices out of the wholesale power price range on a nationwide basis. Wind PPA prices have since fallen, however, and in 2011 and 2012 reconnected with the upper end of the wholesale power price range. In 2013, further PPA price declines, along with a bit of a rebound in wholesale prices, put wind back at the bottom of the range once again. Continuation of these trends in 2014 improved wind's competitiveness even further.



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 2012 through 2014 and compares those levelized long-term PPA prices to wholesale electricity prices in 2014 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.



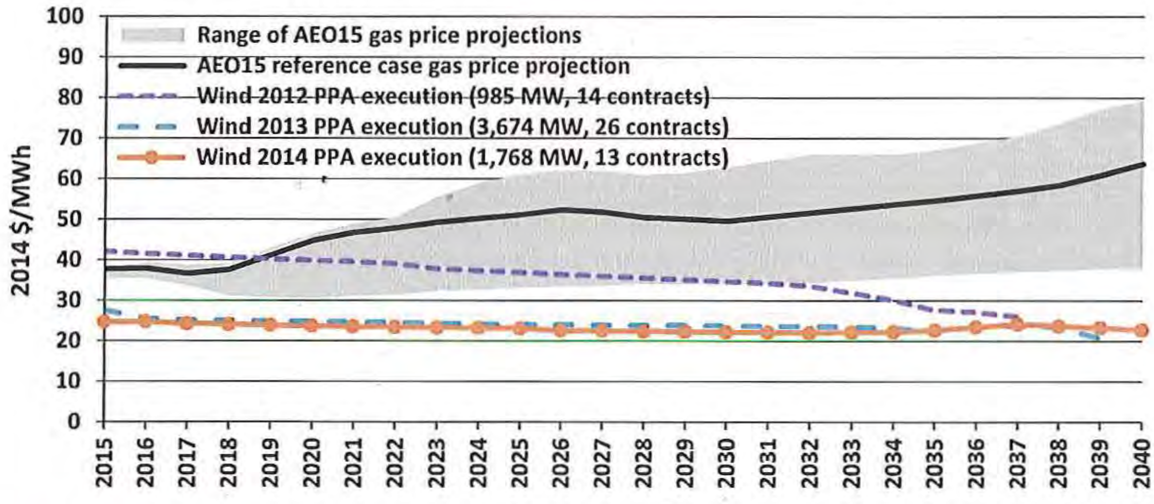
Source: Berkeley Lab, Ventyx, IntercontinentalExchange

Figure 48. Levelized long-term wind PPA prices in 2012-2014 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 49 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 2012, 2013, or 2014 against a range of projections of just the fuel costs of natural gas-fired generation.[59] As shown, average wind PPA prices from contracts executed in 2012 start out higher than the range of fuel cost projections, but decline (in real 2014 $/MWh terms) over time and soon fall within and then eventually below the range. In contrast, the samples of PPAs executed in 2013 or 2014 have average price streams that *begin* below the range of natural gas fuel cost projections, and that remain below even the low-ènd of EIA gas price forecasts through 2040.

[59] The fuel cost projections come from the Energy Information Administration's *Annual Energy Outlook 2015* publication, and increase from around $4.67/MMBtu in 2015 to $8.83/MMBtu (in 2014 dollars) in 2040 in the reference case. The range around the reference case is bounded by the high oil and gas resource case on the low end, and the greater of the high oil price or high economic growth cases on the high end (since AEO 2015 does not include a low oil and gas resource case), and ranges from $4.98/MMBtu to $10.75/MMBtu (again, in 2014 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 8,100 Btu/kWh and gradually decline to around 7,200 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 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.

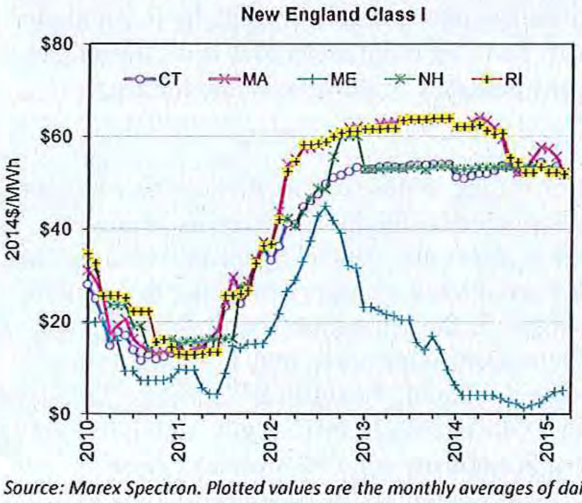
Important Note: Notwithstanding the comparisons made in this section, neither the wind nor wholesale electricity prices (nor fuel cost projections) reflect the full social costs of power generation and delivery. Specifically, the wind PPA prices are reduced by virtue of federal and, in some cases, state 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.

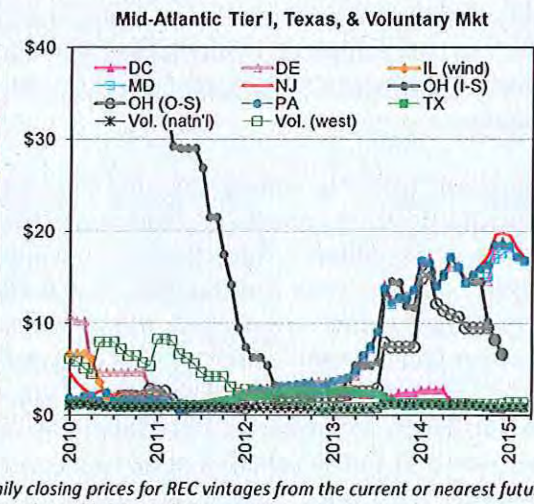
In short, comparing levelized long-term wind PPA prices with either yearly wholesale electricity prices or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to its competition. Nonetheless, 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 Near "Alternative Compliance Payment" Levels in the Northeast, While Rising Modestly among 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 somewhat fragmented in the United States but consist of two distinct segments: compliance markets, in which RECs are purchased to meet state RPS obligations, and green power markets, in which RECs are purchased on a voluntary basis.

The figures below present indicative data of spot-market REC prices in both compliance and voluntary markets. Data for compliance markets focus on "Class I" or "Tier I" RPS requirements, as these are the RPS compliance markets in which wind energy would typically participate. Clearly, spot REC prices have varied substantially, both across states and over time within individual states. That said, prices within regions (New England and the Mid-Atlantic) where renewable generation facilities are eligible for compliance across states are linked to varying degrees. In New England compliance markets (other than Maine), REC prices in 2014 remained relatively high; prices hovered around the $55/MWh alternative compliance payment (ACP) rate in Connecticut and Rhode Island, reflecting an expectation of continued under-supply in the region. Among Mid-Atlantic states, REC pricing generally ranged from $15-20/MWh over the course of the year, rising modestly from the levels reached at the end of the prior year as supplies began to tighten. Prices for RECs offered in the national and western voluntary markets and for RPS compliance in Texas remained at roughly $1/MWh throughout the year, reflecting sustained over-supply.





Source: Marex Spectron. Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded. OH (I-S) refers to Ohio In-State RECs, and OH (O-S) refers to Ohio Out-of-State RECs.

8. Policy and Market Drivers

Availability of federal incentives for wind projects built in the near term is leading to a resurgent domestic market, but a possible policy cliff awaits

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 in wind energy research and development (R&D). 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 projects to elect, for a limited time, a 30% cash grant in lieu of the PTC. The focus in this section is on the PTC and accelerated depreciation.

- Initially established in 1992, the PTC provides a 10-year, inflation-adjusted credit that stood at 2.3¢/kWh in 2014. The historical importance of the PTC to the U.S. wind industry is illustrated by the pronounced lulls in wind 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). In December 2014, the PTC was extended, as was the ability to take the 30% ITC in lieu of the PTC. To qualify, projects had to begin construction before the end of 2014: in effect, a two-week extension.
- 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. Even more attractive "bonus depreciation" schedules have been periodically available, since 2008.

The near-term availability of the PTC/ITC for those projects that reached the "under construction" milestone by the end of 2014 is leading a resurgence of the U.S. wind power market, with solid continued growth in capacity additions expected in both 2015 and 2016. IRS guidelines and aggressive developer response ensure that even the two-week extension of the incentive at the end of 2014 will enable additional wind power growth. With the PTC now expired and its renewal uncertain, however, wind deployment beyond 2016 is also uncertain.

Although the lack of long-term, stable federal tax incentives for wind energy has been a drag on the industry, the prospective impacts of more-stringent EPA environmental regulations on fossil plant retirement, energy costs, and demand for clean energy may create new opportunities for wind. Of special note are the actions to address carbon emissions that have been initiated at the EPA through the Clean Power Plan, which include proposed regulations released in 2013 that would restrict carbon emissions from new power plants as well as proposed regulations released in 2014 that would apply carbon restrictions to existing power plants. Revised, final regulations are to be released in summer 2015, though legal challenges are anticipated. Finally, R&D investments by the 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

Of all wind power capacity built in the United States from 1998 through 2014, roughly 54% is delivered to load serving entities with RPS obligations; for 2014 wind capacity additions, this proportion is 31%. As of June 2015, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 50).[60] Attempts to weaken RPS policies have been initiated in a number of states, and in limited cases—including Ohio in 2014 and Kansas in 2015—have led to a freeze or repeal of RPS requirements. In contrast, other states have substantially strengthened their RPS policies (e.g., Hawaii, in 2015) or, in the case of Vermont, have created a new RPS.

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 8% 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.[61] Incremental growth in RPS requirements through 2025 represents 51% of projected growth in total U.S. electricity generation over that timeframe, though some portion of this 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 4–5 GW/year through 2025, not all of which will be wind.[62] This is below the average of 7 GW of wind power capacity added in each year over the 2007–2014 period, and even further below the average 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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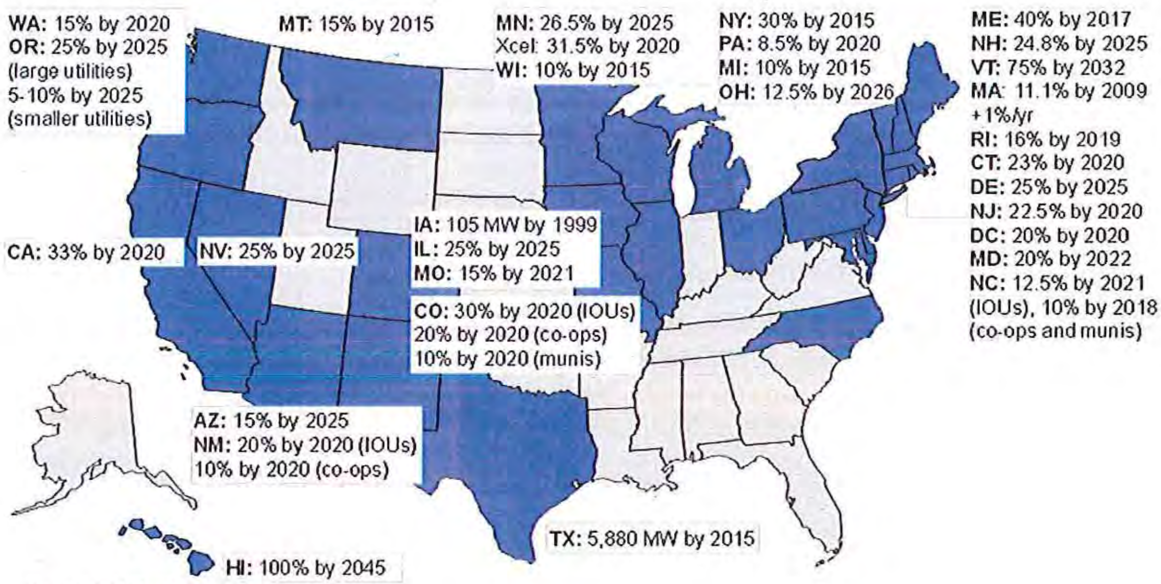
[60] Although not shown in Figure 50, mandatory RPS policies also exist in a number of U.S. territories, and non-binding renewable energy goals exist in a number of U.S. states and territories.

[61] 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.

[62] Again, varying combinations of renewable resource types for each RPS state were assumed in estimating the 4–5 GW/year of average annual renewable capacity additions required to meet RPS obligations through 2025.



Source: Berkeley Lab

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

Figure 50. State RPS policies as of July 2015

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 (see box on next page for a discussion of burgeoning commercial interest in wind energy). State renewable energy funds provide support (both financial and technical) for wind power projects in some jurisdictions, as do a variety of state tax incentives. 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. How these dynamics will evolve as the EPA steps in to regulate power sector carbon emissions remains unclear.

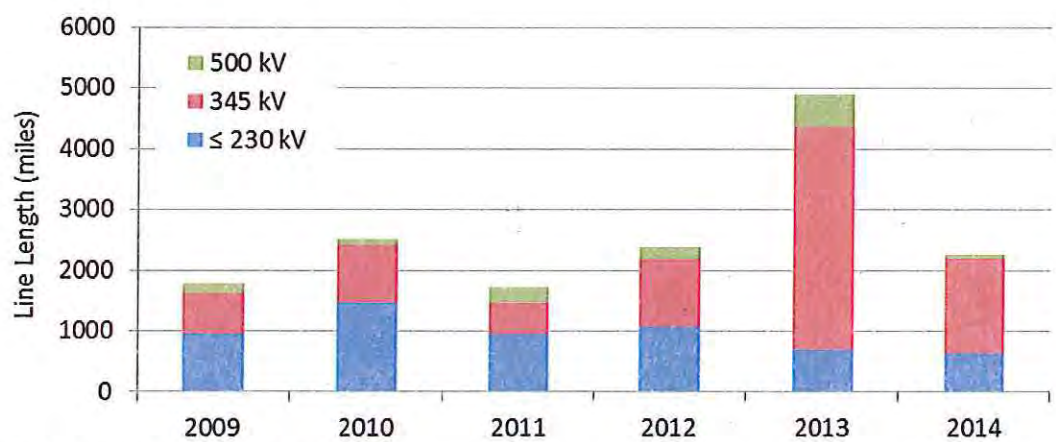
A New Demand Driver: Commercial Purchases of Wind Energy

Although there has been voluntary customer demand for green power for more than a decade, the maturity and declining cost of wind energy has helped spur recent wind purchases from technology companies (e.g., Google, Microsoft, Yahoo, Amazon, Facebook) and business giants (Walmart, IKEA, DOW Chemical) to hospitals, universities, and government agencies. These transactions involve everything from long-term PPAs and shorter-term REC purchases, to direct ownership of wind projects located either on or off the customer's site.

AWEA (2015a) reports over 1,800 MW of wind energy PPAs from these sources. MAKE (2015) estimates that PPAs with commercial and industrial customers supported 1,100 MW of wind through 2014 and will further support an additional 1,700 MW in 2015 and 2016. Finally, Bloomberg NEF (2015a) has identified corporate PPAs for roughly 2,200 MW of wind to be built over the 2014- 2016 timeframe. Though it remains unclear to what degree these offtake arrangements are supporting wind projects that would otherwise not have been built, it is evident that commercial purchases of wind are a significant and growing source of demand for the U.S. wind industry.

Solid progress on overcoming transmission barriers continued

Transmission development has gained traction in recent years. About 2,000 miles of transmission lines came online in 2014—substantially lower than 2013 but consistent with the 2009-2012 time period (see Figure 51). Another 22,000 miles of new transmission lines (or line upgrades) are proposed to come online by March 2017, with almost half of those having a high probability of completion (FERC 2015). The Edison Electric Institute (EEI) estimates that total transmission investment by investor-owned utilities peaked in 2014, at $20.2 billion, after years of steady growth. EEI forecasts consistent, though slightly lower, investments through 2017. EEI states that 46 percent of the transmission projects it is tracking will, at least in part, support the integration of renewable energy (EEI 2015).



Source: FERC monthly infrastructure reports

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

Transmission is particularly important for wind energy because areas with the best wind speeds are often distant from load centers. 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. Uncertainty over transmission siting and cost allocation, particularly for multi-state transmission lines, further complicates matters—especially given the mismatch between the relatively short timeframe needed to develop a wind power project and the longer timeframe required to build new transmission.

One of the largest transmission undertakings devoted to wind power is the Competitive Renewable Energy Zones (CREZ) project in Texas. The CREZ includes almost 3,600 circuit miles of transmission lines and will accommodate up to 18,500 MW of wind power. The nearly $7 billion cost of the 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 (ERCOT 2014). Ninety-nine percent of all CREZ lines have been built (RS&H 2014). The Public Utility Commission of Texas (PUCT) has called for construction of the final CREZ element, a set of transmission lines that would bring 1,100 MW of additional transmission capacity to the Panhandle. However, in April 2015, PUCT staff recommended that Sharyland Utilities, the entity responsible for constructing lines for this portion of the CREZ, be required to secure a separate certificate of convenience and necessity (CCN) for this project, since the utility's prior CCN did not include this transmission capacity (PUCT 2015).

Elsewhere, grid operators SPP and MISO completed—or soon will complete—several transmission projects in their respective territories of relevance to wind (Table 5). In 2014, the U.S. Supreme Court opted *not* to hear a challenge to FERC's previous orders approving MISO's plans to spread the costs of building long-line transmission projects among all of its members.

Table 5. Recent Transmission Projects and Potential Wind Capacity

Transmission Project Name (State)	Voltage (kilovolts)	Estimated In-service Date	Estimated Potential Wind Capacity, MW
Most SPP Priority Projects and Balanced Portfolio Projects (TX, OK, KS, MO)	345	2014	3,200
Most segments of Michigan Thumb Loop Project (MI)	345	2014-15	(MVP Component)
Most CapX Segments (MN, SD, ND, WI)	Mostly 345	2014-15	2,000

Source: AWEA (2015a)

AWEA (2015a) has identified 18 near-term transmission projects that, if all were completed, could transmit 55–60 GW of additional wind capacity (Table 6). Two large projects included in Table 6—both among seven projects targeted for fast-track permitting by the Obama administration in 2011—recently achieved important milestones. In January 2015, the Bureau of Land Management (BLM) approved SunZia Southwest's request for a right-of-way across federally-owned land. In May, BLM and the Western Area Power Authority issued an Environmental Impact Statement for the TransWest Express project: BLM will now decide whether to grant TransWest a right-of-way to cross federal lands. The Missouri PSC, meanwhile, rejected a Clean Line Energy proposal that would have tapped wind projects in Kansas and transmitted the power to Missouri and Illinois.

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
Big Eddy – Knight and Central Ferry – Lower Monumental (OR, WA)	500	2015	4,200
Tehachapi Phases 2-3 (CA)	500	2015-2016	3,800
Maine Power Reliability Program (ME)	345, 115	2015-2017	N/A
Valliant – NW Texarkana (TX; SPP Priority Project)	345	2015	(SPP Priority Project Component)
Lower Rio Grande Valley (TX)	345	2016	N/A
Southline Transmission Project (AZ, NM)	345, 230	2016	1,000
MISO Multi-Value Projects (IA, IL, MI, MN, MO, ND, SD, WI)	345, one 765 line	2015-2020	14,000
TransWest Express (WY)	600 DC	2017	3,000
Grand Prairie Gateway (IL)	345	2017	1,000
Nebraska City – Mullin Creek – Sibley (NE-MO; SPP Priority Project)	345	2017	(SPP Priority Project Component)
Colstrip Upgrade Project (MT)	500	2018	480
Clean Line Projects (AZ, AR, KS, IA, IL, MO, NM, OK, TX)	600 DC	2018-2020	15,500
Pawnee – Daniels Park (CO)	345	2019-2020	500
Gateway West (ID, WY)	500	2019-2021	3,000
SunZia (AZ, NM)	500	2020	3,000
Gateway South (WY, UT)	500	2020-2022	1,500
Boardman-Hemingway (ID, OR)	500	2020	1,000
SPP 2012 ITP10 Projects (KS, MO, OK, TX)	345	2018-2022	3,500
Total Potential Wind Capacity			**55,000 - 60,000**

Source: AWEA (2015a)

FERC continues to implement Order 1000, which was intended to improve intra- and inter-regional transmission planning and cost allocation. Order 1000 requires public utility transmission providers to: participate in a regional transmission planning process; establish procedures to identify transmission needs driven by public policy requirements; and coordinate with neighboring planning regions to solve mutual transmission needs (FERC 2011). FERC is reviewing both regional transmission plans—the CAISO became the first entity to garner FERC's final approval for its plan—and inter-regional transmission plans. FERC has conditionally accepted inter-regional plans put forward by: the Southeastern Regional Transmission Planning Process Region and SPP; SPP and MISO; MISO and PJM; PJM, ISO New England, and New York ISO; and a collection of planning regions in the western U.S. known as the Western entities. In reviewing these plans, cost allocation has been one of FERC's primary concerns. For example, FERC ordered that the CAISO match its neighbors' approach to determining the benefits of inter-regional transmission projects, lest CAISO "pay a disproportionately lower share of costs" for such projects.

Separately, the U.S. District of Columbia District Court of Appeals upheld FERC's statutory authority to issue and implement Order 1000. In another order, FERC held that public power entities could participate in inter-regional transmission planning but could not be bound to any interregional cost allocation unless it voluntarily agreed to do so.

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

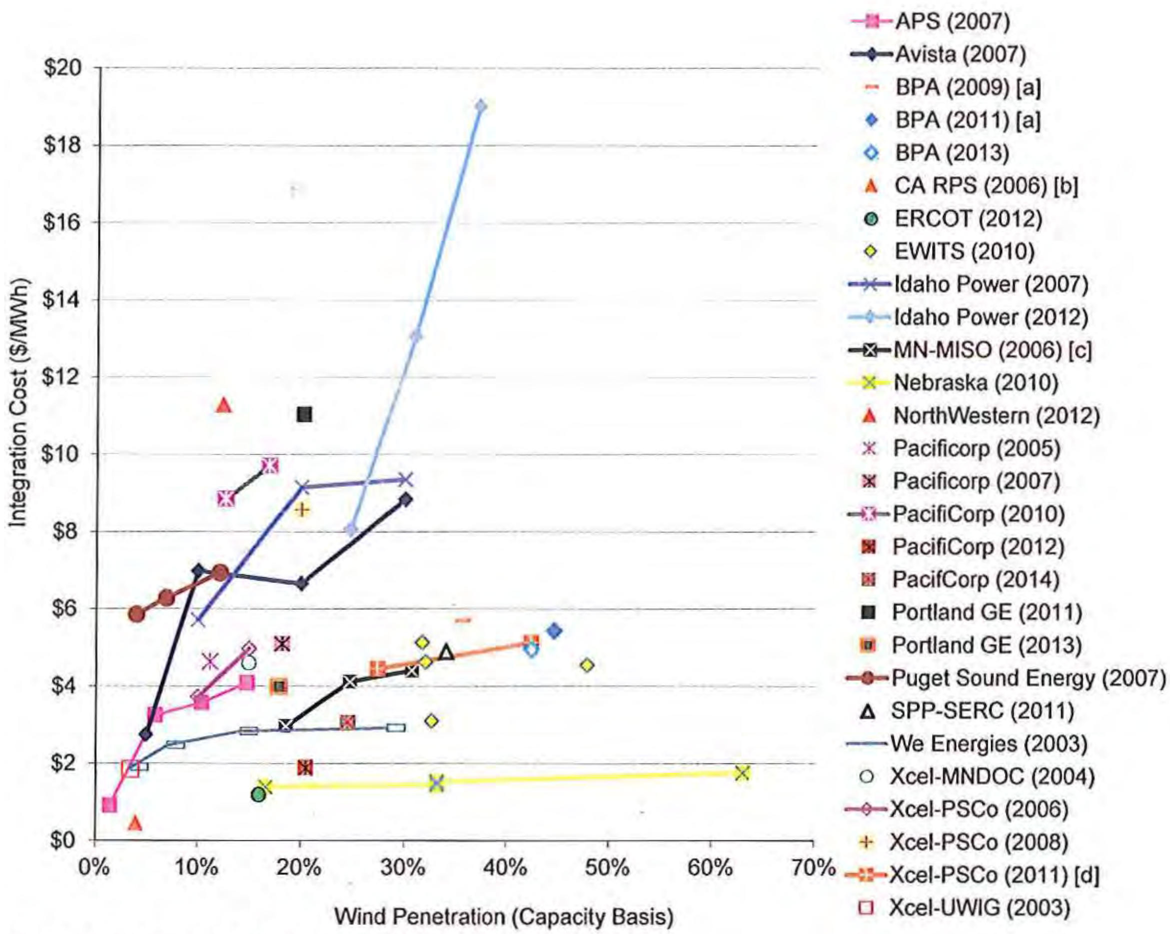
Due to the variable nature of wind, considerable attention is paid to the potential impacts of wind energy on power systems. Concerns about, and solutions to, these issues have affected, and continue to impact, the pace of wind power deployment in the United States. Experience in operating power systems with wind energy is also increasing worldwide, leading to an emerging set of recently published best practices (e.g., Jones 2014, Milligan et al. 2015). Also of note is NERC's Integration of Variable Generation Task Force summary of best practices (NERC 2015) and a guide, called the Variable Energy Resource Checklist, for regulators and staff of state energy offices that are engaged in integration issues.[63]

Figure 52 provides a selective listing of estimated wind integration costs associated with increased wind energy from integration studies completed from 2003 through 2014 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, wind plant output forecasting details, 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. Buckley et al. (2015) 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 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).

PacifiCorp completed a new study of integration costs in 2014, subsequently published in 2015. The new wind integration cost estimate was slightly higher than in an earlier PacifiCorp study due to the use of hourly reserve requirements in the new study and monthly requirements in the previous study. PacifiCorp also estimated that participation in the Energy Imbalance Market with CAISO, discussed below, reduces the wind integration cost by \$0.21/MWh (PacifiCorp 2015).

[63] The checklist can be accessed at: http://wiebver.org/ver-checklist/



[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)

Note: Listed to the right are the organizations for which each study was conducted, and the year in which the analysis was conducted or published.

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

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:

- The PJM Renewable Integration Study (GE Energy 2014a) found no significant operational issues with up to 30% of its energy coming from wind and solar, given adequate transmission expansion and additional regulating reserves. The study found that cycling of thermal plants increases with more renewables, though the associated costs were modest and did not significantly affect the overall economic impact of the renewable generation.
- The Western Wind and Solar Integration Study Phase III (Miller et al. 2015) assessed the ability of the Western grid to respond to large grid disturbances (e.g., loss of a large power plant or major transmission line) under high penetrations of wind and solar (each providing

16.5% of the annual energy). The study did not find any fundamental reasons that prevent the grid from meeting frequency response[64] and transient stability[65] objectives with high penetrations of wind and solar. Good engineering practices and system planning will need to be followed, including the potential need for transmission system improvements to manage local issues, and consideration of events that lead to near-zero commitment of coal plants in the northwestern and southwestern United States. Frequency-responsive controls on wind plants can improve frequency response, though response from wind plants may not always be the most cost-effective solution.

- The Minnesota Renewable Energy Integration and Transmission Study (GE Energy 2014b) found that it would be possible to reliably achieve 40% share of energy from wind and solar in Minnesota with minimal curtailment, as long as some transmission upgrades are made. Similar conclusions were reached in cases with 50% renewables, though transient and dynamic stability analyses were not completed for these cases.

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. Utilities and ISOs/RTOs are also expanding the use of wind forecasting as more experience and confidence is gained.
- Many ISO/RTO areas now treat wind as "dispatchable" in the real-time market where wind can be given a dispatch base-point below its current production capability for economic or reliability reasons (Porter et al. 2015). Designation as a dispatchable resource reduces the need for manual curtailments by system operators and improves integration into wholesale power markets (Potomac Economics 2014a).
- ISOs and utilities continue to refine scheduling and commitment processes, including a shift from hour-ahead to 15-minute scheduling at CAISO and the option for 15-minute scheduling in exchange for a lower wind integration rate at BPA, both in response to FERC Order 764.
- ISOs are considering and, in some cases, implementing changes that support increased flexibility such as consideration of flexibility needs in operational decisions (e.g., flexible ramping constraints) and in assessments of adequacy (e.g., flexible capacity requirements).
- Transmission expansion in wind-rich regions is moderating integration challenges. In ERCOT, the Competitive Renewable Energy Zone transmission upgrades are lowering the frequency of negative prices in the wind-rich region of West Texas along with lowering the frequency of binding transmission constraints between the West and North region, even though installed wind has increased in West Texas (Potomac Economics 2014b). Similarly, transmission upgrades in SPP have been found to create a better-integrated system with higher diversity and greater flexibility to manage high levels of wind energy (SPP 2014).
- Momentum is growing for consolidation of balancing authorities or new practices to improve coordination between balancing authorities. SPP consolidated into one balancing authority in March 2014. An Energy Imbalance Market (EIM) between CAISO and PacifiCorp became

[64] Frequency response is the overall response of the power system to large, sudden mismatches between generation and load.

[65] Transient stability is the ability of a synchronous power system to return to a stable condition following a relatively large disturbance.

financially binding at the start of November 2014. The EIM allows for increased transfers between the two balancing authorities and increases diversity of resources. As of the first quarter of 2015, the benefit of the EIM was averaging $1.75 million per month and reducing renewables curtailment by an average of 3 GWh/month (CAISO 2015). Work is underway to integrate NV Energy into the EIM by October 2015. Puget Sound Energy and Arizona Public Service will join the EIM by October 2016.

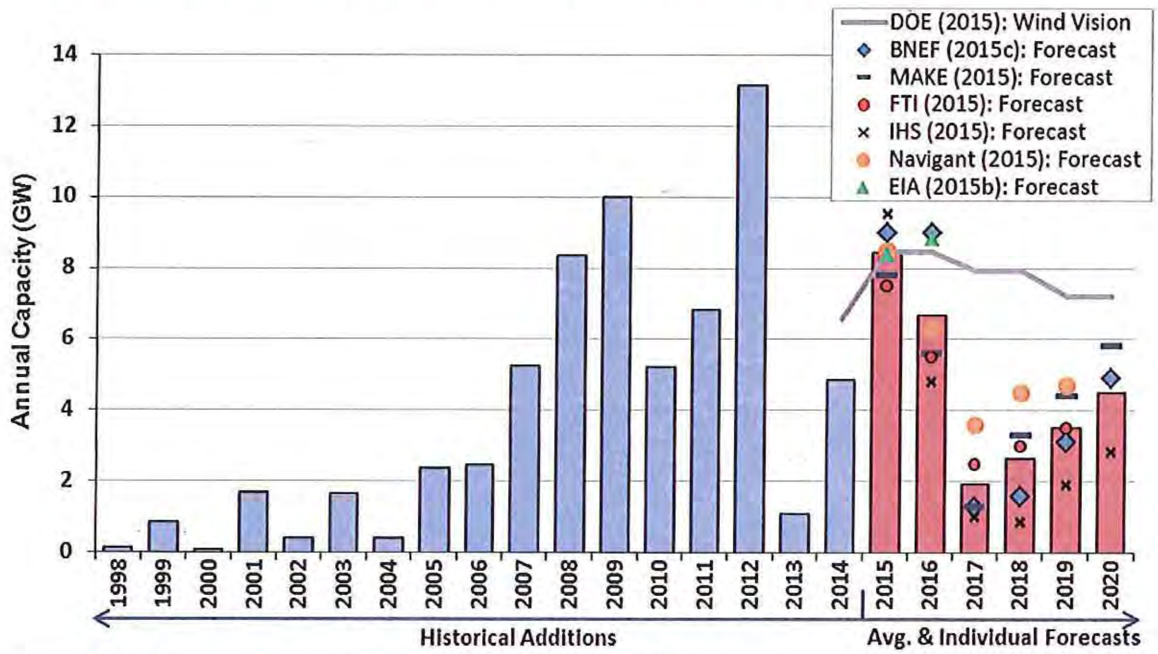
- FERC approved NERC's proposal to adopt a new reliability standard for power balancing control performance. The standard replaces the Control Performance Standard 2 metric included in the previous standard, which was based on maintenance of average imbalances (measured over 10 minutes) within a fixed limit. The new standard includes a requirement that average imbalances (measured over a minute) cannot consecutively exceed a limit for 30 minutes. In the new standard, the imbalance limit for each balancing area is based on the overall system-wide frequency: the limits tighten when frequency deviates from its intended level (indicating system-wide imbalances). The new standard thus better aligns the performance metric with the overall goal of maintaining system frequency. Additionally, evidence from field trials suggests that the new standard will reduce wear and tear on generation units, lower the cost to integrate variable generation, and lead to lower levels of renewable energy curtailment (NERC 2014).

Some utilities continue to charge wind projects directly for balancing services. BPA, Nebraska Public Power District, Puget Sound Energy, and NorthWestern Energy all differentiate balancing charges for variable energy renewables, including wind.[66] Xcel Energy (Colorado) filed a proposal for a new wind integration charge with FERC in May 2014 that was conditionally accepted in December 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).

[66] In addition, utilities in Idaho and Oregon discount their published avoided cost payments for qualifying wind power projects by an estimate of the integration costs.

9. Future Outlook

Because federal tax incentives are available for wind projects that *initiated* construction by the end of 2014, a further resurgence in new builds is anticipated in both 2015 and 2016 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, which have resulted in the lowest power sales prices ever seen in the U.S. wind sector. Growing corporate demand for wind energy and state-level policies play important roles as well. Among the forecasts for the domestic market presented in Figure 53, expected capacity additions range from 7,500 to 9,500 MW in 2015 and from 4,800 to 9,000 in 2016. With AWEA (2015b) reporting that more than 13,600 MW of wind power was under construction at the end of the first quarter of 2015, the industry appears to be on track to meet these expectations. Still, the upper end of the forecast range for 2015 and for 2016 does not approach the record build level achieved in 2012.



Source: AWEA (historical additions), individual forecasts, DOE 2015 (Wind Vision)

Figure 53. Wind additions: historical installations, projected growth, DOE *Wind Vision* report

Projections for 2017 show a steep downturn in additions in that year, and then a steady rebound through 2020. Forecasts for this period are uncertain. The PTC has expired, and its renewal remains in question. The "base-case" forecasts presented in Figure 53 generally assume no further PTC extensions in the near term. 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 further enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy. New and proposed EPA regulations, and the impact of those regulations on fossil plant retirements and demand for low-carbon energy sources, may also create new markets. 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 for 2017 through 2020 reported in Figure 53 span a relatively wide range, with annual capacity additions during that period ranging from a low of 800 MW to a high of 5,800 MW.

In 2015, the DOE published its *Wind Vision* report (DOE 2015), which analyzed a scenario in which wind energy reaches 10%, 20%, and 35% of U.S. electric demand in 2020, 2030, and 2050, respectively. Plotted in Figure 53 are the annual gross wind additions from 2014 through 2020 analyzed by the DOE in order to ultimately reach those percentage targets. Though the DOE study found no insurmountable barriers to reaching 10%, 20%, and 35% wind energy penetration, 2014 wind additions and forecasted growth for 2017 through 2020 fall well short of the pathway envisioned in the DOE report. As discussed in DOE (2015), and as further suggested by these comparisons, achieving 10%, 20%, and 35% wind energy on the timeframe analyzed by the DOE is likely to require efforts that go beyond business as usual expectations.

Appendix: Sources of Data Presented in this Report

Installation Trends

Data on wind power additions in the United States (as well as certain details on the underlying wind power projects) largely come from AWEA (2015a). 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 from Ventyx's Velocity database, except that solar data come from GTM Research. Information on offshore wind power development activity in the United States was compiled by NREL.

Global cumulative (and 2014 annual) wind power capacity data come from Navigant (2015) 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 (2015), 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. 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 2014, 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 2014, 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 comes from Ventyx (2015), AWEA (2015b), and EIA (2015c).

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 (2015a), while U.S. tower and blade manufacturing capability come from AWEA (2015a). The listings of manufacturing and supply-chain facilities are not intended to be exhaustive. OEM profitability data come from a Berkeley Lab review of turbine OEM annual reports (where necessary, focusing only on the wind energy portion of each company's business).

Data on U.S. imports and exports of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. International Trade Commission (USITC), and can 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.

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

HTS Code	Description	Years applicable	Notes
8502.31.0000	wind-powered generating sets	2005-2014	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	2011-2014	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	2012–2014	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	2012–2014	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	2012–2014	exclusive to wind turbine components

As shown in the table, 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 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; and import patterns in the larger HTS trade categories. The assumptions reflect the rapidly increasing imports of wind equipment from 2006 to 2008, the subsequent decline in imports from 2008 to 2010, and the slight increase from 2010 to 2012. To reflect uncertainty in these proportions, a ±10% variation is applied to the larger trade categories that include wind turbine components.

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 were compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on judgment of Berkeley Lab staff. Data on curtailment are from ERCOT (for Texas), MISO (for the Midwest), PJM, NYISO, SPP (for the Great Plains states), ISO-New England, and 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) combined with Berkeley Lab and AWEA data on individual wind projects. Second, NREL used 200-meter resolution data from AWS Truepower—specifically, gross capacity factor estimates—to estimate the quality of the wind resource for each of those turbine locations. These gross capacity factors are derived from average mapped 80-meter wind speed estimates, wind speed distribution estimates, and site elevation data, all of which are run through a standard wind turbine power curve (common to all sites). To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100% assigned in that period. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998–1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the "lower" category includes all projects or turbines with an estimated gross capacity factor of less than 40%, the "medium" category corresponds to ≥40%–45%, the "higher" category corresponds to ≥45%–50%, and the "highest" category corresponds to ≥50%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 37,416 turbines of the 38,616 installed from 1998 through 2014 in the continental United States over that period, or 97%.

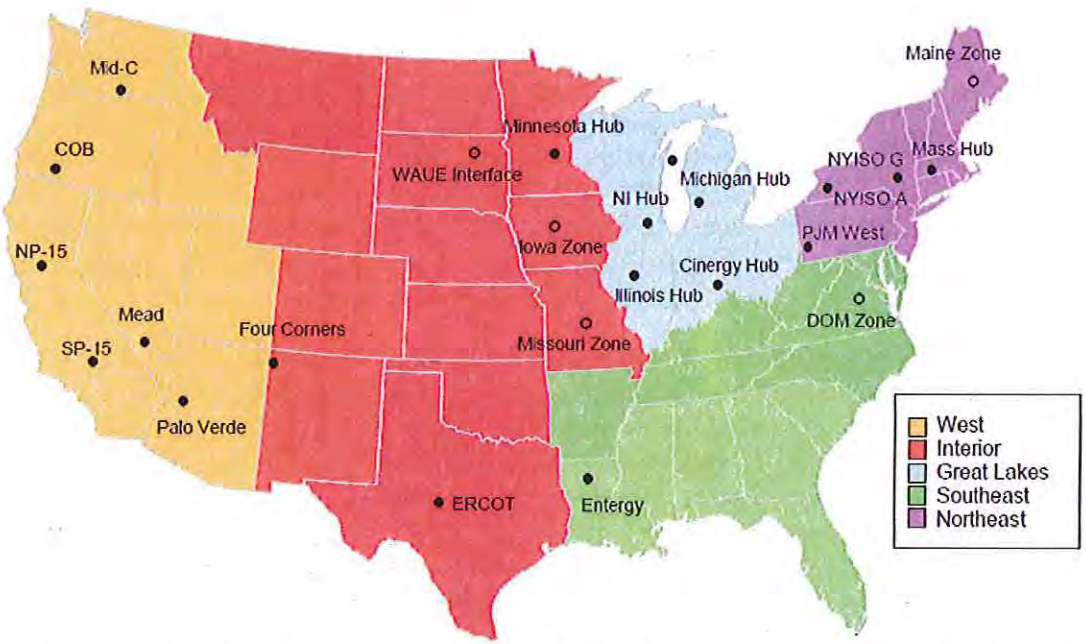
Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission and other regulatory filings. In part because wind turbine transactions vary in the turbines and services offered,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

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, FERC Form 1, various Securities and Exchange Commission filings, filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, the

DOE and Electric Power Research Institute Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009–2012 projects, data from the Section 1603 Treasury Grant program were used extensively. 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 2015* publication are converted from \$/MMBtu into \$/MWh using the heat rates implied by the modeling output (these heat rates start at roughly 8,100 Btu/kWh and gradually decline to around 7,200 Btu/kWh by 2040). REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.



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

Figure 54. Map of regions and wholesale electricity price hubs used in analysis

Policy and Market Drivers

The wind energy policy, transmission, and integration 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
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
ornl.gov/science-discovery/clean-energy/research-areas/sustainable-electricity/wind

Argonne National Laboratory
anl.gov/energy/renewable-energy

Idaho National Laboratory
inl.gov

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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NREL's National Wind Technology Center, Golden, Colorado.

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