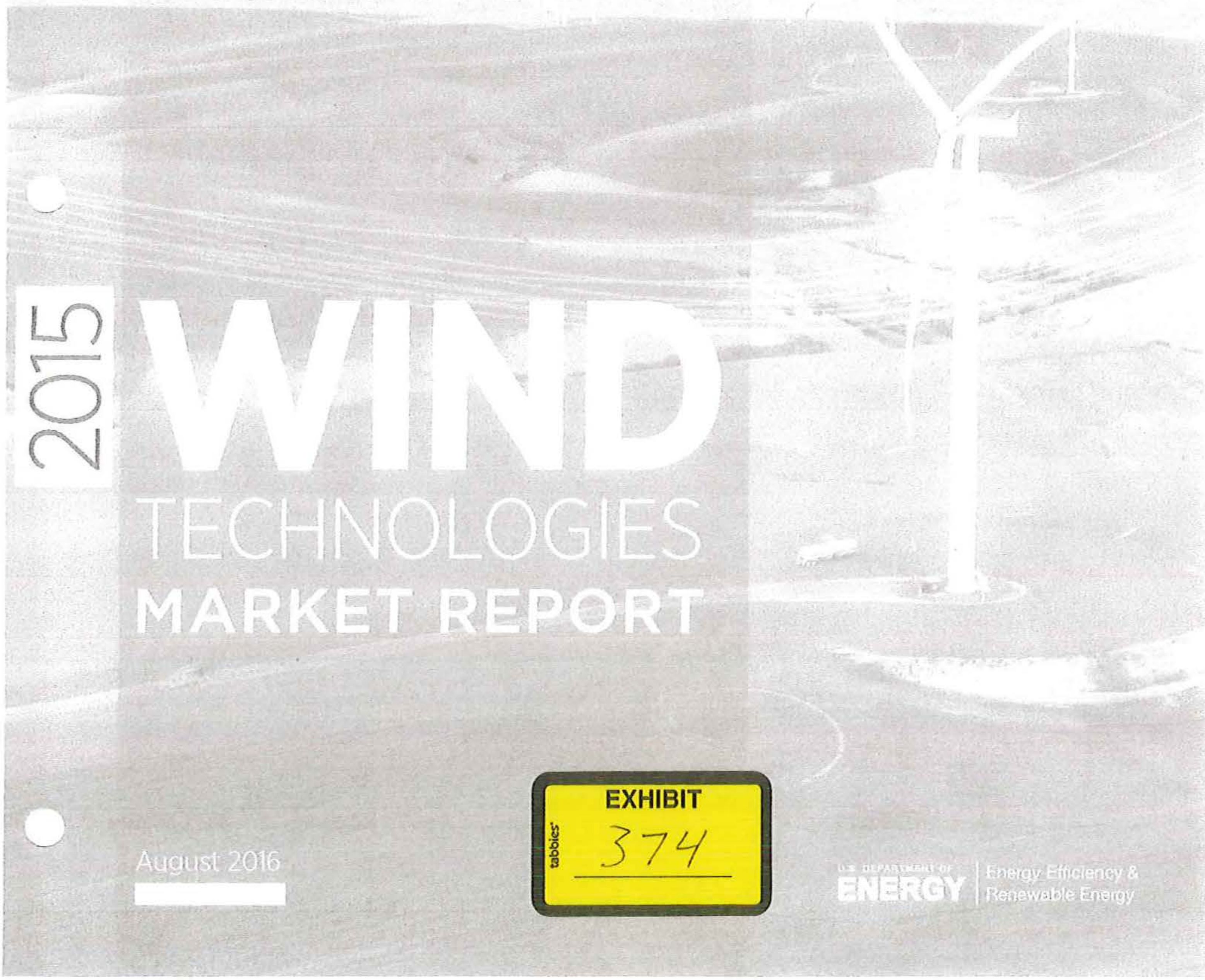


2015

WIND TECHNOLOGIES MARKET REPORT

August 2016

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

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 2015 sample stood at roughly $1,690/kW—down $640/kW from the apparent peak in average reported costs in 2009 and 2010. Early indications from a preliminary sample of projects currently under construction and anticipating completion in 2016 suggest no material change in installed costs in 2016.
- **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 2015, 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

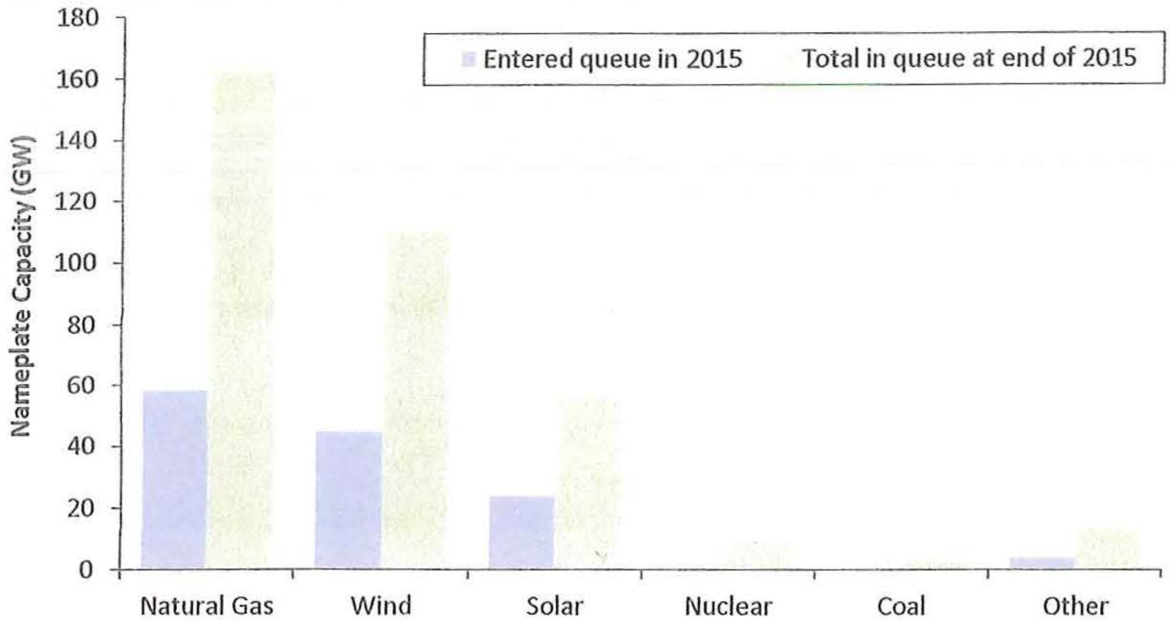
- **Wind PPA prices remain very low.** After topping out at nearly $70/MWh for PPAs executed in 2009, the national average level-through price of wind PPAs within the Berkeley Lab sample has dropped to around the $20/MWh level, inclusive of the federal production tax credit (PTC), though this latest nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country, where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from ~$55/MWh among contracts executed in 2009 to ~$20/MWh today. Today's low PPA prices have been enabled by the combination of higher capacity factors, declining costs, and record-low interest rates documented elsewhere in this report.
- **The relative economic competitiveness of wind power declined in 2015 with the drop in wholesale power prices.** A sharp drop in wholesale power prices in 2015 made it somewhat harder for wind power to compete, notwithstanding the low wind energy PPA prices available to purchasers. This is particularly true in light of the continued expansion of wind development in the Interior region of the U.S., where wholesale power prices are among the lowest in the nation. That said, the price stream of wind PPAs executed in 2014-2016 compares very favorably to the EIA's latest projection of the fuel costs of gas-fired generation extending out through 2040.

Policy and Market Drivers

- **A long-term extension and phase down of federal incentives for wind projects is leading to a resurgent domestic market.** In December 2015, Congress passed a 5-year phased-down extension of the PTC. To qualify, projects must begin construction before January 1, 2020. In May 2016, the IRS issued favorable guidance allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. In extending the PTC, Congress also included a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC will phase down in increments of 20 percentage points per year for projects starting construction in 2017 (80% PTC), 2018 (60%), and 2019 (40%).
- **State policies help direct the location and amount of wind power development, but current policies cannot support continued growth at recent levels.** As of July 2016, RPS policies existed in 29 states and Washington D.C. Of all wind capacity built in the United States from 2000 through 2015, roughly 51% is delivered to load-serving entities with RPS obligations. Among just those wind projects built in 2015, however, this proportion fell to 24%. Existing RPS programs are projected to require average annual renewable energy additions of roughly 3.7 GW/year through 2030, only a portion of which will come from wind. These additions are well below the average growth rate in wind power capacity in recent years.
- **System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain.** Studies show that wind energy integration costs are almost always below $12/MWh—and often below $5/MWh—for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. System operators and others continue to implement a range of methods to accommodate increased wind energy penetrations and reduce barriers to deployment: treating wind as dispatchable, increasing wind's capability to provide grid services, revising ancillary service market design, balancing area coordination, and new transmission investment. About 1,500 miles of transmission lines came on-line in 2015—less than in previous years. The wind industry, however, has identified 15 near-term transmission projects that—if all were completed—could carry 52 GW of additional wind capacity.

Future Outlook

With the five-year phased-down extension of the PTC, annual wind power capacity additions are projected to continue at a rapid clip for several years. Near-term additions will also be driven by improvements in the cost and performance of wind power technologies, which continue to yield very low power sales prices. Growing corporate demand for wind energy and state-level policies are expected to play important roles as well, as might utility action to proactively stay ahead of possible future environmental compliance obligations. As a result, various forecasts for the domestic market show expected capacity additions averaging more than 8,000 MW/year from 2016 to 2020. Projections for 2021 to 2023, however, show a downturn in additions as the PTC progressively delivers less value to the sector. Expectations for continued low natural gas prices, modest electricity demand growth, and lower near-term demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and competition from solar energy in certain regions of the country. At the same time, the potential for continued caution: placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built. Efforts have been made by FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have clogged these queues in past years. One consequence of those efforts 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. Generation capacity in 34 selected interconnection queues, by resource type

Even with this important caveat, the amount of wind capacity in the nation's interconnection queues *still* provides at least some indication of the amount of planned development. At the end of 2015, there were 110 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 110 GW is an increase from the end of 2014 (96 GW), and represented 31% of all generating capacity within these selected queues at that time, higher than all other generating sources except for natural gas. In 2015, 45 GW of wind power capacity entered the interconnection queues, compared to 58 GW of natural gas and 24 GW of solar. The 45 GW of new wind capacity entering the queues in 2015 is the largest annual sum since 2010.

Of note, however, is that the total 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.

Administration (BPA), Tennessee Valley Authority (TVA), and 24 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 88% of the U.S. total. Figures 7 and 8 only include projects that were active in the queue at the end of 2015 but that had not yet been built; suspended projects are not included.

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. The years 2013 and 2014 showed some reversal of that trend, but 2015 was the first year in which > 2 MW turbines were the majority of those installed.

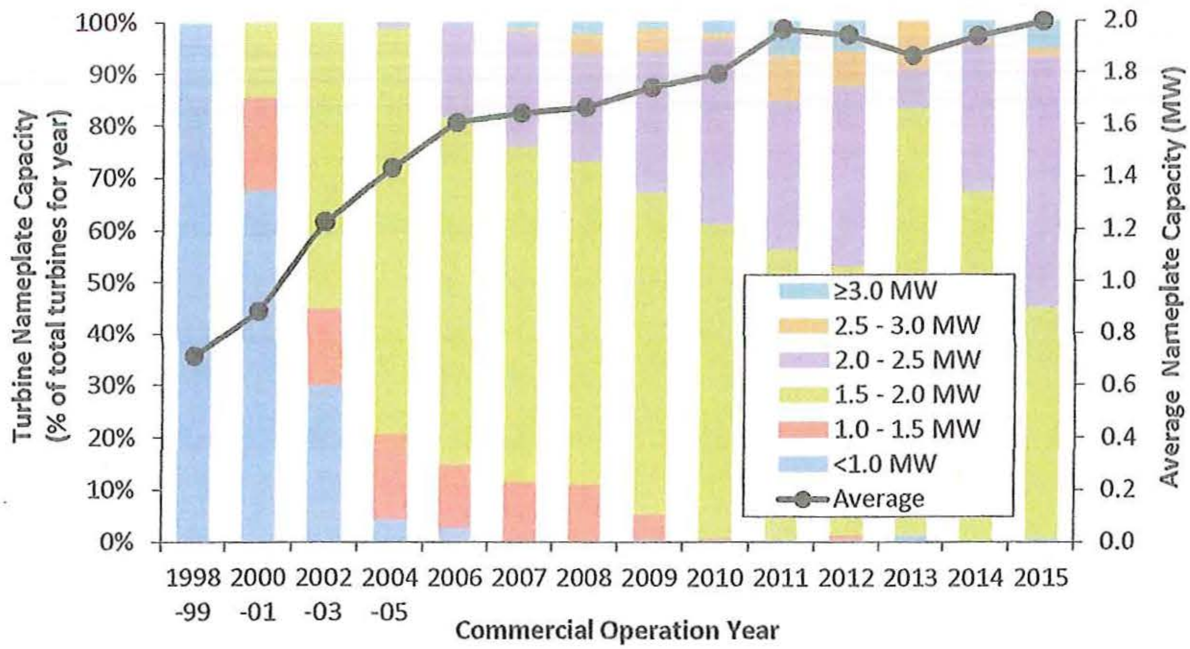


Figure 21. Trends in turbine nameplate capacity

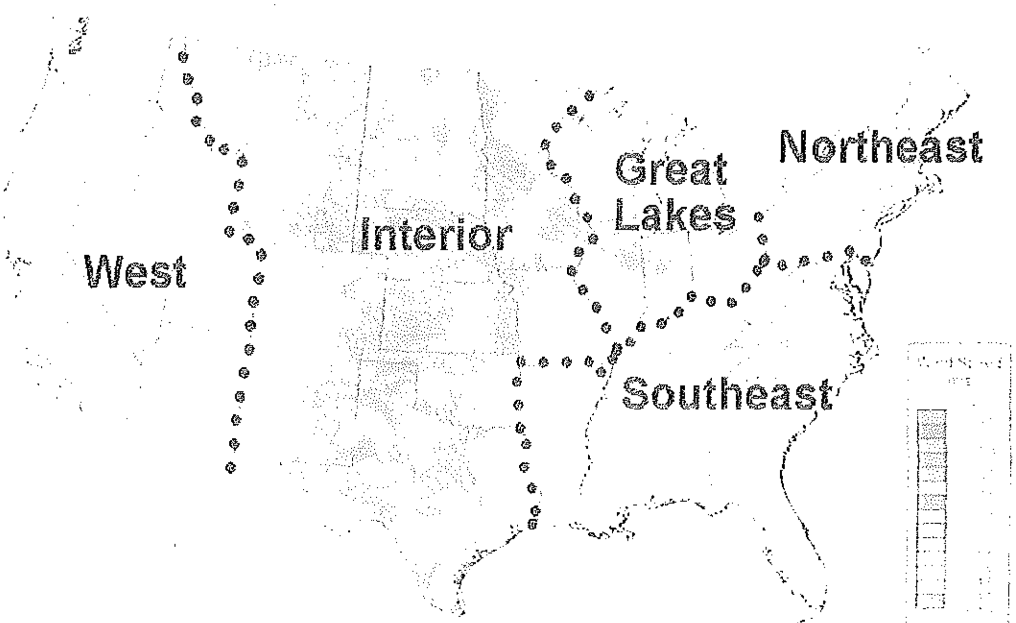
As with nameplate capacity, the average hub height of wind turbines has largely held constant since 2011 (Figure 22). More generally, growth in average hub height has been slow since 2005, with 80 meter towers dominating the overall market. Towers that are 90 meters and taller started to penetrate the market in 2011, however, a trend that has remained steady into 2015, equating to roughly 15% of the market in that year. Finally, although we saw the emergence of >100 meter towers as early as 2007, that segment of the market peaked in 2012 when 16% of newly installed turbines were taller than 100 meters; since 2012, only 1% or less of newly installed turbines in each year (including 2015) have featured towers that tall.

Taller towers (i.e., 90 meters and above) have seen higher market share in the Great Lakes (67%) and Northeast (43%) than in the Interior (11%) 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.

Low specific power machines installed over this four-year period have been regularly deployed in all regions of the country, though their market share in the Great Lakes (81%) and Interior (77%) exceeds that in the West (48%) and Northeast (36%). Similarly, these turbines have been commonly used in all resource regimes including at sites with very high wind speeds, as shown in Figure 28. Turbines with the lowest specific power ratings (180–220 W/m^2), however, have been installed in greater proportions at lower, medium, and higher wind speed sites than at the highest wind speed sites, and are more prevalent in the Great Lakes.

Turning to IEC Class, we see a somewhat similar story. Over this period, Class 3 and Class 2/3 machines have had the largest market share in the Great Lakes (91%) and Interior (78%) regions, but have also gained significant market in the Northeast (49%) and West (39%). Moreover, these turbines have been regularly deployed in both lower- and higher-quality resources sites.

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



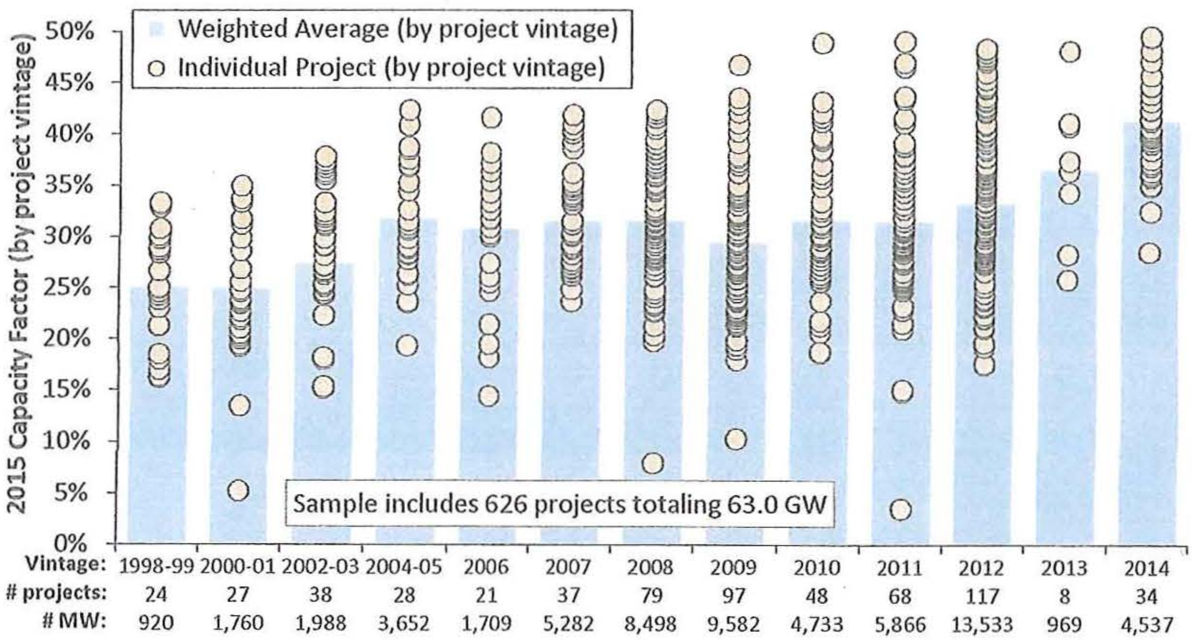
Source: AWS Truepower, National Renewable Energy Laboratory

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

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

One way to partially control for the time-varying influences described in the previous section (e.g., annual wind resource variations or changes in the amount of wind curtailment) is to focus exclusively on capacity factors in a single year, such as 2015.[41] As such, while Figure 30 presents sample-wide capacity factors in each calendar year, Figure 32 instead shows only capacity factors in 2015, broken out by project vintage. Wind power projects built in 2015 are again excluded, as full-year performance data are not yet available for those projects.

Figure 32 shows an increase in weighted-average 2015 capacity factors when moving from projects installed in the 1998–1999 period to those installed in the 2004–2005 period. Subsequent project vintages through 2011, however, show little if any improvement in average capacity factors recorded in 2015. This pattern of stagnation is finally broken by projects installed in 2012, and even more so by 2013- and 2014-vintage projects. The average 2015 capacity factor among projects built in 2014 reached 41.2%, compared to an average of 31.2% among all projects built from 2004–2011, and 25.8% among all projects built from 1998–2003.

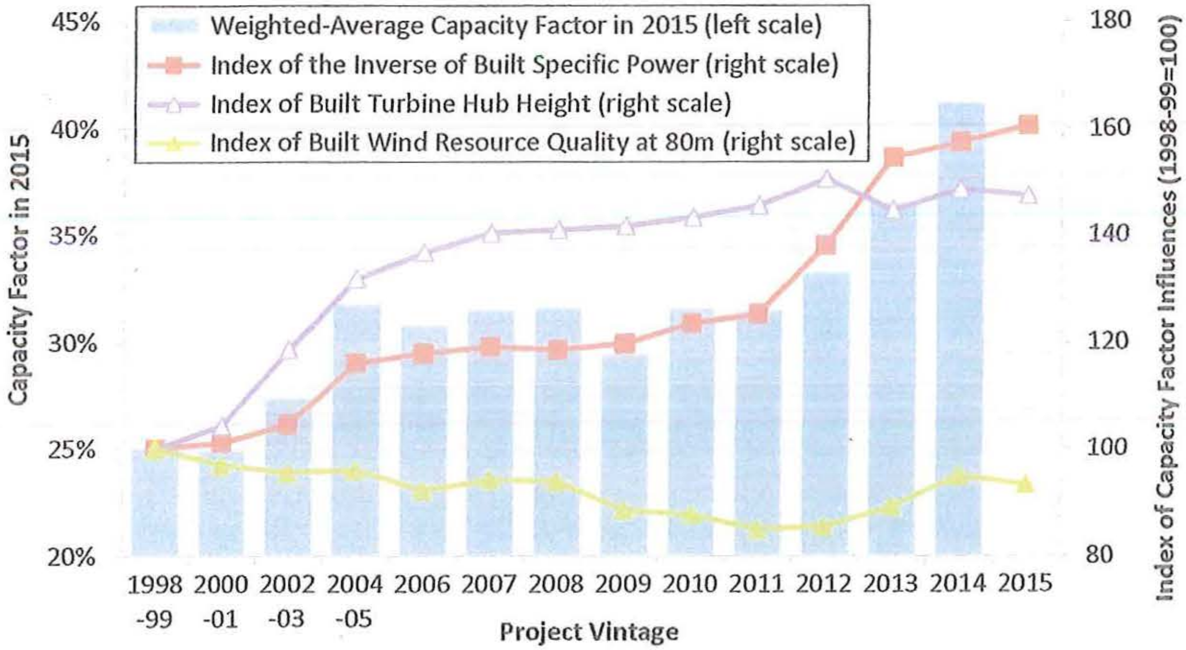


Source: Berkeley Lab

Figure 32. Calendar year 2015 capacity factors by project vintage

The trends in average capacity factor by project vintage seen in Figure 32 can largely be explained by three underlying influences shown in Figure 33: a trend towards progressively lower specific power ratings (note that Figure 33 actually shows the inverse of specific power, so

[41] Although focusing just on 2015 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 2015 was not a representative year in terms of the strength of the wind resource (as mentioned above, it was not – wind speeds were well below normal across much of the U.S. in 2015) or wind power curtailment.



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

Source: Berkeley Lab

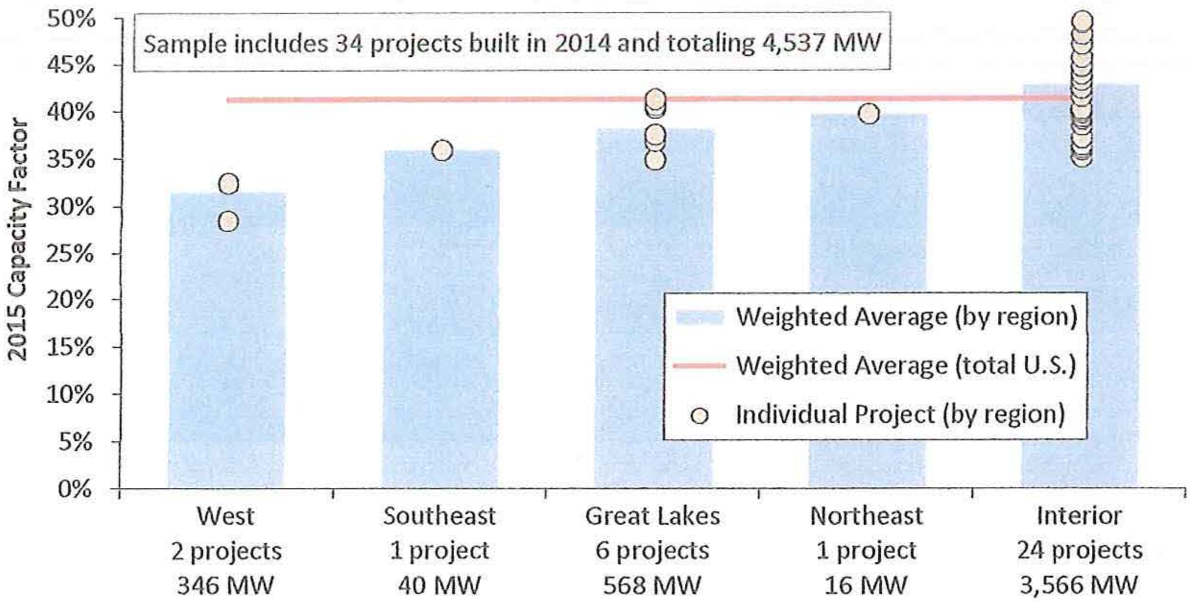
Figure 33. 2015 capacity factors and various drivers by project vintage

In Figure 33, the significant improvement in average 2015 capacity factors from those projects built in 1998-2001 to those built in 2004-2005 is driven by both an increase in hub height and a decline in specific power, and despite a shift towards somewhat-lower-quality wind resource sites. The stagnation in average capacity factor that subsequently persisted through 2011-vintage projects reflects relatively flat trends in both hub height and specific power, coupled with an ongoing decline in wind resource quality at built sites. Finally, capacity factors began to move higher among 2012-vintage projects, and continued even higher among 2013- and 2014-vintage projects, driven by a sharp reduction in average specific power coupled with a marked improvement in the quality of wind resource sites (average hub height stayed relatively constant over this period). Looking ahead to 2016, 2015-vintage projects are likely to perform similarly to those built in 2014 on average, given only modest changes in these three underlying drivers among the 2015 fleet.

To help 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 2015 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 2015 capacity factors than those in a higher specific power range.

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 2015 capacity factors ranging from a minimum of 28.5% to a maximum of 49.5% among those projects built in 2014 (this spread is even wider for projects built in earlier years). Some of the spread in project-level capacity factors—for projects built in 2014 and earlier—is attributable to regional variations in average wind resource quality. As such, Figure 37 shows the regional variation in 2015 capacity factors (using the regional definitions shown in Figure 29, earlier) based on just the sample of wind power projects built in 2014.



Source: Berkeley Lab

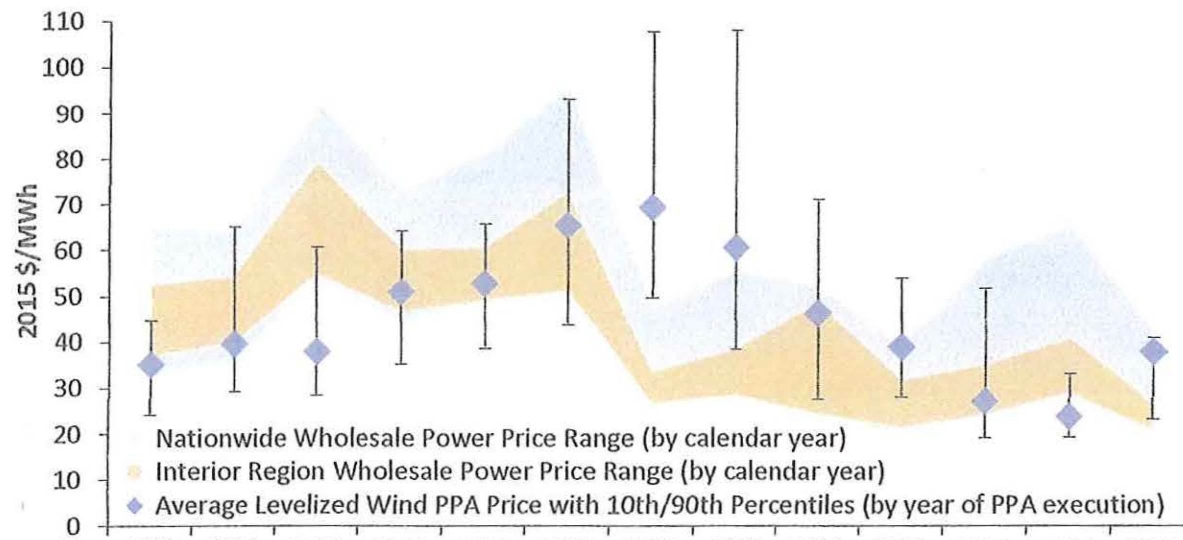
Figure 37. Calendar year 2015 capacity factors by region: 2014 vintage projects only

Although four of the five regions have a very limited sample (attributable to the fact that nearly 80% of the total capacity installed in 2014 was located in the Interior region), focusing only on this most recent vintage of projects is nevertheless appropriate in light of the significant disparity in average 2015 capacity factors among 2014 projects versus earlier vintages (see Figures 32 or 33). In other words, were Figure 37 to include vintages prior to 2014 in an effort to boost sample size, the stark differences in 2015 capacity factor across vintages could partially mask any regional differences. Focusing on just the two regions that include more than two projects in Figure 37, generation-weighted average capacity factors are the highest in the Interior region (42.7%) and a bit lower in the Great Lakes (38.1%).[45] Even within these regions, however, there

[45] Given the relatively small sample size in many regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2015, care should be taken in extrapolating these results. For example, many projects (of various vintages) located in Wyoming and Idaho – both states that faced significantly below-normal wind speeds in 2015 (AWS Truepower 2016) – experienced 2015 capacity factors that were as much as 8 to 9 percentage points below normal, while at the

The relative economic competitiveness of wind power declined in 2015 with the drop in wholesale power prices

The blue-shaded area of Figure 49 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power[66] 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). Similarly, the orange-shaded area shows the range of wholesale prices among only those nodes that are located within the Interior region. Our PPA price sample is increasingly dominated by projects in this region. Finally, the dark diamonds represent the generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) in the years in which contracts were executed (consistent with the nationwide averages presented in Figure 48).



Year:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Contracts:	9	13	17	31	26	39	49	49	43	13	32	16	6
MW:	*570*	*547*	*1,643*	*2,436*	*1,781*	*3,465*	*4,048*	*4,790*	*4,727*	*970*	*4,374*	*1,985*	*401*

Source: Berkeley Lab, FERC, ABB, IntercontinentalExchange

Figure 49. Average levelized long-term wind PPA prices and yearly wholesale electricity prices over time

At least within the sample of projects reported here, average long-term wind PPA prices compared favorably to yearly wholesale electricity prices from 2003 through 2008. Starting in 2009, however, the sharp drop in wholesale electricity prices (driven primarily by lower natural gas prices) squeezed average wind PPA prices out of the wholesale power price range on a

[66] 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). At higher levels of wind penetration, wind power can suppress local wholesale power prices during times of peak output and/or low demand, thereby eroding its value in the wholesale market relative to a flat block of power.

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 and 2014, 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. Subsequently, the sharp drop in average wholesale electricity prices in 2015 has made it somewhat harder for wind to compete in the market. The spike in PPA prices among the small sample of 2015 projects mentioned above did not help, though focusing on the 10th to 90th percentile range rather than the weighted-average PPA price perhaps provides a more representative comparison in that year. Even so, the much narrower and lower range of wholesale power prices in the Interior region is arguably the more relevant comparison in recent years, as project development has been largely concentrated within that region.

The comparison between levelized wind PPA and wholesale power prices in Figures 49 is imperfect, in part because the levelized wind PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale power prices are pertinent to just the single year in question. Figure 50 attempts to remedy this temporal mismatch by presenting an alternative (yet still imperfect) way of looking at how wind stacks up relative to its competition.

Rather than levelizing the wind PPA prices, Figure 50 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown, along with a generation-weighted average) from PPAs executed in 2014, 2015, or 2016 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[67] As shown, the median and generation-weighted average wind PPA prices from contracts executed in the past three years are consistently at or below the low end of the projected natural gas fuel cost range over the entire period, while the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall below the reference case projection and into the lower portion of the fuel cost range from 2024-2040.

Figure 50 also hints at the long-term value that wind power can provide as a "hedge" against rising and/or uncertain natural gas prices. The wind PPA prices that are shown have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain. Actual fuel costs could ultimately be lower or much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

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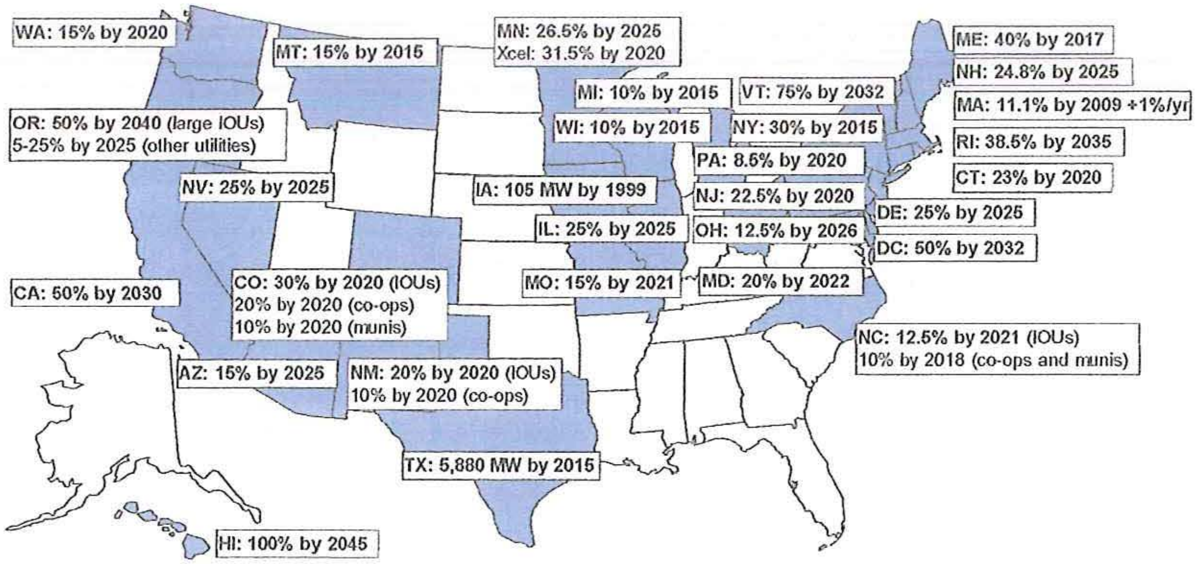
[67] The fuel cost projections come from the EIA's *Annual Energy Outlook 2016* publication, and increase from around \$3.89/MMBtu in 2017 to \$5.36/MMBtu (both in 2015 dollars) in 2040 in the reference case. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from \$/MMBtu into \$/MWh using a flat heat rate of 7 MMBtu/MWh, which is aggressive compared to the heat rates implied by the reference case modeling output (which start at roughly 7.9 MMBtu/MWh in 2017 and gradually decline to just above 7 MMBtu/MWh by 2040).

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

As of July 2016, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 51).[68] Attempts to weaken RPS policies have been initiated in a number of states, and in limited cases—thus far only Ohio in 2014 and Kansas in 2015—have led to a freeze or repeal of RPS requirements. In contrast, other states—including, most recently, California, Hawaii, Oregon, Rhode Island, and Washington, DC—have increased and extended their RPS targets. Vermont has created a new RPS.



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

Source: Berkeley Lab

Figure 51. State RPS policies as of July 2016

Of all wind power capacity built in the United States from 2000 through 2015, roughly 51% is delivered to load serving entities (LSEs) with RPS obligations. In recent years, however, the role of state RPS programs in driving incremental wind power growth has diminished, at least on a national basis; just 24% of U.S. wind capacity additions in 2015 serve RPS requirements. Outside of the wind-rich Interior region, however, 88% of wind capacity additions in 2015 are serving RPS demand, and RPS requirements continue to serve as a strong driver for wind power growth.

In aggregate, existing state RPS policies will require 420 terawatt-hours of RPS-eligible forms of renewable electricity by 2030, at which point most state RPS requirements will have reached their maximum percentage targets. Based on the mix and capacity factors of resources currently used or contracted for RPS compliance, this equates to a total of roughly 130 GW of RPS-

[68] Although not shown in Figure 51, 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.