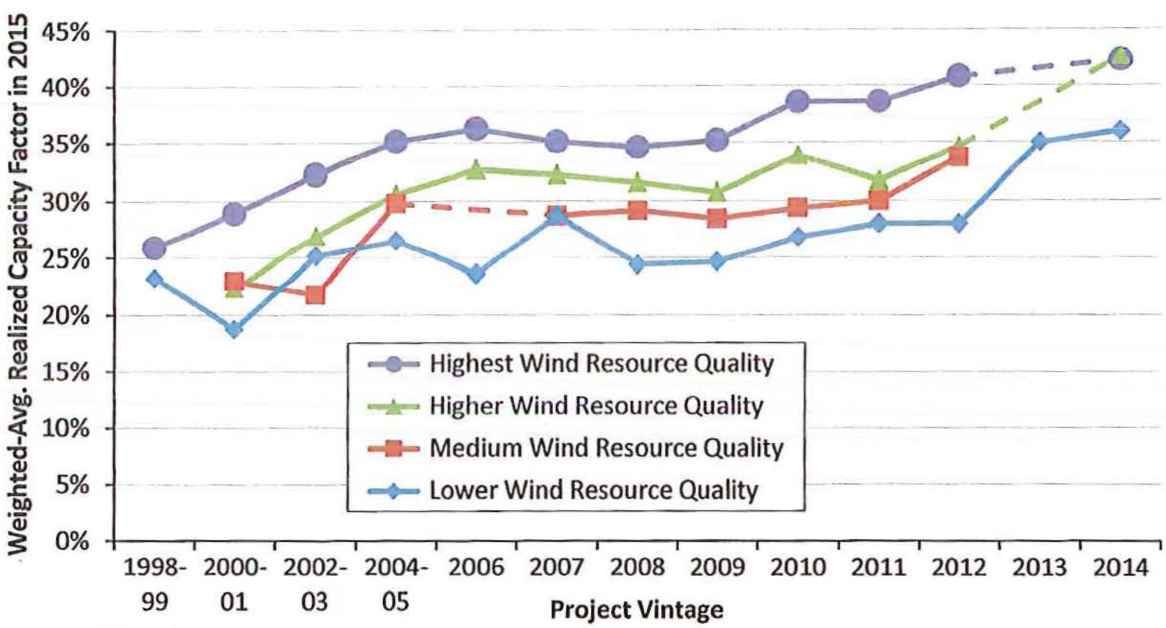
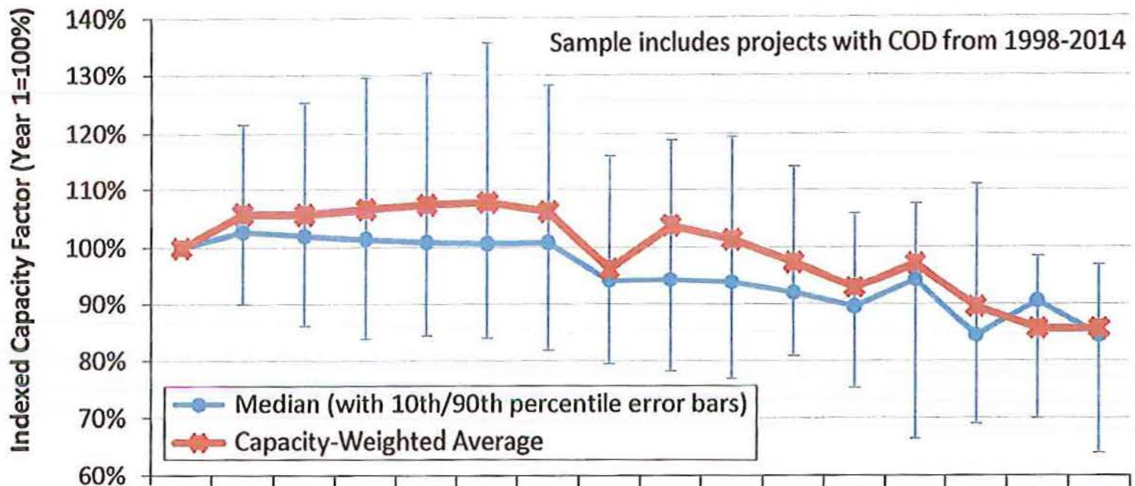


Source: Berkeley Lab

Figure 35. Calendar year 2015 capacity factors by project vintage and wind resource quality

One final variable that could be influencing the apparent improvement in 2015 capacity factors among more recent project vintages is project age. If wind turbine (and project) performance tends to degrade over time, then older projects—e.g., those built from 1998-2001—may have performed worse than more recent vintages in 2015 simply due to their relative age. Figure 36 explores this question by graphing both median (with 10^{th} and 90^{th} percentile bars) and capacity-weighted average capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values).

Figure 36 suggests some amount of performance degradation, particularly once projects age beyond 7-10 years—i.e., a period that roughly corresponds to the initial warranty period, as well as the PTC period. Such degradation among older projects could help to partially explain why, for example, in Figure 30 the sample-wide capacity factors in 2000 and 2001 exceeded 30%, while in Figure 32 the 1998-2001 project vintages (i.e., consisting of essentially the same set of projects) posted average capacity factors of just 25% in 2015.



Years post-COD:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Sample GW:	63.6	58.8	57.8	44.1	38.1	33.3	23.7	15.2	9.9	8.0	5.0	4.3	2.8	2.4	0.6	0.6
Sample projects:	756	721	709	564	478	418	307	207	165	122	99	86	63	53	13	9

Source: Berkeley Lab

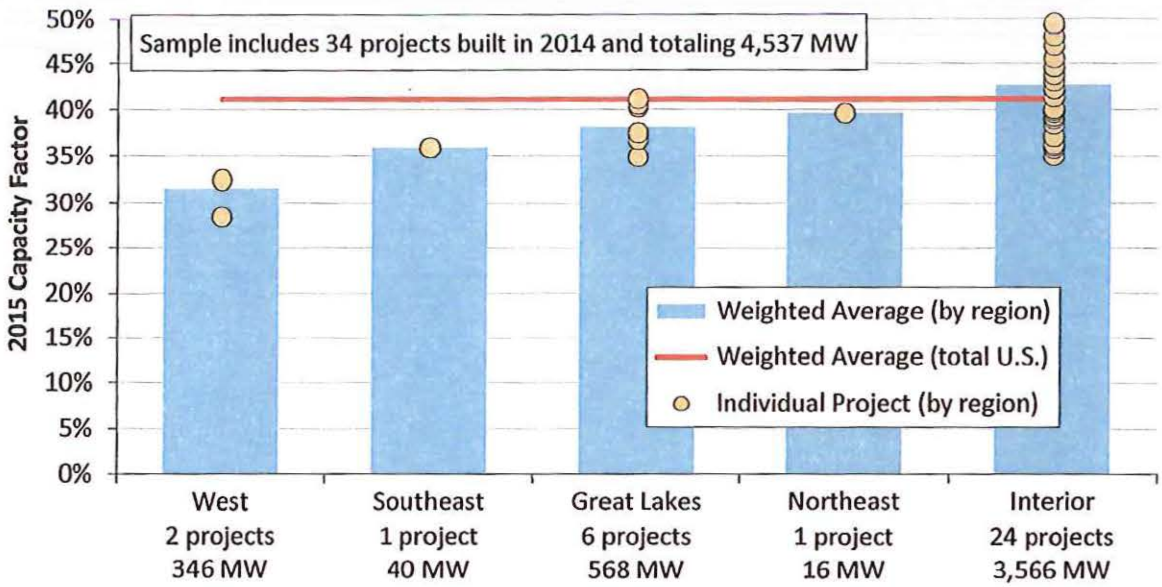
Figure 36. Post-COD changes in capacity factors over time suggest performance degradation

The median values in Figure 36 regularly fall below the capacity-weighted average values, suggesting that smaller projects tend to degrade more, and more rapidly, than larger projects. This difference could perhaps be attributable to less-stringent or -responsive O&M protocols among smaller projects. The PTC could be another influence, if smaller projects have instead more commonly opted for the ITC or its cash counterpart, the Section 1603 grant—neither of which depends on performance. Finally, the up-tick in year two for both the median and capacity-weighted average values could partly reflect the initial production ramp-up period that is commonly experienced by wind projects as they work through and resolve initial "teething" issues during their first year of operations.

Although all of these suppositions surrounding Figure 36 are intriguing and worthy of further study, a number of caveats are in order. First, no attempt was made to correct for inter-year variation in the strength of the wind resource. Although the potential impact of this omission is likely muted by the fact that year five (for example) for one project will be a different calendar year than year five for another project, inter-year resource variation could still play a role. Second, the sample is not the same in each year. The sample shrinks as the number of post-COD years increases, and is increasingly dominated by older projects using older turbine technology that may not be representative of today's turbines. Third, as with all figures presented in this chapter, turbine decommissioning is accounted for by adjusting the nameplate project capacity as appropriate over time (all the way to zero if a project is fully decommissioned), such that each figure, including Figure 36, shows the performance of those turbines that are operating in each period, rather than relative to the original nameplate capacity.

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

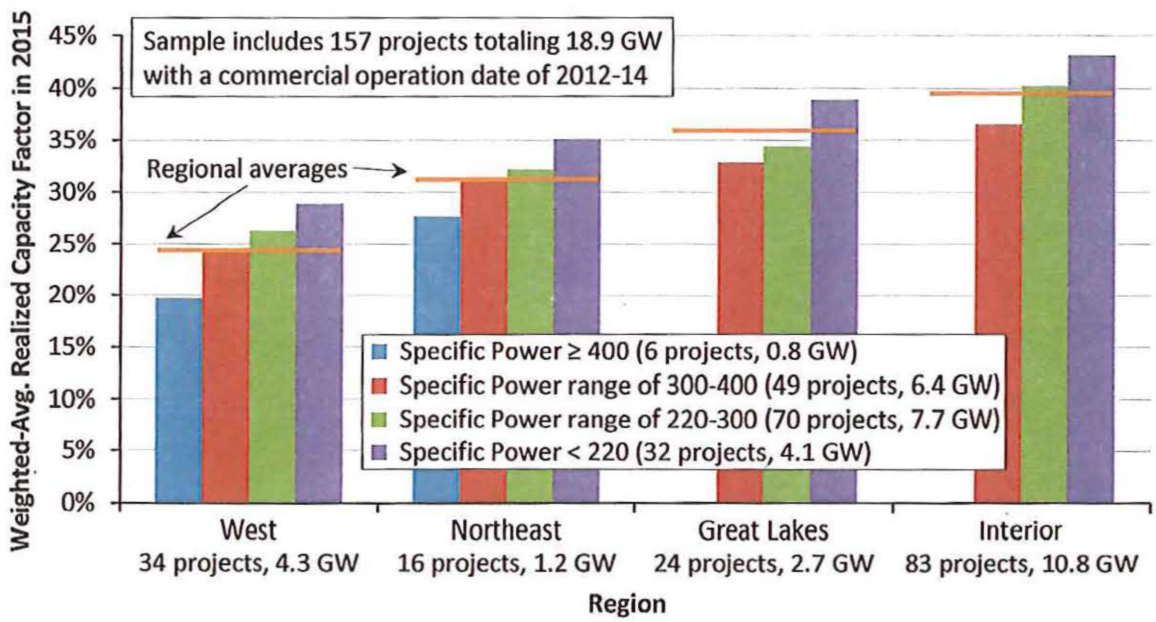
Although four of the five regions have a very limited sample (attributable to the fact that nearly 80% of the total capacity installed in 2014 was located in the Interior region), focusing only on this most recent vintage of projects is nevertheless appropriate in light of the significant disparity in 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

can still be considerable spread—e.g., 2015 capacity factors range from 35% up to 49.5% among projects installed in the Interior region in 2014.

Some of this intra-regional variation can be explained by turbine technology. Figure 38 also provides a regional breakdown, although in this case it includes projects built from 2012-2014, which are further differentiated by average specific power. Including older vintages in Figure 38 is both more necessary (i.e., in order to have sufficient sample within each region to enable a specific power breakout) and less problematic (i.e., given that Figure 38 controls for the impact of specific power) than it would have been for Figure 37.

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 38. Calendar year 2015 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 46% of all turbines installed in the Great Lakes region from 2012–2015 have a specific power rating of less than 220 W/m^2, while the comparable number in the West is 11%. Similarly, 67% of all turbines installed in the Great Lakes region from 2012–2015 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 37 and 38.

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other extreme many projects in Minnesota, Wisconsin, and Michigan – states that were largely spared the weak winds of 2015 (AWS Truepower 2016) – reported higher-than-normal capacity factors in 2015.

Taken together, Figures 30–38 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of factors. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—such as the quality of the wind resource where projects are located, inter-year wind resource variability, and even project age.

6. Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally O&M costs. Sample size varies among these different datasets, and is therefore discussed within each section of this chapter.

Wind turbine prices remained well below levels seen several years ago

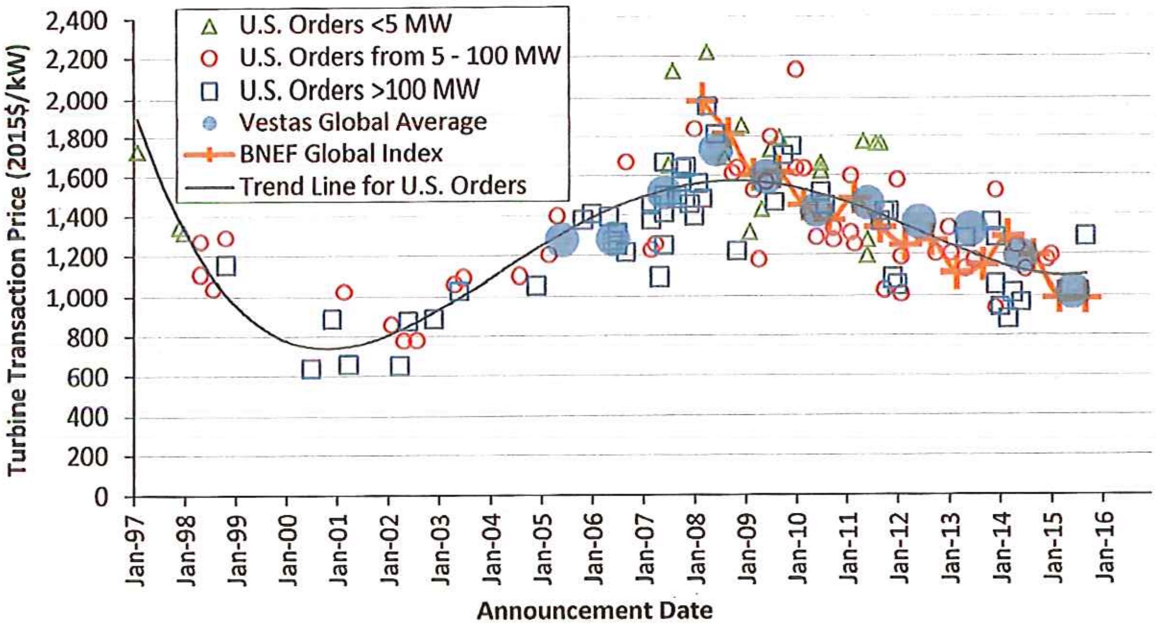
Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Prices maintained their low levels in 2015, aided in part by the strength of the U.S. dollar.

Berkeley Lab has gathered price data for 121 U.S. wind turbine transactions totaling 30,480 MW announced from 1997 through 2015, but this sample includes only nine transactions (1,460 MW) announced in 2014 or 2015. 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.[46] 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, in that only a fraction of the announced turbine transactions have publicly revealed pricing data. Partly as a result, Figure 39—which depicts these U.S. wind turbine transaction prices—also presents data from two other sources: (1) Vestas on that company's global average turbine pricing from 2005 through 2015, as reported in Vestas' financial reports; and (2) Bloomberg NEF (2016a) on that company's global average turbine price index by contract signing date.

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; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter (Bolinger and Wiser 2011).

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



Source: Berkeley Lab

Figure 39. Reported wind turbine transaction prices over time

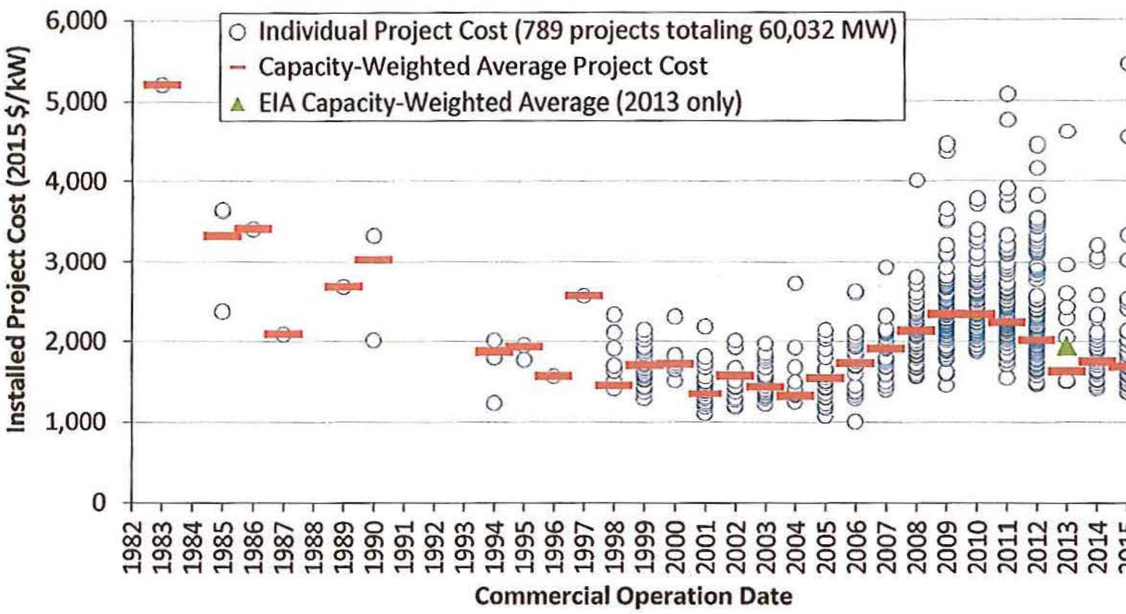
Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 39, our limited sample of recently announced U.S. turbine transactions shows pricing in the \$850–\$1,250/kW range. Bloomberg NEF (2016b) reports average pricing for recent North American contracts of roughly \$1,000/kW. Data from Vestas confirm these pricing points, with average global sales prices in 2015 of \$1,020/kW, when denominated in U.S. dollars.

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 also compiles data on the total installed cost of wind power projects in the United States, including data on 44 projects completed in 2015 totaling 5,772 MW, or 67% of the wind power capacity installed in that year. In aggregate, the dataset (through 2015) includes 789 completed wind power projects in the continental United States totaling 60,032 MW and equaling roughly 81% of all wind power capacity installed in the United States at the end of 2015. 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 40, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of the last decade. 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 behind 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 39) and when those turbines are actually installed and commissioned (the time stamp for Figure 40).[47]



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

Figure 40. Installed wind power project costs over time

In 2015, the capacity-weighted average installed project cost within our sample stood at roughly \$1,690/kW, down \$640/kW or 27% from the apparent peak in average reported costs in 2009 and 2010. Early indications from a limited sample of 18 projects (totaling 3.4 GW) currently under construction and anticipating completion in 2016 suggest no material change in capacity-weighted average installed costs in 2016.[48]

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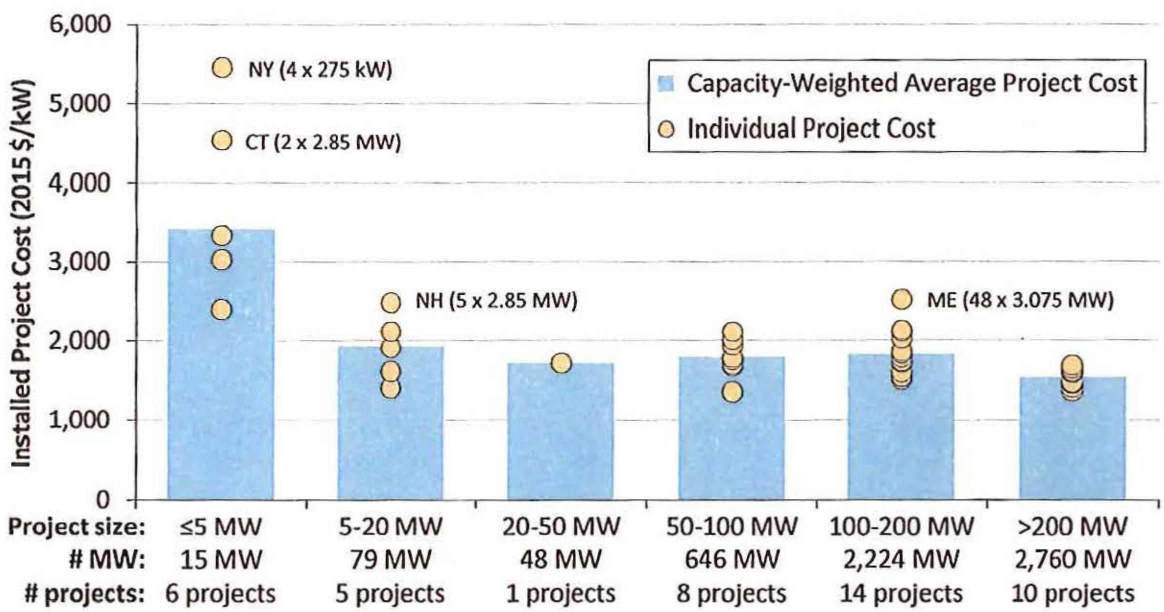
[47] For projects placed in service from 2009 through 2012, Figure 40 partly reflects installed cost estimates derived from publicly available data from the Section 1603 cash grant program. In some cases (although exactly which are unknown), the Section 1603 grant data likely reflect the fair market value rather than the installed cost of wind power projects; in such cases, the installed cost estimates shown in Figure 40 will be artificially inflated.

[48] 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

Also included in Figure 40 is a single weighted-average data point for 2013 from the EIA, which has recently begun to collect installed cost data through its Form 860 survey instrument. Although the EIA's capacity-weighted average cost for 2013 is higher than that derived from our sample (which is perhaps skewed to the low side by one sizable project in a year when little capacity was built), it is nevertheless aligned with the declining cost trend from 2009 to 2015. The EIA plans to report average data for 2014 and 2015 later in 2016; we will include these additional data points in future editions of this report.

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

Average installed project costs exhibit economies of scale, especially at the lower end of the project size range. Figure 41 shows that among the sample of projects installed in 2015, 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. A few notable high-cost projects are called out in Figure 41; all are from the high-cost Northeast region, with the two highest-cost projects either using sub-MW turbines (NY) or representing the first utility-scale wind installation in a state (CT).[49]



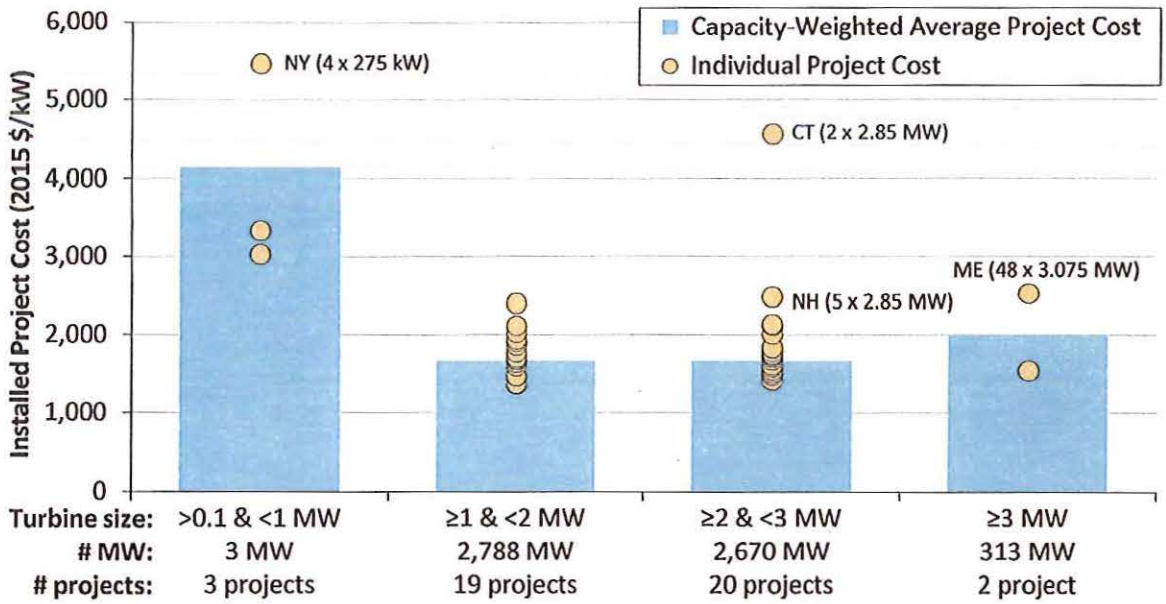
Source: Berkeley Lab

Figure 41. Installed wind power project costs by project size: 2015 projects

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 40 (from 1982 through 2015) in conjunction with global cumulative wind power installations over that same period results in a learning rate of 6.5%.

[49] The relatively high $/kW cost of the Connecticut project is also partly due to the fact that the project's nameplate capacity—which serves as the denominator of the $/kW cost estimate—is capped at 5 MW, even though the two 2.85 MW turbines are capable of generating a total of 5.7 MW. If $/kW costs were based on 5.7 MW rather than 5 MW, the cost of this project would be $3,995/kW rather than $4,554/kW.

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 42 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.[50] The same apparent high-cost projects are noted in Figure 42, with the Connecticut project seemingly more of an outlier in this case, viewed within the context of turbine capacity rather than project capacity.



Source: Berkeley Lab

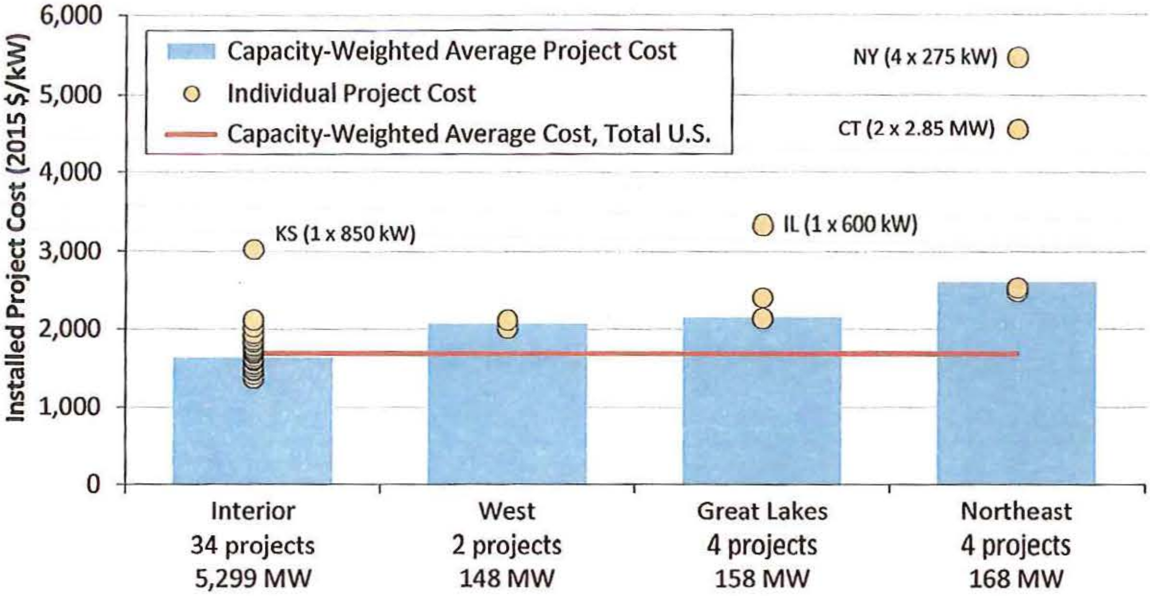
Figure 42. Installed wind power project costs by turbine size: 2015 projects

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 2015, Figure 43 breaks out project costs among four of the five regions defined in Figure 29 (there were no projects built in the Southeast region in 2015).[51] The Interior region—with by far the largest sample—was the lowest-cost region on average, with an average cost of $1,640/kW, while the Northeast was the

[50] 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 41 and 42—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.

[51] For reference, the 73,992 MW of wind installed in the United States at the end of 2015 is apportioned among the five regions shown in Figure 29 as follows: Interior (63%), West (19%), Great Lakes (11%), Northeast (6%), and Southeast (1%). The remaining installed U.S. wind power capacity is located in Hawaii, Alaska, and Puerto Rico and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

highest-cost region (although with a sample of just four projects, two of which stand out as unusually high-cost projects).[52] Viewed within this regional context, the Maine and New Hampshire projects identified as high-cost in Figures 41 and 42 no longer appear as such in Figure 43, while two new single-turbine projects involving sub-MW turbines in the Interior and Great Lakes regions now stand out as high-cost projects for the first time.

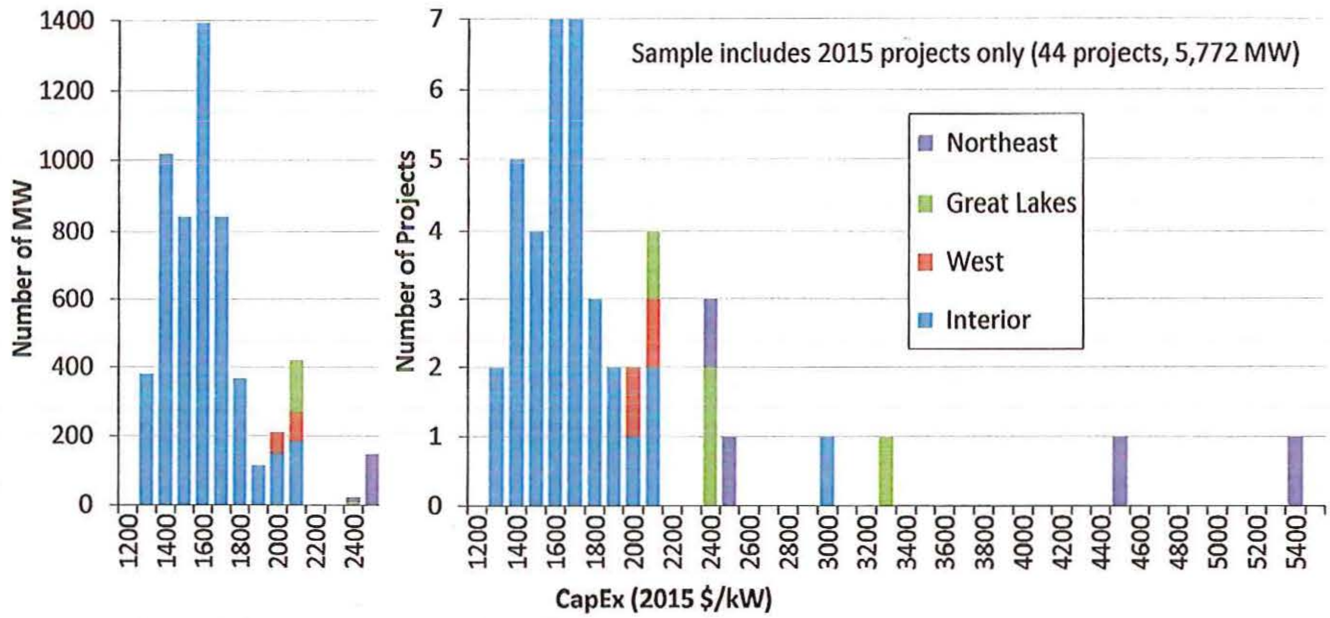


Source: Berkeley Lab

Figure 43. Installed wind power project costs by region: 2015 projects

Finally, Figure 44 shows two histograms that present the distribution of installed project costs among 2015-vintage projects, in terms of both capacity and number of projects. The four projects with costs above $3,000/kW are evident in the histogram of projects, but given their small size, they do not really show up in the capacity histogram; hence it is truncated at $2,500/kW. More generally, it is clear that most of the projects—and all of the low-cost projects—are located in the Interior region, where the distribution is centered on the $1,600-$1,700/kW bin. Projects in other regions have higher costs.

[52] 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 43.



Note: The capacity histogram is truncated at $2,500/kW as a space-saving measure, given that the four projects that have higher costs are all very small and hence imperceptible on the capacity histogram.

Source: Berkeley Lab

Figure 44. Histogram of installed costs by MW and projects: 2015 projects

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

Operations and maintenance costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available market data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 154 installed wind power projects in the United States, totaling 12,080 MW with commercial operation dates of 1982 through 2014. 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 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.[53] Other ongoing expenses, including general and administrative expenses, taxes, property insurance,

[53] 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.

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 paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow should be taken 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 45 shows project-level O&M costs by commercial operation date.[54] Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2015, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2014, only year 2015 data are available, and that is what is shown in the figure.[55] Many other projects only have data for a subset of years during the 2000–2015 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 2000–2015 timeframe. The chart highlights the 71 projects, totaling 8,465 MW, for which 2015 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 45 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 2000–2015 O&M costs for the 24 projects in the sample constructed in the 1980s equal $35/MWh, dropping to $24/MWh for the 37 projects installed in the 1990s, to $10/MWh for the 65 projects installed in the 2000s, and to $9/MWh for the 28 projects installed since 2010.[56] 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;[57]

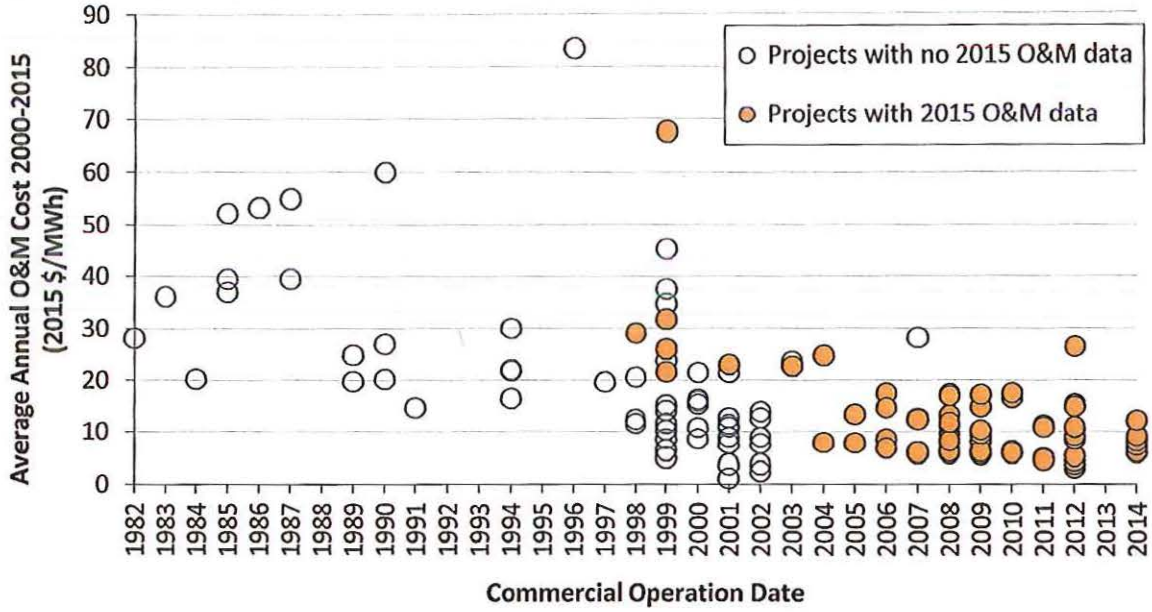
[54] For projects installed in multiple phases, the commercial operation date of the largest phase is used; for re-powered projects, the date at which re-powering was completed is used.

[55] Projects installed in 2015 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 2015 would be year 2016.

[56] If expressed instead in terms of $/kW-year, capacity-weighted average 2000–2015 O&M costs were $68/kW-year for projects in the sample constructed in the 1980s, dropping to $57/kW-year for projects constructed in the 1990s, to $28/kW-year for projects constructed in the 2000s, and to $26/kW-year for projects constructed since 2010. Somewhat consistent with these observed O&M costs, Bloomberg NEF (2016c) shows a general reduction in the cost of a sample of initial full-service O&M contracts (pertaining to the first years of turbine life, and only about 4 GW of which are from North America) since 2008, reaching 21.6 Euro/kW-year in 2015 (~$24/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).

[57] 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 (29 projects totaling 44% of the sample capacity installed since 2000 were installed from 2009-2012—i.e., within the period of eligibility for the Section 1603 grant—though only five of these 29 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.

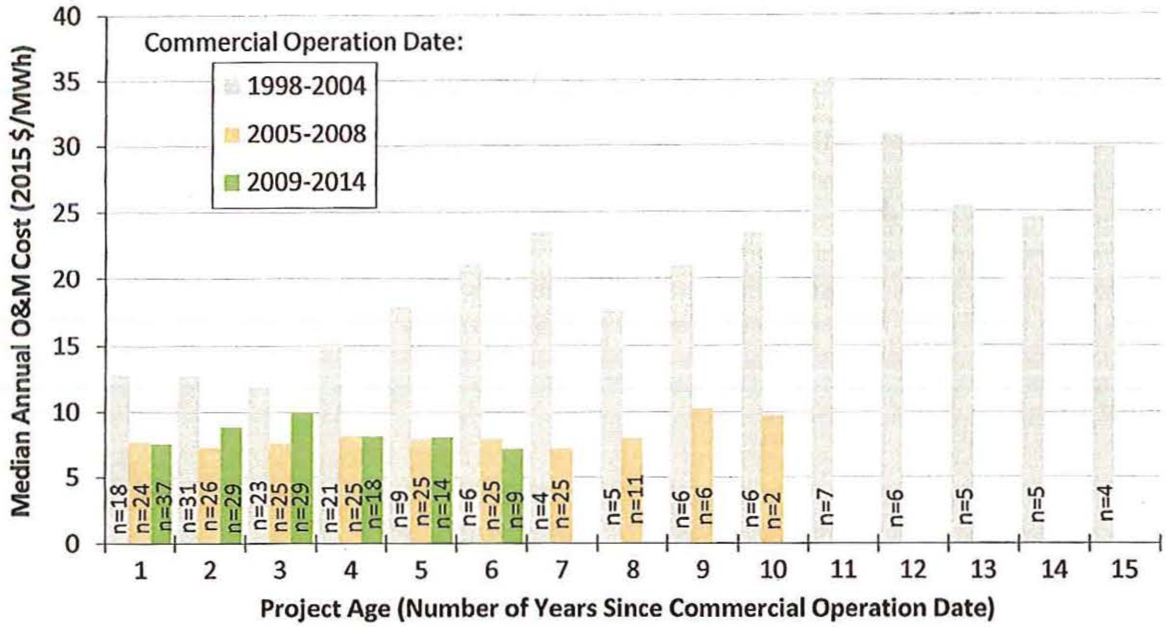


Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure 45. Average O&M costs for available data years from 2000–2015, 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 46 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale, which reportedly can be significant (Bloomberg NEF 2016c). 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 46 shows an upward trend in project-level O&M costs as projects age, at least among the oldest projects in our sample – i.e., those built from 1998-2004 – although the sample size after year 4 is rather limited for these earliest projects. This upward trend is consistent with Bloomberg NEF (2016c) data showing that O&M contract renewals are more expensive than initial service agreements. In addition, the figure shows that projects installed more recently (from 2005–2008 and/or 2009-2014) have had, in general, lower O&M costs than those installed in earlier years (from 1998–2004), at least for the first 10 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 2009-2014 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 46. Median annual O&M costs by project age and commercial operation date

As indicated previously, the data presented in Figures 45 and 46 include only a subset of total operating expenses. In comparison, the financial statements of EDP Renováveis (EDPR), a public company that owned more than 4 GW of U.S. wind project assets at the end of 2015 (all of which has been installed since 2000), indicate markedly higher total operating costs.[58] Specifically, EDPR (2016) reported total operating expenses of $25.5/MWh for its U.S. wind project portfolio in 2015[59] – i.e., more than twice the ~$10/MWh average O&M cost reported above for the 93 projects in the Berkeley Lab data sample installed since 2000.

This disparity in operating costs between EDPR and the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, EDPR breaks out its total U.S. operating costs in 2015 ($25.5/MWh) into three categories: supplies and services, which "includes O&M costs" ($13.5/MWh); personnel costs ($4.0/MWh); and other operating costs, which "mainly includes operating taxes, leases, and rents" ($7.9/MWh). Among these three categories, the $13.5/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).

[58] Past editions of this report also reported O&M costs for Infigen, but in October 2015 Infigen's U.S. wind assets were sold to a privately held company that does not file public financial statements.

[59] Though not entirely clear, EDPR's reported operating expenses may exclude any repair or replacement costs that have been capitalized rather than expensed.

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 387 PPAs totaling 34,558 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation later in 2016 or 2017. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs), and most of them have a utility as the counterparty.[60]

Except where noted, PPA prices are expressed throughout this chapter on a levelized basis over the full term of each contract, and are reported in real 2015 dollars.[61] Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.[62] 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[63]) and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs.

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[60] Though we do have pricing details for some PPAs with corporate off-takers, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a "contract for differences" with the corporate off-taker around an agreed-upon strike price. Because the strike price is not directly linked to the sale of electricity, it is rarely disclosed (at least through our traditional sources, like regulatory filings). Though only a minor omission at present, this distinction could limit our sample more severely in the future if the popularity of corporate offtake agreement continues to grow at its current pace.

[61] 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 34 years, with 20 years being by far the most common (at 58% of the sample; 89% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 7% real discount rate.

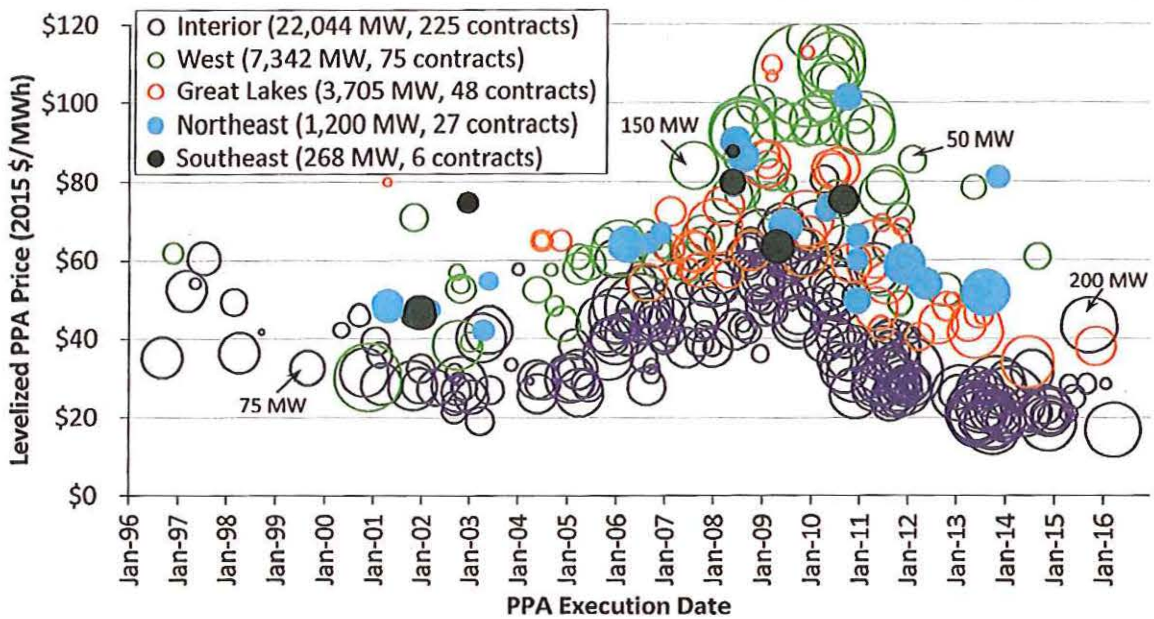
[62] Generation weighting is based on the empirical project-level performance data analyzed earlier in this report and assumes that historical project performance (in terms of annual capacity factor as well as daily and/or seasonal production patterns where necessary) will hold into the future as well. 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).

[63] The estimated levelized PPA price impact of ~$15/MWh is less than the PTC's 2015 face value of $23/MWh for several reasons. First, the PTC is a 10-year credit, whereas most PPAs are for longer terms (e.g., 20 years). Second, the PTC is a tax credit, and must be converted to pre-tax equivalent terms before being compared to PPA prices. Finally, the presence of the PTC constrains financing choices for many wind project owners and drives up the project's weighted average cost of capital. In other words, if not for the PTC, projects could be financed more cheaply; this difference in the weighted average cost of capital with and without the PTC erodes some of the PTC's value (for more information, see Bolinger (2014)).

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to wholesale power prices, and compared to future natural gas prices. In addition, REC prices are presented in a text box on page 67.

Wind PPA prices remain very low

Figure 47 plots contract-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).[64] This trend is particularly evident within the Interior region, which—as a result of its low average project costs and high average capacity factors shown earlier in this report—also tends to be the lowest-priced region over time. Prices generally have been higher in the rest of the United States.[65]



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

Source: Berkeley Lab

Figure 47. Levelized wind PPA prices by PPA execution date and region

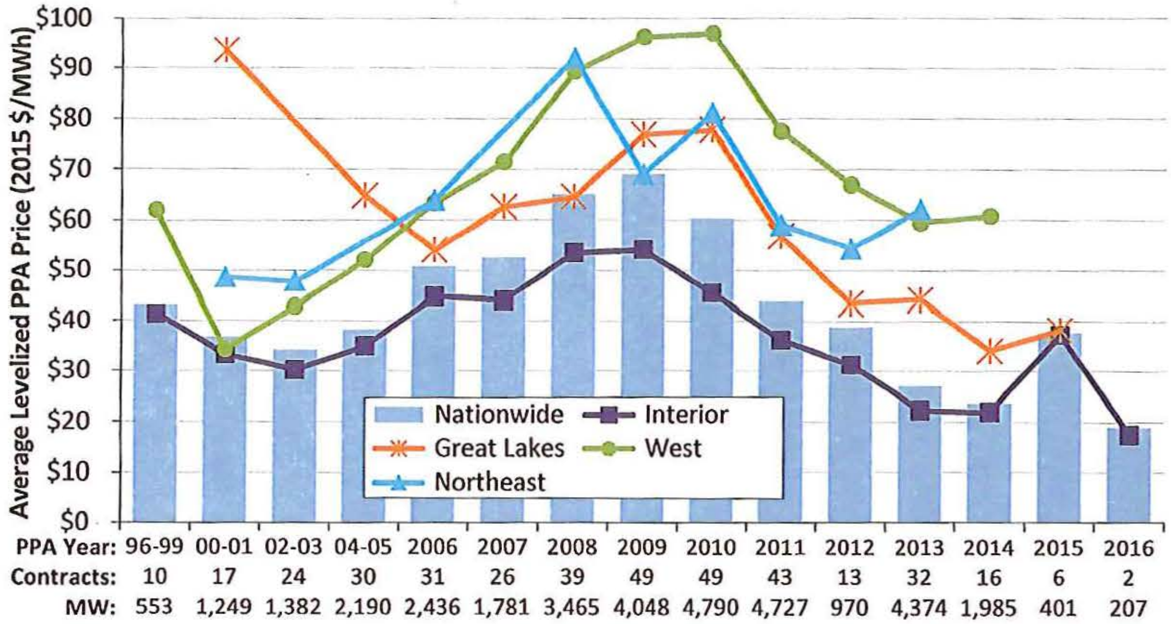
Figure 48 provides a smoother look at the time trend nationwide (the blue columns) by averaging the individual levelized PPA prices shown in Figure 47 by year. After topping out at nearly $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to around the $20/MWh level—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced

[64] Roughly 99% of the contracts that are depicted in Figure 47 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.

[65] Regional differences can affect not only project capacity factors (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region's physical geography, population density, labor rates, or even regulatory processes). It is also possible that regions with higher wholesale electricity prices or with greater demand for renewable energy will, in general, yield higher wind energy contract prices due to market influences.

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. The temporary price spike among PPAs signed in 2015 is attributable to a small sample (just six projects totaling 401 MW) that is dominated by two higher-priced contracts totaling 300 MW, one of which is located in the Interior region but is selling into California (which perhaps explains the higher price).

The trend of rising PPA prices from 2003 to 2009 and then falling prices since then is directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent project vintages, as documented in Chapter 5. This combination of declining costs and improved performance (along with historically low interest rates, as shown earlier in Figure 17) has enabled wind PPA prices to fall to today's record-low levels.



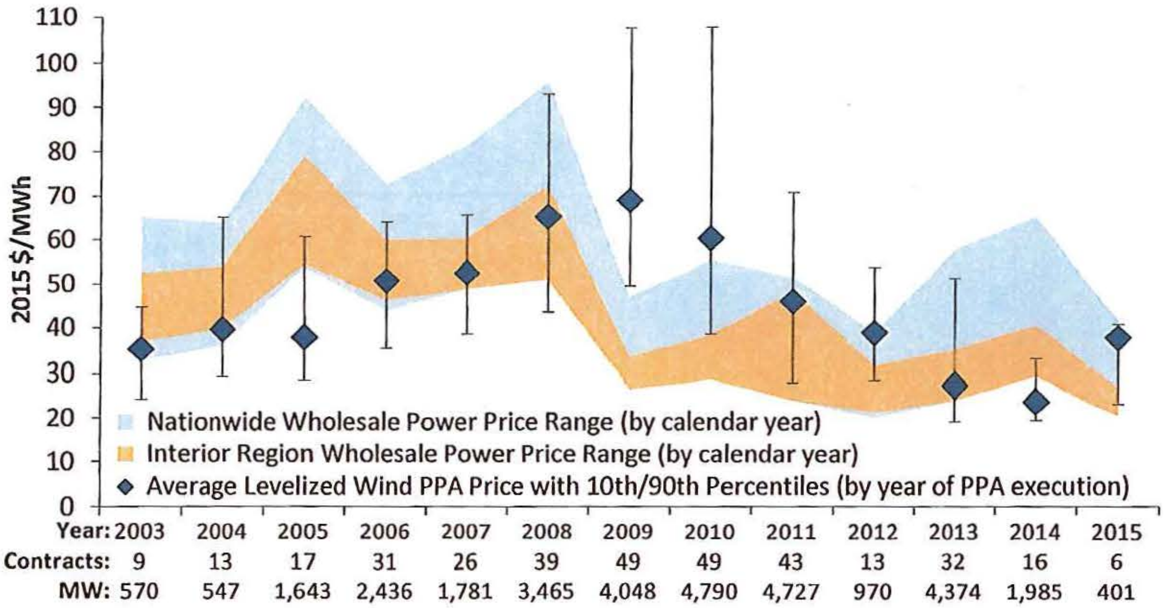
Source: Berkeley Lab

Figure 48. Generation-weighted average levelized wind PPA prices by PPA execution date and region

Figure 48 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 48 owing to its small sample size). Figures 47 and 48 both demonstrate that, based on our contract sample, PPA prices are generally low in the U.S. Interior, high in the West, and moderate in the Great Lakes and Northeast regions. As shown by the close agreement between the two, the large Interior region—where much of U.S. wind project development occurs—dominates the nationwide sample, particularly in recent years.

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 10^{th} and 90^{th} percentiles) in the years in which contracts were executed (consistent with the nationwide averages presented in Figure 48).



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.

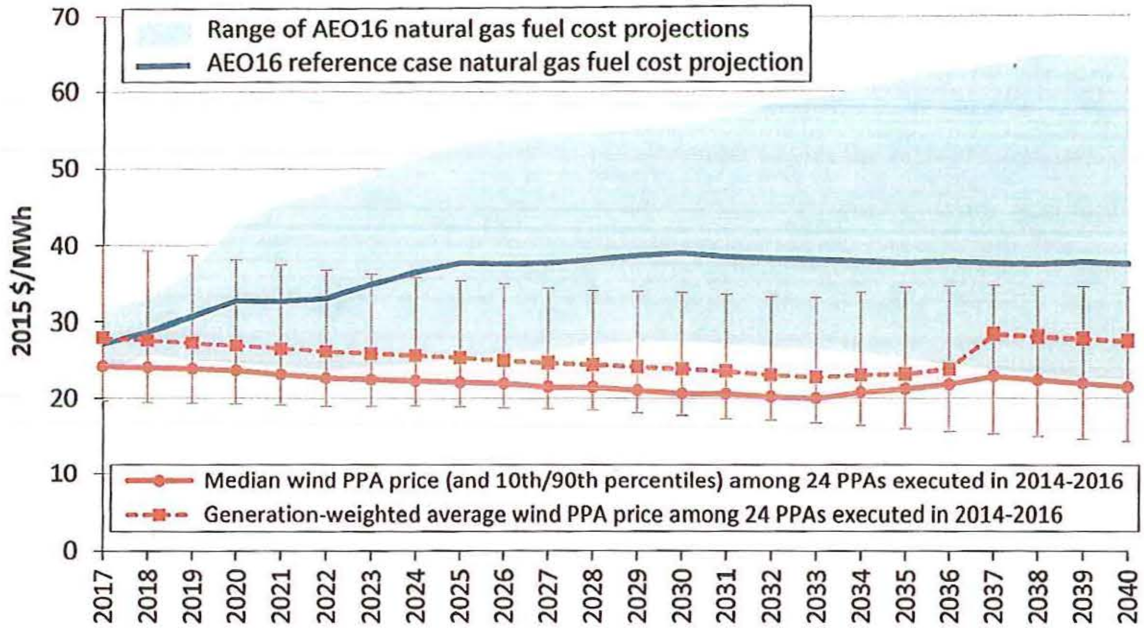
nationwide basis. Wind PPA prices have since fallen, however, and in 2011 and 2012 reconnected with the upper end of the wholesale power price range. In 2013 and 2014, further PPA price declines, along with a bit of a rebound in wholesale prices, put wind back at the bottom of the range once again. Subsequently, 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 10^{th} to 90^{th} 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 10^{th}, 50^{th}, and 90^{th} 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 90^{th} 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.

[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).



Source: Berkeley Lab, EIA

Figure 50. Wind PPA prices and a natural gas fuel cost projections by calendar year over time

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. Among the various shortcomings of comparing wind PPA and wholesale power prices in this manner are the following:

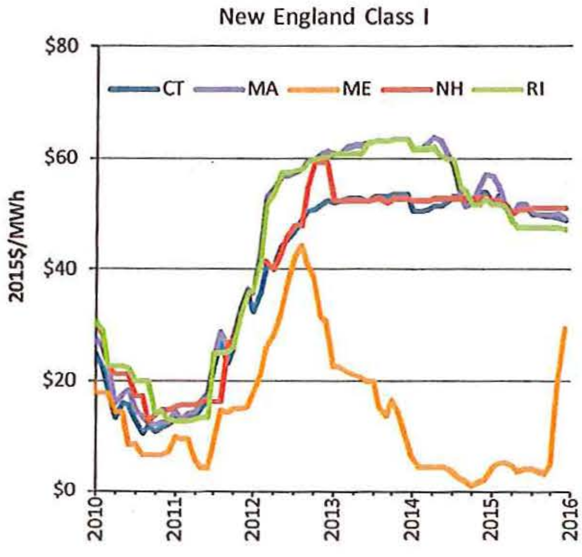
- Wind PPA prices are reduced by virtue of federal and, in some cases, state tax and financial incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by virtue of any financial incentives provided to fossil-fueled generation and its fuel production, as well as by not fully accounting for the environmental and social costs of fossil generation.
- Wind PPA prices do not fully reflect integration, resource adequacy, or transmission costs, while wholesale electricity prices (or fuel cost projections) also do not fully reflect transmission costs, and may not fully reflect capital and fixed (or variable) operating costs.
- Wind PPA prices—once established—are fixed and known, whereas wholesale electricity prices are short-term and therefore subject to change. As shown in Figure 50, EIA projects natural gas prices to rise from current levels, resulting in an increase in wholesale electricity prices.
- The location of the sampled 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. Especially at higher penetrations and in locations where wind generation profiles are poorly correlated with local load profiles, excessive wind generation during times of peak output and/or low load can push the wholesale market value of wind power well below that of a flat block of power.

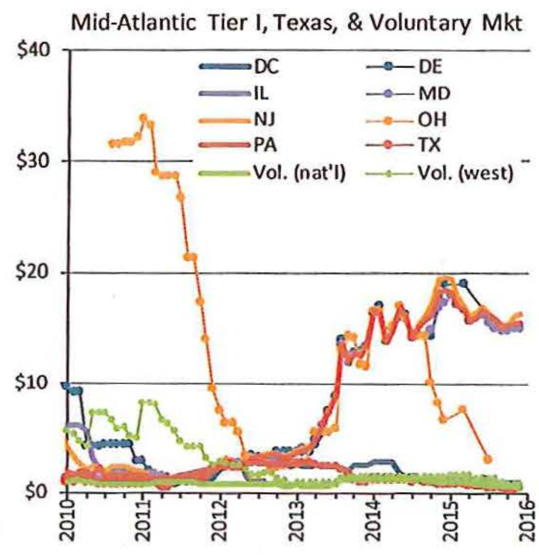
In short, comparing levelized long-term wind PPA prices with either yearly wholesale electricity prices or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to its competition. Nonetheless,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

REC Prices Remained Near "Alternative Compliance Payment" Levels in the Northeast, While Falling 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, though prices within regional power markets (New England and the Mid-Atlantic) are linked to varying degrees. In New England compliance markets (other than Maine), REC prices in 2015 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, falling modestly over the course of the year. 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.





Notes: Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded.

Source: Marex Spectron.

8. Policy and Market Drivers

A long-term extension and phase down of federal incentives for wind projects is leading to a resurgent domestic market

Various policy drivers at both the federal and state levels, as well as federal investments in wind energy research and development (R&D), have been important to the expansion of the wind power market in the United States. At the federal level, the most important policy incentives in recent years have been the PTC (or, if elected, the ITC) and accelerated tax depreciation.

Initially established in 1994, the PTC provides a 10-year, inflation-adjusted credit that stood at $23/MWh in 2015 (Table 5). 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) during 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 2015, Congress passed a long term, 5-year extension of the PTC (or, if elected, the ITC). To qualify, projects must begin construction before January 1, 2020. Moreover, 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. This new guidance lengthened the "safe harbor" completion period from the previous term of two years.

In extending the PTC, Congress also put the wind industry on a glide path to a lower PTC, with a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC will phase down in 20%-per-year increments for projects starting construction in 2017 (80% PTC value), 2018 (60%), and 2019 (40%).

In addition to the PTC, a second form of federal tax support for wind is accelerated tax depreciation, which historically has enabled wind project owners to depreciate the vast majority of their investments over a 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 is leading a resurgence of the U.S. wind power market, with solid continued growth in capacity additions expected over the next five years. The PTC phase down, on the other hand, imposes longer-term risks. Potentially helping to partially fill that void are the prospective impacts of more-stringent EPA environmental regulations on fossil plant retirement, energy costs, and demand for clean energy—which may create new opportunities for wind in the longer term. Of note are the actions to address carbon emissions that have been initiated at the EPA through the Clean Power Plan, though those regulations remain in limbo as legal challenges are resolved. Finally, R&D investments by the DOE continue, and could further reduce the cost of wind energy.

Table 5. History of the Production Tax Credit Extensions

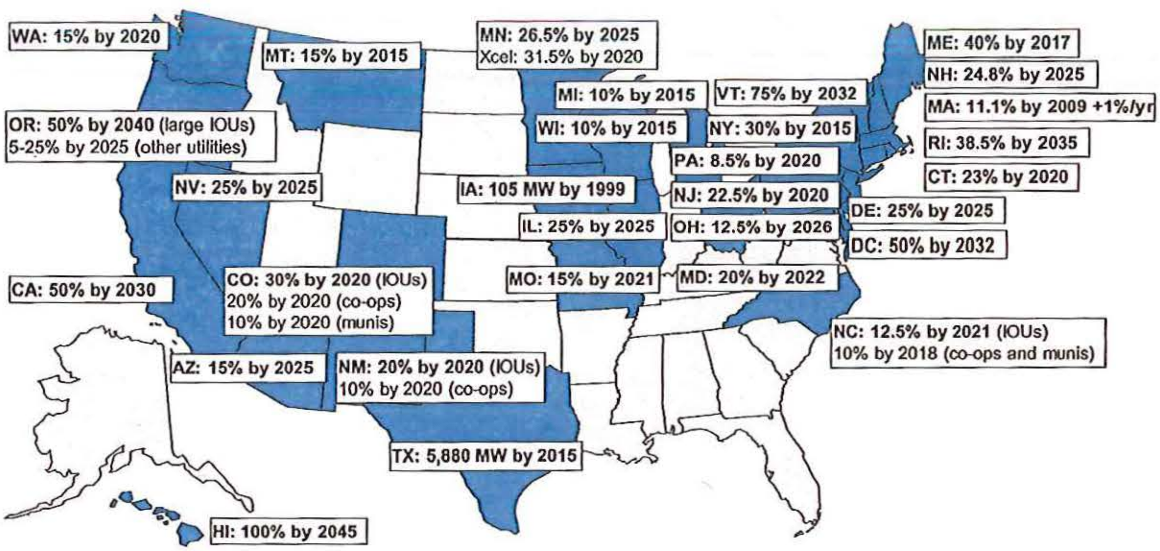
Legislation	Date Enacted	Start of PTC Window	End of PTC Window	Effective PTC Planning Window (considering lapses and early extensions)
Energy Policy Act of 1992	10/24/1992	1/1/1994	6/30/1999	80 months
Ticket to Work and Work Incentives Improvement Act of 1999	12/19/1999 *(lapsed for >5 months)*	7/1/1999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

Notes: Although the table pertains only to PTC eligibility, the *American Recovery and Reinvestment Act of 2009* enabled wind projects to elect a 30% investment tax credit (ITC) in lieu of the PTC starting in 2009; though it is rarely used, this ITC option has been included in all subsequent PTC extensions (and will follow the same phase down schedule as the PTC, as noted in the table: from 30% to 24% to 18% to 12%). Section 1603 of the same law enabled wind projects to elect a 30% cash grant in lieu of either the 30% ITC or the PTC; this option was only available to wind projects that were placed in service from 2009-2012 (and that had started construction prior to the end of 2011), and was widely used during that period. Finally, beginning with the *American Taxpayer Relief Act of 2012*, which extended the PTC window through 2013, the traditional "placed in service" deadline was changed to a more-lenient "construction start" deadline, which has persisted in the two subsequent extensions. Related, the IRS initially issued safe harbor guidelines providing projects that meet the applicable construction start deadline up to two full years to be placed in service (without having to prove continuous effort) in order to qualify for the PTC. In May 2016, the IRS lengthened this safe harbor window to four full years.

Source: Berkeley Lab

State policies help direct the location and amount of wind power development, but 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.

eligible renewable generation capacity needed to meet RPS demand in 2030.[69] Given current renewable energy supplies available for RPS compliance, Berkeley Lab estimates that existing state RPS programs will require roughly 55 GW of renewable capacity additions by 2030, relative to the installed base at year-end 2015.[70] This equates to an average annual build-rate of roughly 3.7 GW per year, not all of which will be wind. This is below the average of 6.6 GW of wind power capacity added in each year over the past decade, and even further below the average 9.5 GW per year of total renewable generation capacity added during that time frame.

In addition to state RPS policies, utility resource planning requirements, principally in Western and Midwestern states, have spurred wind power additions in recent years. So has voluntary customer demand for "green" power (see box below 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 implementing and enforcing carbon reduction policies in some states and regions. The Northeast's Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy, for example, has been operational for a number of 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 through the Clean Power Plan, and the role that RPS programs will play in achieving carbon emissions targets, both remain unclear.

[69] Berkeley Lab's projections of new renewable capacity required to meet each state's RPS requirements assume different combinations of renewable resource types for each RPS state. Those assumptions are based, in large part, on the actual mix of resources currently used or under contract for RPS compliance in each state or region. To the extent that RPS requirements are met with a larger proportion of high-capacity-factor resources than assumed in this analysis, or are met with biomass co-firing at existing thermal plants, the required new renewable capacity would be lower than the projected amount presented here.

[70] This estimate of required renewable electricity capacity additions is derived by comparing, on a region-by-region basis, the total amount of renewable capacity required for RPS demand in 2030 to the current installed base of renewable capacity deemed "available" for RPS compliance. Individual renewable generation facilities are deemed available for RPS compliance if they are currently under contract to LSEs with RPS obligations or if the energy is sold on a merchant basis into regional power markets with active RPS obligations. This analysis ignores several complexities that could result in either higher or lower incremental capacity needs, including: retirements of existing renewable capacity, constraints on intra-regional trade of renewable energy and RECs, and the possibility that resources currently serving renewable energy demand outside of RPS requirements (e.g., voluntary corporate procurement) might become available for RPS demand in the future.

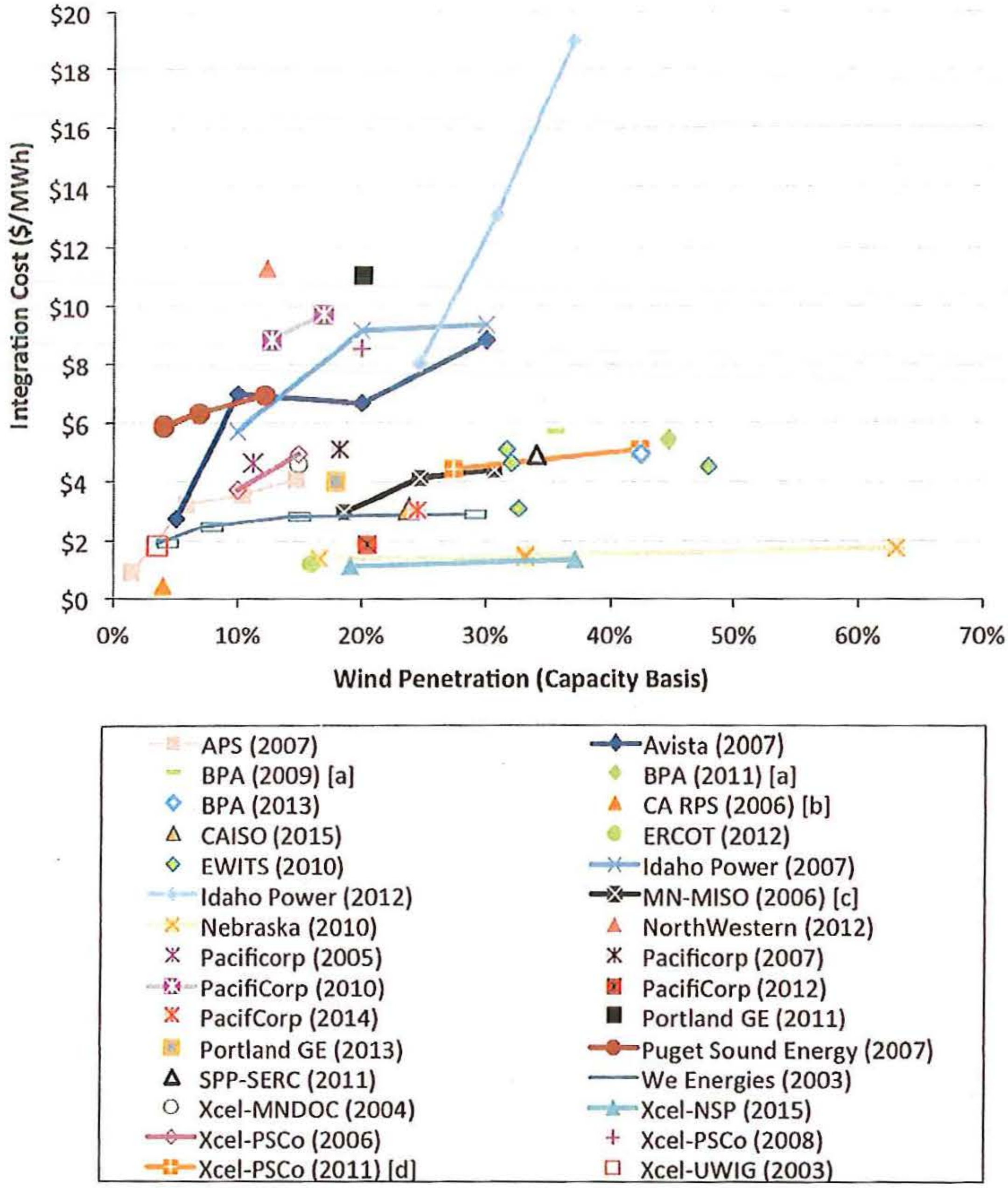
System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain

Wind energy output is variable and often the areas with the best wind speeds are distant from load centers. As a result, integration with the power system and provision of adequate transmission capacity are particularly important for wind energy. Concerns about, and solutions to, these issues 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).

Figure 52 provides a selective listing of estimated wind integration costs at various levels of wind power capacity penetration from studies completed from 2003 through 2015. With one exception, 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 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 output forecasting details, and the degree to which thermal power plant cycling costs are included.[71]

Two new integration cost studies were completed in 2015: one for Northern States Power (NSP) in Minnesota as part of the Xcel-Minnesota integrated resource plan (NSP 2015), and one for the California IOUs as part of the Long Term Procurement Planning process (SCE 2015). The NSP integration costs of $1.1–1.34/MWh in the most recent study are lower than the costs in previous studies in Minnesota due to the more-sophisticated operating practices currently employed by MISO than assumed in previous studies. The costs are primarily due to cycling coal and managing day-ahead forecast errors. The $3.10/MWh integration cost for wind in California is an estimate of the marginal integration cost to accommodate more wind than already planned to meet the 33% RPS. Subsequent analysis by the authors, however, found that the estimates were unreliable largely due to methodological challenges in estimating integration costs (SCE 2016).

[71] Caveats on the interpretation and comparability of these costs discussed in previous versions of this report still apply here.



Notes: [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). Listed below the figure 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 studying wind integration costs, system operators and planners continue to make progress integrating wind into the power system. Strategies for reducing the challenges with wind integration include improved integration of wind into markets and improved coordination between balancing authorities:

- A recent wind integration study by the Southwest Power Pool (SPP 2016a) examined a scenario with enough wind to a have 60% instantaneous wind penetration. Even with additional transmission investments, significant wind curtailment was required to re-dispatch generation around contingency constraints. The study found that curtailment of wind could be substantially reduced if a greater share of wind participated in the market as a dispatchable variable energy resource, and recommended acceleration of certain transmission upgrades.
- ISO-NE is implementing a program to provide dispatch signals to wind generators through a "Do Not Exceed" dispatch program. The signal represents the maximum generation that can be accepted by each wind plant without affecting reliability. Similar to SPP findings, using this signal to control wind will lower overall wind curtailments and increase utilization of the transmission system.
- MISO incorporated a ramp product into its market operations to better manage uncertainty and variability—from wind, in some cases—and to provide a clear price signal for the value of flexible generation.
- In part due to growing shares of wind energy, ERCOT has proposed revisions to its ancillary service markets to unbundle different products and fine-tune requirements to match system conditions and resource capabilities. An economic analysis indicates that the improvements in market design could create benefits on the order of $200 million over the next ten years (Newell et al. 2015).
- In June 2015, SPP began providing balancing services to the Western Area Power Administration's Upper Great Plains Region (WAPA-UGP), Basin Electric Power Cooperative and Heartland Consumers Power District. In October, the three utilities transferred control of their transmission system to SPP. WAPA-UGP is the first federal power marketing administration to become a full member of a regional transmission organization (RTO).
- The western Energy Imbalance Market (EIM) now includes the CAISO, PacifiCorp, and NV Energy. The EIM allows for increased transfers between the participating balancing authorities and it increases diversity of resources. As of the first quarter of 2016, the EIM was averaging $6.3 million per month in consumer benefits and was reducing renewables curtailment by an average of 38 GWh/month (CAISO 2016). Work is underway to integrate Puget Sound Energy, Arizona Public Service, Portland General Electric, and Idaho Power into the EIM. In addition, PacifiCorp is exploring the prospect of becoming a full participating transmission owner within the CAISO, though the governance structure for a multi-state ISO is likely to be the key issue.
- A flexibility assessment of the Western Interconnection found that it is technically feasible to obtain 40% of energy from renewables, though with increasing curtailment. Increased regional coordination of balancing areas and measures that increase load during times when curtailment would occur, such as charging energy storage, can lower the amount of curtailment (E3 2015).

Recent studies of wind integration have sometimes focused on conditions that are likely to be the most challenging. For example, a recent GE transient stability[72] study focused on spring light load, high wind periods in Wyoming when most of the region's synchronous generators will be

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

offline (Miller et al. 2015). Maintaining stability after a major disturbance, like the loss of a large transmission line, will be challenging in some extreme hours under weak system conditions. Achieving acceptable performance is found to require combinations of traditional mitigation strategies, including the potential need for transmission system improvements, and non-traditional wind power plant controls. The changes to wind plant controls would alter the low voltage power logic in a wind plant to suppress active current during severe faults.

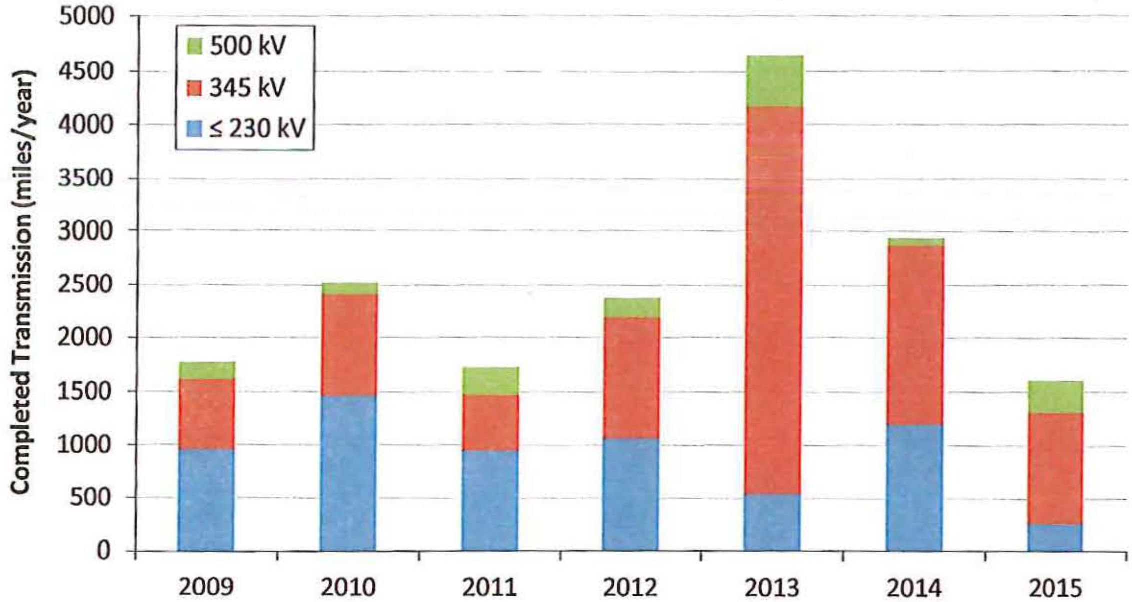
With growing shares of renewables and improvements to technology, wind is increasingly being asked to have the capability to supply grid services:

- FERC eliminated the exemption for asynchronous generators to provide reactive power for new interconnection requests in the pro forma Large Generator Interconnection Agreement (LGIA) and the Small Generator Interconnection Agreement (SGIA) (FERC 2016a). FERC cites the technological advances in inverters that make it inexpensive for new wind projects to be able to provide this function. FERC held a technical conference on compensation for reactive power supply in ISO markets in June 2016.
- FERC also released a Notice of Inquiry soliciting comments on whether the LGIA and SGIA should be revised to require all new generation resources to have frequency response capabilities as a precondition of interconnection (FERC 2016b). In addition, they asked whether existing resources should be required to have primary frequency response capabilities and arrangements for the provision and compensation of primary frequency response. FERC noted that ERCOT, ISO-NE, and PJM already require new generators, including wind in some cases, to have primary frequency response capabilities.
- NERC's Essential Reliability Services Task Force, noting a changing generation resource mix that includes more non-synchronous generation, recommends that all new resources have the capability to support voltage and frequency (NERC 2015).

It is also clear that transmission expansion helps to manage increasing wind energy:

- The recent wind integration study by SPP (SPP 2016a) confirmed the need for transmission projects already identified in the integrated transmission planning process and discovered additional transmission needs beyond the approved projects. Further, some of the approved transmission projects should be expedited so that the projects can be placed in-service sooner than originally scheduled. A separate study by SPP found that 348 transmission upgrades constructed between 2012 and 2014 will provide more than $16 billion in benefits over a 40-year period (SPP 2016b).
- The NSP wind integration study (EnerNex 2014) found that existing wind curtailment in the region is almost all due to transmission congestion. Wind curtailment is expected to be considerably lower after planned regional transmission solutions—identified through the Multi-Value Project Portfolio Analysis—are put in place. Separately, MISO found that its Multi-Value Project, a series of transmission projects encompassing eight states, will have a benefit-to-cost ratio varying from 2.6 to 3.9 and create net benefits of $13.1 to $49.6 billion.

Transmission additions, however, slowed in 2015 compared to previous years. About 1,500 miles of transmission lines came online in 2015, the lowest amount since FERC began publishing this data in 2009 (see Figure 53). As of March 2016, FERC (2016c) estimates that another 14,000 miles of new transmission lines (or line upgrades) are proposed to come online by March 2018, with about 5,500 miles of those having a high probability of completion. The Edison Electric Institute (EEI), meanwhile, projects that transmission investment will amount to $22 billion in both 2016 and 2017 before falling to $20 billion in 2018 (EEI 2015a). EEI states that 46 percent of the transmission projects it is tracking will, at least in part, support the integration of renewable energy (EEI 2015b).



Source: FERC monthly infrastructure reports

Figure 53. Miles of transmission projects completed, by year and voltage

Three major transmission projects that will transport wind energy were completed in 2015, summarized in Table 6. Moreover, AWEA (2016a) has identified 15 additional near-term transmission projects that, if all were completed, could transmit 52.4 GW of additional wind capacity, as depicted in Table 7.

Table 6. Transmission Projects Completed in 2015

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
Maine Power Reliability Program	345, 115	2015	n/a
Most CapX Segments (MN, ND, SD, WI)	Mostly 345, some 230 and 165 lines	2014-16	2,000
Total Potential Wind Capacity			6,200

Source: AWEA (2016a)

Table 7. Planned Near-Term Transmission Projects and Potential Wind Capacity

Transmission Project Name (State)	Voltage (kilovolts)	Estimated In-service Date	Estimated Potential Wind Capacity, MW
Tehachapi Phases 2-3 (CA)	500	2016	3,800
MISO Multi-Value Projects (IA, IL, MI, MN, MO, ND, SD, WI)	345, one 765 line	2015-2020	14,000
Grand Prairie Gateway (IL)	345	2017	1,000
Nebraska City – Mullin Creek – Sibley (NE-MO; SPP Priority Project)	345	2017	(SPP Priority Project Component)
Southline Transmission Project (AZ, NM)	345, 230	2018	1,000
TransWest Express (WY)	600 DC	2018	3,000
Power for the Plains (NM, OK, TX)	115, 230, 345	2016-2020	n/a
Clean Line Projects (AZ, IA, KS, NM, OK)	600 DC	2018-2020	16,000
Pawnee – Daniels Park (CO)	345	2019-2020	500
Gateway West (ID, WY)	500	2019-2021	3,000
Sunzia (AZ, NM)	500	2020	3,000
Boardman-Hemingway (ID, OR)	500	2020	1,000
Gateway South (WY, UT)	500	2020-2022	1,500
SPP 2012 ITP10 Projects (KS, MO, OK, TX)	345	2018-2022	3,500
Total Potential Wind Capacity			**52,400**

Source: AWEA (2016a)

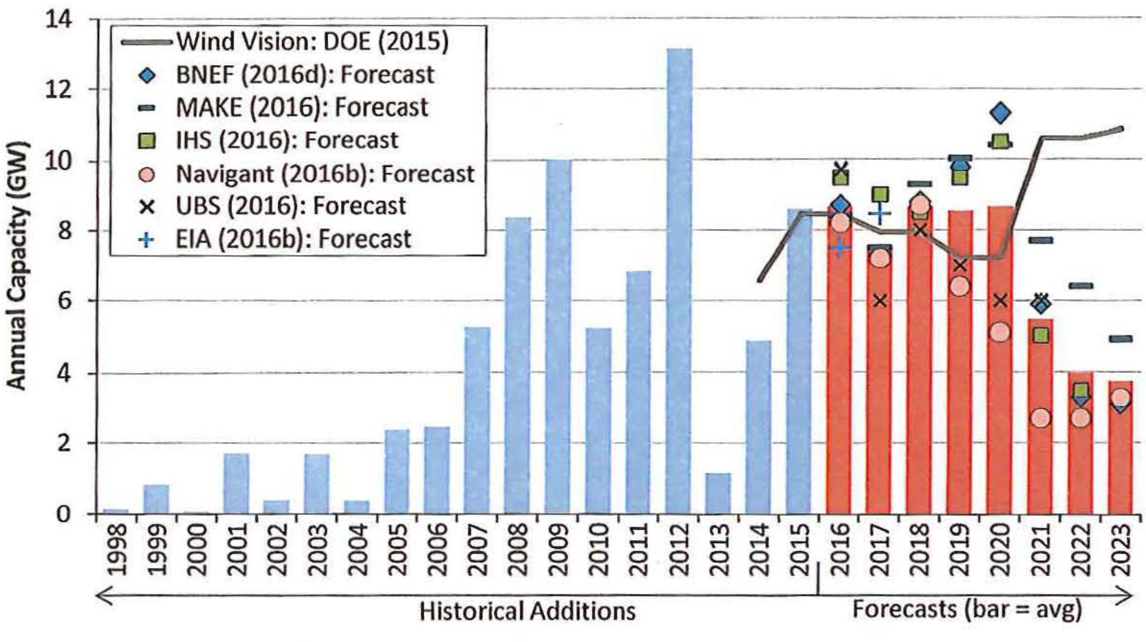
FERC held a technical conference in June 2016 to review the implementation of Order 1000, which was intended to improve intra- and inter-regional transmission planning and cost allocation. Order 1000 requires public utility transmission providers to: participate in a regional transmission planning process; establish procedures to identify transmission needs driven by public policy requirements; and coordinate with neighboring planning regions to solve mutual transmission needs (FERC 2011). Recent literature has suggested that Order 1000 needs to be re-examined. A 2015 report found that most transmission investments are based on meeting reliability needs, and that the increased market efficiency and economic benefits of transmission are not evaluated comprehensively in transmission plans. That same study found that inter-regional transmission planning is still very much in its infancy and has not resulted in identifying viable inter-regional transmission projects (Pfeifenberger et al. 2015). Others note that Order 1000 has resulted in a wide variance of cost allocation methodologies because FERC left cost allocation to RTOs and individual transmission owners (Edelston 2015).

Transmission also figured prominently in two legal proceedings. The Seventh Circuit Court of Appeals upheld FERC's requirement in Order 1000 that transmission owners remove the right-of-first-refusal provisions for building new transmission from their transmission tariffs (U.S. Court of Appeals 2016). In April 2016, DOE announced it will use its authority under Section 1222 of the Energy Policy Act of 2005 (EPAct) to participate in the development of a planned Clean Line Energy Partners LLC transmission project, known as the Plains and Eastern project, that would stretch from western Oklahoma to eastern Arkansas (DOE 2016). If developed, the project could transmit up to 4,000 MW. This is the first time that the DOE is utilizing its authority under EPAct to participate in the development of a transmission project.

9. Future Outlook

With the 5-year extension of the PTC signed in December 2015 and IRS guidance allowing a safe-harbor period of 4 years in which to complete construction, but with progressive reductions in the value of the credit for projects starting construction after 2016, annual wind power capacity additions are projected to continue at a rapid clip for several years, before declining. 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 play important roles as well, as might utility action to proactively get out ahead of possible future CPP compliance obligations.

Among the forecasts for the domestic market presented in Figure 54, expected capacity additions average more than 8,000 MW/year from 2016 to 2020, somewhat higher than the pace of growth witnessed since 2007. With AWEA (2016b) reporting that more than 15,000 MW of wind power were under construction or at an advanced stage of development at the end of the first quarter of 2016, the industry appears to be on track to meet these expectations at least in the early years.



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

Figure 54. Wind additions: historical installations, projected growth, DOE *Wind Vision* report

Forecasts for 2021 to 2023 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 renewable energy 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, declines in the price of wind energy over the last half decade have been substantial, helping to improve the economic position of wind even in the face of low natural gas prices. The potential for continued technological advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and state RPS requirements. EPA's Clean Power Plan, depending on its ultimate fate, may also create new markets for wind. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse underlying potential trends, wind capacity additions, especially after 2020, remain deeply uncertain.

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 54 are the annual gross wind additions from 2014 through 2023 analyzed by the DOE in order to ultimately reach those percentage targets. As shown, actual and projected wind additions from 2014 through 2020 are consistent with the pathway envisioned in the DOE report. Projected growth from 2021 through 2023, however, is well below the *Wind Vision* pathway. 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 (2016a). 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 ABB 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 2015 annual) wind power capacity data come from Navigant (2016a) 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 (2016a), 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 2015, 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, but as yet built, at the end of 2015 are included. Suspended projects are not included in these listings. Data on projects that are in the nearer-term development pipeline comes from ABB (2016), AWEA (2016b), and EIA (2016c).

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) and AWEA (2016a), while U.S. tower and blade manufacturing capability come from AWEA (2016a). 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 they can be obtained from the USITC's DataWeb (http://dataweb.usitc.gov/). 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	2005-2015	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	2011-2015	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	2012–2015	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	2012–2015	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	2012–2015	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014-2015	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[73]

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 for all HTS codes considered, except for nacelles shipped under 8503.00.9560. For nacelles, the variation applied is ±50% of the total estimated wind import value under HTS code 8503.00.9560.

[73] This was effective in 2014 as a result of Customs and Border Protection ruling number HQ H148455 (April 4, 2014). That ruling stated that nacelles alone do not constitute wind-powered generating sets, as they do not include blade assembly which are essential to wind-powered generating sets as defined in the HTS.

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from AWEA and Chadbourne and Park LLP. 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. The data include only projects with turbines greater than or equal to 50 kW that began operation in 1998 through 2015. Some turbines—especially in 2015—have not been rated within a numerical IEC Class, but are instead designated as Class "S," for special. In such instances, they were not included in the reported average fleet-wide IEC class over time. 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 (FAA) Digital Obstacle (i.e., obstruction) files (accessed via ABB Ventyx' Intelligent Map) and FAA Obstruction Evaluation files 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 41,149 turbines of the 41,999 installed from 1998 through 2014 in the continental United States over that period, or 98%.

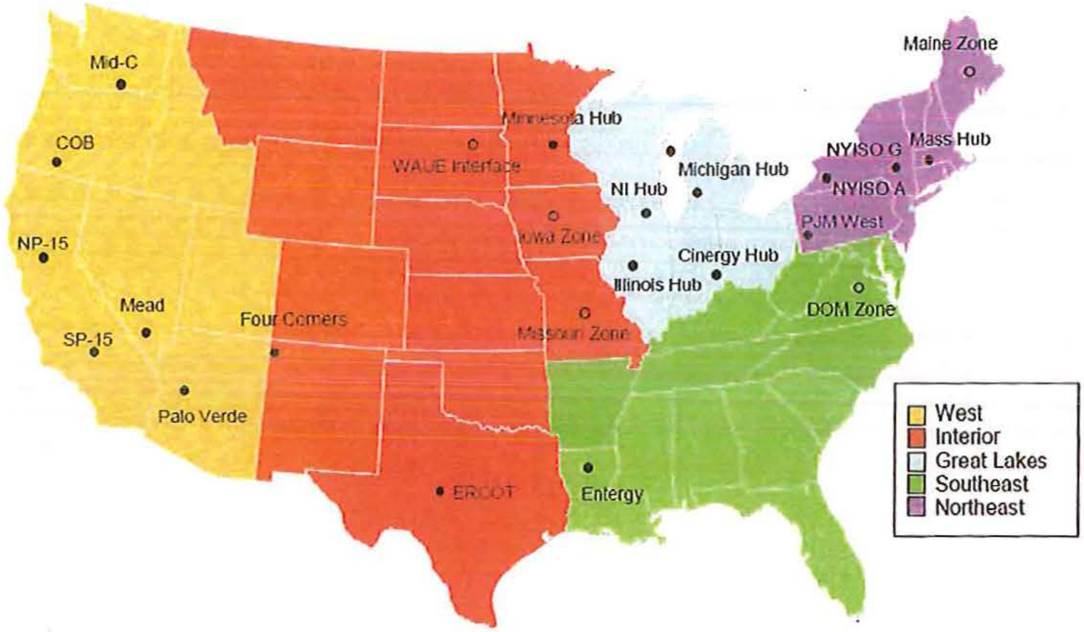
Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange

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 Intercontinental Exchange (ICE) as well as ABB 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, the reference case fuel cost projection from the EIA's *Annual Energy Outlook 2016* is converted from \$/MMBtu into \$/MWh using a heat rate of 7 MMBtu/MWh. 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 55. Map of regions and wholesale electricity price hubs used in analysis

Policy and Market Drivers

The wind energy policy and grid 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 WEBSITES

U.S. DEPARTMENT OF ENERGY WIND PROGRAM
energy.gov/eere/wind

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-area/clean-energy

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
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FOR MORE INFORMATION ON THIS REPORT, CONTACT:

Ryan Wiser, Lawrence Berkeley National Laboratory
510-486-5474; RHWiser@lbl.gov

Mark Bolinger, Lawrence Berkeley National Laboratory
603-795-4937; MABolinger@lbl.gov

On the Cover
Portland General Electric Tucannon Wind Farm
Photo by Josh Bauer/NREL 38025

2015 WIND TECHNOLOGIES MARKET REPORT

For more information, visit:
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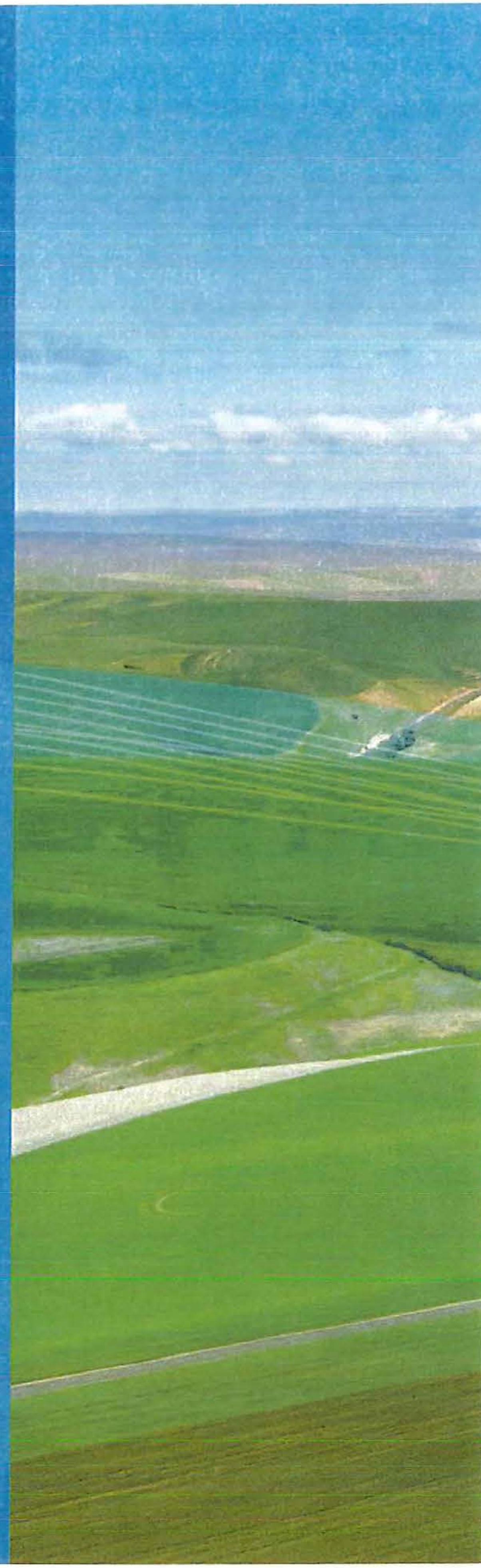
Energy Efficiency & Renewable Energy



Westar Energy.

Westar Energy breaks ground on Western Plains wind farm.

Topeka, Kan., April 12, 2016 – Westar Energy welcomed local leaders and landowners Monday to break ground and celebrate as construction begins on the 280 megawatt Western Plains Wind Farm near Spearville.

"We are committed to modernizing the power supply that serves our customers, and wind energy has an important role. We believe that using a variety of generation sources – traditional fossil fuel plants, nuclear, and renewable wind and solar – all working together is the best way to keep energy prices low, make sure electricity is there when our customers need it and care for the environment," John Bridson, senior vice president, generation and marketing, told the crowd of about 75 people.

Westar in collaboration with Infinity Wind Power will develop Western Plains Wind Farm in Ford County, Kan., which will bring Westar's renewable energy total to more than 1,700 megawatts when it's online early next year. Westar selected turbines from Siemens, key components of which will be assembled in the Siemens facility in Hutchinson, Kan. Mortensen Construction will build the wind farm. Representatives from Infinity, Siemens and Mortenson, also welcomed the crowd.

The Western Plains Wind Farm will stimulate economic development in Ford County through land lease royalties paid to local landowners and payments to local and county government, expected to be about $75 million during the first 20 years of operation. Additionally, this project creates more than 200 construction jobs, followed by about three dozen permanent jobs, and involving $435 million capital investment.

Download Photo
Photo caption: From left, Tom Kristensen, construction executive, Mortensen Construction, John Bridson, senior vice president, generation and marketing, Westar Energy, Eli Bosco, vice president, project development, Infinity Wind Power, and Dave Lucas, regional vice president, Midwest field sales, Siemens Power Systems.

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Westar Energy, Inc. (NYSE: WR) is Kansas' largest electric utility. For more than a century, we have provided Kansans the safe, reliable electricity needed to power their businesses and homes. Every day our team of professionals takes on projects to generate and deliver electricity, protect the environment and provide excellent service to our nearly 700,000 customers. Westar has 7,200 MW of electric generation capacity fueled by coal, uranium, natural gas, wind, sun and landfill gas. We are also a leader in electric transmission in Kansas. Our innovative customer service programs include mobile-enabled customer care, expanding use of smart meters and paving the way for electric vehicle adoption. Our employees live, volunteer and work in the communities we serve.

For more information about Westar Energy, visit us on the Internet at http://www.WestarEnergy.com. Westar Energy is on Facebook: www.Facebook.com/yourwestar and Twitter: www.Twitter.com/WestarEnergy.

Westar Energy breaks ground on Western Plains wind farm.

Media Contact:
Gina Penzig
Media Relations Manager
Phone: 785-575-8089
Gina.Penzig@westarenergy.com
Media line: 888-613-0003

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line.	)))))))	File No. EA-2016-0358

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the Cross-Surrebuttal Testimony of Matt Langley was served upon the parties to this proceeding by email this 21st day of February 2017.

/s/ Terri Pemberton
Terri Pemberton
Attorney for Infinity Wind Power