Benchmarking Wind Power Operating Costs in the United States:

Results from a Survey of Wind Industry Experts

Authors:

Ryan Wiser, Mark Bolinger, Eric Lantz[1]

[1] National Renewable Energy Laboratory

Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

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Abstract

This paper draws on a survey of wind industry professionals to clarify trends in the operational expenditures (OpEx) of U.S. land-based wind power plants. The paper also highlights key drivers of those trends. We find that average all-in lifetime OpEx has declined from approximately $80/kW-yr (~$35/MWh) for projects built in the late 1990s to a level that is approaching $40/kW-yr (~$11/MWh) for projects under construction in 2018. Turbine operations and maintenance (O&M) costs—inclusive of scheduled and unscheduled maintenance—represent the single largest component of overall OpEx and the primary source of cost reductions over the last decade. We observe wide ranges of OpEx over time; for example, survey respondents cite a range in average expected costs for projects commissioned between 2015 and 2018 from $33/kW-yr to $59/kW-yr. Notably, these broad ranges include high levels of variability in both turbine O&M costs and non-turbine OpEx. Potential technical and strategic drivers of this variability are highlighted. We also use historical OpEx learning rates, showing a 9% OpEx reduction for each doubling of global installed wind capacity, to project a further $5–$8/kW-yr (12%–18%) OpEx reduction from 2018 to 2040. When compared with the broader literature, these findings suggest that continued OpEx reductions may contribute 10% or more of the expected reductions in land-based wind's levelized cost of energy. Moreover, these estimates may understate the importance of OpEx owing to the multiplicative effects through which operational advancements influence not only O&M costs but also component reliability, performance, and plant-level availability—thereby affecting levelized costs though OpEx reduction and by enhancing annual energy production and plant lifetimes. Given the limited quantity and comparability of previously available OpEx data, the data and trends reported here may usefully inform OpEx assumptions used by electric system planners, analysts, modelers, and research and development managers. The results may also provide useful benchmarks to the wind industry, helping developers and asset owners compare their OpEx expectations with historical experience and other industry projections.

1 Introduction

The levelized cost of energy (LCOE) of wind power plants is driven by five primary parameters: upfront capital expenditures (CapEx), operational expenditures (OpEx), project performance, financing and tax assumptions, and project life. Among these factors, long-term OpEx has been understudied. While a robust and growing literature on turbine and component reliability exists (e.g., Echavarria et al. 2008; Spinato et al. 2009; Keller et al. 2016; Sheng 2017; Artigao et al. 2018), data on OpEx trends are limited.

More specifically, extensive literature on land-based wind CapEx has tracked trends over time and across countries (IRENA 2018; Wiser and Bolinger 2018; IEA Wind 2018), established data-driven cost-reduction trajectories based on learning curves (Wiser et al. 2011; Lindman and Söderholm 2012; Rubin et al. 2015; Samadi 2018), and developed engineering models to understand past and possible future cost-reduction options (Sieros et al. 2012). A growing literature also emphasizes improvements in wind project performance, especially as turbine rotor diameters and hub heights have increased (IRENA 2018; Wiser and Bolinger 2018). Facilitating the development of these literatures has been the availability of substantial project-level data on land-based wind CapEx and performance (IRENA 2018; Wiser and Bolinger 2017; IEA Wind 2018).

Project-level data on land-based wind plant OpEx, on the other hand, are not widely available (IRENA 2018; Wiser and Bolinger 2018; BNEF 2015a) owing to the proprietary nature of the data and the fact that lifetime OpEx data are only available after the full life of plants, which can be 20 years or more. Few plants have been operating for 20 years, and those that have are using turbine technology of vastly different scale and sophistication compared with modern projects. As a result, OpEx for early plants may not be relevant for estimating OpEx for newer plants (IRENA 2018; Wiser and Bolinger 2018; Poore and Walford 2008). A lack of standardization in both intra- and inter-firm data collection and management (e.g., limited tracking of specific costs that result from specific maintenance issues) has further hindered the development of OpEx datasets and intelligence (DNV KEMA 2018).

Even when wind OpEx data are available, they can be hard to interpret. In some cases, data are reported as actual realized costs; in other cases, as long-term cost expectations. The number of years covered by the data, relative to expected wind project life, may vary. Costs are often reported in $/kW-yr terms, but also as $/MWh, $/turbine, or $/project. Costs may vary by project size, location, and other factors. Turbine operations and maintenance (O&M) is sometimes contracted out to the turbine manufacturer or an independent service provider with varying servicing terms and durations. In other cases, O&M is self-provided by the wind plant owner. Turbines are typically under manufacturer warranty during the first years of operations, so costs due to unscheduled maintenance may be embedded in turbine purchase agreements, thereby reducing annual O&M costs for the project owner. Finally, a wide and diverse set of costs can be embedded within the OpEx category: turbine O&M (scheduled and unscheduled), balance of plant (BOP) O&M, land costs, property or other local taxes or payments, grid and electrical use, insurance, asset management and administration, and others. Less mature turbines have sometimes required extensive and costly in-field retrofits (e.g., gearboxes) due to premature component failures, which may or may not be considered part of OpEx. Absent clarity on what costs are included, establishing clean comparisons across various sources of OpEx data is impossible.

The result is not only a wide array of OpEx estimates in the literature but, more importantly, a general lack of fidelity and confidence in those estimates. Lacking solid data, for example, the U.S. Department of Energy and the National Renewable Energy Laboratory have assumed no change in land-based wind OpEx in the United States since 2014 (Stehly et al. 2017; DOE 2015). During the years leading up to 2014, their OpEx estimates rose as they were adjusted to account for anecdotal data suggesting that actual costs were higher than originally forecast, in part due to premature component failure for certain turbines (Tegen et al. 2013; DOE 2008). The U.S. Energy Information Administration has similarly assumed an increasing cost of wind plant OpEx in successive versions of its *Annual Energy Outlook* (e.g., EIA 2011, 2015, 2018), reflecting uncertainty in and lack of solid historical data on OpEx as well as recognition that realized OpEx was coming in higher than previous expectations.

Understanding past and current land-based wind plant OpEx is important for several reasons. First, OpEx represents a sizable and potentially growing share of LCOE, especially as wind's LCOE declines owing to lower upfront costs and better performance. Ten years ago, analysts often attributed up to 20%–25% of land-based wind LCOE to OpEx (Blanco 2009; EWEA 2009; Walford 2006), associating approximately half of OpEx directly with turbine O&M (Blanco 2009; DNV KEMA 2018). Recent data suggest that OpEx accounts for 25% to more than 35% of overall LCOE (IEA Wind 2018; Stehly et al. 2017).

Second, operational practices and OpEx have important connections to other parameters that influence wind's LCOE. Specifically, turbine O&M practices directly influence turbine component reliability and related downtime, turbine performance, and overall wind plant availability (Echavarria et al. 2008; Spinato et al. 2009; Keller et al. 2016; GL Garrad Hassan 2018; DNV KEMA 2018; Artigao et al. 2018; van Kuik et al. 2016), thereby affecting annual production and project lifetime. CapEx and OpEx are also related, because higher-cost, more reliable turbines may yield lower long-term OpEx, and vice versa.

Third, OpEx represents an important lever for wind plant LCOE reductions. IEA Wind (2018), for example, found that OpEx reductions accounted for 9%–11% of overall land-based wind LCOE reductions from 2008 to 2016 in Norway, Germany, and Denmark, 17% in Sweden, and 0% in Ireland. Wiser et al. (2016) reported on a survey of wind experts, who collectively anticipated that OpEx would decline 9%, on average, by 2030; the experts expected that the lower OpEx would account for 11% of the overall decline in land-based wind LCOE from 2014 to 2030, with plant lifetime extensions (related to OpEx, as noted above) accounting for another 14%. Dykes et al. (2017) forecasted a 25% reduction in OpEx for plants built in 2030, contributing to 13% of the projected overall LCOE reduction from 2015 to 2030; they also expected project lifetime extensions accounting for another 22% of the LCOE reduction.

Finally, OpEx for older plants can dictate the economics and timing of plant refurbishment and repowering, which are increasingly important as the wind fleet ages (Ziegler et al. 2018; Mertes and Milligan 2018; Rubert et al. 2018). Though past work has generally found OpEx decreasing over time—with new generations of wind technology—and with increasing turbine size, studies also show that OpEx can increase as projects age (Wiser and Bolinger 2018; IEA Wind 2018; Blanco 2009; EWEA 2009; BNEF 2018; Briggs 2017; Lemming et al. 1999; Rademakers et al. 2003; Vachon 2002; Hahn 1999; Lillian 2018).

Recognizing that wind plant OpEx is an important but sometimes overlooked driver of overall LCOE trends for land-based wind, this paper draws from a survey of senior members of the U.S. wind industry to clarify past and current trends in land-based wind OpEx as well as key drivers of those trends.[1] We supplement the survey with a review of literature containing empirical OpEx data for U.S. wind plants. We compare our resulting estimates for average OpEx with other U.S. and global OpEx benchmarks. Finally, we extrapolate historical data to estimate future land-based wind OpEx, and we compare those estimates of potential cost reductions with other recent assessments.

Our core contributions to the broader literature are twofold. First, using an industry survey methodology, we seek consistent historical and recent data on OpEx and clarity on the drivers of OpEx. Given the limited quantity and comparability of previously available data, the data and trends reported here may usefully inform OpEx input assumptions used by electric system planners, analysts, and modelers. The results may also provide useful benchmarks to the wind industry, helping developers and asset owners compare their OpEx expectations with historical experience and other industry projections. Second, we project future OpEx based on historical learning rates. To our knowledge, ours is the first attempt to document a learning rate for OpEx, and to use those findings to forecast a future range in OpEx. These results too may help inform planners, analysts, modelers, research and development managers, and others—and can be compared to and inform other attempts to project future wind power OpEx.

[1] Note that this paper focuses on land-based wind. Offshore wind faces higher OpEx given the uniquely challenging environmental in which offshore projects operate (Wiser et al. 2016; Stehly et al. 2017; IRENA 2018).

2 Survey Methods

We conducted the wind industry survey in mid-2018 via email and phone correspondence. We sought historical and recent quantitative data on all-in total OpEx for land-based wind projects in the United States, inclusive of costs related to scheduled and unscheduled maintenance, operations personnel, land leases, property taxes, and other operations activities. We also sought qualitative insights into OpEx drivers. We received responses from 11 wind developers/owners/financiers (out of 19 asked), two wind turbine manufacturers (out of five asked), and three consultants (out of five asked)—for an overall response rate of 55%, though some respondents offered only limited qualitative insight.

Recognizing that OpEx data are considered confidential and are not widely and consistently compiled, we sought—in effect—whatever data and insight we could obtain. By implication, we did not require respondents to fill out a highly standardized formal survey instrument. Instead, we sought quantitative and qualitative insight by starting with an emailed survey that was then used to frame further interactions and discussion. In some cases, respondents provided a record of average OpEx for plants built historically up to the present. In other cases, they provided a single point-in-time estimate. Most responded in terms of fixed annual costs ($/kW-year), but others used $/MWh, which we converted to $/kW-yr based on capacity factors for projects built in various years as reported in Wiser and Bolinger (2018). While we primarily focused on all-in OpEx, some respondents broke out total OpEx into its constituent parts. Finally, some assessed only a portion of OpEx (solely turbine O&M, for example, or all costs except for property taxes); we sometimes supplement those respondent-provided data with averages of other data to *estimate* respondent-specific all-in OpEx.

Where possible, we distinguish between actual realized costs and cost expectations. For wind plants built far in the past, we primarily report actual realized costs, in part because these costs have often been higher than the expected costs when the plants were commissioned. For more recent projects, actual lifetime costs can only be known in the future, so we primarily report their expected lifetime costs at time of plant commissioning. Survey respondents generally reported a convergence between actual and expected OpEx occurring around 2010, which lends credence to our approach in this regard.

To increase the quantity of data and the robustness of results, we combine the survey-derived data with empirical OpEx data for U.S. wind plants from the broader literature (Wiser and Bolinger 2018; GL Garrad Hassan 2018; DNV KEMA 2018; BNEF 2018; Infigen 2008-2014). Specifically, wherever possible, all quantitative results presented in this paper include relevant data from both the survey and—to a lesser extent—from the other available data sources noted above; these other sources tend to fill some holes in the survey-derived OpEx data, especially for projects built from the late 1990s through the mid- to late-2010s. To facilitate comparisons, we convert all survey and literature data to real 2017 U.S. dollars, with adjustments and assumptions required in some cases to place OpEx estimates on equal footings. All OpEx data are reported on a levelized basis, with a 5% real discount rate used, as needed.

3 Land-Based Wind Power OpEx Trends and Drivers

This section describes estimates of OpEx reductions over time, expected versus actual OpEx over time, turbine O&M costs over time, recent estimates of all-in OpEx and OpEx components, and drivers of the range of OpEx estimates observed.

3.1 OpEx Reductions Over Time

All-in levelized lifetime wind OpEx estimates for land-based wind projects in the United States are summarized in Figure 1, over time by year of plant commissioning. Each data point represents a different levelized lifetime OpEx estimate for projects constructed in the year noted on the x-axis—most come from the industry survey but some from the broader literature. Data points joined by lines longitudinally reflect sources that provided multiple estimates, each associated with projects that had different commercial operation dates. Data points joined by vertical lines reflect the range of OpEx in any specific commercial operation year as revealed by a data source. Different colors are used to signify different types of data sources: wind developers and owners (blue), turbine original equipment manufacturers [OEMs] (green), and industry consultants (grey).

Though there is considerable data spread, a consistent and sizable downward trend in OpEx is observed over the entire period. All-in lifetime OpEx is reported to have averaged approximately $80/kW-yr for projects built in the late 1990s, dropping to an average *anticipated* lifetime OpEx in the low- to mid-$40s/kW-yr for recent projects. The trends do not appear to vary by the source of estimates (wind developers/owners, turbine OEMs, consultants). Given the notable increase in wind capacity factors over this period, the decline in OpEx is even greater in $/MWh terms, from approximately $35/MWh for projects built in the late 1990s to less than $12/MWh for more-recent projects.

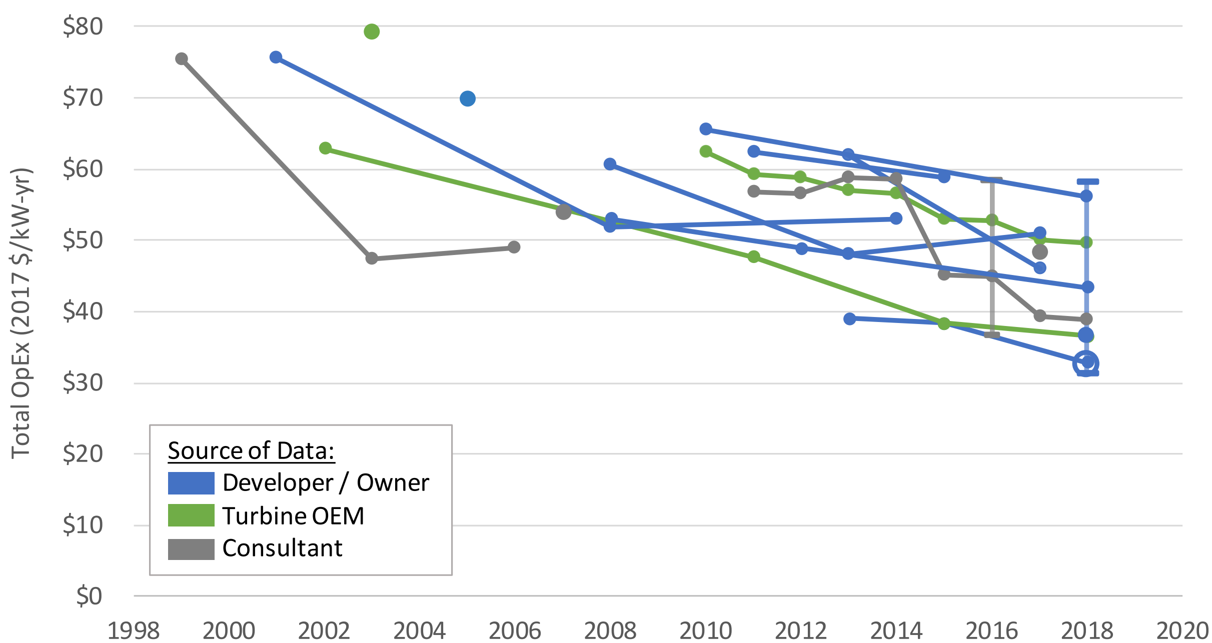

Figure 1. All-in Lifetime OpEx Estimates, Based on Plant Commissioning Date

Survey respondents and the broader literature attribute this reduction in OpEx to several factors. Wind turbines, wind plants, and owner-fleets have all increased in size[2], and each increase has reduced costs through economies of scale—spreading fixed costs over more capacity, reducing required labor per unit of output, enabling optimization of spare parts supply, reducing the cost of component repair and retrofit, and more. In addition, wind technology and operational practices have matured, which has made components more reliable (requiring less in-field repair and retrofit), made widespread the use of automated 24/7 monitoring and condition-based monitoring equipment, and improved predictive and preventative maintenance. Competitive forces and learning have also come into play, with a diversity of improved and more highly optimized OEM service offerings competing with a growing market for third-party service providers and owner self-provision of O&M services. See Section 3.6 for additional discussion of a subset of OpEx drivers.

Results associated with evolving wind project lifetimes—which are related to OpEx—also emerged from the survey. A number of respondents suggested that improved technology, O&M practices, and competitive pressures have increased assumed economic lifetimes to 25 or 30 years, making the previously standard 20-year assumption obsolete. Facilitating this development has been the introduction of life-extension programs by OEMs and analyses that show that actual site-specific accumulated fatigue damage is in many cases lower than design-certification fatigue damage.

3.2 OpEx Expectations vs. Reality

For wind plants built in the more distant past, Figure 1 reports actual realized costs. Survey respondents, however, consistently indicated that actual OpEx for plants built from the late 1990s through about 2010 were substantially higher than expected OpEx at the time of plant commissioning. They identified premature component failures, especially of gearboxes, as a notable cause of these discrepancies during this period of time. Competitive pressure to attract purchasers and financiers also often resulted in overly optimistic OpEx forecasts during this timeframe. As a result, though actual OpEx declined for projects built from 1998 to 2010 due to economies of scale, improved component reliability and other advancements (Figure 1), expectations for lifetime OpEx actually increased (not shown in the figure). One developer, for example, reported an increase in OpEx expectations from $59/kW-yr in 2006 to $66/kW-yr in 2010. Another reported an increase in expectations from $38/kW-yr in the 2001–2005 period to $61/kW-yr in the 2006–2010 timeframe. Other developers and OEMs confirmed this trend of increasing OpEx expectations.

Respondents generally portrayed a convergence between actual and expected OpEx occurring around 2010. Reported reasons for that convergence include industry growth/maturation and an associated increase in component failure and O&M cost data (as well as an overall decline in the rate of premature component failures, including gearboxes). Additionally, the growing market for long-term “full-wrap” (i.e., O&M contracts that provide full coverage for scheduled and unscheduled maintenance and repair) O&M contracts with availability guarantees offered by turbine OEMs and third-party service providers encouraged a level of sophistication, knowledge, and risk internalization not previously present in the

[2] As one example, the average nameplate capacity of wind turbines installed in the U.S. in 1998 and 1999 was 0.7 MW, a figure that jumps to 2.3 MW for turbines installed in 2017.

industry. The estimates included in Figure 1 after 2010 largely derive from lifetime OpEx expectations, informed by early-year actual realized OpEx since commercial operations.

These conclusions from the survey are consistent with the broader literature. Wind Energy Update (2010) reported that actual O&M costs were coming in at double or triple the figures originally projected during this period. Debt ratings associated with FPL's (now NextEra's) wind portfolio over time illustrate multiple successive revisions towards higher OpEx expectations as actual costs came in (Fitch 2005, 2008, 2010, 2011, 2012). Cohen et al. (2004) reviewed early-year OpEx and expected future OpEx for 10 wind projects built from 1998-2002, with lower estimates than likely realized in practice based on the data presented in this paper. DNV KEMA (2018) and GL Garrad Hassan (2018) noted the prevalence and cost of serial gearbox failures before 2010, which contributed to unexpectedly high OpEx for some projects and increased overall fleet-wide average OpEx expenditures. Notably, during this period and absent better data, analysts and modelers regularly used OpEx estimates that were lower than the OpEx subsequently realized in practice (EIA 2011; DOE 2008; Chapman and Wiese 1998).

3.3 Turbine O&M Costs and Non-Turbine OpEx Over Time

Turbine O&M costs—inclusive of scheduled and unscheduled maintenance—represent the single largest component of overall wind plant OpEx as well as the primary source of OpEx reductions over the last decade. Figure 2 depicts a range of data on turbine O&M, from the late 2000s to the present by year of plant commissioning. Most data points reflect levelized lifetime turbine O&M costs for wind plants that enter commercial operations in the year specified. However, in the case of the two OEM data points, one is for 5-year and the other for 10-year full-wrap contracts. Additionally, one developer provided a data point for turbine O&M for the first 10 years or more of project life, and one consultant provided data on turbine O&M with each year reflecting the O&M contracts that they were able to obtain—ensuring variable durations, with the majority likely 10 years or less. Overall, though considerable variability exists in the data, turbine O&M cost reductions of around $10/kW-yr are apparent.

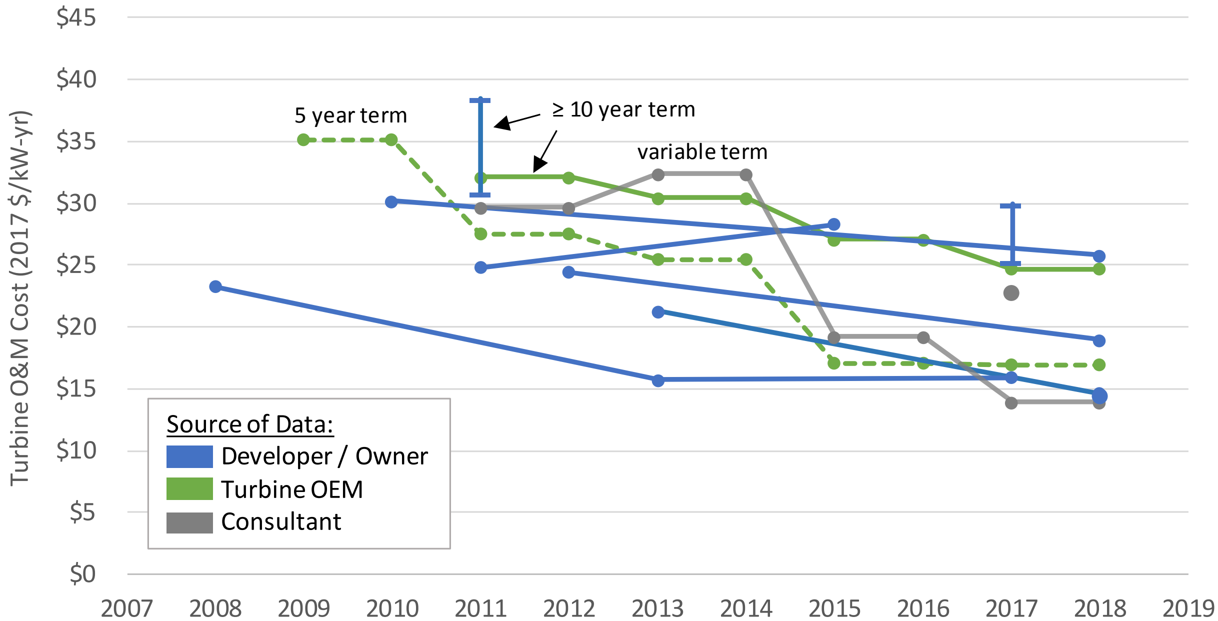

Figure 2. Total Turbine O&M Costs, Based on Plant Commissioning Date

This reduction is consistent with public information provided by the largest wind-project fleet owner in the North America—NextEra Energy, which owned 14 GW of wind through mid-2018. NextEra (2018) highlights a 25% reduction in wind turbine and BOP O&M costs from 2014 to 2018, enabled by NextEra's portfolio scale and purchasing power. It is also generally consistent with a recent benchmarking study conducted by IHS Markit (Lillian 2018), which found that larger, newer wind projects have O&M costs that average 25% less per megawatt-hour than ones using smaller turbines installed before 2010.

Respondents indicated that reductions in the non-turbine components of OpEx were less significant during this period, with some indicating possible cost increases. For example, U.S. land lease payments are often calculated as a percentage of gross revenue, so declining wind energy prices will have reduced average land lease costs, all else being equal. However, such land contracts often embed a minimum per-MW payment, and minimum payments have been triggered more frequently as wind prices have declined, thus limiting overall cost reductions. Additionally, in some areas of the country, increased competition for attractive wind sites over time has tended to boost required lease payments. Other costs—such as insurance, BOP maintenance, and property tax—have not declined much over this period, if at all, with at least one respondent indicating that insurance costs may have increased.

3.4 Recent All-in OpEx Estimates

Based on the data gathered and presented so far, all-in OpEx appears to have declined over time, though the data show a wide range of OpEx at each point in time (Figure 1). Figure 3 shows the range of expected lifetime OpEx for projects commissioned between 2015 and 2018. Levelized expected OpEx varies by data source, with a range of $33/kW-yr ($9/MWh) to $59/kW-yr ($16/MWh). Across all sources, the average for these recent projects is $44/kW-yr ($12/MWh).

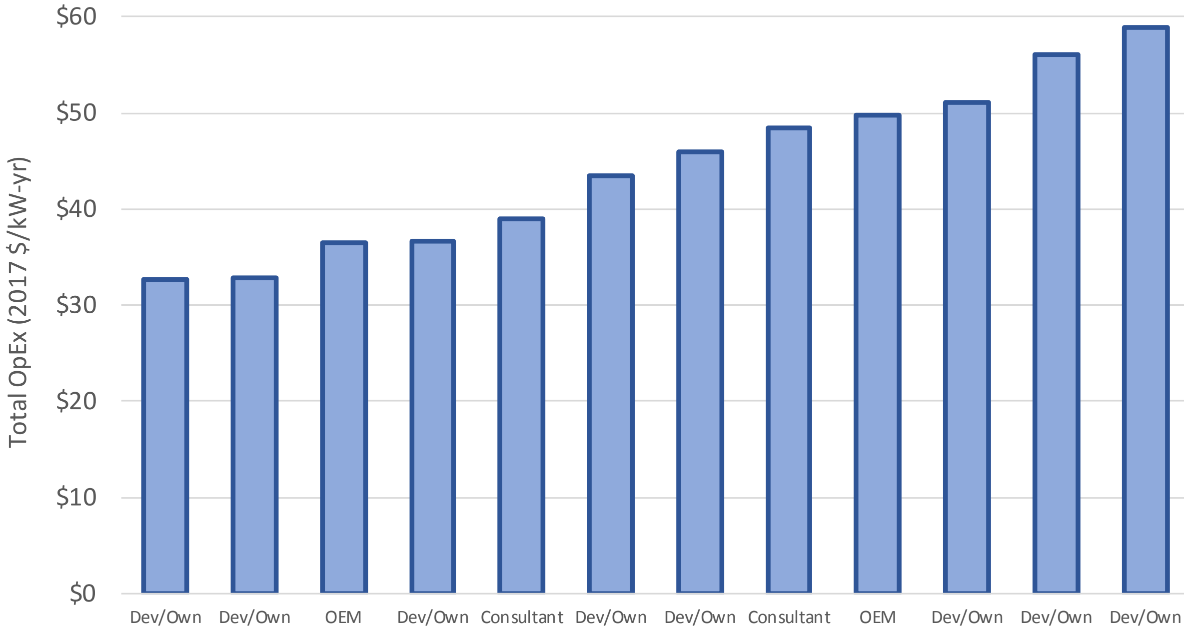

Figure 3. All-in OpEx Expectations for Projects Commissioned 2015–2018, by Respondent Type

Because respondents provided data on average costs, often for large wind project fleets, the costs reported here are a range across fleets of projects; the range across individual projects would be larger still. This lack of widespread industry consensus on OpEx projections is consistent with findings in Brodeur (2018). Some drivers of the observed cost range are described in Section 3.6.

3.5 Recent Estimates of OpEx Components

Once a wind project emerges from its warranty phase, maintenance costs can become substantial, and uncertainty in major component lifetimes can increase the difficulty of estimating maintenance costs accurately. In effect, the wind industry is trying to predict 30 years of failure rates of newer equipment for which past historical failure rates may not apply. Because of this, uncertainty in turbine O&M costs might be expected to be the primary driver of the range in recent all-in OpEx estimates. Other costs—such as those related to insurance, land payments, and routine maintenance—are often easier to predict, so greater convergence in those costs might be expected.

However, based on the industry survey, we find that turbine O&M and non-turbine OpEx represent nearly equal drivers of the range in recent all-in levelized OpEx estimates. As shown in Figure 4, recent turbine O&M cost expectations range from $14–$28/kW-yr ($20/kW-yr average), whereas all other costs range from $18–$35/kW-yr ($25/kW-yr average). Consistent with the data presented earlier, most of the turbine O&M cost data represent full lifetime expectations, but some reflect terms as short as 5 years. The non-turbine OpEx costs, meanwhile, are all full-lifetime expectations.

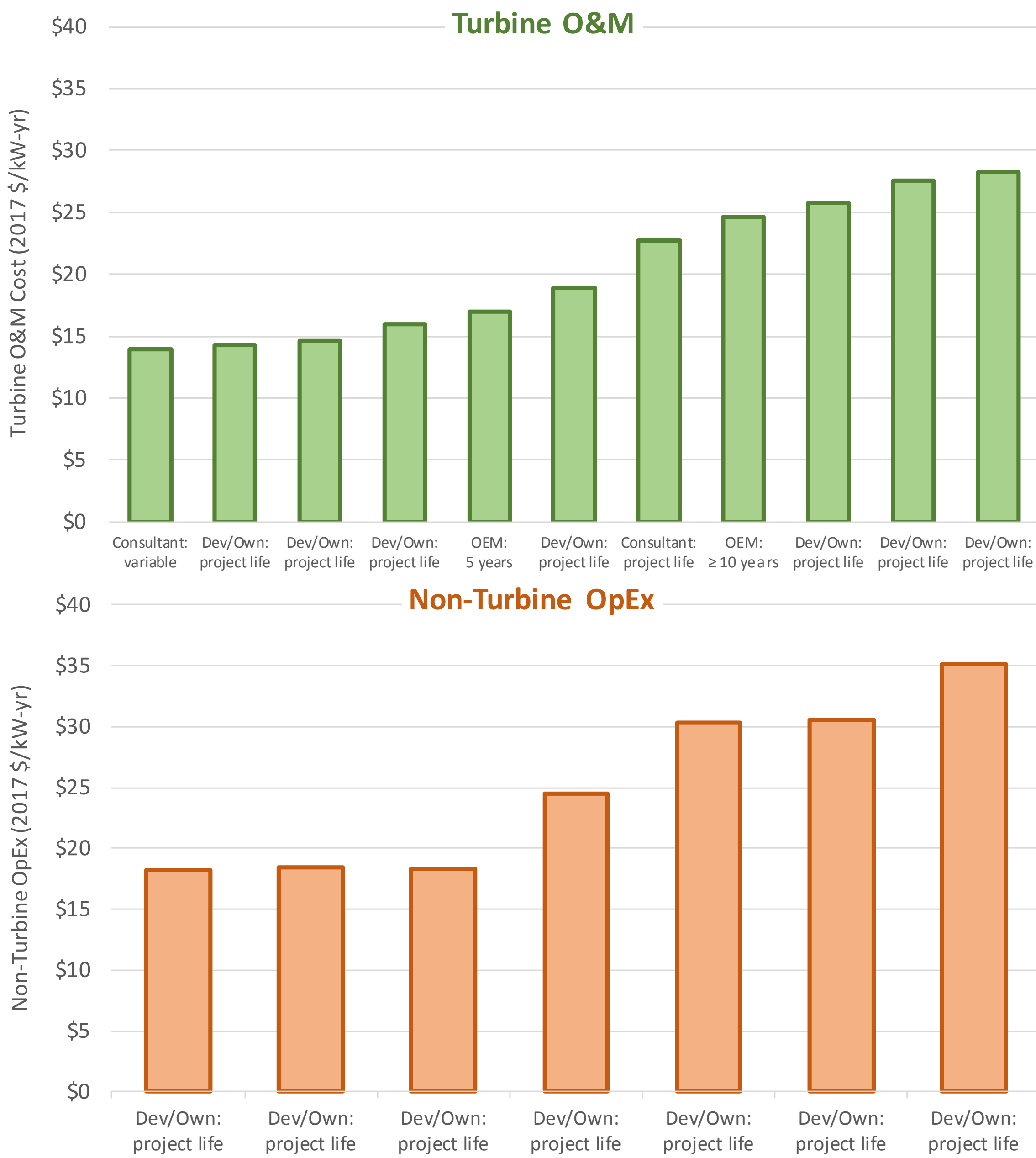

Figure 4. Wind OpEx Expectations for Projects Commissioned 2015–2018: Turbine O&M (top), and Non-Turbine OpEx (bottom)

Non-turbine OpEx includes costs related to BOP O&M, land leases, property or other local taxes or payments, grid and electrical use, insurance, asset management and administration, and other activities. Though the survey did not seek detailed cost breakdowns, a subset of wind developers and asset owners who responded to the survey provided relevant data (Figure 5). Turbine O&M (inclusive of scheduled and unscheduled maintenance) is clearly the largest single element, with property taxes, land lease payments, and BOP O&M representing the next tier of cost elements, followed by a larger number of less-significant factors.

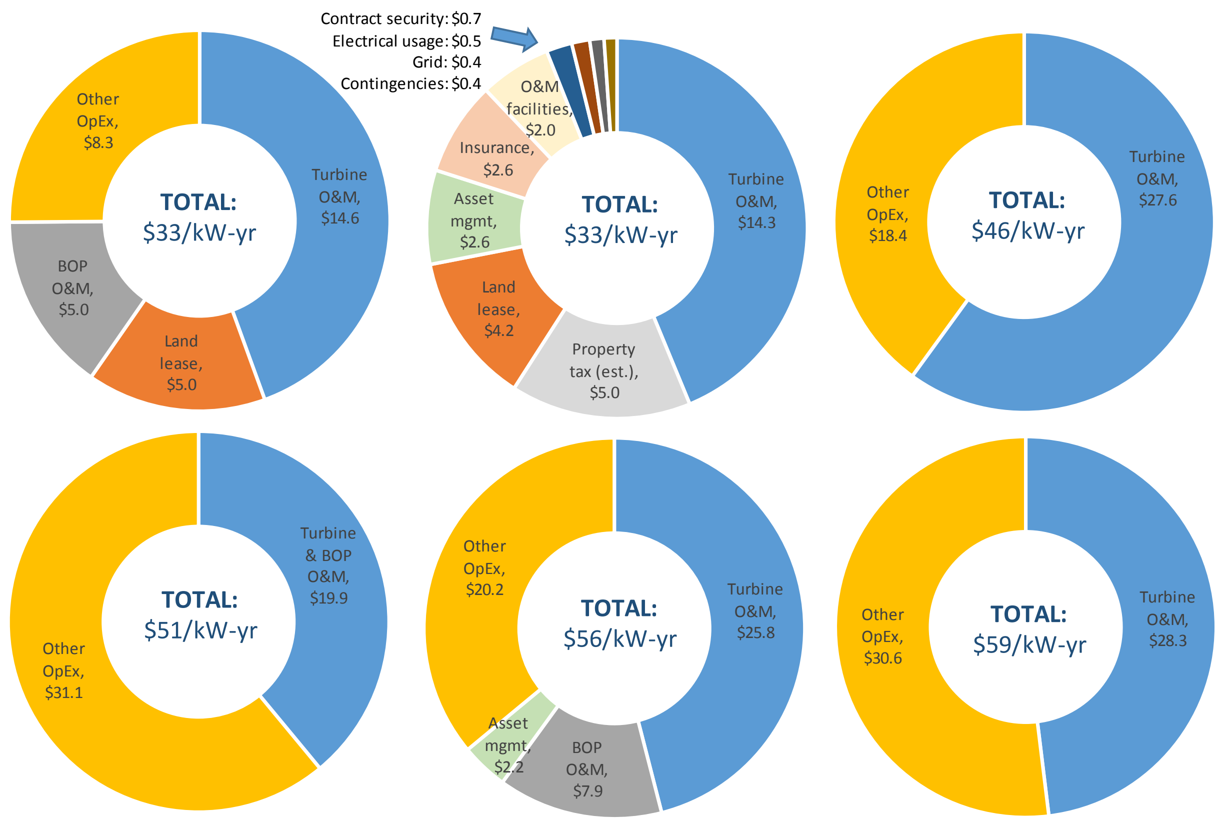

Figure 5. Wind OpEx Expectations for Projects Commissioned 2015–2018 by Component, for various Respondents

3.6 Drivers for Range in OpEx Estimates

Though reporting inconsistencies might account for some of the wide range in all-in OpEx estimates summarized above, survey respondents noted various substantive explanations for the OpEx trends and variability. Some of these are more technical in nature, whereas others are strategic. Here the focus is on explaining variability in OpEx estimates at any given point in time; however, some of these same drivers have also impacted trends in OpEx over time.

3.6.1 Technical factors impacting OpEx:

- **Project Size:** Some costs are fixed, regardless of project size, or consist of fixed and variable components—spare parts and labor, crane mobilization, infrastructure for predictive maintenance, insurance, asset management, etc. Such costs will not scale linearly with size on a $/kW-yr basis, but will instead offer economies of scale, a fact confirmed by BNEF (2018), Briggs (2017), and IHS Markit (Lillian 2018). One developer noted a spread in costs from $75/kW-yr (for plants of about 40 MW in size) to $45/kW-yr (for plants of about 250 MW in size).

- **Turbine Size:** Some costs are fixed, regardless of turbine size. Moreover, as turbines have grown, the number of parts per MW has declined, often reducing replacement costs even as crane mobilization expenses increase. That turbine size impacts OpEx has been widely reported for decades (e.g., BNEF 2018; Lemming et al. 1999; EWEA 2009; Poore and Walfrod 2008; Vachon 2002; Hahn 1999).

- **Owner Fleet Size:** Wind project owners with larger fleets may choose to self-perform turbine O&M, opening one important route to lower OpEx as described in the "strategic factors" list below. Even those who choose not to self-perform O&M can benefit from larger fleet sizes, as fixed turbine O&M costs and non-turbine OpEx may be spread across more capacity (enabling labor and spare parts optimization, as two examples) and larger fleet sizes may also enable a degree of purchasing power for services and parts, resulting in lower costs (NextEra 2018, New Energy Update 2018).
- **Turbine Maturity:** More-mature turbines have generally experienced lower OpEx than less-mature turbine models, as the latter have sometimes been subject to greater risk of serial component failure and accordant retrofit costs. One respondent noted a realized OpEx twice as high for a less-mature turbine deployed in the mid-2000s than for more-mature turbines available at the time, due in large measure to serial component failures and resultant retrofit activity. The reduced frequency of component failures was noted as a key driven for lower OpEx over time.
- **Failure Rates and Project Life:** Regardless of turbine maturity, there remains endemic uncertainty in component reliability and failure. In effect, the wind industry is trying to predict 20 to 30 years of failure rates for newer equipment for which past historical failure rates may not apply. And, while assumed project lifetimes have increased from the previous 20-year standard to 25-30 years today, the timing and degree of this shift varies across the industry. As such, some of the variability in estimated OpEx simply reflects varied assumptions about future component failure and project life.
- **Location:** Regions with greater concentrations of wind projects can benefit from ready access to service infrastructure, whereas regions with lower concentrations present longer service distances and transport times. Regions that feature cold weather, winter storms, lightning, dust, corrosion, and challenging terrain can also push up costs. The interior wind belt is often considered the least-cost area of the country, with higher costs for projects located on or near the coasts.
- **Wind Resource:** Higher wind speeds and capacity factors, as well as shear and turbulence, tend to increase wear-and-tear and turbine O&M costs in $/kW-yr terms. This is one reason why some participants strongly prefer to think of OpEx in $/MWh terms, noting that maintenance would naturally be expected to scale more so with plant production than capacity.
- **Property Tax or PILOT Costs:** Property tax rates and rules vary broadly by jurisdiction, yielding one of the more variable elements in overall wind project OpEx. Payments in lieu of taxes (PILOT) are similarly variable, depending on the jurisdiction and circumstances of the development.

3.6.2 Strategic factors impacting OpEx:

- **Self-Provision vs. OEM Full Wrap:** OEMs have historically dominated the service market, benefiting from experience, scale, technical knowledge, preventative maintenance skill, and access to spare parts; OEMs earn relatively high margins in that business, but can deliver quality service and quick turn-around times when unplanned maintenance needs arise. Experienced wind plant owners with larger fleets, however, have progressively moved towards self-provision of turbine O&M. Many survey respondents noted that self-provision will increase with time, offering an opportunity for significant OpEx reductions compared with OEM full-wrap contracts, and also enabling asset owners to more easily make tradeoffs between OpEx, plant performance, and profitability.[3] Recent literature supports these views (BNEF 2015), with Briggs (2017) finding a 30% potential reduction in turbine O&M cost due to self-provision and IHS Markit showing a 19% cost reduction (Ford 2018). One respondent even suggested that smaller developers and asset owners would soon be squeezed out of the market owing to their inability to benefit from the cost savings of self-provision over a large fleet. Another respondent, however, mentioned that independent service providers or even the owners of large wind fleets might step-in and offer cost-competitive O&M to owners that have smaller fleets. Finally, it is important to recognize that lower costs enabled by self-provision come with increased risk (Briggs 2017; Ford 2018). Another respondent—who is associated with a large wind project fleet—indicated that their company prefers OEM-provided full-wrap contracts because the extra costs incurred are more than offset (in their case) by increased asset performance, backed by liquidated damages if availability performance guarantees are not achieved. This developer further explained that full-wrap contracts may increase turbine O&M costs by 10%–12% but have reduced asset-management expenses and helped enable availability of above 97%.

- **Plant Profitability:** Wind projects that offer high operating profits from power sales or production tax incentives tend to warrant more intensive O&M activities, resulting in higher O&M costs compared with lower-profit projects. One survey respondent, for example, noted that they tend to overstaff their profitable sites with technicians, provide staffing for 16–24 hours per day, monitor all farms with a 24/7 operating center, and strive to return malfunctioning turbines to service quickly. This has resulted in energy-based availability higher than 97%, with the additional costs overshadowed by the higher revenue from power sales and production tax credits. The same developer does not apply the same operational rigor to less-profitable projects. One fully merchant project that sells power into the local wholesale power market and not under a lucrative sales agreement, for example, is only covered with a day shift and does not receive overly proactive efforts on large corrective maintenance issues. The energy-based availability for this site is 92%, and the O&M costs needed to increase that availability are not justified in the current market. Another asset owner indicated that some of its focus on O&M trails off after the 10th year of project operations as the 10-year federal production tax credit rolls off, and the focus on maximizing the value of that tax incentive therefore disappears. Some decline in both OpEx and plant performance is anticipated when projects reach that stage of their lifecycle.
- **OEM Service Provision:** OEMs that sell turbines and enter into service contracts simultaneously in a bundled fashion may, at times, embed some ongoing turbine O&M costs in upfront turbine prices, which reduces apparent ongoing OpEx; alternatively, the opposite may also be true, with some turbine costs embedded in the O&M contract. In addition, an OEM that believes its turbine is the most desirable for any specific site or period may be able to boost the price of full-wrap service contracts.
- **Buyer vs. Seller:** Those seeking to sell wind development assets tend to present OpEx estimates that are more optimistic, assuming lower levels of component failure over time, whereas potential asset buyers often choose a more-conservative stance.

[3] Full-wrap contracts generally provide incentives to meet availability guarantees at minimum cost, but those incentives may result in O&M practices that do not optimally maximize plant profitability.

4 Comparisons with Other Recent Benchmarks

As reported in Section 3.4, all-in levelized lifetime OpEx expectations for U.S. land-based wind have recently averaged $33/kW-yr to $59/kW-yr, with an average across respondents of $44/kW-yr for projects entering commercial operations from 2015 through 2018. These values can be compared to other recent U.S. and global benchmarks (Table 1), not all of which have transparent methodologies or substantial data underpinnings.

As shown, notwithstanding the limitations of many of the other benchmarks, the estimates presented in this paper often fall within the range of other estimates, in which case our findings may bolster confidence in the previously available literature. In other cases, our results diverge from the broader literature, in which case our findings may inform upward or downward adjustments to these other benchmarks, especially where limited data are otherwise used.

Table 1. Other Recent U.S. and Global Land-Based Wind OpEx Benchmarks

Geographic Scope	Commercial Operation Data	All-in OpEx ($/kW-yr)	Source
United States	2017	30–40	Lazard (2017)
United States	2016	51	NREL (2018), Stehly (2017)
United States	2020	47	EIA (2018)
United States	2014	44	IEA (2017), new policies
United States	2020	49	IEA/NEA (2015)
United States & Europe	2014	60	Wiser et al. (2016)
Global: 18 countries	2020	22 (China) 40–64 (12 countries) > 70 (5 countries)	IEA/NEA (2015)
Global: 9 regions	2015	30 (China) 34–54 (7 regions) 56 (Japan)	IEA (2017), new policies
Europe: 5 countries	2016	37–60	IEA Wind (2018)
Europe: low to high wind speed	2014	42–48	Valpy and English (2018)
China & Central/South America	2008–2016	35	IRENA (2018)

Figure 6 compares the average reduction in U.S. wind OpEx from 2008 to 2016 reported in this paper (see the later text around Figure 7 describing those values) with the reduction observed in five European countries and reported in IEA Wind (2018). The U.S. data fall within the range of other countries shown in both 2008 and 2016, and the percentage cost reduction in the United States over this period (17%) is consistent with that shown for Germany, Norway, and Denmark. Overall, these comparisons provide support for the U.S. OpEx data presented earlier.

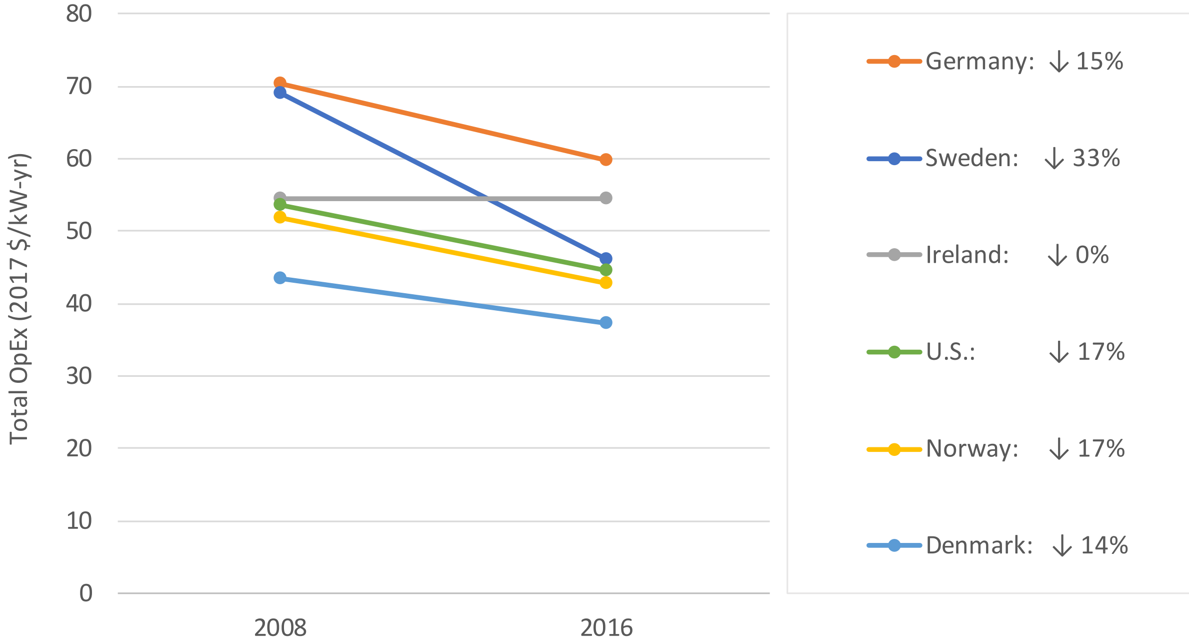

Figure 6. Comparison of Country-Level All-in Wind OpEx Reductions from 2008 to 2016

5 Estimating Future OpEx for Land-Based Wind

Historical cost data are sometimes used to estimate learning rates, which trace the relationship between the cost of wind, for example, and cumulative installed wind capacity. These historical learning rates are then commonly extrapolated to forecast possible future costs (Luderer et al. 2014; Williams et al. 2017).

The use of learning rates to project future costs has been criticized. In part this is because learning rates offer little insight into the myriad causal mechanisms that result in cost reduction, some of which may not be directly related to 'learning' per se (Mukora et al. 2009). Additionally, there is no inherent reason that future costs should fall at the same learning rate as in the past (Arrow 1962; Ferioli et al. 2009). Moreover, the use of learning rates to understand wind costs has primarily focused on understanding trends in CapEx (Wiser et al. 2011; Lindman and Söderholm 2012; Rubin et al. 2015; Samadi 2018). Wiser et al. (2016) and Williams et al. (2017), however, argue that applying learning rates to wind LCOE is more appropriate, because LCOE has been the principal criterion for assessing industry progress and technological advancements, and because reducing CapEx is only one way to reduce wind's LCOE.

Notwithstanding the criticisms, the application of learning rates to wind energy remains common (Wiser et al. 2011; Lindman and Söderholm 2012; Rubin et al. 2015; Samadi 2018), and represents a useful, simple means of estimating future wind costs or reinforcing estimates derived through other methods. Recent analyses suggest historical global learning rates of 6%–9% for land-based wind CapEx, meaning the CapEx has declined by 6%–9% for each doubling of cumulative global installed wind capacity (IRENA 2018; Wiser et al. 2016). LCOE-based learning rates have recently been shown to be higher, typically ranging from slightly below 10% to nearly 20% (Wiser et al. 2016; Williams et al. 2017; IRENA 2018). That LCOE-based learning exceeds CapEx-based learning illustrates the fact that CapEx improvements have not been the sole means of reducing wind's LCOE, a fact easily confirmed by the observed improvement in wind project performance over time (Wiser and Bolinger 2018; IRENA 2018; IEA Wind 2018).

All-in OpEx reductions have also contributed to LCOE-based learning. From the survey results and empirical data we have used in this study, Figure 7 depicts estimated average lifetime (levelized) historical OpEx for U.S. land-based wind, by project commissioning date. To represent the broad range of survey and literature-based data presented earlier, the figure also depicts an illustrative range in OpEx over time that spans the majority of data reported earlier in this paper.

Pairing these data with global cumulative installed capacity,[4] we estimate an OpEx-based learning rate of 9% over the 1998–2018 period, meaning that all-in OpEx in the United States has historically declined by 9% for each doubling of cumulative global installed wind capacity. Though OpEx reductions may be due to a variety of forces unrelated to cumulative global wind installations (e.g., many of the non-turbine O&M cost categories, some of which may have increasing costs over time), we find that this

[4] Because the wind industry is global in scope, we assume that OpEx-based learning primarily accrues through global wind capacity additions, not solely U.S. additions. While this thesis may be true for technical advancements such as condition monitoring, component reliability, and turbine size, learning may be driven by U.S. capacity additions for other components of OpEx such as those affected by the overall size of wind project fleets. To test whether the learning rate would differ substantially were learning assumed to be primarily domestic in nature, we also estimate a learning rate based on cumulative U.S. installed wind capacity—resulting in an estimate of 9%, the same as the global learning rate cited in the text above, albeit with a slightly lower R^2 value of 0.960.

simple learning model performs very well ($R^2 = 0.978$). This OpEx learning rate is at the high end of the CapEx learning rate range (6%–9%), suggesting that historical advancements to reduce all-in OpEx have been "doing their share" to reduce the LCOE of wind energy.

We then apply the 9% historical learning rate to estimate future land-based wind OpEx reductions through 2040 under "business as usual" conditions (assuming the learning rate remains steady, and applies to all-in OpEx considering all OpEx categories in sum), using a representative range of future projections for global installed capacity from IEA (2017) and GWEC (2016).[5] Based on this method, all-in lifetime OpEx for newly installed U.S. wind projects is projected to *average* \$35–\$37/kW-yr by 2040. This represents a \$5–\$8/kW-yr (12%–18%) reduction from the 2018 average depicted in the figure (\$42.5/kW-yr [\$11/MWh], slightly lower than the average over the 2015–2018 period highlighted earlier due to an assumed continued reduction in OpEx over this period). If achieved, this OpEx reduction would reduce the LCOE of land-based wind by as much as \$2/MWh.

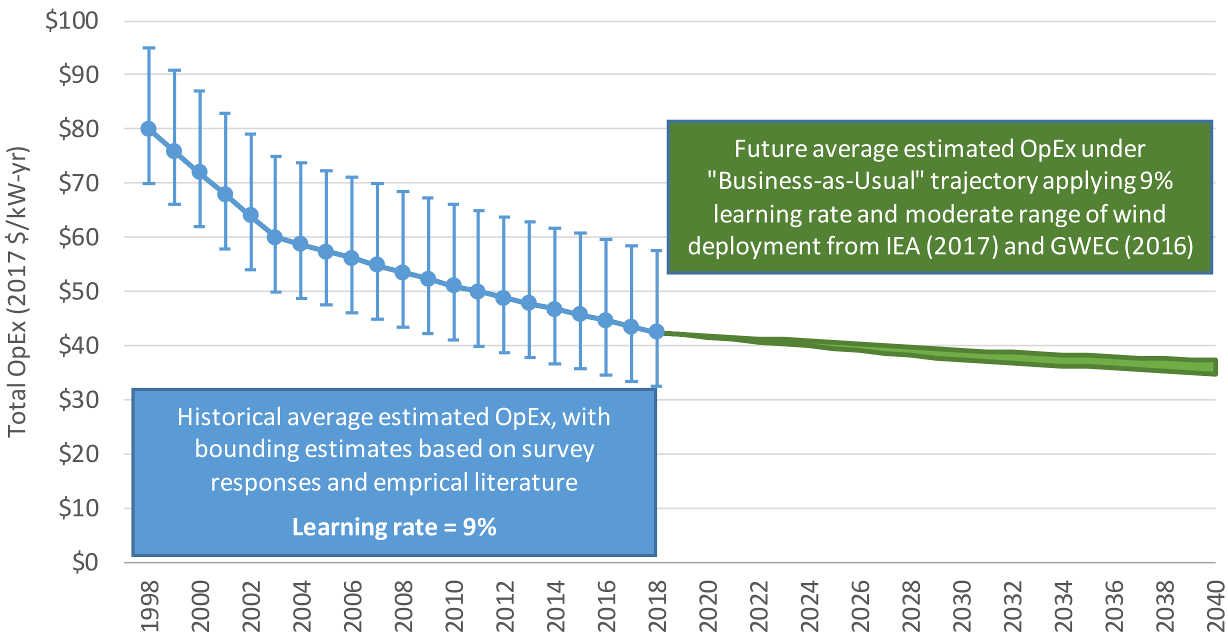

Figure 7. Average All-in Wind OpEx Over Time, with Future Projections

Our approach of using an historical learning curve to project future OpEx has limitations, but may nonetheless inform other estimates by providing a simple transparent reference point. We compare the learning-based reductions in land-based wind OpEx to other recent forecasts of OpEx developments through 2025, 2030, and/or 2040 (Table 2). These other forecasts use a range of methods, but in many cases are based on expert intuition. Our learning-based estimates are broadly consistent with these projections, with notable exceptions. For example, EIA (2018) assumes no further advancements in OpEx, which seems overly conservative given historical developments. On the other end of the

[5] The IEA (2017) "New Policies" scenario estimates 1,700 GW of wind by 2040, whereas the GWEC (2016) "Moderate" scenario forecasts 2,770 GW.

spectrum, Dykes et al. (2017) as well as Wiser et al. (2016) present more aggressive R&D scenarios with effective rates of OpEx reductions that are considerably higher than past rates.

Table 2. Comparing Land-Based Wind OpEx Projections through 2040

Source	Future All-in OpEx Reduction
Current Work: *Business as usual scenario*	\$3.4–\$5.2/kW-yr (8%–12%; \$0.9–\$1.3/MWh) from 2018 to 2030 \$5.2–\$7.7/kW-yr (12%–18%; \$1.3–\$1.9/MWh) from 2018 to 2040
Wiser et al. (2016)	Mid case: \$5.3/kW-yr (9%) from 2014 to 2030 Low case: \$14.8/kW-yr (25%) from 2014 to 2030
Dykes et al. (2017)	Low case: \$13/kW-yr (25%) from 2015 to 2030
DOE (2015)	Mid case: \$4/kW-yr (8%) from 2014 to 2030 Low case \$8/kW-yr (16%) from 2014 to 2030
EIA (2018)	Mid-case: No OpEx cost reduction through 2040
IEA (2018)	Mid-case: \$4/kW-yr (9%) from 2015 to 2030
Valpy and English (2014)	Mid-case: \$2.5–\$2.9/kW-yr (6%) from 2015 to 2025
BNEF (2018)	Mid-case: \$5.2/kW-yr from 2018 to 2025 considering only turbine O&M
BNEF (2015a)	Mid-case: \$1.7/MWh (14%) from 2015 to 2025
IRENA (2016)	Mid-case: \$3/MWh from 2015 to 2025

Future OpEx-reduction mechanisms likely include continuations and enhancements of past mechanisms. Also consistent with past trends, greater opportunities for future cost reduction likely exist within the turbine O&M category than within the many components of non-turbine OpEx.

Specifically, economies of scale may offer further reduction opportunities as both turbines and turbine fleets continue to grow. As one respondent put it, there are 50% fewer turbines in a 400 MW project that features 4 MW turbines than in one that uses 2 MW machines. Yet, the turbine-to-technician ratio remains the same (8:1 to 10:1), and you have 50% fewer gearboxes to change but each gearbox does not cost 100% more, but instead perhaps 25-50% more. Moreover, a similar crane would be used in either case, such that a gearbox change-out for a single 4 MW turbine takes approximately half the time of two 2 MW change-outs. The same general math holds for generators, oil changes, and blades.

Beyond continued economies of scale, additional research and experience is expected to yield better component reliability, thereby reducing O&M costs. Increased competition among O&M service providers and O&M self-provision could also yield OpEx reductions. Finally, further standardization and application of advanced condition monitoring, drones, and data analytics ('digitization') for predictive maintenance, facilitated by the growing amount of available data and experience, are anticipated. One respondent, in particular, noted that the wind industry is somewhat unique for its high degree of unplanned O&M, and emphasized that the move from reactive to prognostic and proactive maintenance enabled by condition-based monitoring and data analytics is an area of particular focus at present.

The future LCOE of land-based wind is uncertain, with a range of estimates available in the literature (for a summary, see Wiser et al. 2016). Overall, however, the learning-based OpEx estimates reported above suggest that continued OpEx reductions may contribute 10% or more of the overall land-based wind LCOE reductions expected through 2030 (Dykes et al. 2017; Wiser et al. 2016; BNEF 2015a; IRENA 2016). Moreover, these estimates may understate the role of OpEx owing to the multiplicative effects through which operational advancements influence not only O&M costs, but also component reliability, performance and plant-level availability, and thereby annual energy production and plant lifetimes. Wiser et al. (2016) reported results from a survey of international experts who ranked 28 different possible drivers of future wind LCOE reductions. The 5th, 7th, and 8th highest-rated items were “improved component durability and reliability,” “extended turbine design lifetime,” and “operating efficiencies to increase plant performance.” Towards the bottom of the list were “maintenance process efficiencies” (16th), “maintenance equipment advancements” (22nd), and “reduced fixed operating costs, excluding maintenance” (27th). Those expert survey results confirm the important links between plant operations, O&M costs, component reliability, performance, and plant lifetime, and suggest that impacts on component reliability and plant performance and lifetime may be considerably more important in defining future LCOE trajectories than OpEx trajectories alone.

6 Conclusions

Wind plant OpEx is an important but sometimes overlooked driver of overall LCOE trends for land-based wind. This paper draws primarily from a survey of senior members of the U.S. wind industry to describe historical and current trends in land-based wind OpEx and to provide insights into drivers of those trends. We compare the resulting estimates for average OpEx with other U.S. and global OpEx benchmarks, and we extrapolate the historical data to estimate future land-based wind OpEx, comparing the resulting estimates with other recent assessments.

We find that average all-in lifetime OpEx in the United States has declined from roughly $80/kW-yr (~$35/MWh) for projects built in the late 1990s to levels approaching $40/kW-yr (~$11/MWh) for projects under construction in 2018. Turbine O&M costs—inclusive of scheduled and unscheduled maintenance—represent not only the single largest component of overall OpEx, but also the primary source of OpEx reductions over the last decade.

Reductions in OpEx are attributed to several factors. Wind turbines, wind plants, and owner-fleets have all increased in size, and each increase has reduced costs through economies of scale. In addition, wind technology and operational practices have matured, which has made components more reliable, made widespread the use of automated 24/7 monitoring and condition-based monitoring equipment, and improved predictive and preventative maintenance. Competitive forces, including a diversity of improved OEM service offerings and a growing market for third-party service providers and owner self-provision of O&M, have also placed downward pressure on OpEx.

Actual OpEx for plants built from the late 1990s through about 2010 were substantially higher than expected OpEx at the time of plant commissioning, resulting in year-over-year increases in OpEx expectations even as actual OpEx declined. Premature component failures, especially gearbox failures, were a key cause of these discrepancies, particularly for some plants and specific turbines. It is believed that a convergence between actual and expected OpEx occurred around 2010.

Though all-in OpEx has declined over time, each point in time contains a wide range of OpEx estimates. For projects commissioned between 2015 and 2018, average lifetime expected costs are reported (often for large fleets of projects) to range from $33/kW-yr to $59/kW-yr ($9–16/MWh). This range is driven roughly equally by variations in turbine O&M costs and all other OpEx categories combined. Some drivers of OpEx variability are more technical in nature, including turbine, project, and fleet size; wind project location; turbine maturity and assumed rates of component failure; wind resource; and local tax rules. Other drivers are strategic in nature, including the choice between OEM versus self-provision of O&M services as well as tradeoffs between the cost and value of enhanced O&M practices.

The all-in OpEx values presented in this paper are often within the range of other recent U.S. and global benchmarks, but they may also inform upward or downward adjustments to some of these benchmarks where limited data are otherwise used. We find a 9% reduction in U.S. wind plant OpEx for each doubling of cumulative global installed wind capacity—that is, a learning rate of 9%. This OpEx learning rate is at the high end of the CapEx learning rate range (6%–9%), suggesting that historical advancements to reduce OpEx have been “doing their share” to reduce the LCOE of wind energy.

We apply the 9% historical learning rate to estimate future land-based wind OpEx reductions under business as usual conditions, finding a possible \$5–\$8/kW-yr (12%–18%) reduction in all-in OpEx from 2018 to 2040, which would reduce the LCOE of land-based wind by as much as \$2/MWh. This estimate is broadly consistent with other projections, with notable exceptions.

These findings suggest that continued OpEx reductions—primarily related to turbine O&M—could contribute 10% or more of the overall land-based wind LCOE reductions expected in the future. Moreover, these estimates may understate the importance of OpEx owing to the multiplicative effects through which operational advancements influence not only O&M costs but also component reliability, performance, and plant-level availability—thereby affecting levelized costs though OpEx reduction and by enhancing annual energy production and plant lifetimes

Given the limited quantity and comparability of previously available OpEx data, these findings can inform OpEx assumptions used by electric system planners, analysts, modelers, and research and development managers. The results may also provide useful benchmarks to the wind industry, helping developers and asset owners compare their OpEx expectations with historical experience and other industry projections. That said, the estimates presented here are not reliable or precise enough to enable detailed comparisons. Additional effort is clearly required to systematically collect standardized data on wind project OpEx to ensure the comparability of varying data sources and to better understand the differences that remain in OpEx expectations.

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