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Wind Technology, Cost, and Performance Trends for Denmark, Germany, Ireland, Japan, Norway, Sweden, the European Union, and the United States 2016−2019

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NOTICE

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List of Acronyms

CapEx	capital expenditures
COD	commercial operation date
EU	European Union
IEA	International Energy Agency
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
m	meter
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
OpEx	operational expenditures
TCP	Technology Collaboration Programme
W	watt
WACC	weighted average cost of capital
yr	year

Executive Summary

This report documents wind technology and cost trends in 2016 and 2019 and builds on prior analysis conducted by the International Energy Agency Wind Technology Collaboration Programme (IEA Wind TCP) Task 26 working group. The cost of wind energy during this period is compared with the market value of wind energy in the respective electricity market for each participating country and the European Union. Comparable prior versions of this work have focused on country-specific technology and cost trends from 2008 to 2016. This report takes a more synthesized crosscutting approach by abstracting international trends from individual country data and experiences in 2016 and 2019. The cost and performance data used for this analysis were obtained from IEA Wind TCP Task 26 Data Viewer,[1] except for market value data.

Overall, we find a continued trend toward larger, taller machines with lower specific power and higher capacity factors. These trends have persisted in parallel with reductions in wind project capital costs, driving down the levelized cost of energy for all countries reporting data. Specifically, an average levelized cost of energy reduction of 13% for wind energy projects to €51/megawatt-hour for plants commissioned in 2019 relative to 2016 is observed (Figure ES1). An analysis of the components of levelized cost change indicate that changes in capital cost and capacity factor each accounted for 46% of the absolute cost reduction; combined, they account for a total of 92% of the estimated reduction. This result re-emphasizes the importance of trends in technology such as specific power when assessing wind energy learning rates in addition to capital costs. As the levelized cost of energy has fallen, we have also seen a general trend of increased value of wind energy, providing enhanced grid parity for wind energy projects commissioned in 2019; however, grid value trends have varied in the past, so it is unclear whether this will be sustained going forward. Nevertheless, it suggests possible benefits for managing wind energy value across power systems. Looking ahead, policymakers aiming to foster wind deployment would likely benefit from continuing to consider both the cost and value of wind energy when designing land-based wind energy policy measures.

[1] IEA Wind TCP Task 26 Data Viewer will no longer be maintained on the Task 26 website but will be migrated and maintained on the IEA Wind TCP Task 53 website.

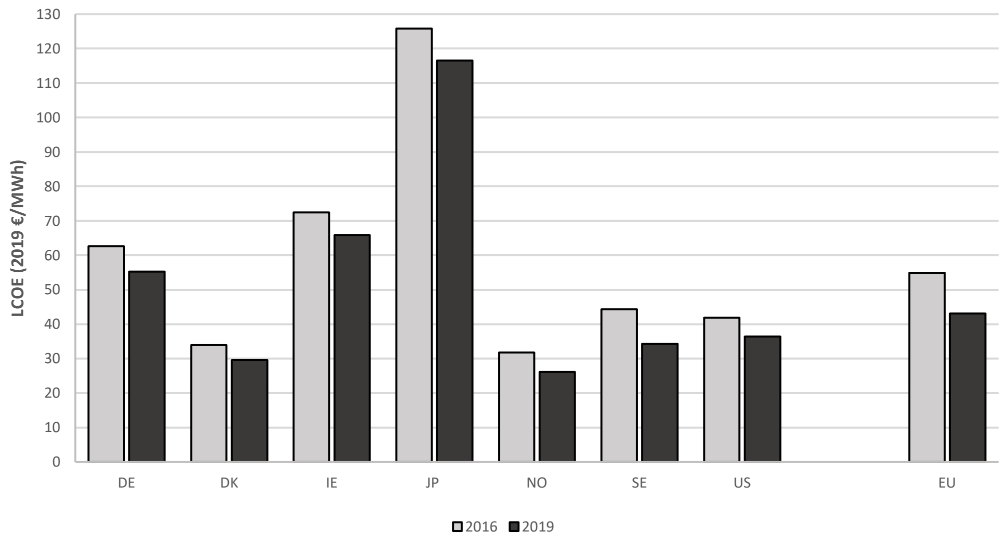

Figure ES1. Levelized cost of energy (LCOE) estimates in euros per megawatt-hour (€/MWh) for participating countries and the European Union for 2016 and 2019.

DE = Germany; DK = Denmark; IE = Ireland; JP = Japan; NO = Norway; SE = Sweden; US = United States; EU = European Union

Table of Contents

List of Figures

List of Tables

1 Introduction

The International Energy Agency Wind Technology Collaboration Programme (IEA Wind TCP) Task 26, Cost of Wind Energy, is an international collaboration focused on exploring the historical and future cost of wind energy as well as the market value wind energy provides to the electricity system. Countries that are currently represented by participating organizations in IEA Wind TCP Task 26 and included in this report are Denmark, Germany, Ireland, Japan, Norway, Sweden, and the United States; the European Union is also represented as an aggregation of data from multiple countries collected by the European Commission's Joint Research Centre.[2]

This report focuses on comparing technology, cost, and market value trends in each participating country in 2016 and 2019 and builds from previous analysis conducted under the auspices of Task 26. Schwabe, Lensink, and Hand (2011) explored differences in the cost of wind energy in 2008 among countries participating in Task 26 at that time; Vitina et al. (2015) presented turbine- and project-level trends in the wind industry from 2008 to 2012; and Dalla Riva et al. (2018) described turbine- and project-level trends that influenced the cost and value of wind energy from 2008 to 2016, which was complemented by Duffy et al. (2020). Further, Wiser, Rand, et al. (2021) and Beiter et al. (2021) explored future trends in wind technology and costs with additional studies on the wind energy value trends (Ea Energy Analyses 2022). As with prior reports, this report uses levelized cost of energy (LCOE) as the primary metric to estimate the cost of wind energy and focuses on the evaluation of technology, cost, and market value trends among participating countries.

For this evaluation, wind project size, turbine size, specific power and hub height, project performance, investment costs (capital expenditures, or CapEx), operation and maintenance costs (operational expenditures, or OpEx), and project financing are considered for calculating LCOE. Additional details on the LCOE calculation methodology used in this report are in Section 2.2. The report also includes an assessment of the value of wind energy for available countries in Section 2.3. The LCOE reduction associated with wind power plant technology advances paired with the market value of wind energy assessment helps illuminate the core economic proposition that wind power offers to the broader electricity sector.

This cost of energy analysis is limited to land-based wind projects. All costs are presented in both real euros (EUR or €) and real U.S. dollars (USD or $) and represent currency values for the year 2019. The World Bank currency conversion rates and gross domestic product deflators are used to convert between currencies and to convert prior year currency to 2019 values to adjust for inflation in the manner developed by the Intergovernmental Panel on Climate Change (Krey et al. 2014).

[2] Task 26 participants that are not part of this specific report include the Netherlands and the United Kingdom.

2 Methods

The primary elements required to estimate LCOE include capital investment cost, expected annual operation costs, project financing costs, and expected annual energy production. The estimates represent "typical" or "average" characteristics of projects installed in a given year. Each wind project is unique, such that there is significant variation in all the primary parameters and thereby significant variation in LCOE. However, the "typical" or "average" estimates in this report provide an indication of general trends between 2016 and 2019.

The LCOE calculations in this report use the equations described in Section 2.2. This formulation reflects the following simplifying assumptions:

- Investment costs (also referred to as capital expenditures, or CapEx) are incurred in total at project initiation.
- Operations and maintenance costs (also referred to as OpEx) are an annual average value expended each year of the project's economic life.
- Energy production is an annual average value expected each year of the project's economic life.

2.1 Task 26 Data Viewer

Many of the parameters required to estimate LCOE are informed by a rich database of statistics for projects installed and operating in each respective country. These project statistics are visualized in the IEA Wind TCP Task 26 Data Viewer.[3] The data sources are unique to each country, and the sample sizes vary by country and parameter. Most of the data originate from the wind industry, which is reported to national government sources that are publicly available. Some data are reported directly by wind project developers to government agencies or research organizations.

2.2 Levelized Cost of Energy Calculation

The LCOE can be described as the revenue required for each unit of energy produced by a wind project to result in a net present value of zero over the wind project's lifetime. In other words, the sum of the discounted costs equals the sum of the discounted benefits, as shown below:

$$\sum_{n=1}^{N} \frac{LCOE \times E_n}{(1-r)^n} = \sum_{n=1}^{N} \frac{C_n + OM_n + D_n}{(1-r)^n}$$

where:

$LCOE$ = levelized cost of energy (megawatt-hour)

E_n = energy produced by wind project in year n

[3] IEA Wind TCP Task 26 Data Viewer will no longer be maintained on the Task 26 website but will be migrated and maintained on the IEA Wind TCP Task 53 website.

C_n = capital investment cost incurred in year n

OM_n = operation and maintenance cost incurred in year n

D_n = decommissioning cost incurred in year n

N = lifetime of wind project

r = discount rate, assumed to be the real after-tax WACC.

The equation can be simplified by assuming:

- All capital investment costs are incurred in year 1 ($C_n = C_0$).
- Energy production can be represented by an annual average value that is unchanged from one year to the next ($En = E$).
- Operation and maintenance costs can be represented by an annual average value that does not change from one year to the next ($OMn = OM$).
- Decommissioning costs are either neglected or, to the extent that funds are set aside at project initiation, included in the initial capital investment, C_0 ($Dn = 0$).

In each country, depreciation of the capital investment is tax-deductible; it is assumed that the before-tax revenues would cover the after-tax costs. Substituting the above and solving for LCOE results in the following:

$$LCOE = \frac{\left(\frac{1 - T \times PVD}{1 - T}\right) CRF \times C_0 + OM}{E}$$

$$CRF = \frac{1}{\sum_{n=1}^{N} (1 + r)^n}$$

$$PVD = \sum_{m=1}^{M} \frac{DF_m}{(1 + d)^m}$$

where:

CRF = capital recovery factor

PVD = present value of depreciation

T = corporate tax rate

DF_m = fraction of capital depreciated in year m

d = nominal discount rate for depreciation

M = depreciation period.

For comparison among countries, a number of common assumptions are made, including:

- The discount rate, *r*, is assumed to be the real after-tax WACC for a wind project owner/investor. The method for estimating this value is based on the fraction of the capital investment associated with equity or debt, estimated rate of return for equity investors, and debt rates available in each year of the analysis, 2016 and 2019. The after-tax, nominal WACC is computed as follows:

$$Nominal\ after\ tax\ WACC = Dt(1-T)IR + Eq \times RE$$

$$Real\ after\ tax\ WACC = \frac{(1 + Nominal\ after\ tax\ WACC)}{(1+i)} - 1$$

  Where *Dt* is the fraction of the capital investment financed by debt, *Eq* is the fraction of the capital investment financed with equity, *IR* is the nominal interest rate on debt, and *RE* is the nominal return on equity. The real after-tax WACC is a function of the nominal after-tax WACC and the inflation rate, *i*.
- An inflation rate, *i*, of 2% is assumed to be common for all countries and for all years in the analysis period. This value is used solely to translate the nominal WACC to real terms for use in estimating LCOE. This value reflects the wind project owner's perception of inflation over the life of the wind plant in the year in which the wind plant reaches commercial operation.[4]
- The depreciation discount rate, *d*, is assumed to be the nominal after-tax WACC in each year.
- The wind project lifetime, *N*, is assumed to be 20 years for all countries and for all years in the analysis period. This value is consistent with assumptions in prior IEA Wind TCP Task 26 analysis (Dalla Riva et al. 2018) and remains in common use by other analysts and modelers. The wind industry has used 20-year project life assumptions for many years but has transitioned over the last decade to use assumptions that can range from 20 to more than 30 years.

Energy production estimates are derived primarily from an analysis of wind project capacity factors from projects operating in calendar year 2019, for projects commissioned between 2016 and 2019. Because wind resource conditions in 2019 may not correspond to expected annual average wind speed over the life of the wind project, the 2019 capacity factors are adjusted based on a country-specific wind index such that the resulting performance estimates can be considered those that would be anticipated in a "normal" wind year.

The LCOE equation also includes the effect of national corporate tax rates and asset depreciation schedules applicable in each country. In some countries, these parameters changed over the analysis period, and the impact on LCOE is discussed. For this analysis, a 20-year project life is assumed across all countries and years, consistent with past Task 26 publications; some wind

[4] Note that country- and year-specific data were used to translate all currency values (e.g., investment and operation costs) into real 2019 currency for this analysis.

industry members have begun to use 25- or even 30-year project lives, and the analysis presented here does not reflect that trend.

The simplified LCOE formulation used in this report provides a transparent approach to estimating the cost of energy a project developer may have expected when bringing wind projects to commercial operation in each year from 2016 to 2019 in the respective country. This approach provides a simple method for illustrating changes in LCOE over this period that result from high-level changes to the primary inputs described earlier based on observations related to wind projects that achieved commercial operation in each year—2016 and 2019—in the respective country. LCOE does not include sources of revenue or policy incentives, such as tax credits or feed-in premiums.

2.3 Market Value of Wind Energy

Although wind project LCOE is a useful metric, it is also helpful to understand the value that wind power offers to the broader electricity sector in terms of offsetting other electricity costs. As such, each country includes an estimate of the annual average "market value" of wind. While the specific calculations vary somewhat by country to accommodate unique geographic attributes, the basic concept is—each year—to multiply the hourly energy production of wind projects by the relevant hourly wholesale electricity price. The resulting "market value" estimates can be thought of as the amount of revenue wind plants in the country would have earned if they had sold their power to the local wholesale power market. Given the ability of electricity purchasers to procure electricity from the wholesale market, these "market value" estimates of wind can also be considered as the electric-system costs avoided by virtue of wind supply.

It is important to recognize that wind projects are often not exposed to these market value estimates. Instead, many projects sell their output under long-term contracts at fixed or negotiated prices or receive extra market incentives like feed-in premiums. Moreover, even though the gap between LCOE and market value is related to issues of grid parity, comparing the cost and value of wind energy should be done with care. First, these metrics relate to direct, electric sector costs and values, and do not consider broader societal considerations, such as health and environmental impacts among other societal values that are of interest to policymakers and decision-makers. In other words, there is a distinction between what is often termed "market value" and the "societal" or "system" value of wind. Second, wholesale electricity markets are imperfect and may not comprehensively reflect all electric system costs due to structural design choices and the impact of various policy interventions, impacting any resulting market value estimates. Third, the wind LCOE estimates reflect long-term (20-year) values, whereas the annual market value estimates are single-year, historical figures that may change over time, ensuring that the two separate values are not perfectly comparable. For example, in countries with temporary excess or deficiencies in electric supply, or in cases where fuel or carbon costs are expected to increase in the future, the current market value may be a poor predictor of future market value.

Notwithstanding these many caveats, estimates of the market value of wind energy, over time, do inform discussions of grid parity and the need for continued policy support for wind, when loosely contrasted with the LCOE of wind energy.

3 Results and Discussion

Our results are divided into four primary categories. First, we detail trends in key parameters and metrics that highlight changes in wind turbine technology and LCOE inputs in 2016 and 2019. Second, we assess the LCOE trends for these years. Third, we evaluate the detailed LCOE component trends. Finally, we include an analysis on the market value of wind data.

3.1 Technology, Capital Cost, Performance, and Financing Trends

3.1.1 Technology Trends

Wind turbine technology is defined by four primary characteristics. These characteristics include the height of the wind turbine hub above the ground, the nameplate rating of the machine, the rotor diameter, and the wind turbine's specific power.[5] The observed values and respective changes in wind turbine characteristics for each of the participating countries between 2016 and 2019 are shown in Figure 1.

[5] Specific power is the ratio of the wind turbine's nameplate generation capacity rating (in watts) to its rotor-swept area (in square meters).

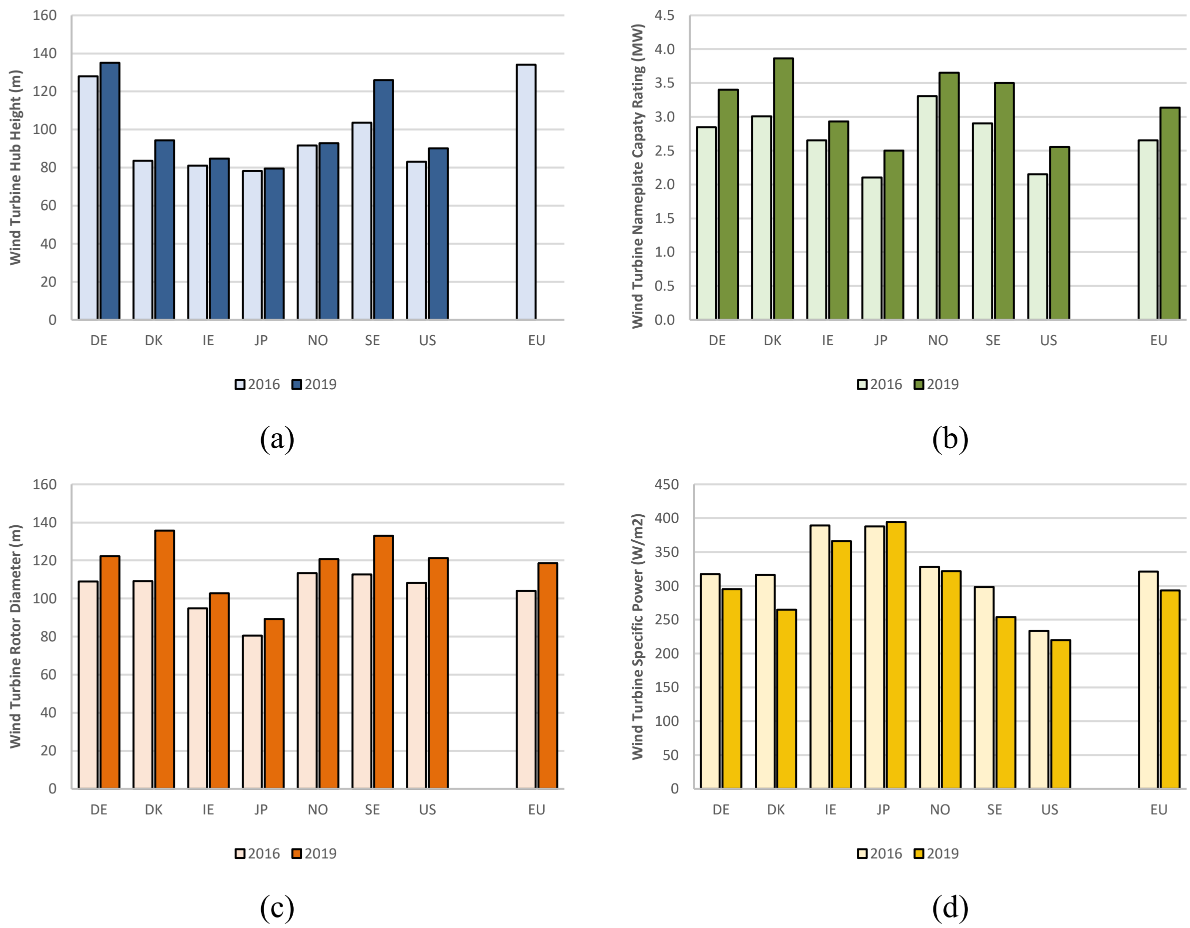

Figure 1. Turbine technology trends in participating countries and the European Union for 2016 and 2019: (a) hub height (in meters [m]), (b) nameplate capacity (in megawatts [MW]), (c) rotor diameter (in meters), and (d) specific power (in watts per square meter [W/m^2]).

Notes: Turbine technology data for each country and the European Union vary by year; the details on data sample sizes are summarized on the IEA Wind Task 26 Data Viewer. Wind turbine hub height data are unavailable for the European Union in 2019. DE = Germany; DK = Denmark; IE = Ireland; JP = Japan; NO = Norway; SE = Sweden; US = United States; EU = European Union.

For this sample of countries, there is a continued trend toward larger and taller wind turbines from 2016 to 2019. The observed average hub heights by country increased from a range of approximately 78–128 meters (m) to a range of 80–135 m; overall, the average country-specific increase across this sample was 8%.[6,7] The largest increases in hub heights were observed in Sweden and Denmark with a 23-m and 11-m increase, respectively.[8] While hub heights increased for all reporting countries, Japan and Norway only observed a hub height increase of approximately 1 m. The tallest hub heights remain in Germany at an average of approximately 135 m in 2019; taller hub heights tend to be used in regions with more modest wind resource

[6] European Union was excluded because hub height data were unavailable for 2019.
[7] All averages in this analysis are calculated presuming each country and the European Union are single units, with no weighting applied.
[8] The data sample size for Denmark in 2019 is limited and only includes one project consisting of four turbines and two test turbines. Additional details on data sample size can be found on the IEA Wind TCP Task 26 Data Viewer.

quality or in locations with particularly high wind shear profiles (i.e., large increases in wind speed with increased height above ground level). The lowest average hub height of 80 m is reported for Japan, which reflects turbine design considerations for typhoon regions.

The trend of larger wind turbines is also apparent with increases in turbine nameplate capacity. The range of nameplate ratings increased from 2.1–3.3 megawatts (MW) to 2.5–3.9 MW, resulting in an average increase from 2.7 MW in 2016 to 3.2 MW in 2019 (an 18% increase). For all countries, the increase in turbine rating ranged from 0.28 MW to 0.86 MW, or approximately 11% to 29%. Within the range, Denmark experienced the greatest increase in average nameplate rating from 3 MW to 3.9 MW; on the other hand, Ireland had the least increase in average nameplate capacity from 2.7 MW to 2.9 MW. Japan reported the lowest average turbine ratings of 2.1 MW and 2.5 MW in 2016 and 2019, respectively. In Japan, installing wind turbines in earthquake- and typhoon-prone regions deters relatively larger turbine ratings.

Wind turbine rotor diameters grew for all countries, from a range of 81–113 m in 2016 to 89–136 m in 2019; on average, rotor diameter increased approximately 13%, from 104 m to 118 m. Denmark showed the largest growth in rotor diameter: 109 m in 2016 to 136 m in 2019 (24% change). Average rotor diameters also increased notably for Sweden (133 m), Germany (122 m), and the Unites States (121 m), changes of 12%–18%. While all countries showed rotor diameter growth over this period, Ireland, Japan, and Norway showed slower rotor diameter growth, at 10 m (11%) or less in 2019 relative to 2016. In Japan wind projects are installed in relatively mountainous regions, increasing wind turbine transportation limitations, and hindering wind turbine size increase.

The growth of rotor diameter and increase in rotor-swept area was relatively greater than that of turbine nameplate capacity for all countries, except for Japan, resulting in a generalized trend of decreasing specific power from 2016 to 2019. With all else equal, these lower specific power values will boost capacity factors because there is more rotor-swept area available (resulting in greater energy capture) for each watt of rated turbine capacity. In general, turbines with low specific power were originally designed for sites with lower wind speed; they were intended to maximize energy capture in areas where the wind resource is modest and where large-rotor machines would not be placed under excessive physical stress due to high or turbulent winds. However, as wind technology has developed and control systems have advanced to better manage loads, these large low-specific-power machines continue to be deployed on sites with stronger and more turbulent winds (Duffy et al. 2020). In aggregate, specific power ranged from 233 to 389 watts per square meter (W/m^2) in 2016 and from 220 to 394 W/m^2 in 2019 with an average decrease from 315 to 301 W/m^2 (or 4%). Japan, which experienced a 2% increase to 394 W/m^2, is a notable outlier within this sample of countries, as all others observed a decrease. If the specific power data for Japan are excluded, the average specific power decreases from 315 to 288 W/m^2, or 9%. Of the countries that experienced a reduction of specific power from 2016 to 2019, Denmark had the largest decrease, from 316 to 265 W/m^2, and Norway had the smallest decrease, from 329 to 322 W/m^2. In 2016, the highest average specific power was observed in Ireland at 389 W/m^2, and the United States reported the lowest average value at 233 W/m^2. In 2019, the highest average specific power was observed in Japan at 394 W/m^2, with the lowest value again seen in the United States at 220 W/m^2. Many factors, including country-specific wind speeds and resource conditions, siting constraints, capacity constraints, localized market conditions, and subsidy designs, all impact the technology characteristics within each country.

3.1.2 Capital Cost and Financing Trends

The cost components considered in this analysis include the wind project investment costs (also referred to as capital expenditures, or CapEx), real after-tax weighted average cost of capital (WACC), and the operations and maintenance costs (also referred to as OpEx). A summary of the CapEx, WACC, and OpEx values for 2016 and 2019 are presented in Figure 2.

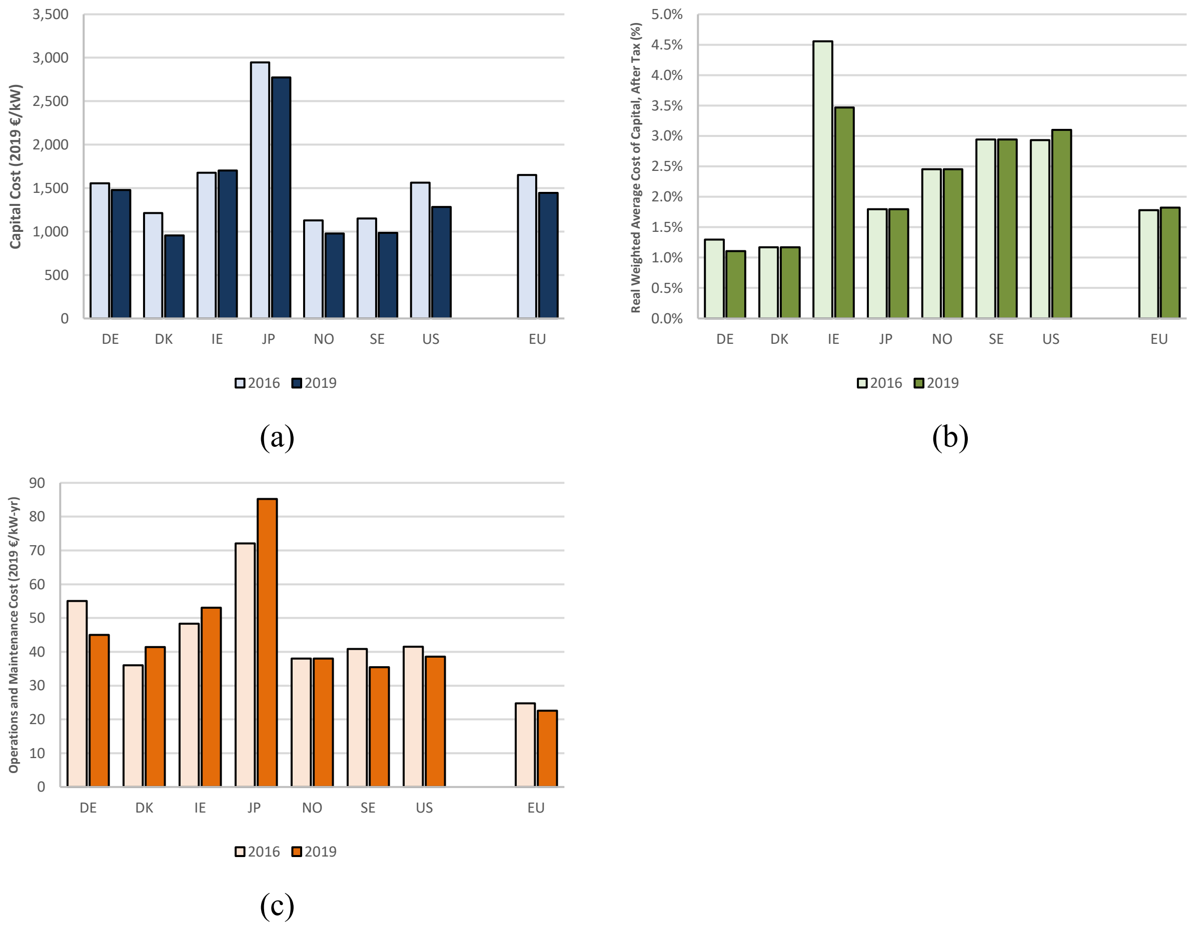

Figure 2. Wind energy project cost trends in participating countries and the European Union for 2016 and 2019: (a) capital cost, (b) real weighted average cost of capital, and (c) operations and maintenance cost

Capital costs fell by a combined all-country average of 10% between 2016 and 2019. Nearly all the countries recorded a reduction in capital costs, with a range of about €1,130/kilowatt (kW) to €2,950/kW in 2016 and €960/kW to €2,770/kW in 2019 (Figure 2(a)). The largest drops in capital costs were conveyed by Denmark (21%) [see footnote 8] and the United States (18%). The remaining participant countries, apart from Ireland, realized reductions ranging from 5% to 15%. In Ireland, capital costs remained nearly level during this period, resulting from a decline in turbine prices but offset by increased grid and construction costs. One of the driving factors for reductions in reported installed project costs for the United States was lower turbine prices (Wiser, Bolinger, et al. 2021). Generally, cost decreases are explained by technology learning, economies of scale (e.g., larger machines and wind projects), and changes in market conditions, including competitive conditions. Competitive pressure has increased in recent years because of increased utilization of auction schemes in procurement processes as well as competition from relatively low-cost solar photovoltaics and, in North America, low-cost natural gas.

For many of the countries the real, after-tax WACC did not change in 2019 from observed levels in 2016. However, a considerable decrease in WACC was reported by Ireland, from 4.56% to 3.47% (24%), and by Germany, from 1.3% to 1.1% (15%) (Figure 2[b]). In Ireland, the decline in WACC is a result of projects utilizing less expensive institutional capital. Trending the other direction, slight increases in WACC were reported by the United States, from 2.93% to 3.1% (6%), and the European Union, from 1.78% to 1.82% (2%). The increase in WACC for the United States is largely a product of the changes in economywide debt interest rates. More broadly, as wind power continues to be perceived as a more mature technology with a proven track record, new projects may attract lower risk premiums, thus reducing the cost of debt and, subsequently, WACC.

OpEx ranged from €25/kilowatt-year (kW-yr) to €72/kW-yr in 2016 and from €23/kW-yr to €85/kW-yr in 2019 for all countries (Figure 2[c]). The OpEx at the low end of each range are reported for the European Union. However, these costs may not be directly comparable to other OpEx statistics reported by the other countries because the European Union data capture direct turbine maintenance contracts and ignore other OpEx such as land lease payments, insurance costs, and owner costs. Germany, Sweden, the United States, and the European Union all experienced decreased OpEx in 2019 compared to 2016, with the greatest reduction in Germany (18%) and more modest reductions in the United States (7%). OpEx rose in Denmark (15%), Ireland (10%), and Japan (18%). No change in OpEx was reported by Norway. Reasons for OpEx increases are county-specific but could include wind plant size, lack of skilled maintenance labor, age of the operating wind fleet, and cost and availability of spare parts.

3.1.3 Performance Trends

The average wind speed of sites where wind turbines of 1 MW or larger were connected to the grid in 2016 and 2019 were reported for each of the countries except for Germany and the European Union and are illustrated in Figure 3(a). The wind speeds are expressed at the same height for each country, but height can vary across countries. In 2019 Denmark, Japan, and Sweden connected turbines to the grid at sites with higher wind speeds than in 2016. Conversely, Ireland, Norway, and the United States installed wind turbines at lower-quality resource areas in 2019. This comparison only considers average wind speed data for wind turbines installed in two specific years, and results for this type of analysis can have different outcomes year over year. In practice, actual changes in annual average wind speed are complex and include both climatological and country-specific aspects that are not detailed in this report.

The 2019 generation weighted average capacity factor data for projects with commercial operation dates (COD) of 2016 and 2019 are shown in Figure 3(b).[9] The generation weighted average represents the average performance of the wind fleet in each country, weighted by each project's relative contribution to wind-generated electricity production in the country of focus; it

[9] Projects with a COD in 2019 do not have a full year of performance data; hence, each country and the European Union provided an estimate of the expected generation in 2019.

also has an applied wind index used to correct performance to a "typical" annual wind resource year. The percent of total installations that the sample represents varies by metric, country, and year. Information on the completeness of the sample can be found on the IEA Wind TCP Task 26 Data Viewer under data type "sample size." Because the projects with COD in 2019 do not have a full year of performance data, each country and the European Union provided an estimate of the expected generation in 2019. From this, capacity factors increased for all countries at various levels except for the United States, which experienced a slight decrease in capacity factor. In general, capacity factors in 2016 ranged from 25% to 42% in 2016 and from 27% to 45% in 2019, an overall 0.5%–13% increase for the countries estimating higher capacity factors in 2019. In some cases, increased capacity factor is not always a direct result of better-quality wind speeds but also results from a shift in technology explained by higher hub heights or lower specific powers. The observed higher capacity factors are important because they reduce LCOE. Higher capacity factors can (when achieved through turbine designs that shift generation from higher to lower wind speed periods) also result in lower integration costs and an increased wholesale market value for wind, as highlighted in Duffy et al. (2020).

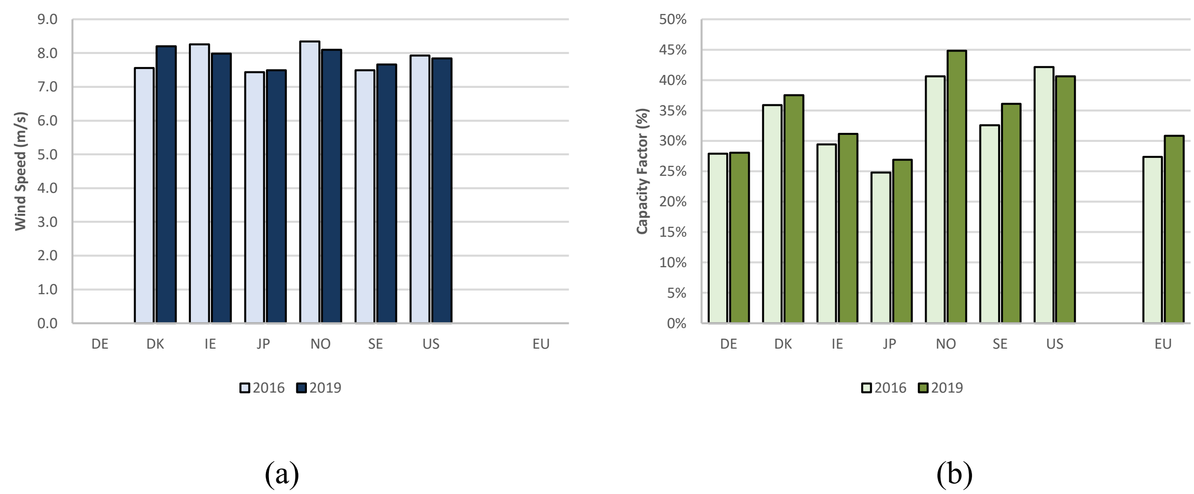

Figure 3. Wind energy project resource and performance: (a) wind speed, (b) capacity factor.

Note: Wind speed data are not available for Germany and the European Union. Performance data for projects with COD in 2019 do not have a full year of data; hence, each country and the European Union provided an estimate of the expected generation in 2019.

3.2 Levelized Cost of Energy Trends

LCOE is estimated using the methodology outlined in Section 2.2 and assumes the national tax and depreciation rates specific to each country. The assumed operating life is 20 years, and our calculations assume there is no degradation in performance as the plant ages.[10] Figure 4 shows the results of this measure for the participating countries. In 2016, values of LCOE ranged from €32/megawatt-hour (MWh) to €126/MWh and fell to €26/MWh–€117/MWh in 2019. The calculated generation costs for Norway were the lowest of the sampled countries, and Japan documented the highest cost of the set for 2016 and 2019. The values for Ireland (€72/MWh [2016] and €66/MWh [2019]) and Germany (€63/MWh [2016] and €55/MWh [2019]) are higher than the other countries, which cluster in the €34/MWh–€55/MWh range in 2016 and €30/MWh–€43/MWh range in 2019. LCOE reduction ranged from 8% to 23%, with Japan at the low end and Sweden at the high end. For all countries, the average decrease in LCOE between 2016 and 2019 is approximately 13%. While each country experiences a unique combination of investment costs, financing costs, operating costs, and capacity factors, generation cost for all countries decreased in 2019.

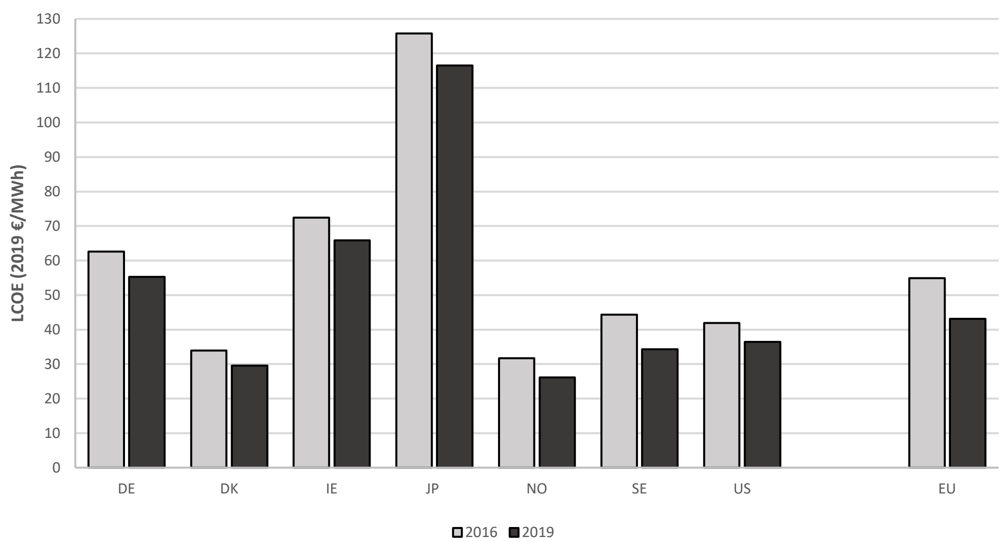

Figure 4. Levelized cost of energy estimates for participating countries and the European Union for 2016 and 2019

3.3 Components of Levelized Cost of Energy Change

The factors contributing to the declines in LCOE reported in Section 3.1 are illustrated for each country in Figure 5. Overall, increased capacity factors (resulting in greater energy outputs) have had the greatest effect on reducing LCOE, contributing to reductions of up to €9.8/MWh. On

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[10] LCOE calculations assume the wind plant operates for 20 years; however, wind turbines today are typically designed to operate for 30 years. Changing the assumed wind plant life from 20 to 30 years in the calculation significantly lowers LCOE. For example, the calculated LCOE for the United States in 2019 assuming a 20-year plant life is €37/MWh but shifting to a 30-year plant life reduces LCOE to €30/MWh (a 19% reduction). Extending plant life to 30 years in the LCOE calculation will have the same relative impact for all countries and the European Union.

average, the increased capacity factors reduced LCOE by €3.4/MWh, accounting for 46% of the absolute cost reduction of all the countries and the European Union. The key driver of increased capacity factors appears to be the trend toward lower-specific-power machines, except for Japan. In Japan's case, the specific power trended upward; however, capacity factor increased from projects being installed in better-quality wind resource areas in 2019 compared to 2016. In the United States, the specific power continued to trend downward, but projects installed in 2019 tended to be at poorer-quality wind resource sites than those installed in 2016, resulting in a decrease in capacity factor and a modest increase in generation cost. In other countries, the combination of falling specific power and higher hub heights combined to increase capacity factors.

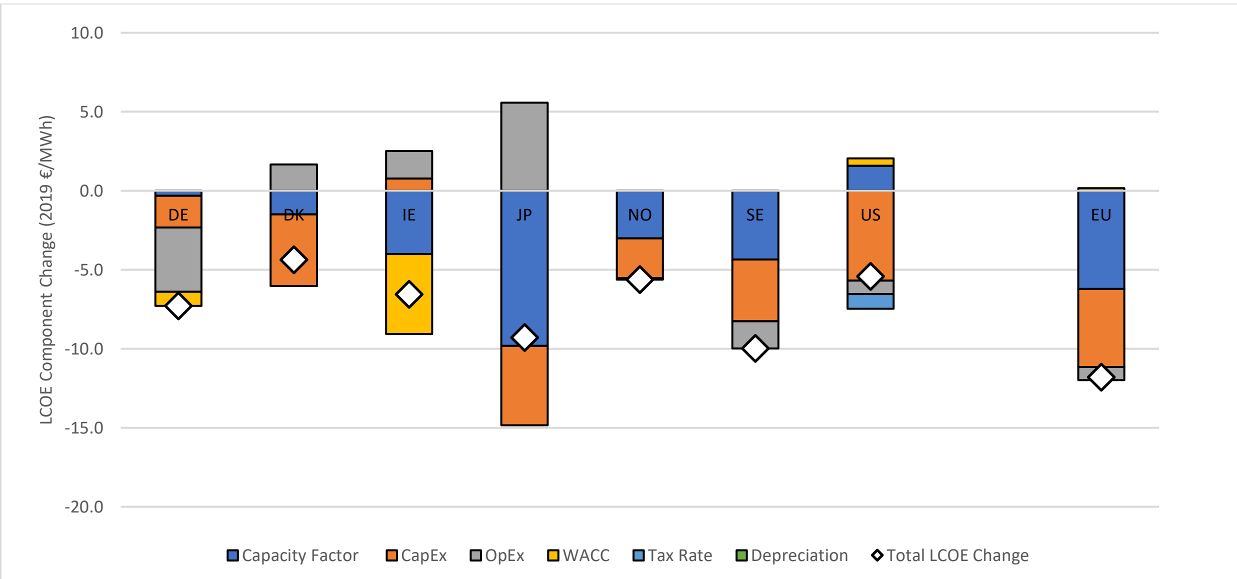


Figure 5. Contribution of input variables to changes in LCOE in 2016 and 2019

Falling project investment costs (CapEx) have contributed significantly to lower LCOE in Sweden, the United States, Denmark (see footnote 8), Japan, and the European Union, with reductions between €3.9/MWh and €5.7/MWh attributable to this factor; this is consistent with the significant CapEx reductions recorded in these countries (see Section 3.1). To a lesser extent, CapEx changes in Germany resulted in a smaller LCOE reduction of €2/MWh. In contrast to the other countries, Ireland experienced a slight increase in LCOE (€0.8/MWh) with the CapEx increase in 2019. On average, the decreased CapEx reduced LCOE by €3.5/MWh, accounting for 46% of the absolute cost reduction of all the countries and the European Union.

About half the countries reported a change in WACC in 2016 and 2019. The falling costs of finance, as measured by WACC, resulted in LCOE reductions in Germany (€0.9/MWh) and Ireland (€5.1/MWh). On the other hand, increases in the cost of financing in the United States and European Union led to an increase in generation costs of €0.5/MWh and €0.2/MWh, respectively. Finance costs remained the same for Sweden, Denmark, Japan, and Norway in 2016 and 2019 and did not impact LCOE.

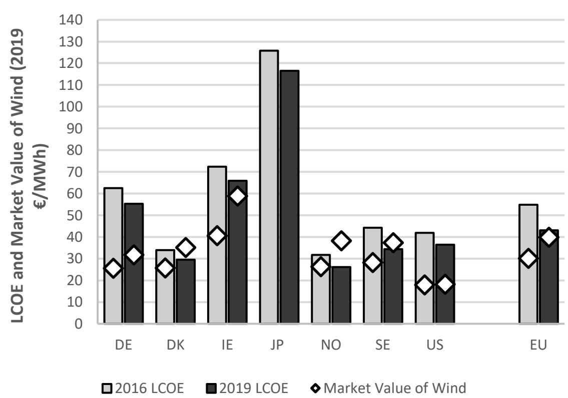
Operational costs resulted in a €4.1/MWh decrease in Germany's LCOE, with smaller effects for Sweden (€1.7/MWh), the United States (€0.8/MWh), and the European Union (€0.8/MWh).

OpEx increased for Japan, affecting generation cost by €5.6/MWh. Higher OpEx also increased LCOE for Ireland (€1.8/MWh) and Denmark (€1.7/MWh). Norway reported the same OpEx in 2016 and 2019 with no impact to LCOE. Changes in corporate tax had minor effects on LCOE in the United States and Norway, lowering generation cost by €0.9/MWh and €0.1/MWh, respectively. Corporate tax rate in 2019 had no effects in the other countries and the European Union compared to 2016. Depreciation rules for all countries and the European Union in 2019 remained the same as in 2016.

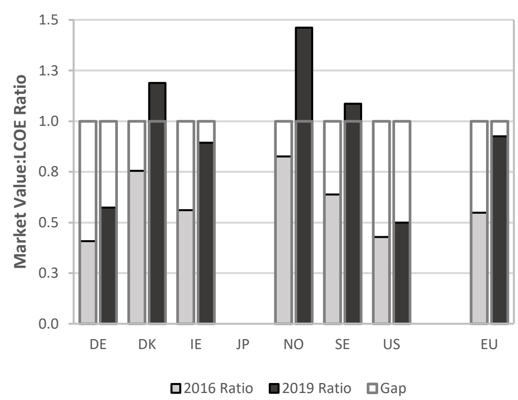
3.4 Market Value of Wind Energy

In this section we compare LCOE estimates to the market value of wind. This value can be thought of as the amount of revenue wind plants in each country would have earned if they had sold their power to the local wholesale power market and received no other policy or financial incentives. It should be noted that LCOEs are estimated over a 20-year project lifespan, whereas the market values of wind energy are for individual years. As such, comparisons should be handled with care.

An important policy consideration is whether the LCOE of wind has fallen to the price it can earn in wholesale electricity markets; LCOE at or below this value would not need the types of direct supports that have traditionally been used to promote the technology. Figure 6(a) shows LCOE for 2016 and 2019 as well as the market value of wind energy. Market value data for this analysis were provided by all countries and the European Union except for Japan (Blanckley and Kelly 2019; Telsnig, et al. 2022; Ea Energy Analyses 2022; Netztransparenz.de 2022; Wiser, Bolinger, et al. 2021). The overall average value of wind energy has increased by 33% between 2016 and 2019 and LCOE has fallen by 13%, thus indicating the grid parity gap has narrowed between 2016 and 2019. Several factors may explain the leveling or increase in wholesale electricity prices in the countries analyzed, including the prices of fossil fuels in 2016 and 2019, which impact generation costs and variable renewable energy production.



(a)



(b)

Figure 6. Wind energy project LCOE and electricity price trends in participating countries and the European Union for 2016 and 2019: (a) LCOE and the wholesale market value of wind energy, (b) ratios of wholesale value and LCOE

Note: Market value of wind energy data are not available for Japan.

The data emphasize the ongoing importance of understanding and forecasting the relative grid parity gap between wind energy costs and wholesale electricity prices and how policy responses must consider the dynamic nature of this relationship. For example, the sudden removal of policy supports when electricity prices are relatively high may quickly result in the loss of investment incentives when they fall. While it is difficult for policymakers to forecast the market value of wind, increases in wholesale price could lead to grid parity in the near to medium terms.

Figure 6(b) shows the ratio of the market value of wind to LCOE in both 2016 and 2019 and indicates whether the grid parity gap is increasing or decreasing in each country. Ratios have increased for all countries and the European Union, with the greatest escalations observed in Norway, Sweden, and Denmark (see footnote 8). The figure also shows that three countries (Denmark, Norway, and Sweden) have reported a market-value-to-LCOE ratio greater than 1 in 2016 or 2019, indicating LCOE estimates are less than or equal to the price of power from the respective country's electricity grid.

4 Conclusions

This report presents the findings of recent work undertaken by the International Energy Agency Wind Technology Collaboration Programme Task 26, Cost of Wind Energy, in relation to technological and cost trends in land-based wind energy in seven participating countries and the European Union. Results indicate that there is a general trend toward larger, taller machines with lower specific powers resulting in higher capacity factors. Between 2016 and 2019, average hub heights, rotor diameters, and nameplate capacities for all countries grew by approximately 8% to 100 m, 13% to 118 m and 18% to 3.2 MW, respectively.[11] The relatively greater increase in swept area than nameplate capacity resulted in a 4% decrease in specific power to 301 W/m² and a 6% increase in capacity factor to 35%.

In 2019, capacity factors increased for all countries at various levels except for the United States, which experienced a slight decrease in capacity factor due to projects being installed in lower quality resource areas in that year. In general, capacity factors ranged from 25% to 42% in 2016 and from 27% to 45% in 2019, an overall 0.5%–13% increase for the countries that estimated higher capacity factors in 2019.

Wind project capital costs fell for all countries by an average of 10% to €1,450/MW between 2016 and 2019. Ireland was the only country that reported a 2% increase in project costs. The cost of finance from 2016 to 2019 did not change for many of the countries except for Ireland, Germany, and the United States. Ireland's WACC (real after-tax) was reduced by 24% to 3.5%, and Germany's WACC fell by 15% to 1.1%. The WACC in the United States increased by 6% to 3.1%.

Increases in capacity factors and falling capital costs in concert with project financing, operating costs, taxation, and depreciation trends resulted in an overall reduction of 13% in average levelized costs of energy for land-based wind projects, which by 2019 averaged €51/MWh. However, large variations in national values were observed: in 2019 Norway recorded the lowest LCOE at €26/MWh due to a combination of a suitable average capacity factor and low capital costs; Japan logged the highest value of €117/MWh from high average CapEx and OpEx in addition to a less ideal capacity factor. Sweden experienced the greatest reduction of LCOE—a drop of 23% driven by reductions in capital cost and increases in capacity factor.

An analysis of the components of LCOE change found that decreases in capital costs and increases in capacity factors had the largest impact on lower LCOE, each accounting for a 46% decrease in the all-country average between 2016 and 2019. About half the countries did not report a change in WACC; however, calculating the all-country average ranked WACC third in components that lowered LCOE. WACC had a significant impact on lowering the LCOE in Ireland. Overall, there was little to no change in country-specific tax rate and depreciation; these components had insignificant impacts on LCOE. Operating cost fell for three countries and the European Union; however, the other three countries experienced an increase, resulting in an all-country average increase in LCOE of 3%. This particular result should be treated with caution due to significant OpEx data uncertainty. Wind-related technology learning literature tends to

[11] Hub height data for the European Union is excluded because data were not available for 2019.

focus on capital cost trends, although this only partly explains changes in the cost of wind energy production. Therefore, while larger turbines and the associated economies of scale will play an important future role in reducing wind energy costs, the impact of technological advances to enhance energy production should not be underestimated.

While levelized costs of energy have fallen in all countries, the value of wind energy has remained level or increased for Ireland, the United States, and the European Union. While the value of wind energy trends closer to grid parity, it is difficult to predict whether prices will increase to close the grid parity gap for land-based wind energy. Hence, policymakers should consider both the cost and value of wind energy and understand the volatility of this gap when assessing competitiveness and designing policy measures to incentivize investment in wind projects.

Renewable energy technologies such as wind, which require evidence-based policy supports, need consistent, accurate, and readily available data that can be used for national policymaking and international benchmarking. A wide variety of national data sources were used in this study, and while many of these were of high quality and internationally comparable, some areas for improvement were identified. In particular, the quality and representativeness of operating cost data were a concern given the importance of operating costs to life cycle costs. Similarly, there was uncertainty regarding the cost of finance and financial structure. Data on the breakdown of capital costs were not collected, which hindered understanding of where costs changes were occurring in the supply chain. Improving data quality requires up-front planning at a national level.

In addition to improving data access and quality, several other extensions of this work hold merit. First, our analysis focused on a narrow subset of countries for which data are collected though an International Energy Agency collaboration, but this analysis could usefully be expanded to a broader set of major wind energy markets globally. Second, our assessment focused on land-based wind power, but as offshore wind power expands, it will be valuable to conduct similar assessments that disentangle cost drivers.

Finally, our analysis focused on 2016 and 2019, but future work would extend the time frame both back and forward in time, in part to inform future cost projections. The cost of land-based wind is not expected to remain stagnant and is influenced by changes in raw material prices, labor rates, and others; however, continued advancements in wind energy technological may support future cost reductions (Beiter et al. 2021). While we do not project future costs in this report, an assessment of historical costs and the applications of learning curves are means of doing so, and the work presented here provides useful guidance in this regard. In particular, and as discussed previously, learning curves for wind have, with few exceptions, focused on extrapolating the capital cost of wind into the future. And yet, as shown in this report, there are multiple means of reducing the levelized cost of wind energy—not only through capital cost improvements, but also through increased performance, lower operating costs, and improved financing. Any analysis that considers only capital cost improvements and that ignores other cost-reduction pathways is therefore likely to understate the potential for further cost reductions.

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Appendix A. Wind Plant Technology, Cost, and Performance Data from 2008 to 2019

This appendix provides a summary of the wind turbine technology characteristics and primary elements required to estimate levelized cost of energy (LCOE) from 2008 to 2019. While the analysis of the report is focused on the changes between 2016 and 2019, this appendix presents the historical data collected by the task since 2008. Visualizations and the sources of the data are presented on the [IEA Wind TCP Task 26 Data Viewer](). [12]

A.1 Denmark

Table A1. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for Denmark

		Commercial Operation Date											
Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019 [h]
Project size	MW	7.6	11.1	12.0	13.6	12.0	12.5	13.6	20.2	17.9	14.6	10.3	11.6
Wind turbine nameplate capacity rating	MW	2.2	2.5	2.9	2.7	3.1	3.1	2.9	3.1	3.0	3.5	3.6	3.9
Wind turbine rotor diameter	m	89	94	96	97	105	103	106	106	109	118	118	136
Wind turbine hub height	m	78	81	82	80	87	86	94	86	84	90	87	94
Wind turbine specific power	W/m2	366	359	400	364	364	368	330	347	316	321	328	265
Net energy production [a]	*Capacity factor %*	33	35	32	33	32	30	37	36	36	39	36	38
	(Full load hours)	*(2,851)*	*(3,059)*	*(2,826)*	*(2,888)*	*(2,833)*	*(2,638)*	*(3,276)*	*(3,155)*	*(3,143)*	*(3,456)*	*(3,174)*	*(3,287)*
Investment cost [b]	*2019 €/kW*	1,541	1,435 [c]	1,549 [c]	1,380 [c]	1,342	1,384	1,388	1,317	1,213	1,041	1,220	957
	(2019 $/kW)	*(1,726)*	*(1,606)*	*(1,734)*	*(1,545)*	*(1,503)*	*(1,549)*	*(1,554)*	*(1,474)*	*(1,358)*	*(1,166)*	*(1,366)*	*(1,071)*
Operational expenditures (OpEx) [b]	*2019 €/kW/yr*	40 [d]	40 [d]	40 [d]	40 [d]	40 [d]	40	32	46	36	30	30	41
	(2019 $/kW/yr)	*(44)*	*(44)*	*(44)*	*(44)*	*(44)*	*(44)*	*(36)*	*(51)*	*(40)*	*(34)*	*(34)*	*(46)*
After-tax weighted average cost of capital (WACC) [e]	*% nominal*	5.0	5.0	5.0	5.0	5.0	3.1	3.2	3.2	3.2	3.2	3.2	3.2
	(% real)	*(2.9)*	*(2.9)*	*(2.9)*	*(2.9)*	*(2.9)*	*(1.1)*	*(1.1)*	*(1.2)*	*(1.2)*	*(1.2)*	*(1.2)*	*(1.2)*
Corporate income tax rate	*%*	25	25	25	25	25	25	24	23	22	22	22	22
Depreciation schedule [f]		Max 25%/year					Max 15%/year						
LCOE [g]	*2019 €/MWh*	$52	$46	$52	$47	$47	$46	$34	$39	$34	$26	$32	$30
	(2019 $/MWh)	*$58*	*$51*	*$59*	*$53*	*$53*	*$51*	*$39*	*$44*	*$38*	*$30*	*$36*	*$33*

[a] Net energy production in calendar year 2019: generation-weighted average, wind-index adjusted. The wind index adjusts wind project output in a given calendar year to represent output in a "typical" wind year. Full load hours based on 8,760 hours in 2019. Since the projects with a commercial operation date (COD) in 2019 do not have a full year of performance data, an estimate of the expected generation in 2019 is provided.
[b] Investment cost and OpEx converted to real 2019 euros and U.S. dollars. OpEx includes both fixed and variable components but is presented in terms of fixed cost.
[c] For 2009–2011, the capacity-weighted average was not available; therefore, the median was used.
[d] OpEx between 2008 and 2012 have been assumed equal to the 2013 value.
[e] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.

[12] IEA Wind TCP Task 26 Data Viewer will no longer be maintained on the Task 26 website but will be migrated and maintained on the IEA Wind TCP Task 53 website.

[f] Linear depreciation of 100% of the initial capital investment over 5 years, maximum of 25% per year, from 2008 to 2012; linear depreciation of 100% of the initial capital investment over 8 years, maximum of 15% per year, from 2013 to 2019.
[g] LCOE was calculated assuming a 20-year amortization period.
[h] The data sample size for Denmark in 2019 is limited and only includes one project consisting of four turbines and two test turbines. Additional details on data sample size can be found on the IEA Wind TCP Task 26 Data Viewer.

A.2 Germany

Table A2. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for Germany

		Commercial Operation Date [a]											
Parameter [a]	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	MW												
Wind turbine nameplate capacity rating	MW	2.0	1.9	2.0	2.2	2.4	2.6	2.7	2.7	2.8	3.0	3.2	3.4
Wind turbine rotor diameter	m	78	79	80	83	88	95	99	104	109	113	118	122
Wind turbine hub height	m	93	95	99	105	110	117	115	122	128	128	133	135
Wind turbine specific power	W/m2	426	401	393	408	394	378	364	328	317	308	301	295
Net energy production [b]	*Capacity factor %*	21	21	23	22	24	25	26	27	28	28	28	28
	(Full load hours)	(1,814)	(1,853)	(1,986)	(1,961)	(2,073)	(2,201)	(2,279)	(2,355)	(2,445)	(2,490)	(2,456)	(2,458)
Investment cost [c]	*2019 €/kW*	1,518	1,622	1,727	1,720	1,713	1,684	1,654	1,625	1,554	1,592	1,477	1,477
	(2019 $/kW)	(1,699)	(1,816)	(1,933)	(1,926)	(1,918)	(1,885)	(1,852)	(1,819)	(1,740)	(1,782)	(1,653)	(1,653)
OpEx [c]	*2019 €/kW/yr*	65	64	64	63	63	60	58	55	55	57	59	45
	(2019 $/kW/yr)	(72)	(72)	(72)	(71)	(70)	(67)	(64)	(62)	(62)	(64)	(66)	(50)
After-tax WACC [d]	*% nominal*	5.6	5.2	4.8	4.5	4.1	3.8	3.5	3.2	3.3	3.1	3.1	3.1
	(% real)	(3.5)	(3.1)	(2.8)	(2.4)	(2)	(1.7)	(1.4)	(1.2)	(1.3)	(1)	(1.1)	(1.1)
Corporate income tax rate	%	29.5	29.4	29.4	29.4	29.5	29.6	29.6	29.7	29.7	29.7	29.7	29.7
Depreciation schedule		Germany: 2008–2010 [e]			Germany: 2011–2019 [f]								
LCOE [g]	*2019 €/MWh*	104	103	98	96	87	78	72	66	63	62	61	55
	(2019 $/MWh)	(116)	(116)	(109)	(107)	(97)	(87)	(80)	(74)	(70)	(69)	(68)	(62)

[a] Turbines with nameplate ratings of 500 kilowatts (kW) or greater are included. Sources: Rehfeldt and Wallasch (2008); Wallasch, Rehfeldt, and Wallasch (2011); Wallasch et al. (2013); Wallasch, Lüers, and Rehfeldt (2015); Wallasch et. al. (2018); Wallasch et. al. (2019); Netztransparenz.de. (2020a, 2020b); BPB (2017); Core Energy Market Data Register (MaStR).
[b] Net energy production in calendar year 2019: generation-weighted average, wind-index adjusted. The wind index adjusts wind project output in a given calendar year to represent output in a "typical" wind year. Full load hours based on 8,760 hours in 2019. Since the projects with COD in 2019 do not have a full year of performance data, an estimate of the expected generation in 2019 is provided.
[c] Investment costs and OpEx converted to real 2019 euros and U.S. dollars. CapEx and OpEx are survey-based assumptions, any remaining gaps are estimated by linear interpolation. OpEx include both fixed and variable components but are presented in terms of fixed costs. Investment costs are based on average turbine configuration and corresponding typical cost for such configuration. The balance of plant costs were added to the turbine cost estimate.
[d] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.
[e] Linear depreciation of 100% of the initial capital investment with different depreciation periods for components of a wind park (e.g., turbine [16 years], cabling and grid connection [20 to 25 years], and infrastructure [19 years]).
[f] Linear depreciation of 100% of the initial capital investment over 16 years for the entire wind project.

[g] LCOE was calculated assuming a 20-year amortization period. Wind turbine fatigue life prediction is assumed to be 20 years.

A.3 Ireland

Table A3. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for Ireland

		Wind Project Year of Installation											
Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	MW	16.7	14.5	9.1	9.0	16.7	20.9	28.2	15.5	24.1	19.7	19.5	18.5
Wind turbine nameplate capacity	MW	2.0	2.1	1.6	2.1	2.4	2.3	2.8	2.7	2.7	2.7	2.9	2.9
Wind turbine rotor diameter	m	73	78	67	75	80	88	100	89	95	95	100	103
Wind turbine hub height	m	65	70	64	72	72	78	87	73	81	83	84	85
Wind turbine specific power	W/m2	463	420	439	469	484	376	364	457	389	395	375	366
Net energy production [a]	*Capacity factor %*	28	28	34	32	35	33	31	30	29	32	32	31
	(Full load hours)	*(2,457)*	*(2,477)*	*(2,956)*	*(2,803)*	*(3,109)*	*(2,925)*	*(2,740)*	*(2,627)*	*(2,577)*	*(2,780)*	*(2,818)*	*(2,728)*
Investment cost [b]	*2019 €/kW*	1,424	1,742	1,893	1,624	1,776	1,703	1,776	1,446	1,677	1,650	1,638	1,702
	(2019 $/kW)	*(1,594)*	*(1,950)*	*(2,120)*	*(1,818)*	*(1,988)*	*(1,907)*	*(1,988)*	*(1,618)*	*(1,877)*	*(1,848)*	*(1,834)*	*(1,905)*
OpEx [b, c]	*2019 €/kW/yr*	48	48	48	48	48	48	48	48	48	50	56	53
	(2019 $/kW/yr)	*(54)*	*(54)*	*(54)*	*(54)*	*(54)*	*(54)*	*(54)*	*(54)*	*(54)*	*(56)*	*(63)*	*(59)*
After-tax WACC [d]	*% nominal*	7.4	7.4	7.4	7.4	7.4	6.7	6.7	6.7	6.7	6.5	6.0	5.5
	(% real)	*(5.2)*	*(5.2)*	*(5.2)*	*(5.2)*	*(5.2)*	*(4.6)*	*(4.6)*	*(4.6)*	*(4.6)*	*(4.4)*	*(3.9)*	*(3.5)*
Corporate income tax rate	%	13	13	13	13	13	13	13	13	13	13	13	13
Depreciation schedule [e]		Linear depreciation of 100% capital investment over 20 years											
LCOE [f]	*2019 €/MWh*	71	81	73	68	66	65	71	64	72	66	65	66
	(2019 $/MWh)	*(79)*	*(91)*	*(81)*	*(76)*	*(74)*	*(72)*	*(80)*	*(71)*	*(81)*	*(74)*	*(73)*	*(74)*

[a] Net energy production in calendar year 2019: generation-weighted average, wind-index adjusted. The wind index adjusts wind project output in a given calendar year to represent output in a "typical" wind year. Full load hours based on 8,760 hours in 2019. Since the projects with COD in 2019 do not a have full year of performance data, an estimate of the expected generation in 2019 is provided.

[b] Investment costs and OpEx converted to real 2019 euros and U.S. dollars.

[c] OpEx include both fixed and variable components but are presented in terms of fixed costs.

[d] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.

[e] Linear depreciation of 100% of the initial capital investment over 20 years.

[f] LCOE was calculated assuming a 20-year amortization period.

A.4 Japan

Table A4. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for Japan

Commercial Operation Date													
Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	MW	21.5	12.3	14.7	15.1	7.6	4.6	10.0	12.3	11.8	9.1	15.3	14.1
Wind turbine nameplate capacity	MW	1.7	2.1	1.9	2.1	2.0	2.0	2.1	2.1	2.1	2.1	2.7	2.5
Wind turbine rotor diameter	m	76	79	80	84	79	81	83	83	81	84	95	89
Wind turbine hub height	m	68	73	72	72	78	78	78	75	78	76	81	80
Wind turbine specific power	W/m2	390	400	383	372	428	369	383	393	388	387	380	394
Net energy production [a]	*Capacity factor %*									25	27	27	27
	(Full load hours)									*(2,172)*	*(2,348)*	*(2,383)*	*(2,356)*
Investment cost [b]	*2019 €/kW*					3,354	2,356	2,348	2,158	2,948	2,243	2,774	2,774
	(2019 $/kW)					*(3,755)*	*(2,638)*	*(2,629)*	*(2,416)*	*(3,300)*	*(2,511)*	*(3,106)*	*(3,106)*
OpEx [b, c]	*2019 €/kW/yr*									72	72	89	85
	(2019 $/kW/yr)									*(81)*	*(81)*	*(100)*	*(95)*
After-tax WACC [d]	*% nominal*	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	(% real)	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*	*(1.8)*
National tax rate	*%*	30	30	30	30	30	30	30	30	30	30	30	30
Depreciation schedule [e]		Linear depreciation of 100% capital investment over 20 years											
LCOE [f]	*2019 €/MWh*	$99	$109	$118	$127	$136	$105	$106	$100	$126	$96	$117	$117
	(2019 $/MWh)									*$141*	*$107*	*$131*	*$130*

[a] Median net energy production values presented. Data before 2016 is not publicly available.
[b] Investment costs and OpEx are the median values for wind projects with capacity above 7.5 MW and are converted to real 2019 euros and U.S. dollars.
[c] OpEx include both fixed and variable components but are presented in terms of fixed costs.
[d] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.
[e] Linear depreciation of 100% of the initial capital investment over 20 years.
[f] LCOE was calculated assuming a 20-year amortization period.

A.5 Norway

Table A5. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for Norway

		Commercial Operation Date											
Parameter [a]	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	MW	36.0	-	-	69.6	69.6	69.6	21.7	21.7	108.0	108.0	63.3	98.6
Wind turbine nameplate capacity	MW	2.3	-	-	2.5	2.5	2.5	3.0	3.0	3.3	3.3	3.5	3.7
Wind turbine rotor diameter	m	75	-	-	90	90	90	99	99	113	113	120	121
Wind turbine hub height	m	66	-	-	79	79	79	80	80	92	92	93	93
Wind turbine specific power	W/m2	527	-	-	342	342	342	398	398	32	328	311	322
Net energy production [b]	*Capacity factor %*	32	-	-	33	33	33	43	43	41	41	39	45
	(Full load hours)	*(2,833)*	-	-	*(2,872)*	*(2,864)*	*(2,864)*	*(3,803)*	*(3,803)*	*(3,556)*	*(3,556)*	*(3,376)*	*(3,928)*
Investment cost [c]	*2019 €/kW*	1,106	-	-	1,574	1,574	1,574	1,475	1,475	1,127	1,076	1,053	978
	(2019 $/kW)	*(1,223)*	-	-	*(1,741)*	*(1,741)*	*(1,741)*	*(1,632)*	*(1,632)*	*(1,247)*	*(1,205)*	*(1,179)*	*(1,095)*
OpEx [c, d]	*2019 €/kW/yr*	46	-	-	46	46	46	41	41	38	38	38	38
	(2019 $/kW/yr)	*(51)*	-	-	*(51)*	*(51)*	*(51)*	*(45)*	*(45)*	*(42)*	*(43)*	*(43)*	*(43)*
After-tax WACC [e]	*% nominal*	7.7	-	-	5.5	5.5	5.5	5.0	5.0	4.5	4.5	4.5	4.5
	(% real)	*(5.6)*	-	-	*(3.4)*	*(3.4)*	*(3.4)*	*(2.9)*	*(2.9)*	*(2.5)*	*(2.5)*	*(2.5)*	*(2.5)*
Corporate income tax rate	%	28	-	-	28	28	28	28	27	25	22	22	22
Depreciation schedule [f]		Linear depreciation of 100% capital investment over 20 years								Accelerated 5 year			
LCOE [g]	*2019 €/MWh*	$56	-	-	$61	$61	$61	$41	$40	$32	$31	$32	$26
	(2019 $/MWh)	*$62*	-	-	*$67*	*$67*	*$67*	*$45*	*$45*	*$35*	*$34*	*$35*	*$29*

[a] No projects were installed in 2016; hence, 2017 data are represented for 2016.
[b] Net energy production in calendar year 2019: generation-weighted average, wind-index adjusted. The wind index adjusts wind project output in a given calendar year to represent output in a "typical" wind year. Capacity factors for projects installed from 2008 to 2015 are based on metered generation data from Statnett combined with modeled wind indices from Kjeller Vindteknikk. Full load hours based on 8,760 hours in 2019. Since the projects with COD in 2019 do not have a full year of performance data, an estimate of the expected generation in 2019 is provided.
[c] Investment costs and OpEx converted to real 2019 euros and U.S. dollars.
[d] OpEx include both fixed and variable components but are presented in terms of fixed costs.
[e] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.
[f] Linear depreciation of 100% of the initial capital investment over 20 years applied for projects installed from 2008 to 2015. Linear depreciation of 100% of the initial capital investment over 5 years applied for projects installed from 2016 to 2019.
[g] LCOE was calculated assuming a 20-year amortization period.

A.6 Sweden

Table A6. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for Sweden

		Commercial Operation Date											
Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	MW	4.4	4.7	6.5	8.4	10.2	13.8	21.9	37.5	20.5	19.4	37.1	73.1
Wind turbine nameplate capacity	MW	1.4	1.6	1.8	2.0	2.1	2.1	2.4	2.6	2.9	2.9	3.4	3.5
Wind turbine rotor diameter	m	74	84	87	89	96	101	104	112	113	116	126	133
Wind turbine hub height	m	83	87	95	97	99	113	105	109	104	113	123	126
Wind turbine specific power	W/m2	378	347	341	348	314	304	310	296	298	273	272	254
Net energy production [a]	*Capacity factor %*	27	27	29	29	29	30	30	33	33	32	38	36
	(Full load hours)	*(2,348)*	*(2,356)*	*(2,567)*	*(2,575)*	*(2,532)*	*(2,637)*	*(2,593)*	*(2,928)*	*(2,851)*	*(2,835)*	*(3,305)*	*(3,161)*
Investment cost [b]	*2019 €/kW*	1,371	1,718	1,571	1,580	1,449	1,319	1,321	1,203	1,150	1,262	1,291	984
	(2019 $/kW)	*(1,517)*	*(1,900)*	*(1,738)*	*(1,747)*	*(1,603)*	*(1,459)*	*(1,461)*	*(1,330)*	*(1,273)*	*(1,413)*	*(1,445)*	*(1,101)*
OpEx [b, c]	*2019 €/kW/yr*	61	67	57	60	61	54	44	42	41	39	37	35
	(2019 $/kW/yr)	*(68)*	*(74)*	*(63)*	*(66)*	*(67)*	*(60)*	*(49)*	*(47)*	*(45)*	*(44)*	*(42)*	*(40)*
After-tax WACC [d]	*% nominal*	8.0	7.6	7.3	6.9	6.5	6.1	5.8	5.4	5.0	5.0	5.0	5.0
	(% real)	*(5.9)*	*(5.5)*	*(5.1)*	*(4.8)*	*(4.4)*	*(4.0)*	*(3.7)*	*(3.3)*	*(2.9)*	*(2.9)*	*(2.9)*	*(2.9)*
National tax rate	*%*	26	26	26	26	26	22	22	22	22	22	22	22
Depreciation schedule [e]		Linear depreciation of 100% capital investment over 20 years											
LCOE [f]	*2019 €/MWh*	$86	$100	$81	$80	$75	$62	$58	$46	$44	$47	$40	$34
	(2019 $/MWh)	*$95*	*$111*	*$89*	*$88*	*$83*	*$69*	*$64*	*$51*	*$49*	*$52*	*$45*	*$38*

[a] Net energy production in calendar year 2019: generation-weighted average, wind-index adjusted. The wind index adjusts wind project output in a given calendar year to represent output in a "typical" wind year. The wind index for 2016 is based on the average energy outputs from approximately 900 wind turbines over the period 2007–2016. Capacity factors for projects installed from 2008 to 2014 are based on metered generation data from the Electricity Certificate Registry. Full load hours based on 8,760 hours in 2019. Since the projects with COD in 2019 do not have a full year of performance data, an estimate of the expected generation in 2019 is provided.
[b] Investment costs and OpEx converted to real 2019 euros and U.S. dollars.
[c] OpEx include both fixed and variable components but are presented in terms of fixed costs.
[d] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.
[e] Linear depreciation of 100% of the initial capital investment over 20 years.
[f] LCOE was calculated assuming a 20-year amortization period.

A.7 European Union

Table A7. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for the European Union

Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	MW	14.4	14.3	13.7	13.0	15.8	10.5	8.9	10.1	9.0	9.9	11.8	15.5
Wind turbine nameplate capacity rating	MW	2.0	2.1	2.2	2.2	2.3	2.5	2.6	2.6	2.7	2.7	2.9	3.1
Wind turbine rotor diameter	m	82	86	87	88	91	94	98	103	104	106	110	119
Wind turbine hub height	m	80	89	91	92	99	96	111	125	134	-	-	-
Wind turbine specific power	W/m2	380	366	368	364	363	362	353	321	321	321	311	293
Net energy production	*Capacity factor %*	-	-	-	-	-	-	-	28	27	28	30	31
	(Full load hours)	-	-	-	-	-	-	-	*(2,481)*	*(2,397)*	*(2,448)*	*(2,642)*	*(2,703)*
Investment cost [b]	*2019 €/kW*	2,385	2,568	2,538	2,478	2,361	1,930	2,013	1,757	1,651	1,545	1,477	1,445
	(2019 $/kW)	*(2,670)*	*(2,875)*	*(2,841)*	*(2,774)*	*(2,643)*	*(2,161)*	*(2,254)*	*(1,967)*	*(1,848)*	*(1,730)*	*(1,654)*	*(1,617)*
OpEx [b, c]	*2019 €/kW/yr*	30	31	30	29	29	28	30	25	25	24	23	23
	(2019 $/kW/yr)	*(33)*	*(34)*	*(33)*	*(33)*	*(32)*	*(31)*	*(33)*	*(28)*	*(28)*	*(27)*	*(26)*	*(25)*
After-tax WACC [d]	*% nominal*	4.6	4.7	4.7	4.6	4.4	5.0	4.8	4.0	3.8	4.6	3.9	3.9
	(% real)	*(2.5)*	*(2.6)*	*(2.6)*	*(2.5)*	*(2.4)*	*(2.9)*	*(2.7)*	*(2.0)*	*(1.8)*	*(2.6)*	*(1.8)*	*(1.8)*
Corporate income tax rate	*%*	20	20	20	20	20	20	20	20	20	20	20	20
Depreciation schedule [e]		Linear depreciation of 100% capital investment over 20 years											
LCOE [f]	*2019 €/MWh*	-	-	-	-	-	-	-	$57	$55	$55	$45	$43
	(2019 $/MWh)	-	-	-	-	-	-	-	*$64*	*$61*	*$61*	*$50*	*$48*

[a] Net energy production in calendar year 2019: generation-weighted average, wind-index adjusted. The wind index adjusts wind project output in a given calendar year to represent output in a "typical" wind year. Full load hours based on 8,760 hours in 2019. Since the projects with COD in 2019 do not have a full year of performance data, an estimate of the expected generation in 2019 is provided.

[b] Investment costs and OpEx converted to real 2019 euros and U.S. dollars.

[c] OpEx include both fixed and variable components but are presented in terms of fixed costs.

[d] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2%. This assumption is used to convert nominal WACC to real WACC.

[e] Linear depreciation of 100% of the initial capital investment over 20 years.

[f] LCOE was calculated assuming a 20-year amortization period.

A.8 United States

Table A8. Wind Plant Technology, Cost, and Performance Data From 2008 to 2019 for the United States

		Commercial Operation Date											
Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project size	*MW*	80.7	92.0	78.7	75.3	92.4	89.2	117.8	138.4	123.9	114.9	126.2	178.8
Wind turbine nameplate capacity rating	*MW*	1.7	1.7	1.8	2.0	2.0	1.9	1.9	2.0	2.2	2.3	2.4	2.6
Wind turbine rotor diameter	*m*	79	82	84	89	94	98	100	103	108	113	116	121
Wind turbine hub height	*m*	79	79	80	81	84	81	83	83	83	86	88	90
Wind turbine specific power	*W/m2*	332	329	319	315	286	254	250	244	233	230	230	220
Net energy production [a]	*Capacity factor %*	30	29	31	30	33	36	41	40	42	41	40	41
	(Full load hours)	*(2,596)*	*(2,560)*	*(2,732)*	*(2,630)*	*(2,858)*	*(3,172)*	*(3,567)*	*(3,541)*	*(3,692)*	*(3,598)*	*(3,518)*	*(3,558)*
Investment cost [b]	*2019 €/kW*	2,049	2,240	2,237	2,141	1,931	1,809	1,676	1,528	1,562	1,497	1,328	1,282
	(2019 $/kW)	*(2,294)*	*(2,507)*	*(2,504)*	*(2,397)*	*(2,162)*	*(2,026)*	*(1,877)*	*(1,711)*	*(1,749)*	*(1,675)*	*(1,487)*	*(1,435)*
OpEx [b, c]	*2019 €/kW/yr*	50	49	47	46	46	45	44	43	42	41	40	39
	(2019 $/kW/yr)	*(56)*	*(54)*	*(53)*	*(52)*	*(51)*	*(50)*	*(49)*	*(48)*	*(47)*	*(45)*	*(44)*	*(43)*
After-tax WACC [d, e]	*% nominal*	5.7	6.1	6.1	6.0	5.6	5.7	5.5	5.3	5.0	5.1	5.6	5.2
	(% real)	*(3.7)*	*(4.1)*	*(4.1)*	*(3.9)*	*(3.5)*	*(3.6)*	*(3.5)*	*(3.2)*	*(2.9)*	*(3.1)*	*(3.5)*	*(3.1)*
Corporate income tax rate	*%*	40	40	40	40	40	40	40	40	40	40	27	27
Depreciation schedule [f]		MACRS 5 year											
LCOE [g]	*2019 €/MWh*	81	90	84	83	68	58	48	44	42	42	39	36
	(2019 $/MWh)	*(91)*	*(101)*	*(94)*	*(93)*	*(76)*	*(65)*	*(54)*	*(49)*	*(47)*	*(47)*	*(44)*	*(41)*

[a] Capacity factors calculated using the “wind index weighted” project-level wind resource indices developed by Lawrence Berkeley National Laboratory for 2019 to normalize each project’s output in that year for inter-annual variation before calculating the generation-weighted average. Since the projects with COD in 2019 do not have a full year of performance data, an estimate of the expected generation in 2019 is provided.

[b] Investment costs and OpEx converted to real 2019 euros and U.S. dollars using The World Bank currency conversion rates and gross domestic product deflators.

[c] OpEx include both fixed and variable components but are presented in terms of fixed costs.

[d] The average WACC in each year is based on the following assumptions: (1) no Production Tax Credit, (2) debt/equity ratio of 65%/35%, (3) a levered after-tax equity return of 10% (does not change over time), (4) cost of debt varies each year based on movements in the 20-year swap rate (as reported by Intercontinental Exchange) and in the bank spread (as reported by Bloomberg New Energy Finance with recent gaps in the data filled based on Norton Rose Fulbright’s annual “Cost of Capital” series), and (5) combined state and federal tax rate assumed to be 40% through 2017, dropping to 27% in 2018.

[e] The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2% and is used to convert nominal WACC to real WACC.

[f] Depreciation of 100% of the initial capital investment over 5 years using the Modified Accelerated Cost-Recovery System (MACRS).

[g] LCOE was calculated assuming a 20-year amortization period.