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IEA Wind TCP Task 26

**Wind Technology, Cost, and
Performance Trends in Denmark,
Germany, Ireland, Norway, Sweden, the
European Union, and the United States:
2008-2016**

Technical report



iea wind

NOTICE

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Nomenclature or List of Acronyms

AVG	average
BEAT	Base erosion anti-abuse tax
BImSchG	Bundes-Immissionsschutzgesetz (Federal Immission Control Act)
BNEF	Bloomberg New Energy Finance
BNetzA	Bundesnetzagentur (Federal Network Agency)
BWE	Bundesverband WindEnergie (German Wind Energy Association)
CapEx	capital expenditure
DOE	U.S. Department of Energy
EEG	Erneuerbare-Energien-Gesetz (Renewable Energy Sources Act)
EEX	European Energy Exchange
EMHIRES	European Meteorological derived high resolution renewable energy source
EPEX	European Power Exchange
ETS	Emissions Trading System
EU	European Union
FIT	feed-in tariff
FIP	feed-in premium
FLH	full load hours
IEC	International Electrotechnical Commission
ITC	investment tax credit
GW	gigawatt
IEA	International Energy Agency
JRC	Joint Research Centre
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
m	meters
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
NVE	Norwegian Water Resources and Energy Directorate
O&M	operation and maintenance
OpEx	operational expenditure
PPA	power purchase agreement
PTC	production tax credit
REFIT	renewable energy feed-in tariff
SEA	Swedish Energy Agency
SEM	single electricity market
SMP	system marginal price

TSO	transmission system operator
TWh	terawatt-hour
ÜNB	Übertragungsnetzbetreiber (transmission system operator)
VDMA	Verband Deutscher Maschinen- und Anlagenbau (Mechanical Engineering Industry Association)
WACC	weighted average cost of capital
yr	year

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1 Overview

The International Energy Agency Wind Technology Collaboration Programme (IEA Wind TCP) Task 26—The Cost of Wind Energy represents an international collaboration dedicated to exploring the past, present, and future cost of wind energy. The countries that are currently represented by participating organizations in IEA Wind TCP Task 26 included in this report are Denmark, Germany, Ireland, Norway, Sweden, the European Union, and the United States. This report discusses trends from 2008 through 2016 that affected the cost of land-based wind energy in each country.¹ The cost of wind energy during this period is compared with the market value of wind energy in the respective electricity market for each country.

This report builds from previous analysis conducted since the inception of Task 26 in 2009. Schwabe et al. (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, including wind project size, turbine size, specific power and hub height, project performance, investment costs, operation and maintenance (O&M) costs, and project financing. These inputs are used to calculate the levelized cost of energy (LCOE), a widely recognized metric for understanding how technology performance, capital investment, operations, and financing impact the life cycle cost of building and operating a wind project. Both prior reports—as well as this report—used this metric to estimate the cost of wind energy.

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 presented in each chapter 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 of the primary parameters and thereby significant variation in LCOE. However, these “typical” or “average” estimates in this report provide an indication of general trends between 2008 and 2016.

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](#) and are available for download. The specific data used in this report are compiled in [the attached supplemental data appendix](#). The data sources are unique to each country, and the sample sizes vary by country and parameter. Most of the data originates from the wind industry, which is reported to national government sources that are publicly available. Some data is reported directly by wind project developers to government agencies or research organizations.

These project-level data illustrate how wind turbine technology, wind project investment and operation costs, wind plant energy production, and wind project financing costs vary with the specific wind turbine technology installed in a given year. These trends illustrate how wind turbine and wind plant technology have changed from 2008 to 2016 along with the corresponding changes to wind plant cost and performance.

¹ The members of IEA Wind Task 26 also study the cost of offshore wind energy. For more information, visit: <https://community.ieawind.org/task26/results>.

This cost of energy analysis is restricted to land-based wind projects. All costs are presented in both real U.S. dollars (USD or \$) and real euros (EUR or €) and represent currency values for the year 2016. The World Bank currency conversion rates and gross domestic product deflators are used to convert between currencies and to convert prior year currency values to 2016 currency values to adjust for inflation in a manner developed by the Intergovernmental Panel on Climate Change (Krey et al. 2014); the deflator and currency conversion values are included in [the attached supplemental data appendix](#).

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

- Investment costs (also referred to as CapEx) are incurred in total at project initiation
- O&M 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.

Energy production estimates are derived primarily from an analysis of wind project capacity factors from projects operating in calendar year 2016, for projects commissioned between 2008 and 2016. Because wind resource conditions in 2016 may not correspond to expected annual average wind speed over the life of the wind project, the 2016 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. A full year of performance data for projects commissioned during 2016 was not available for each country, requiring varying approaches to estimate the long-term performance for projects commissioned that year.

The equation in Appendix A 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 in each chapter. For the purpose of this analysis, a 20-year project life is assumed across all countries and years, consistent with past Task 26 publications; some wind industry members have begun to use 25- or even 30-year project lives, and the analysis presented here does not reflect that trend. Additional details and common assumptions are described in Appendix A.

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 2008 to 2016 in the respective country. In particular, this approach provides a simple method for illustrating changes in LCOE over this time 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—2008 through 2016—in the respective country. LCOE does not include sources of revenue or policy incentives, such as tax credits or feed-in premiums.

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 chapter 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 cost and value of wind 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, 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.

Each country chapter in this report discusses four primary topics. The first section of each chapter describes the wind industry in terms of installed capacity along with near- and medium-term projections if available. Revenue and policy incentives are also discussed. The second section describes turbine- and project-level trends that influenced the cost of energy from 2008 to 2016. The third section describes the estimated LCOE of new wind projects installed in each year of the analysis period and identifies the primary elements that contributed to changes in LCOE (e.g., energy production, investment costs, operating costs, and project financing costs). The fourth section compares the estimated LCOE for new wind plants with the market value of wind energy observed in each year.

This report focuses on trends in each country independently. However, technology advances that are intended to increase energy capture, such as taller towers and lower specific power, along with documentation of increasing capacity factors are evident in most of the countries. This increase in energy production is often coupled with level or decreasing investment and operating costs as well as lower cost of capital, resulting in lower LCOE from 2008 to 2016. LCOE

reduction associated with wind power plant technology advances is important because the calculated “market value” of wind energy has also declined over this period. Continued technology advances that reduce the cost of wind energy are required to improve the cost-competitiveness of wind energy in electricity markets. Additional publications that explore similarities and differences among the countries are underway.

2 Denmark

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2.1 Wind Energy Development in Denmark

After a general overview of the capacity installed and the long-term target for both land-based and offshore wind energy, this analysis focuses on land-based wind from 2008 to 2016. A detailed analysis of offshore wind development and cost will be provided in the forthcoming IEA Wind TCP Task 26 Offshore Wind report. In general, the data used in this chapter is updated until 2016. However, when available, 2017 information is included.

2.1.1 Domestic Wind Energy Capacity, Production, and Targets

At the end of 2017, the total installed capacity of wind energy in Denmark reached 5.5 gigawatts (GW), of which around 4.2 GW are land-based and 1.3 GW offshore. The entire period from 2008 to 2016 has been characterized by a steady growth in capacity, averaging 262 megawatts (MW) net additions per year. In 2017, the country experienced one of the highest land-based gross capacity additions in its wind turbine history with a total of 345 MW.

Wind power covered 43.6% of national electricity consumption in 2017, up from 37.5% in 2016, which was also a more moderate wind year compared to 2017 (see Figure 1). This value represents a new world record of penetration of variable renewable energy, namely solar and wind, at a country level.

Note that the number of turbines above 500 kilowatts (kW) in Denmark has not largely increased in the period analyzed. While the number of turbines has only grown by 22%, from 3,085 to 3,755, the total capacity installed increased 75%. This growth can be explained by the fact that smaller and older turbines were decommissioned, whereas newer turbines installed are larger and have higher capacity factors. Moreover, offshore wind development has contributed by providing a high capacity rating per turbine.

From 2008 to 2016, a total of 378 MW of land-based turbines were decommissioned, corresponding to an average of 42 MW per year.² Until the end of 2011, repowering was supported by a specific repowering scheme in the form of an additional feed-in premium.

² More information on the repowering of older turbines will be available in a *forthcoming report on repowering*.

In the near future, a sharp increase in the wind capacity installed is expected, as a result of four planned offshore wind plants, totaling a capacity of 1,350 MW. The plants were auctioned in 2015/2016 and are projected to be built in the next 3–4 years.³

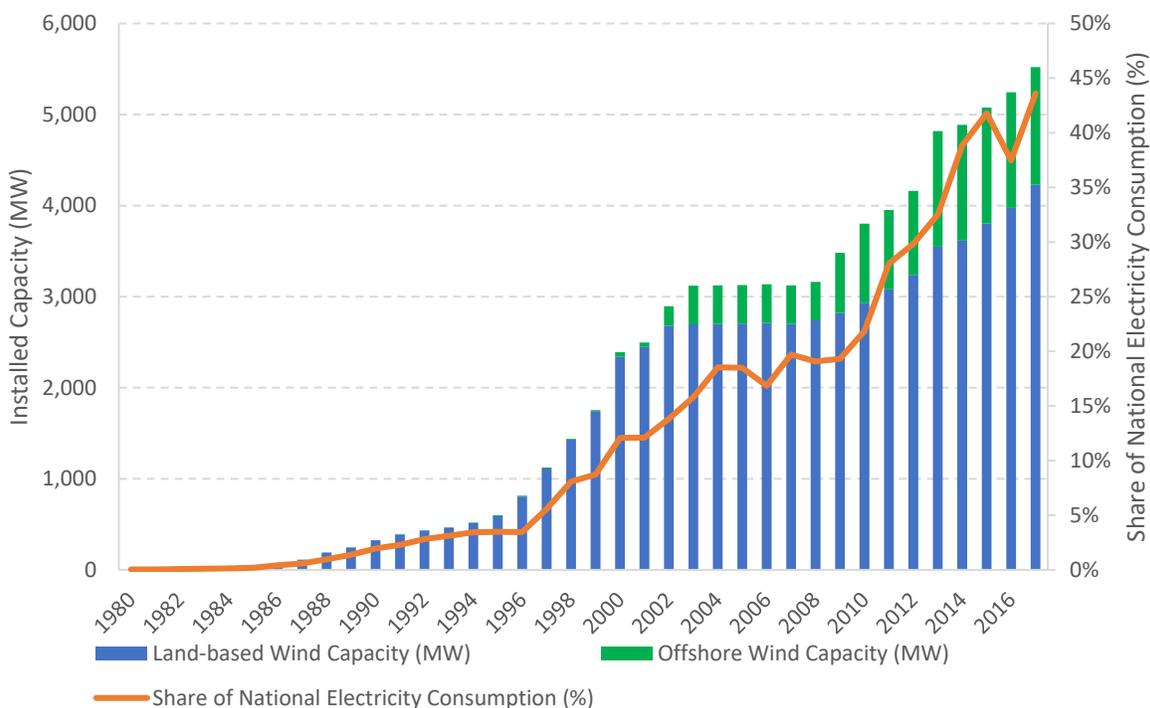


Figure 1. Wind power growth in Denmark from 1980 to 2017

Sources: Annual Danish Statistics (Danish Energy Agency 2018a) and Stamdataregister (Danish Energy Agency 2018b)

On June 29, 2018, all parties in Danish parliament agreed on a new energy deal (*Energiaftale*) setting out long-term targets and specific actions for the period from 2020 to 2024 (Danish Ministry of Energy, Utilities and Climate 2018). By 2030, the energy deal sets out a target of supplying 55% of the national energy consumption from renewable energy. The renewable share in electricity consumption should be more than 100%, and coal will be phased out from electricity generation, which follows up on Ørsted’s - formerly DONG Energy made a commitment to phase out or convert their coal power plants by 2023 (Ørsted 2017). Denmark’s long-term target is to achieve a “low-emission” society in 2050 and ensure net-zero emissions by 2050 at the latest.

For wind power, the energy deal includes three new offshore wind plants of at least 800 MW each, which are planned to be fully operational before 2030 and will be auctioned in 2019/2020, 2021, and 2023. No specific targets for land-based wind power are provided in the energy deal, and wind power will have to compete in “technology-neutral” auctions with other renewable technologies. However, the agreement invokes an upper limit of 1,850 onshore wind turbines in 2030 (down from 4,224 today). The details of how this target is to be achieved are yet to be

³ Horns Rev 3 (407 MW, ultimo 2019), Kriegers Flak (605 MW, 2022) and the two near-shore wind farms of Vesterhav Syd and Vesterhav Nord (combined 350 MW, 2020)

determined. The upper limit does not automatically imply a restriction on total land-based wind capacity, which could still increase compared to the 4.2 GW installed today, when newer, larger turbines are deployed, and replace older, smaller turbines.

The Danish transmission system operator (TSO), Energinet, publish their analysis assumptions (*Analyseforudsætninger*) every year, which are widely used as reference figures for the analyses of the future development of the power system.⁴ The latest projection from Energinet (2017) anticipates a large increase in Denmark's wind capacity, driven by an almost threefold increase in offshore wind capacity by 2030. Energinet expects the total wind capacity in 2030 is expected to reach 8.8 GW, of which 57% on land and 43% offshore. In the TSO projection, wind would exceed 10 GW in 2040 (5.8 GW thereof being land-based and almost 5 GW offshore).

2.1.2 Revenue and Policy Incentives

The development of land-based wind in the period analyzed has been mainly driven by direct subsidies for the electricity produced. The 2009 *Promotion of Renewable Energy Act* established a feed-in premium (FIP) of DKK 0.25 per kilowatt-hour (kWh) (3,4 €-cent/kWh) of production, granted on top of the revenues for the electricity sold in the wholesale market, for the first 22,000 full load hours to all turbines connected as of 21 February 2008.

The period for which the FIP is granted was revised in 2014. The formula used to calculate the total amount of electricity incentivized considers a base amount of full load hours equal to 6,600 and an incremental amount depending on the rotor area, as follows:

$$\begin{aligned} \text{Production incentivized [MWh]} \\ = 6,600 [h] \cdot \text{rated power [MW]} + \text{rotor area [m}^2\text{]} \cdot 5.6 [\text{MWh/m}^2\text{]} \end{aligned}$$

An additional subsidy for the technical lifetime of the wind power project to cover balancing costs has been active since 2008 and its value was adjusted over time, from the original 0.0237 DKK/kWh to the current 0.009 DKK/kWh (0.32 to 0.12 c€/kWh).

Furthermore, wind power projects in Denmark benefit from wind turbine eligibility for accelerated depreciation rules based on a declining balance method. In the 2008–2012 period, wind turbines could be depreciated by 25% of their respective residual value annually. As of 2013, the rate decreased to 15% (SKAT 2018).

The *Promotion of Renewable Energy Act* introduced, among other regulations, a local citizens' option to purchase a share of a wind power project (*Køberetsordningen*). Under this rule, a power project must offer at least 20% of the shares in the wind turbine to those living in the proximity of the project site, or within the same municipality.

Part of the reason for the high capacity installation in 2017 was that the FIP support scheme expired the 21 February 2018 and the uncertainty on future incentives on land-based wind pushed developers to expedite the construction and connection process.

⁴ From 2018 onward, the Danish Energy Agency is responsible for the document. See: <https://ens.dk/service/fremskrivninger-analyser-modeller/analyseforudsætninger-til-energinet>.

A long debate about the new support scheme for land-based wind revealed that a number of stakeholders, including the political opposition and the Danish Wind Energy Association (*Vindmølleindustrien*), were pushing for a new agreement to maintain the climate ambition and avoid stagnation in the wind industry. In September 2017, the government signed a resolution outlining the design principles of new support schemes: technology neutrality, the FIP model, and support for the entire lifetime of the plant (20 years) (Danish Ministry of Energy, Utilities and Climate 2017). The new technology-neutral auctions, details of which are under discussion, will cover from 2018 to 2019. It will be a common tender scheme for land-based wind, solar photovoltaics, and offshore wind under the “open-door” scheme, based on a pay-as-bid principle. The price ceiling is set to 0.13 DKK/kWh (1.75 c€/kWh) and the total budget is roughly 800 million DKK (107 million €).⁵ Additionally, roughly 350 million DKK (47 million €) are set aside for test turbines, which will receive a market premium of 0.11–0.13 DKK/kWh (1.48–1.75 c€/kWh) if erected in 2018, and a premium corresponding to the average winning auction bid in 2018 if erected in 2019.⁶ The support period is 3 years in national test centers and 20 years elsewhere.

The Danish Ministry of Energy, Utilities and Climate expects the auctions in 2018 and 2019 to result in new wind and solar capacity corresponding to 140 MW of ‘land-based wind-equivalents’⁷ in total, excluding test turbines (Danish Ministry of Energy, Utilities and Climate 2018).

As part of this new framework, the right of local citizens to buy shares of wind projects and other regulations could be revised; moreover the subsidy for balancing cost has been reduced to partly finance the new scheme.

Until 2017, the support mechanisms for renewable energy were financed through a Public Service Obligation Tariff, levied on consumers through the electricity bill. In November 2016, it was abolished by the parliament and as a result, the related costs will gradually be transferred to the state budget with a phase-out period of 5 years, from 2017 to 2022 (Danish Ministry of Energy, Utilities and Climate 2016).

The new energy deal for the period from 2020 to 2024 continues the setup of technology-neutral auctions, with a total budget of 4.2 billion DKK (563 million €), and including support for test turbines. Given this budget is 5.25 times higher than the one for 2018/2019, at least around 735 MW of “land-based wind-equivalents,” could be expected as a result from the auctions. However, continued technology cost reductions and increasing power prices might increase this number. The support scheme is yet to be decided, and awaits evaluation of the feed-in premium

⁵ Further details on the auction design can be found on the Danish Energy Agency website: <https://ens.dk/service/aktuelle-udbud/teknologineutrale-udbud-2018-2019>.

⁶ The first resolution signed in September 2017 had a budget of 150 million DKK for test turbines. This budget was later changed to a total of 360 million DKK, the difference being deducted from the budget for auctions. <https://via.ritzau.dk/pressemeddelelse/test-af-vindmoller-far-hojere-prioritet?publisherId=9426318&releaseId=12251836>.

⁷ One hundred and forty MW assuming all capacity is assigned to wind. Since the capacity factor of land-based wind power is roughly three times the one of solar power, each megawatt of wind could be substituted by 3 MW of solar.

model for 2018/2019. Additionally, auction design, which allows the bidder to choose between feed-in premiums and feed-in tariffs, will be analyzed.

2.2 Wind Energy Project Trends in Denmark Since 2008

In this section, trends regarding wind projects in Denmark are presented for wind projects installed from 2008 through 2016. The full data set can be accessed and downloaded via the [IEA Wind TCP Task 26 Data Viewer](#). The specific data used in this report and the data used to convert monetary values to real 2016 euros and US dollars are compiled in [the attached supplemental data appendix](#).

Wind power projects in Denmark have been characterized as being a relatively small size, although slightly increasing over time, reaching about 20 MW in 2015/2016. The average nameplate capacity, growing in the period from 2008 to 2012, has levelled off at approximately 3 MW. The average hub height of turbines installed in Denmark has been relatively constant—around 80 to 90 meters (m), mainly because of a planning limit of 150 m on the tip height of turbines.⁸

Thanks to a slight growth in rotor diameter and stable nameplate capacity, the specific power of turbines installed in Denmark has declined over time, from a record high of 400 W/m² in 2010 to 316 W/m² in 2016. This decline is reflected in a consistent decreasing share of International Electrotechnical Commission (IEC) Class I turbines among newly installed projects in Denmark throughout the period and the emergence of IEC Class III turbines from 2013 onward. In 2014, one out of five new turbines were classified as IEC Class III, making it a record year.

For turbine sites installed in Denmark the quality of wind resource has been relatively stable throughout the review period, typically within a range of 7–8.5 meters per second (m/s) average annual wind speed at 100 m height. The data seem to indicate no signs of depletion of good sites, despite the high turbine density reached in the country.

Although average wind index corrected capacity factors in Denmark have been generally high—above 34%—throughout the entire period analyzed, there is a trend toward increased values in more recent years. This is a result of the aforementioned stable quality of wind sites combined with a decrease in specific power. With an average of 41%, which corresponds to roughly 3,600 full load hours, wind turbines installed in 2014 set a record.

Wind turbine technology deployed in Denmark shows a reduction in specific power and an increase in capacity factors from 2008 to 2016 (Figure 2). The two factors show a strong inverse correlation: a reduction in specific power results in an increase in capacity factors, while higher specific power causes lower capacity factors. This outcome is particularly evident in 2014. However, there are other factors that contribute to the evolution of capacity factors, such as hub height and resource quality, in the sites deployed.

⁸ In Denmark, the limit for turbine tip height (maximum height of the turbine including blades) of newly installed turbines is 150 m. Exceptions to this can be granted only by the Ministry for the Environment.

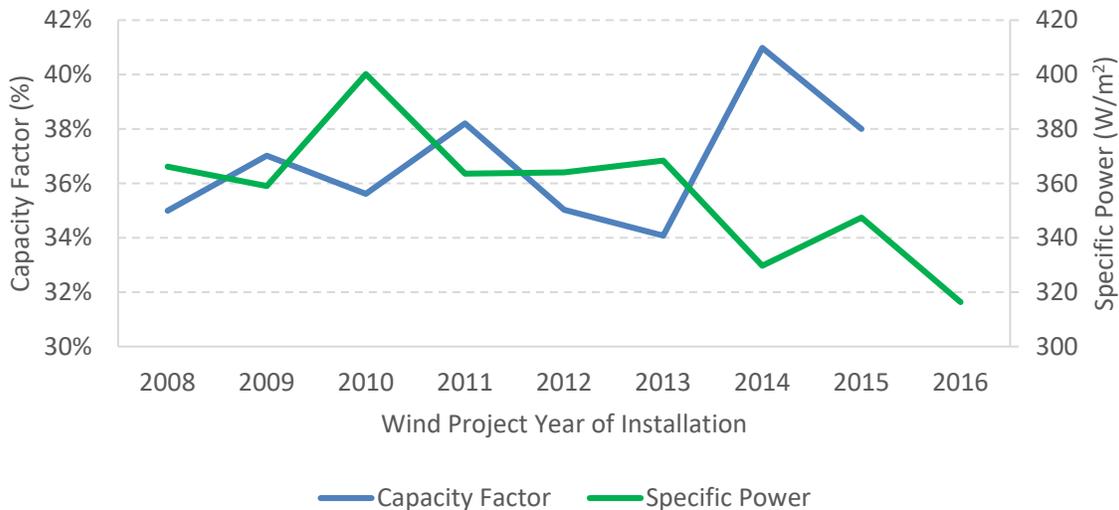


Figure 2. Specific power and capacity factors for wind projects installed in Denmark from 2008 to 2016

As for the investment cost of land-based wind turbines, following a period of cost decline between 2008 and 2011 and a consequent stabilization period from 2013 to 2014, the cost decreased substantially in 2015 and 2016. The capital cost of turbines is now at a record-low capacity-weighted average of 1,153 €/kW (\$1,275/kW). The average fixed O&M cost has been stable at around 40 €/kW/yr (\$44/kW/yr) with a reduction in 2016, down to 33 €/kW/yr (\$37/kW/yr). Besides, data for O&M indicate a large span across different projects.

Interviews with banks and developers (Ea Energy Analyses 2017) suggest a trend toward reduced cost of financing for land-based wind in Denmark. Weighted average cost of capital has been going down from 2013 to 2016 compared to 2008–2012. The main driver for this reduction is a substantially lower cost of debt, as well as lower cost of equity, while the debt -equity ratio seems to have been stable during the entire period.

2.3 Cost of Wind Energy Generation in Denmark Since 2008

2.3.1 Sources and Assumptions

To analyze the evolution of the LCOE in Denmark from 2008 to 2016, the average characteristics of the projects constructed in every year are considered.

We used different national sources to collect project-level data, with the most important ones being the following:

- **The “core data registry” (*Stamdataregister*).** Published by the Danish Energy Agency, the registry is based on monthly data reports from the Danish TSO, Energinet, and grid companies, and provides details regarding the characteristics and production data of each grid-connected wind turbine (Danish Energy Agency 2018b).

- The “wind turbine project overview” (*Vindmølleprojektoversigt*) database. Hosted by the Danish TSO Energinet⁹, the database contains data on size, location, and ownership of grid-connected projects (Energinet 2018b).
- **Public wind energy project-share purchase information documents.** These documents are in accordance with the requirements of the “share purchase right” (*Køberetsordning*) regulation, and provide details on the projects’ top-level, cost-price information.¹⁰

The sample size of the data used is relatively complete for recent years (2013–2016), yet sparser for the previous period. More details about the sample size can be found in [the attached supplemental data appendix](#).

For the LCOE calculation, capacity-weighted values for the investment and O&M costs were chosen, whereas the wind-indexed average capacity factors were considered.¹¹

As for financing costs, data for 2008–2012 from a previous IEA Wind TCP Task 26 report (Schwabe et al. 2011) have been augmented with interviews of developers and banks active in the land-based wind sector in Denmark to assess the industry’s evolution until 2016. The structure of project financing has remained unchanged throughout 2008–2016, with 80% annuity-based debt being typical in Denmark. The typical cost of lending and equity from 2008 to 2012 featured a typical debt rate of 5% (nominal) and an equity rate in the range of 9% to 11% (nominal). The last 4 years have been characterized by lower financing costs. From 2013 on, land-based wind projects have been financed at the nominal level of about 6%–9% return on equity and 1.5%–3% return on debt. In addition, the Danish corporate tax rate has gradually decreased, by one percentage point per year through 2016 (before 2013: 25%, 2014: 24%, 2015: 23%, and 2016: 22%).

Table 1. Financial Parameters and Resulting Weighted Average Cost of Capital in Denmark

Parameter	Unit	2008–2012	2013–2016
Debt/equity ratio	%	80/20	80/20
Return on equity	%	9–11	6–9
Return on debt	%	5	1.5–3
Corporate tax	%	25	25→22*
Weighted average cost of capital (after-tax, nominal)	%	4.8–5.2	2.1–4.3

* Corporate tax has been decreasing by 1% a year from 2013 to 2016 and stabilized to 22%.

⁹ The responsibility to update the wind turbine project overview database has been passed on to the Danish Energy Agency as for 1 January 2018. Data on previous projects is still available on Energinet website.

¹⁰ It should be noted that the investment cost information from the *Køberetsordning* documents hereby presented is representative of the year when the investment decision was made (and share purchase made available to the local residents), not the year of installation.

¹¹ The wind index value for 2016 was equal to 0.91; therefore, all capacity factors have been normalized, dividing each annual value by this factor.

Denmark applies an accelerated depreciation scheme for land-based wind turbines that is based on a declining balance method at an annual rate of 15% for turbines above 1 MW built after January 2013 (25% before 2013).¹²

2.3.2 Trends Since 2008

The characteristics of the typical projects used for the calculation and the resulting LCOE for 2008–2016 are displayed in Table 2.

As can be noted from the resulting values, there has been a significant reduction in LCOE in Denmark in the period analyzed: from 47 €/MWh in 2008 to 32 €/MWh in 2016 (\$52/MWh to \$35/MWh), a reduction of 32%. Another aspect to be noted is that the LCOE did not reduce constantly, but rather fluctuated up and down in consecutive years. This is mainly caused by yearly variation in the investment costs and capacity factors of new projects. Because the capacity factor refers to the production in 2016 of typical projects installed in the various years, the fluctuations do not reflect changes in the wind conditions across years but are only attributable to either a technology difference (e.g., different rotor size or hub height) or a variation in the wind quality of the sites deployed.

¹² More information on the Danish Tax Administration Legal guide 2018 (SKAT 2018) section C.C.4.5.5 about depreciation of renewable energy plants can be found here: www.skat.dk/SKAT.aspx?oID=1975608.

Table 2. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed From 2008 to 2016 in Denmark

Source: Elaboration of data from Stamdatregister (Danish Energy Agency 2018b) and material shared under the Share Purchase Right (Energinet 2018b)¹³

Parameter	Unit	Wind Project Year of Installation									
		2008	2009	2010	2011	2012	2013	2014	2015	2016	
Net energy production ^a	Capacity factor %	35	37	36	38	35	34	41	38	36 ^b	
	(Full load hours)	(3,074)	(3,252)	(3,128)	(3,356)	(3,077)	(2,993)	(3,600)	(3,338)	(3,161) ^b	
Investment cost ^c	2016 €/kW	1,506	1,401 ^d	1,513 ^d	1,348 ^d	1,311	1,352	1,359	1,284	1,153	
	(2016 \$/kW)	(1,665)	(1,550)	(1,674)	(1,492)	(1,451)	(1,495)	(1,503)	(1,420)	(1,275)	
O&M cost ^c	2016 €/kW/yr	39 ^e	39 ^e	39 ^e	39 ^e	39 ^e	39	38	45	33	
	(2016 \$/kW/yr)	(43)	(43)	(43)	(43)	(43)	(43)	(42)	(49)	(37)	
After-tax WACC ^f	% nominal	5.0	5.0	5.0	5.0	5.0	3.1	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)	
Corporate income tax rate	%	25	25	25	25	25	25	24	23	22	
Depreciation schedule ^g		Maximum 25%/year (yr)					Maximum 15%/yr				
LCOE ^h	2016 €/MWh	47	42	46	40	42	39	33	36	32	
	(2016 \$/MWh)	(52)	(47)	(51)	(44)	(47)	(44)	(36)	(40)	(35)	

^a Net energy production in calendar year 2016: 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 8,784 hours in 2016.

^b In 2016, a full year of energy production data was not available for projects installed during 2016. Therefore, the capacity factor associated with projects installed in 2016 is estimated using wind-index adjusted 2017 generation data.

^c Investment cost and O&M cost converted to real 2016 euros and US dollars. Details are in [the attached supplemental data appendix](#). O&M cost includes both fixed and variable components but is presented in terms of fixed cost.

^d For 2009–2011, the capacity-weighted average was not available; therefore, the median was used.

^e O&M costs between 2008 and 2012 have been assumed equal to the 2013 value.

^f The forward-looking expectation of inflation over the life of the wind plant was assumed to be 2% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. This assumption is used to convert nominal WACC to real WACC.

^g 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 2016.

^h LCOE was calculated assuming a 20-year amortization period.

To analyze the main drivers for the observed reduction of LCOE, we performed a decomposition analysis. One parameter at a time was changed from the 2008 value to the 2016 value, and the effect of the single parameter variation on the LCOE was assessed separately.¹⁴ The results summarized in Figure 3 show that the two main factors influencing the large LCOE reduction experienced in Denmark are WACC and investment cost, which combined are responsible for

¹³ Additional data and graphic visualization can be accessed and downloaded in the [IEA Wind TCP Task 26 Data Viewer](#).

¹⁴ Because taxation rate and after-tax WACC are related, WACC was varied, thereby keeping the tax at the 2008 level, and then the corporate tax was varied, keeping the same before-tax WACC.

80% of the reduction. The third most influential factor is the reduction of O&M costs, followed by lower impacts from capacity factors and taxation.



Figure 3. Sources of LCOE reduction in Denmark from 2008 to 2016

Note: green denotes reduction and orange denotes increase

2.4 Wind Energy in the Danish Electricity Market

Wind energy in Denmark has reached a substantial penetration level: 43% of power demand in 2017. In combination with the high wind penetration in neighboring countries, namely Germany, the high level of wind generation, characterized by low variable cost (thus short-term marginal cost), puts downward pressure on wholesale market prices. The average price experienced by the wind generator, referred to as market value of wind (or wind-weighted price), is therefore affected and is generally lower than the average market price.

The market value of wind is calculated as the ratio between the annual revenue of wind power in the market and its annual generation. It represents the average revenue per energy unit of wind produced and is computed using historical values from the Danish TSO Energinet (2018a), as follows:

$$MV = \frac{\sum_t^T p_t \cdot E_t}{\sum_t^T E_t} = \bar{p}_{wind}$$

where t is the hour of the year ($1, \dots, T$), E is the land-based wind energy production at the hour t , and p is the market price at the hour t in the bidding area considered; both as reported in Energinet (2018a).

To calculate an average value for the two bidding zones in Denmark, DK1 and DK2, both total revenues and average price were weighted using the total annual land-based wind generation in each area.

In 2017, the market value of land-based wind was 15% lower than the average price (4.5 €/MWh difference). Thus, when comparing the revenues of wind power with LCOE, the market value of wind should be considered rather than the average wholesale price of electricity. In any case, since the economics of wind turbines depend on the evolution of the price in the lifetime of the plant, a specific year comparison of LCOE and market value can only be considered indicative.

2.4.1 Trends Since 2008

The power market in Denmark and other European countries showed significant declines in average power prices from 2008 to 2016. While part of the decline can be attributed to increasing penetration of low-marginal cost variable renewable energy (wind and solar power) in Denmark and neighboring countries, it is by far not the only reason. Reduced fuel and EU Emissions Trading System (ETS) prices, as well as contraction of demand at the European level have played an important role (Bublitz and Fichtner 2017; Hirth 2018).

Comparing the development of power prices to the market value of wind power also indicates a trend toward increasing price pressure on wind energy compared to the average power price. From 2008 to 2011, market value for wind was between 5% and 9% below the average market price, but this value increased to 12% to 16% between 2012 and 2016.¹⁵

The period from 2008 to 2011 shows that market value for land-based wind exceeded LCOE, thus showing grid parity, when looking at an individual year (Figure 4). Whether or not this means that land-based wind is viable on pure market terms would however depend on whether these conditions are stable over the lifetime of the project. From 2012 to 2016, decreasing power prices meant that market value for wind power did not exceed LCOE. Expectations for continued reduction in costs toward 2020 and the recovery of power prices in 2017–2018—mainly because of increasing coal and ETS prices—suggest that grid parity for land-based wind might be reached in Denmark, and could be competitive with traditional energy resources in the near future. However, the ability of land-based wind power to become viable on pure market terms will depend on the future development of power prices, market value, and the possibility to attract capital at a low cost.

¹⁵ As of (and including) 2011, the shown market value is calculated for land-based wind only, whereas market value is shown for all wind until and including 2010. Market value for land-based wind is a little (3%–5%) below the market value for offshore wind, thus, part of the lower market value on the graph from 2011–2016 is a result of better statistics. However, the observations regarding increasing relative difference to average market price also hold true, when evaluating the market value of all Danish wind.

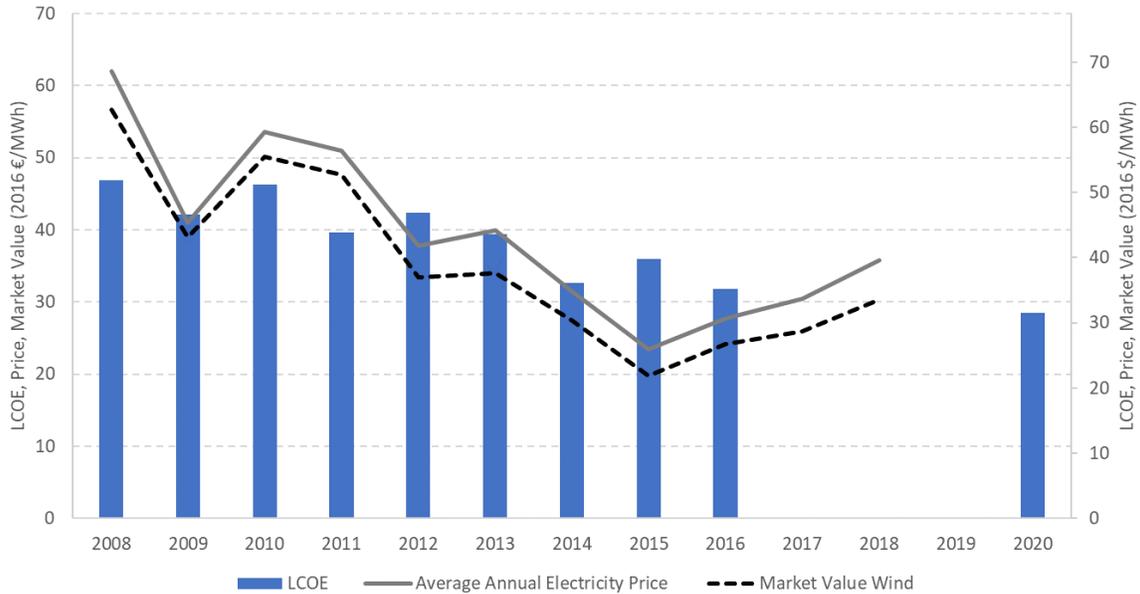


Figure 4. LCOE, average wholesale electricity price, and market value of wind¹⁶ in Denmark from 2008 to 2016, with a projection to 2020

The gap with grid parity represents the required additional revenue on top of the realized wholesale electricity price (market value) to make the turbine profitable (Figure 5). A negative value—e.g., in 2008, 2010, and 2011—implies profitability, with market revenues higher than annual production cost.

Considering that the FIP that turbines received in the period was around 33.6 €/MWh (25 øre/kWh) for an amount of full load hours equal to roughly 7 years, the corresponding 20-year equivalent subsidy value would be equal to 14 €/MWh.¹⁷ As shown in Figure 5 (excluding 2015), this more than covered the gap with LCOE.

¹⁶ Annual average electricity prices and market value have been converted to real 2016 terms. For 2008–2011, no specific data on hourly land-based generation was available. Therefore, the market value reported in the graph refers to the total wind generation including offshore. The value of average electricity price for 2018 refers only to Q1 (i.e., from January to March).

¹⁷ With a discount rate of 5%, receiving 33.6 €/MWh for 7 years corresponds to receiving 14 €/MWh for 20 years.

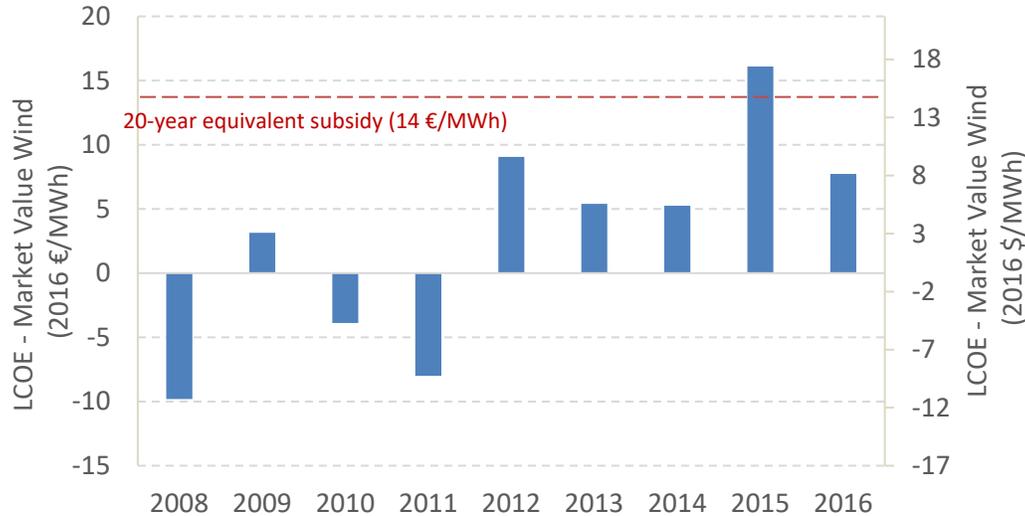


Figure 5. Difference between LCOE and market value of wind from 2008 to 2016 in Denmark

Note: The red line indicates the 20-year-equivalent subsidy value of 14 €/MWh, indicating the level of the former Danish support scheme for the period 2008–2017.

2.4.2 Expectations for the Future

The expected LCOE for 2020 shown in Figure 4 is based on estimates from the technology data catalogues by the Danish Energy Agency (Danish Energy Agency 2018c).¹⁸ The reference turbine in 2020 is rated at 3.5 MW, with a rotor diameter of 120 m resulting in a specific power of 309 W/m² and a hub height of 90 m. The assumptions used to calculate the LCOE, using the same financial parameters as for 2016 (nominal WACC 3.2% and corporate tax 22%), are shown in Table 3.

Table 3. Input Values for Wind Projects Projected for Installation in 2020 in Denmark; Costs in Real 2016 €

Source: Danish Energy Agency 2018c

	Rating [MW]	CF [%]	Investment Cost Excluding Grid Connection [€/kW]	Fixed O&M [€/kW/yr]	Variable O&M [€/kWh]
2020 reference turbine	3.5	36	970	25	2.61
			[\$/kW]	[\$/kW/yr]	[\$/kWh]
			1,073	28	2.89

¹⁸ In the technology data catalogue, the assumptions for 2020 are related to the year of FID. Therefore, the value used is an interpolation between 2015 and 2020. “Grid connection cost” in the technology catalogue refers to the external grid for connecting a turbine (or a wind plant) to the main grid. As these costs are paid for by the TSO, they are not included in the historic data behind the LCOE calculations for 2008–2016. Land-lease costs are not included in the technology catalogue data. In 2015, Energinet made an analysis of costs related to land acquisition for land-based wind, and showed that this factor will gain increased importance as the total capacity increases and the available sites get more expensive (Energinet 2015).

The resulting LCOE for 2020 is 29 €/MWh (\$32/MWh), which is slightly lower than the 2016 level (31€/MWh), but the reduction in the 4-year period is only 6%, compared to a 30% reduction between 2012 and 2016. The lower magnitude of the reduction can partly be explained by the fact that the same financial parameters are used in 2016 and 2020, whereas WACC was the most influential parameter for the reduction in the previous period.

On the revenue side, future contracts and price projections from various reports indicate a general trend towards higher electricity prices in 2020 compared to today, driven by higher ETS and coal prices and potential decommissioning of older coal power plants across Europe. A higher electricity price could potentially bring wind power closer to grid parity and to profitability without subsidies in the near future in Denmark. On the other side, in absence of adequate integration measures, more wind power in the system might increase the price pressure on wind, potentially reducing the market value of wind.

2.5 Summary

At the end of 2017, the total installed capacity of wind energy in Denmark reached 5.5 GW— with 4.2 GW being land-based and 1.3 GW offshore. The entire period from 2008 has been characterized by a steady growth in capacity to reach a 43.6% of national gross electricity consumption covered by wind in 2017.

This development has been fueled by direct subsidies in the form of FIPs of 3.4 €-cent/kWh (3.8 \$-cent/kWh) for a period of roughly 7 years. The scheme expired in February 2018 and will be followed by technology-neutral (e.g., offshore wind, land-based wind, and solar) auctions in 2018 and 2019, competing for an FIP for 20 years. The government expects the auctions to result in capacity additions totaling 140 MW of “land-based wind equivalents” over the 2-year period, which is significantly less than the average annual deployment level of around 180 MW/year (yr) between 2008 and 2016.

The specific power of turbines installed in Denmark has declined over time to reach 316 W/m² in 2016. Conversely, turbine hub height has been quite stable throughout the period – around 80 to 90 m. Interestingly, data on wind resource at sites deployed over time show that there is no indication of depletion of good wind sites in Denmark, where the average wind speed of sites is stable at around 8 m/s at 100 m. The combination of these effects and mostly the reduction in specific power of the last few years result in capacity factor values reaching an average of around 40% in 2015–2016.

The LCOE for the average land-based wind project experienced a significant reduction, corresponding to 32%, from 2008 to 2016, decreasing from around 47 €/MWh (\$52/MWh) to 32 €/MWh (\$35/MWh), mainly as a result of lower investment and financing costs.

From 2008 to 2016, there are a few years in the first part of the period in which the market value of wind power exceeds the LCOE, meaning wind power reaches grid parity. However, the general trend of reduced cost was accompanied by declining power prices, and between 2012 and 2017 the market value was below the LCOE for land-based wind. Increasing power prices in Denmark in 2017 and the first quarter of 2018—mainly related to higher coal and ETS prices— suggests that grid parity for land-based wind in Denmark might again be reached before 2020.

Yet, determining whether land-based wind power will be viable on pure market terms will depend on the future development of power prices and market value, the possibility to attract low cost capital, as well as the development of the European Union ETS price.

3 Germany

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3.1 Wind Energy Development in Germany

Germany has a long history of wind energy development. This was especially evident since the Renewable Energy Sources Act (EEG; Erneuerbare-Energien-Gesetz) was launched, as annual wind energy installations increased significantly. By the end of 2017 annual installations resulted in a total wind capacity of about 56.8 GW in Germany. In the following sections, land-based wind energy development and trends in Germany are analyzed to assess the cost of wind energy. General developments are represented with a particular focus on the period from 2008 to 2016.

3.1.1 Domestic Wind Energy Capacity, Production, and Targets

Land-based wind energy development in Germany has been going on nonstop since the early 1990s. Although there have been phases with lower or higher annual development, the implementation of the renewable energy act has shown an increase in annual installations for several years. In 2002, a record peak of annual installation of more than 3 GW was set. Installations slowed down a little (about 2 GW/yr) until 2013, when the 3 GW mark was achieved again. The annual installations have grown ever since, with up to 5.5 GW of installed wind capacity in 2017.

The new installations within the focus period from 2008 to 2016 totaled 25.2 GW. The lowest number of annual installations was observed in 2010 (1.4 GW), with a maximum of 4.4 GW observed in 2016.

As the German wind turbine portfolio matured,¹⁹ the dismantling of older turbines increased. Despite incomplete databases on decommissioned wind turbines, more than 2 GW of existing wind capacity were identified. Some of those old turbines were replaced by new state-of-the-art technologies (repowering), while others could not be altered due to local restrictions.

At the end of 2017, the cumulative land-based wind capacity in Germany reached 51.4 GW. Additionally, 5.4 GW of offshore wind capacity was installed by the end of 2017. Figure 6 shows the cumulative capacity for both land-based and offshore wind energy in Germany (BDB 2018; Deutsche WindGuard 2012–2018; BNetzA 2014–2018).

¹⁹Incentives such as the repowering bonus (see Chapter 4.1.2) also motivated the decommissioning of older turbines.

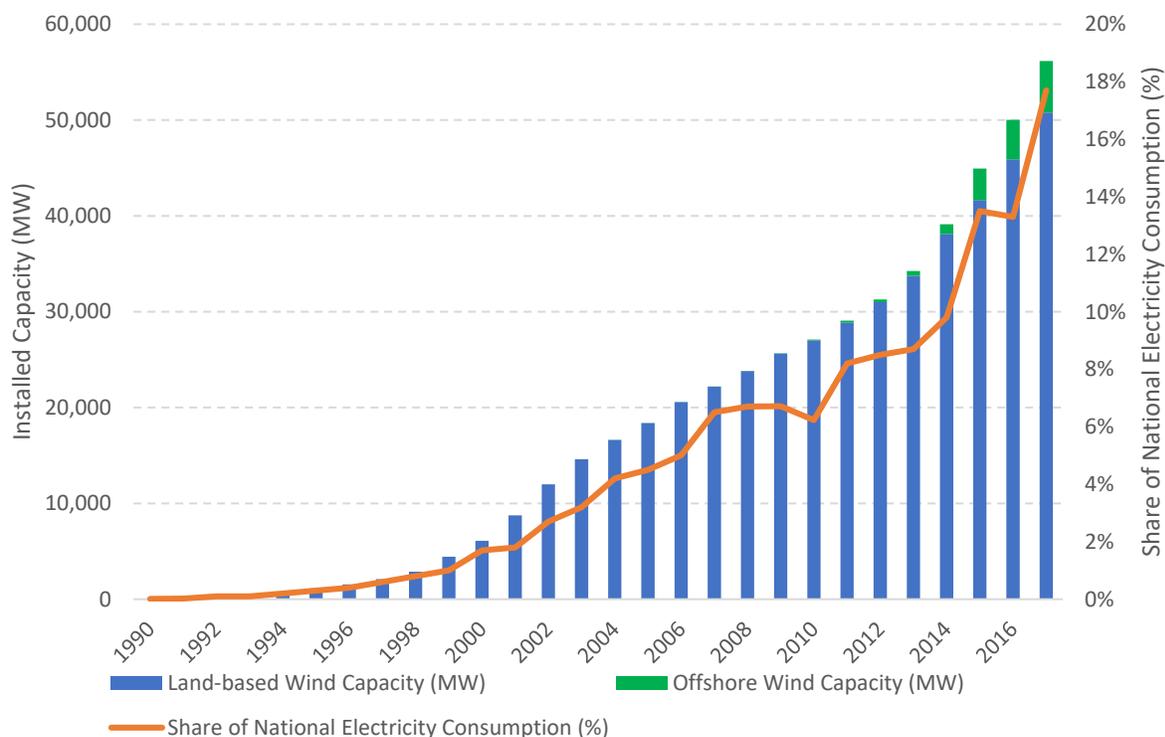


Figure 6. Wind power growth in Germany from 1990 to 2017

The share of annual electricity demand related to wind energy varies from year to year because it depends not only on the size of the fleet but also on the specific wind conditions, electricity consumption, and import/export of electricity of each year. Production of wind energy within the focus period of this report increased from 41.4 TWh in 2008 to 79.9 TWh²⁰ in 2016. This increase constitutes about a doubling of the share of electricity consumption from 6.7% in 2008 to 13.3%²¹ in 2016 (AGEE-Stat 2018). In 2017, as shown in Figure 6, 17.7% of the electricity demand was met by wind energy generation.

Targets for the future development of renewable energy were set by the German government and translated into development corridors within the EEG. Germany aims to supply 40%–45% of the national energy consumption from renewable energy sources by 2025, 55%–60% by 2030, and a minimum of 80% by 2050 (BGBI 2014, 2017). The distribution among different renewable energy sources has not been defined; however, for land-based wind, an annual target of 2.5 GW net installation (commissioning minus decommissioning) was defined in 2012 and a flexible cap²² was established in 2014. In order to reach those targets, the EEG offers a reallocation-financed support²³ of renewable energies.

The target of net installation was largely surpassed during the last years. With tenders for land-based wind energy pending for turbines with a permit date later than 31 December 2016, the

²⁰ Land-based wind energy (67.7 TWh) and offshore wind energy (12.3 TWh)

²¹ Land-based wind energy (11.3%) and offshore wind energy (2%)

²² Flexible cap: Net installations above target lead to increased reduction of feed-in premium and vice versa

²³ Cost allocation by a surcharge on electricity consumers

number of approved wind farms peaked in 2016. Those turbines qualify for subsidized remuneration without obligation to participate in the tender if installed before the end of 2018. Afterward, the installation of subsidized utility-scale land-based wind turbines is regulated by the volume tendered. Most projects awarded in the 2017 tender do not yet possess a permit and need to be commissioned within 4.5 years, whereas the projects awarded in 2018 that own building permits need to be realized within 30 months.

The tendered volume was set to 2.8 GW in 2017 and 2018 and to 2.9 GW from 2019 onward in the 2017 EEG amendment; however, the volume might be subject to change under future amendments (BGBI 2017).

3.1.2 Revenue and Policy Incentives

Revenue streams and policy incentives for wind energy development were amended several times from 2008 until today. This section addresses the general principle of the policy incentive structure for land-based wind in Germany during the focus period.

Since the implementation of the EEG in 2000 until 2016,²⁴ every land-based wind energy project in Germany received a feed-in tariff (FIT)/sliding feed-in premium (FIP)²⁵ to support wind energy development. The voluntary change from a FIT to the sliding FIP came into force with the EEG amendment of 2012. The amount of the FIT/sliding FIP varied over the support time (20 years in total) from a high initial tariff/premium to a reduced basic tariff. In general, depending on the date of commissioning, the value of the initial and basic FIT/ sliding FIP was reduced regularly; however, with several EEG amendments, the value changed and bonuses were introduced or terminated. The period of validity of the high initial tariff depends on the quality of the turbine site and the generated yield. With the so-called “reference yield model,” the period is calculated for every project separately and varies from 5 years (very high wind/high yield) to 20 years (less wind/very low yield). The model was created to ensure wind energy development in all parts of Germany, not only in the north where the wind resource is strongest. The method to calculate the duration of the initial tariff was altered by the EEG amendment in 2014. Turbine operators who agreed to sell their generation at the electricity exchange and receive the turbine-specific market value plus the sliding FIP as remuneration received an additional management bonus to compensate for the extra marketing effort. Turbines installed before 2012 were allowed to market themselves and thus received the bonus. From 2016 on (EEG amendment in 2014), marketing at the energy exchange with a sliding FIP became compulsory for newly commissioned turbines with no bonus paid. Further bonuses were paid in the focus period for repowering projects (2004–2014 with different definitions) and turbines able to provide certain ancillary services (2009–2014) (BGBI 2004, 2009, 2012, 2014, 2017).

For turbines that will be installed under the new tender system, which was established in 2017, several amendments in the remuneration scheme were introduced. For example, the reference yield model was newly designed; the increased initial and basic sliding FIP was replaced by a

²⁴ Transitional period until end of 2018

²⁵ The value of the sliding FIP is determined by the total value of remuneration (defined in the EEG, comparable to a FIT) minus the average market value of land-based wind at the energy exchange. Projects with a market value above the average market value therefore receive a surplus and vice versa.)

single sliding FIP for the whole 20-year funding period; and the value of total remuneration (average market value plus sliding FIP²⁶) is determined for each turbine by tender. At the same time, the site-specific differentiation of total remuneration included in the reference yield model is meant to allow low wind projects to bid competitively against high wind projects.

The value of the FIT/sliding FIP is defined as a nominal value. Neither initial nor basic FIT/sliding FIP nor single-tender-defined sliding FIP are adjusted for inflation during the project lifetime. When considering real cost it should be recognized that the real remuneration resulting from the EEG subsidy is decreasing over the project lifetime. Therefore, when comparing the FIT/sliding FIP with the LCOE (in 2016 values), real 2016 FIT/ sliding FIP differs methodically from the values defined in the EEG or defined by tender.

3.2 Wind Energy Project Trends in Germany Since 2008

This section presents trends regarding wind projects in Germany. The full data set is available for download in the [IEA Wind TCP Task 26 Data Viewer](#). The specific data used in this report and the data used to convert monetary values to real 2016 euros and U.S. dollars are compiled in [the attached supplemental data appendix](#).

The characteristics of wind turbines installed in Germany from 2008 to 2016 have been subject to an ongoing upscaling. The average nameplate capacity of wind turbines grew from 1.9 MW in 2008 by 48% to 2.8 MW in 2016. The average rotor diameter increased by 38%, from 79 m to 109 m. The average hub height of turbines increased from 94 m to 128 m, resulting in a 36% increase in hub height over the 8 years considered. It should be noted that there is a rather large variance between different regions due to wind resources, specific site conditions, and different local restrictions. With emerging low-wind-speed technologies (turbines with a low specific power) on the German turbine market, the average specific power of newly installed turbines has declined from 2012 onward. After relative steady specific power around 400 W/m² until 2012, specific power dropped by 20% to 317 W/m² in 2016. Figure 7 shows the development of the two technology-specific key factors: specific power and hub height. (Deutsche WindGuard 2012-2018; BNetzA 2014-2018; BDB 2018).

²⁶ The sliding FIP does not become negative if the market value exceeds the value of total remuneration or a successful bid.

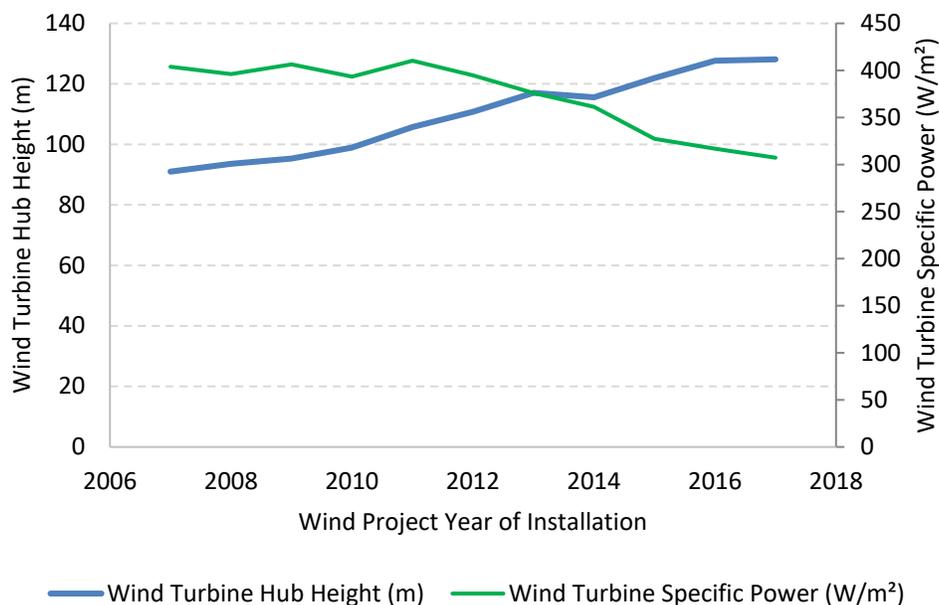


Figure 7. Hub height and specific power for wind projects installed in Germany from 2007 to 2017

The average wind-index-corrected capacity factors²⁷ in Germany have been generally low, ranging from 21% to 27% throughout the period analyzed. The trend points toward slightly higher values with the newer installations that feature the lower-specific-power turbines with higher hubs.²⁸

The average capital expenditure (CapEx) for projects installed in Germany increased from 2008 to 2012, from about 1,460 €/kW in 2008 to a maximum²⁹ of 1,640 €/kW in 2012 (\$1,633/kW to \$1.862 /kW). Average values started dropping with growing pressure on cost to about 1,490 €/kW in 2016 (\$1,682/kW). One driving force of the increasing cost in the beginning of the focus period is the upscaling of hub heights and rotor diameters, which led to an increase in yield. Even though investment costs per kilowatt rose over time, the investment costs per kilowatt-hour declined. However, with increased pressure on the wind industry to reduce costs, average CapEx per kilowatt has been dropping in recent years despite continued turbine upscaling. The average annual O&M costs per capacity installed (including both the variable and fixed cost average over the turbine lifetime for an average project) have been stable at around 60–62 €/kW/yr until 2012 (\$67–\$69/kW/yr). By 2016, O&M costs decreased to 52 €/kW/yr (\$53/kW/yr). However, these data have a large span across different projects for CapEx as well as O&M cost.

²⁷ Real specific production per year adjusted for a typical annual production by a wind yield index for the quality of the considered year depending on the region of installation for each turbine.

²⁸ Production data coverage close to 100%. Data displacement in 2008/2009 (lack of data in 2008/surplus of data in 2009) is a result of turbines erected in 2008 and feeding in for the first time in 2009, which are treated differently in various databases.

²⁹ No cost survey was conducted in 2011, 2013, and 2014. Therefore, the turning point of average cost development cannot be identified exactly.

Observation of the German market suggests a trend toward reduced WACC for land-based wind projects from 2008 to 2016. The main driver for this reduction is a substantially lower cost of debt as well as a reduced cost of equity. In addition, the debt-equity ratio varied slightly over time. After initial reductions of debt share resulting from good revenues of projects until 2015, the assumed debt share increased in 2016 because of a reduced sliding FIP. The values used to calculate WACC are averaged over 20 years of operation, which does not reflect real project cash flows.

3.3 Cost of Wind Energy Generation in Germany Since 2008

To analyze the evolution of the LCOE in Germany from 2008 to 2016, the average characteristics of the projects constructed in every year were considered. Before describing the trends observed between 2008 and 2016, we will first present the underlying sources and assumptions.

3.3.1 Sources and Assumptions

Different public and private sources were used to create the data sets needed for the LCOE calculations. The most important ones include:

- Several analyses of the cost of wind energy conducted by Deutsche WindGuard implemented in various years on behalf of different clients and authorities including data collection via surveys and interviews with turbine manufacturers, project developers, and banks (Rehfeldt and Wallasch 2008; Rehfeldt et al. 2011; Wallasch et al. 2013, 2015)
- Wind energy development statistics by Deutsche WindGuard (*Status des Windenergieausbaus in Deutschland*), semiannual statistics on wind energy development in Germany since 2012 on behalf of BWE and VDMA Power Systems (Deutsche WindGuard 2012–2018)
- Renewable energy installations core database of the Federal Network Agency (BNetzA 2014–2018), registry of new renewable energy plants since August 2014
- Operators-Database (BDB 2018); installation data and yield index for wind energy turbines in Germany (BDB 2017)
- Master data and motion data by TSOs (*Stamm- und Bewegungsdaten*); data sets on turbines installed and production in 2016 by German TSOs compiled by the Federal Network Agency (Netztransparenz.de. 2017a, 2017b).

Since most main parameters result from merging different information, a specific sample size is not available. Most parameters include rather complete information on the technology installed or turbine yield fed into the grid, along with additional information based on surveys and interview-based assumptions.³⁰

To calculate the LCOE, some additional assumptions related to the capacity factors as described earlier are included. Real wind energy production, especially in the north of Germany, is affected by the curtailment caused by grid bottlenecks. Turbine operators receive compensation if their

³⁰ Details about the sample size for the basic parameters can be found in the [IEA Wind TCP Task 26 Data Viewer](#).

turbines are curtailed. Therefore, the curtailed energy is included in the LCOE calculation even though it was never delivered to the grid. If the theoretical available but curtailed electricity is taken into consideration, the theoretical capacity factors increase from 22% in 2008 to 28% in 2016 (BNetzA 2017).

Average values for investment cost are based on several surveys and data analyses on the cost of land-based wind energy in Germany conducted by Deutsche WindGuard. Investment cost is strongly related to the configuration of turbines installed. Turbine cost assumptions are based on cost data supplied by manufacturers and weighted by the configuration of the annual installations. For the average cost in a specific year, annual capacity-weighted average hub height and specific power are used to express the trend in turbine cost.³¹ In addition to the cost for turbines, components such as foundation, infrastructure, grid connection, compensatory measures, and project development have to be taken into account. Estimates for these additional costs stem from several data surveys with project developers³² (Rehfeldt and Wallasch 2008; Rehfeldt et al. 2011; Wallasch et al. 2013, 2015).

Average values for O&M costs are based on several surveys and data analyses with project developers on the cost of land-based wind energy in Germany conducted by Deutsche WindGuard. Variable as well as fixed O&M costs are included, but the data are presented as fixed O&M costs only. The data employed represent expected O&M cost during the project lifetime. Costs that vary over the project lifetime values for the first and second decade are averaged for this analysis (Rehfeldt and Wallasch 2008; Rehfeldt et al. 2011; Wallasch et al. 2013, 2015).

WACC assumptions are based on interviews and surveys with banks, average corporate taxes, returns on debt of specific renewable energy loans, and further assumptions regarding the typical financing structure. Based on these assumptions, the average WACC of the respective year is calculated. Cash flows and fanatical structures specific to the German energy industry, which result from the design of the remuneration scheme, are not reflected in the assumptions. (Rehfeldt and Wallasch 2008; Rehfeldt et al. 2011; Wallasch et al. 2013, 2015).

The depreciation schedule used for Germany was changed slightly in 2011. Before 2011, different durations of depreciation were used for turbines (16 years), cabling and grid connection (20 to 25 years), and infrastructure (19 years). From 2011 on, depreciation for the whole wind project was set to 16 years to equal the depreciation time of the turbines. This leads to a slightly accelerated depreciation schedule (BFH 2011).

Furthermore, the LCOE as defined in this report does not take into account the specific cash flow of German wind projects that is induced by the increased sliding FIP in the initial phase followed by the lower basic sliding FIP; both defined in nominal values and not adjusted for inflation. Therefore, a comparison of the subsidy-free real 2016 LCOE of the past years to the remuneration defined by the renewable energy act is misleading and not recommended.

³¹ This methodology differs from the methodology in previous analyses.

³² Several surveys conducted in 2008, 2010, 2012, 2015, and 2016 with manufacturers, developers, and banks combined with data on installation characteristics have been used to assume averages. Missing data years on cost data were filled in according to observed trends with linear interpolation.

3.3.2 Trends Since 2008

The characteristics of the typical projects used for the calculation and the resulting LCOE from 2008 to 2016 are displayed in Table 4. The LCOE for the representative wind power project in Germany is estimated using a basic equation for LCOE analyses described in Appendix A. Country-specific flow of income caused by an increased initial feed-in premium as well as varying O&M cost and debt rates over the turbine lifetime are not taken into account. Specifically for Germany, the LCOE of real projects has a wide range because the subsidy policy incentivizes the development of wind energy projects all over Germany—in high wind sites at the coastlines as well as in the less wind-intensive areas in the southern inland regions. Therefore, the results shown in Table 4 give an estimate of LCOE for a theoretical average project.

Table 4. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed from 2008 to 2016 in Germany

Parameter ⁱ	Unit	Wind Project Year of Installation								
		2008	2009	2010	2011	2012	2013	2014	2015	2016
Net energy production ^a	Capacity factor %	22	22	24	23	24	26	27	28	28 ^b
	(Full load hours)	(1,922)	(1,969)	(2,142)	(2,037)	(2,136)	(2,295)	(2,412)	(2,479)	(2,479) ^b
Investment costs ^c	2016 €/kW	1,476	1,568 ^e	1,660	1,672 ^e	1,683	1,647 ^e	1,611 ^e	1,575	1,520
	(2016 \$/kW)	(1,633)	(1,734 ^e)	(1,836)	(1,849 ^e)	(1,862)	(1,822 ^e)	(1,782 ^e)	(1,742)	(1,682)
O&M costs ^c	2016 €/kW/yr	62	62 ^e	62	61 ^e	61	58 ^e	56 ^e	53 ^e	53
	(2016 \$/kW/yr)	(69)	(69 ^e)	(68)	(68 ^e)	(67)	(64 ^e)	(62 ^e)	(59 ^e)	(59)
After-tax WACC ^d	% nominal	5.6	5.2 ^e	4.8 ^e	4.5 ^e	4.1	3.8 ^e	3.5 ^e	3.2 ^e	3.3
	(% real)	(3.5)	(3.1 ^e)	(2.8 ^e)	(2.4 ^e)	(2.0)	(1.7 ^e)	(1.4 ^e)	(1.2 ^e)	(1.3)
Corporate income tax rate	%	29.5	29.4	29.4	29.4	29.5	29.6	29.6	29.7	29.7
Depreciation schedule		Germany: 2008 – 2010 ^f			Germany: 2011 – 2016 ^g					
LCOE ^h	2016 €/MWh	95	94	87	89	83	73	66	61	60
	(2016 \$/MWh)	(105)	(104)	(97)	(99)	(92)	(81)	(73)	(67)	(67)

^a Net energy production in calendar year 2016: 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 8,784 hours in 2016.

^b In 2016, a full year of energy production data was not available for projects installed during 2016. Therefore, the capacity factor associated with projects installed in 2016 is the same as the capacity factor associated with wind projects installed in 2015.

^c Investment costs and O&M costs converted to real 2016 euros and US dollars. Details are available for download in a separate file. O&M costs 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% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. This assumption is used to convert nominal WACC to real WACC.

^e For years without survey- or interview-based values, linear interpolation has been used.

^f 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]).

⁹ Linear depreciation of 100% of the initial capital investment over 16 years for the entire wind project.

^h LCOE was calculated assuming a 20-year amortization period.

ⁱ Sources: BDB (2017, 2018); Deutsche WindGuard (2012–2018); BNetzA (2014–2018); Rehfeldt and Wallasch (2008); Rehfeldt et al. (2011); Wallasch et al. (2013, 2015); Netztransparenz.de. (2017a, 2017b); BPB (2017); BNetzA (2017)

There has been a significant reduction of LCOE in Germany in the period analyzed. LCOE went from 95 €/MWh in 2008 to 60 €/MWh in 2016 (\$105/MWh to \$67/MWh)—a 39% reduction. Note that all cost parameters are average in order to calculate LCOE and are subject to large standard deviations. Furthermore, the capacity factor refers to the average index-rated production in 2016 of all turbines with a certain installation year.³³

To analyze the main drivers behind the impacts on LCOE, a decomposition analysis was conducted, wherein one parameter at a time was changed from its 2008 value to the 2016 value. The result of the single parameter variation³⁴ on the LCOE is represented in Figure 8.³⁵

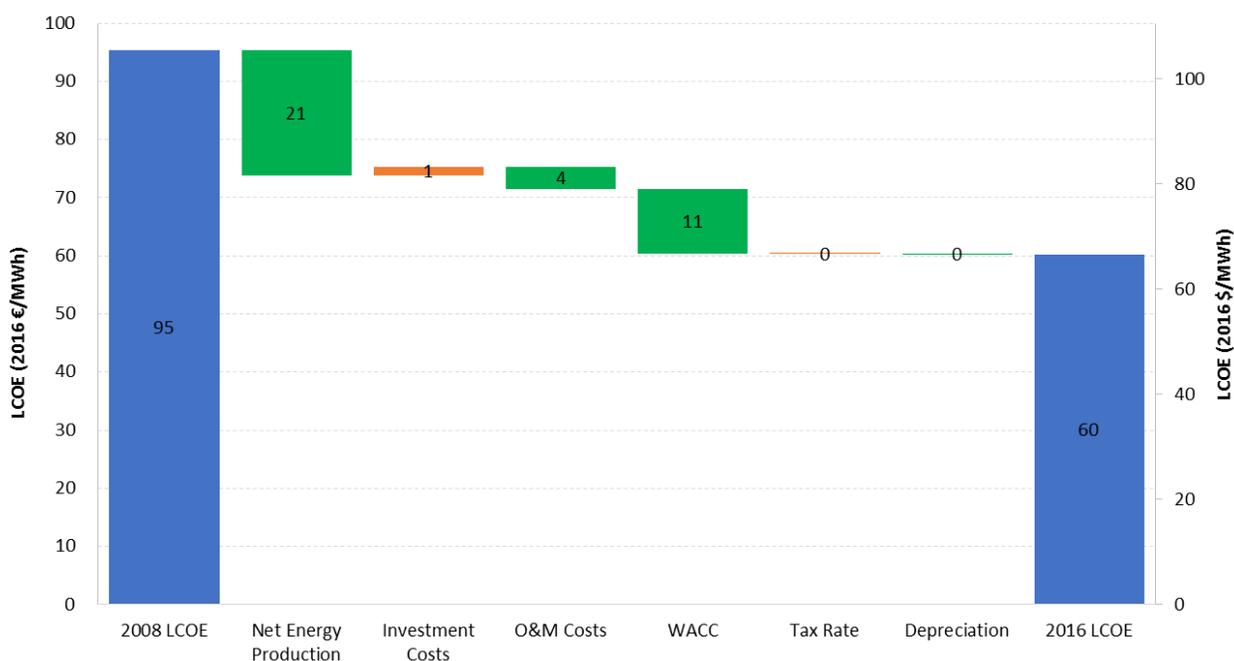


Figure 8. Sources of LCOE reduction in Germany from 2008 to 2016

Note: green denotes reduction and orange denotes increase³⁶

³³ Average curtailed energy of the whole fleet in a specific region is added to the energy delivered to the grid since compensation is paid for curtailment because of grid bottlenecks.

³⁴ Since taxation rate and after-tax WACC are related, WACC was varied to keep the tax at the 2008 level, and then the corporate tax was varied to keeping the same before-tax WACC.

³⁵ The sequence of parameters slightly changes the results.

³⁶ Net energy production in this analysis is represented by the theoretical capacity factor of an average wind turbine and the average turbine capacity.

The increased net energy production has the largest impact on LCOE reductions from 2008 to 2016, whereas CapEx slightly increases LCOE. The increase of net energy production³⁷ was possible mainly by scaling up the installed hub heights (by 36%) and reducing the specific power (by 20%). Higher wind speeds are available at larger heights while the low specific powers improve production in the partial-load range. Although technology cost has been reduced considerably, the turbines installed in 2016 come at a slightly higher price than the 2008-turbines from taller hub heights and larger rotors. Improvement in operational expenditures (OpEx) reduces the LCOE for German wind energy projects. WACC—being the second largest factor in LCOE reduction between 2008 and 2016—reduces LCOE mainly because of lower interest rates for debt. Tax and depreciation have a low impact on LCOE compared to the other factors.

3.4 Wind Energy in the German Electricity Market

The penetration level of land-based wind energy has been increasing ever since wind energy development in Germany started. Land-based wind supplied 6.7% of the net electricity demand in 2008 and increased to 11.3% in 2016. In Germany, most of the wind energy is sold at the energy exchange at day-ahead, and to a smaller extent, intraday markets. The average price for a kilowatt-hour of wind at the electricity exchange is referred to as the market value of land-based wind in Germany. The average price at the overall market is considered the average electricity price. With prices at the exchange dropping when a large amount of low marginal cost renewable energy is available, the value of wind is generally less than the average electricity price.

The market value of wind is calculated on a monthly basis to define the sliding FIP by weighing the average hourly price of electricity at the EPEX Spot market with the actual hourly generated wind energy. This methodology was implemented in 2012. From 2015 on, the market value is determined by using a projection of the actual hourly generated wind energy to weight the Spot market price (Netztransparenz.de 2018). The monthly market value of all hourly contracts at the EPEX Spot market is published and used to define the value of the sliding FIP for the production of a specific turbine in that month.³⁸ To represent the electricity prices, the EEX annual physical electricity index (Phelix) is used.³⁹

3.4.1 Trends Since 2008

Figure 9 represents the LCOE for wind turbine generators installed in a specific year over time. One has to take into consideration that these projects are expected to produce energy at the cost displayed for about 20 years. Furthermore, the figure indicates the corresponding value of wind and the average electricity price. These are annual values relevant for all turbines in operation in that year. The most noticeable trend when reviewing the development of LCOE and value of wind is that while the LCOE of wind power decreased between 2008 and 2016, the average electricity price declined as well. In 2017, a slight rebound of electricity price and market value of land-based wind was observed. In 2012, the market value of land-based wind was 12% lower

³⁷ Net energy production is influenced by the wind project location. From 2008 to 2016, the share of annual installations in northern Germany was rather steady, while approximately 10% of annual installations moved from central Germany to the south. Further factors, such as restrictions or regulatory curtailment, might also influence the production of installed turbines.

³⁸ Land-based wind only—offshore wind market value in the past usually has been higher than the land-based wind market value.

³⁹ As published in several press releases and presentations of EPEX and EEX from 2009 to 2017.

than the average electricity price. By 2016, the value of land-based wind was 17% below the electricity price.

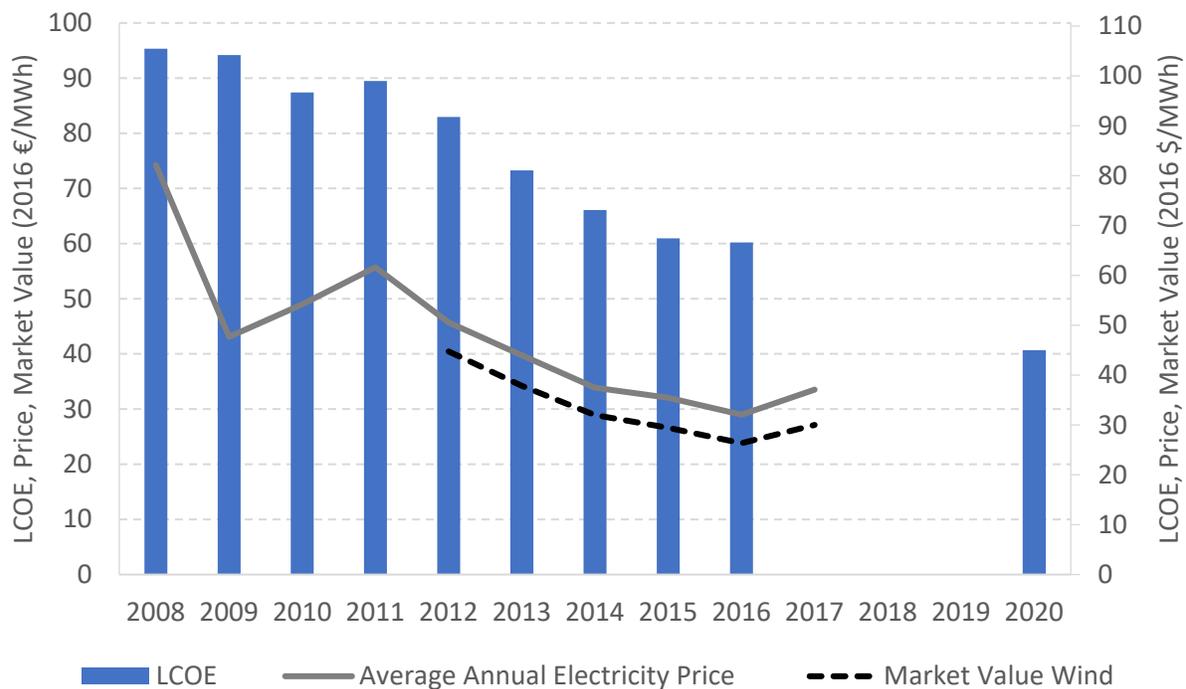


Figure 9. LCOE, average wholesale electricity price, and market value of wind in Germany from 2008 to 2016, with a projection to 2020

Since the decline of LCOE was a little sharper than the decline of market value, the nominal gap (difference between market value and LCOE) shows a slight reduction over time. However, when comparing LCOE to market value, consider that turbines installed in a specific year carry their LCOE for the whole turbine lifetime, whereas market value for the whole fleet develops steadily.

3.4.2 Tender Results and Expectations for the Future

Tenders for land-based wind energy projects were introduced to Germany in 2017. Three tender rounds took place in 2017, with participation predominantly from citizen projects without permits. The projects without permits were excluded from participation in the four tender rounds of 2018,⁴⁰ leaving only permitted projects to enter the tender. The award criterion is a low sliding FIP at the reference wind site. The average capacity-weighted tender-defined sliding FIP at the reference site as well as the range are depicted in Figure 10 for each tender round. Note that the tender results in 2017 and 2018 do not equal the LCOE of installations in 2017 and 2018 but in later years. Developers have to install the projects within 54 months for 2017 tenders and within 30 months for 2018 tenders.⁴¹ Furthermore, the tender results do not equal the remuneration given to projects in that tender, but the sliding FIP in nominal remuneration for theoretical

⁴⁰ Two rounds closed by the time of the analysis (February and May 2018), with two more expected in August and November 2018.

⁴¹ In case of lawsuits against the permit of the turbine, a 6-month extension may be granted.

projects with the specific yield of the reference site. Projects with lower energy yield receive a higher sliding FIP; projects with higher energy yield receive a lower sliding FIP.

The nominal capacity-weighted average accepted bids for land-based wind of the five tender rounds varied considerably. After a steep decline of successful bid values in 2017, when projects without permits⁴² and a realization period of 54 months dominated the tender, the values increased again in 2018. Projects without permits were excluded from the first two tender rounds in 2018; therefore, the allowed realization time was reduced to 30 months. Accepted bids in the May 2018 tender were on a similar level as the first tender in May 2017. This is not only because of the need for a permit and the shortened realization time, but also because of a lack of competition in the latest round.

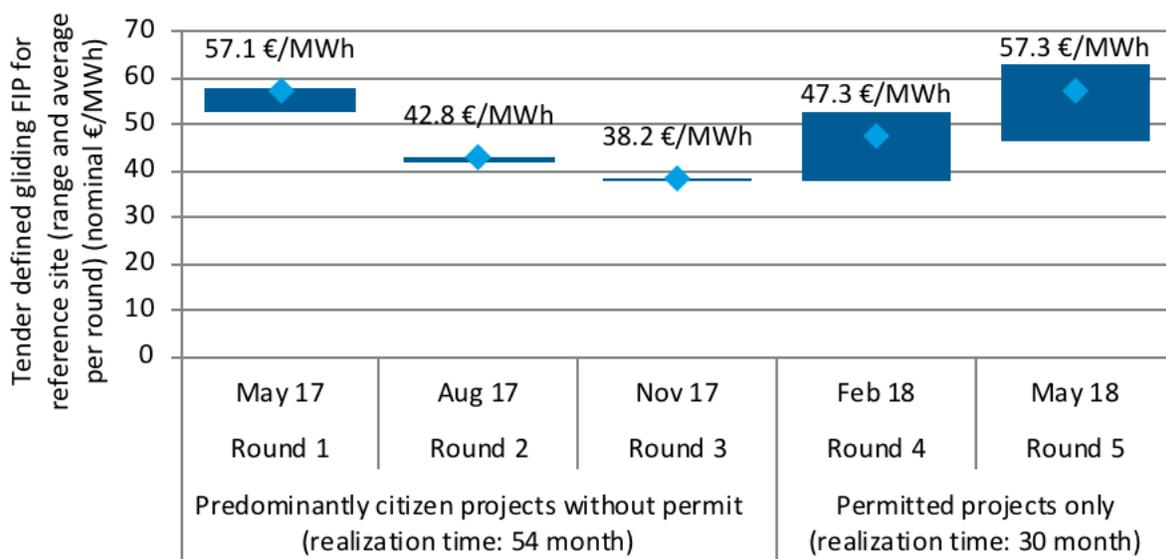


Figure 10. Tender-defined sliding FIP (nominal) for the reference site (range and average per round) for German land-based wind energy tender rounds in 2017 (round 1-3) and 2018 (round 4-5)

In the following, recent tender results are assumed to be closely related to the LCOE expected by the bidding project developer. They are therefore utilized for the estimate of the future LCOE. Effects of possible strategical bids are not included in the LCOE projections,⁴³ neither are effects of the uniform pricing for the 2017 award.

The future LCOE projection for 2020 is derived from the accepted bid values in the first five wind energy tender rounds in Germany. Theoretically, all of the accepted bids could be relevant for wind energy projects installed in 2020.⁴⁴ Hence, a capacity-weighted average of all tender

⁴² Permit according to the Federal Immission Control Act (BImSchG).

⁴³ If the bid values have been set strategically, for example, in order to increase market shares or under consideration of an expected increase of wind market value to values above the bid, a higher real LCOE has to be assumed for 2020 installations.

⁴⁴ 2018 tender winners need to be installed by July or October 2020, whereas 2017 tender winners are due to lose the awarded capacity in October 2021, January 2022 or April 2022. Half a year prior to losing the bid, a penalty has to be paid for late installation.

rounds is assumed a typical value⁴⁵ for 2020 installations. Because the bid value does not represent the remuneration, to estimate the real 2016 LCOE a correction depending on the turbine technology and the real energy yield as well as a correction for inflation over turbine lifetime has to be implemented. A small sample of turbines accepted in the tender (8% of accepted wind turbine generators) reported that the expected quality of the site has been registered in the turbine database of the Bundesnetzagentur (BNetzA). The average site quality of those turbines is about 80%, which means they are expected to produce 20% less than a project at the reference wind site. Therefore, they benefit from the site differentiation and will receive a higher sliding FIP. An 80% wind site corresponds to a correction factor of 1.16. Consequently, for such a project the accepted bid value is multiplied by 1.16 to calculate the sliding FIP.

Considering all the previously mentioned assumptions, the tender results point to a LCOE of 41 €/MWh in 2016 EUR for projects installed in 2020. The assumed LCOE could vary in the case of accepted bids of upcoming tender rounds rising or falling significantly or turbines accepted in the tender with low bid values not being installed because of too tightly calculated bids. Comparing⁴⁶ the modified tender results to the LCOE in 2016, another cost reduction of 32% must be realized by 2020 if tender participants bid at the expected cost and want to be able to operate projects economically at this remuneration.

3.5 Summary

The levelized costs of land-based wind energy in Germany decreased significantly between 2008 and 2016, from 95 €/MWh (\$105/MWh) in 2008 to 60 €/MWh (\$67/MWh) in 2016. This equals a reduction of 39%. The main drivers identified for this LCOE reduction are increased energy production and decreased WACC and OpEx. Increased energy production was enabled by technology development in Germany, which features high towers and reduced specific power while keeping CapEx nearly constant.

The market value of land-based wind energy in Germany is significantly lower than the average annual electricity price. Value of land-based wind as well as average electricity prices decreased between 2012 and 2016, therefore the need for subsidy remains until market values and costs meet.

The results of the first tender rounds for land-based wind in Germany point to a further need for cost reduction to secure ongoing wind energy installations in the country. Cost pressure and new technology developments could enable the necessary reductions. Realization quota of award projects of different tender rounds will provide evidence for realized cost reductions in upcoming years.

⁴⁵ Assuming participating bidders used the expected cost as bid values under consideration of the advantages of citizen projects without taking into consideration further sources of remuneration.

⁴⁶ Comparing these values is not totally consistent because the methodology of deriving the LCOE from the bid values is not the same as the methodology used for 2008–2016 LCOE.

4 Ireland

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4.1 Wind Energy Development in Ireland

This chapter first provides a summary of the status of wind energy policies and deployment in the Republic of Ireland between 2008 and 2016 before discussing changes in the levelized cost of wind energy and comparing this to electricity prices in the all-island of Ireland market. All prices and costs are adjusted to a 2016 base year.

The development of land-based wind energy is a central component of Ireland’s energy policy and to meeting its greenhouse gas emissions’ reduction targets for 2020 and 2030. It is by far the largest source of renewable electricity, providing over eight times the amount of energy as the next largest source, hydropower, in 2015 (SEAI 2016). Current Irish energy policy does not incentivize offshore wind energy, with just 25 MW commissioned in 2004. However, offshore wind will be eligible to tender in future renewable electricity support schemes (see below).

4.1.1 Domestic Wind Energy Capacity, Production, and Targets

The Republic of Ireland has a target of producing 40% of all electricity from renewable sources by 2020—the vast majority of which (37%) will come from wind. By 2018, 260 wind farms with a total installed capacity of 3,365 MW were operating nationally (IWEA 2018) where the peak national electricity demand is on the order of 5 GW. Wind energy met approximately 25% of the country’s energy needs in 2017 (Wind Europe 2018). Figure 11 shows the annual and cumulative wind energy additions in Ireland up to 2017. The latter was a record-breaking year with 568 MW of new capacity added.

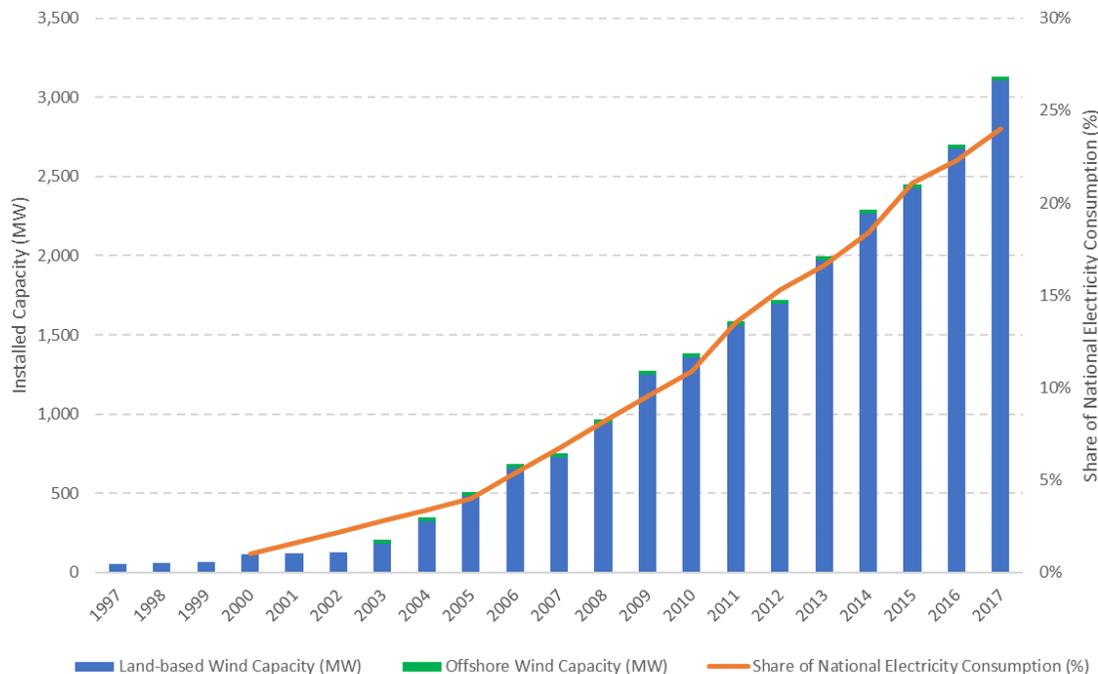


Figure 11. Wind power growth in Ireland from 1997 to 2017

In its most recent generation capacity report (Eirgrid 2017), the TSO anticipates significant growth in wind energy in Ireland and is projecting an installed capacity of slightly more than 4 GW in 2020, growing steadily to approximately 5 GW by the mid-2020s. It is currently envisioned that these additions will be land-based, since there are currently no active price support schemes for incentivizing offshore wind development.

4.1.2 Revenues and Policy Incentives

Ireland currently operates a single mandatory pool electricity market with a single marginal price called the single electricity market (SEM). Power providers bid prices and quantities into the market on a day-ahead basis and all energy delivered receives the system marginal price (SMP). Wind participates in this market where it receives priority dispatch (subject to system security) and is a price taker. The main policy instrument used to incentivize wind energy investment and operation in Ireland in recent years has been a 15-year contracted renewable energy feed-in tariff (REFIT) which guarantees a minimum prices for wind energy by compensating wind energy producers for differences between REFIT and market prices. Although the scheme has been closed since 2015, contracted wind farms are still being built and commissioned. REFIT compensates large wind farms with a “balancing payment” to cover the cost of managing the short-term variability of wind generation in the SEM (approximately 10 €/MWh), and a “reference price” that sets an index-linked minimum unit revenue of approximately 70 €/MWh on energy supplied to the pool.

The Irish government incentivizes energy-efficient investments through the Accelerated Capital Allowance scheme that allows companies to write down the cost of registered energy-efficient equipment in the year of purchase, thus allowing 100% depreciation in year 1 of the investment. Although wind projects are eligible for participation in this scheme, there is little evidence they

do so. This may be because of the fact that most wind farms are developed by special purpose vehicles, which may not generate the profitability required to avail the large capital write-offs required. Wind farms investors are also eligible for certain personal tax exemptions under the Employment Investment Incentive Scheme (and its predecessor, the Business Expansion Scheme), subject to certain investment limits.

Two market developments currently underway in Ireland will significantly impact large-scale wind energy business models. The first is that the government is in the process of designing a new renewable electricity support scheme. Although not yet finalized, this is likely to be a technology-neutral auction mechanism that will provide a 15-year uniform-price sliding FiP support contract for new wind projects. A second development is that the all-island of Ireland electricity market is being redesigned to comply with the European target model. The new structures are likely to be introduced in late 2018 and, importantly, will make wind producers responsible for the cost of imbalances between forecast and delivered electricity for the first time in Ireland. The exact pricing structure of the balancing prices has not yet been published and it is unclear how the wind industry will respond to the resulting additional risk. The renewable electricity support scheme may also require wind developers to make their projects open to community participation to address the increasing social resistance to land-based wind farm development.

Unlike other countries with significant shares of wind energy generation, the Irish electricity system is poorly interconnected with adjacent networks (from a system inertia perspective) and, as such, faces significant technical system integration problems. As a result, wind energy output is often curtailed during periods of high wind and/or low demand. To counter this problem, the TSO has introduced measures in recent years that have increased the instantaneous system nonsynchronous generation penetration (i.e., wind power output in the case of Ireland) limit from 50% in 2015 to 65% of system demand in 2018 with a planned limit of 75% in 2020. This increased limit has reduced wind curtailment from 5.1% in 2015 to 2.8% in 2016, although 5% is currently used for future studies.

Renewable energy subsidies in the Republic of Ireland are funded through the Public Services Obligation levy that is implemented as a monthly charge on consumers energy bills.

4.2 Wind Energy Project Trends in Ireland Since 2008

Wind power has developed significantly since the first commercial wind farm was developed in western Ireland in 1992. Because the prevailing winds over the island are southwesterly, the majority of wind developments have occurred in the less densely populated west of Ireland, although recently there has been more activity in central areas of the country. This section of the report presents summary statistics for wind farm technology and cost data collected from a variety of publicly available sources, which include nameplate capacity, rotor diameter, hub height, specific power, site wind speeds, investment costs, O&M costs, and financing costs. Some of these data are used to estimate the average annual LCOE for wind; these are compared to the market prices for electricity and are used to identify which technology and financial variables are contributing to LCOE changes. Further details on the data sets can be found in the [IEA Wind TCP Task 26 Web Data Viewer](#).

Over the 2008–2016 study period, the average wind project size was observed to increase from a range of 10–15 MW to 15–30 MW. This growth was accompanied by a large increase in the range of project sizes with a number of much larger projects evident since 2013 compared to preceding years (an increase from 40–60 MW to 70–90 MW). These larger project sizes have coincided with a trend toward larger turbine nameplate capacities, the average sizes of which have increased from 2 MW to 2.75 MW over the period with a significant number of 3-MW machines being installed at the end of the period in 2016. Rotor diameter and hub height have also increased; average diameters in 2016 were over 90 m, up from approximately 70 m in 2008, while average hub heights have increased from 65 to 80 m over the period. The relatively greater increase in rotor swept areas compared to nameplate capacities has resulted in lower specific powers. Figure 12 shows how specific powers have decreased from an average of approximately 450 W/m² over the 2008–2012 period to approximately 380 W/m² for the 2013–2016 period (although 2015 was an exception with a higher average specific power). Specific power values at the end of the period are, however, higher than those reported for other European countries and the United States. The distribution of specific powers in Ireland was much tighter in 2012–2016, with 50% of samples in the 350–400 W/m² range, down from 400 to 600 W/m² in 2008–2012. This trend does not seem to be explained by the development of lower wind resource sites, as average wind speeds for new developments have remained relatively stable at approximately 8 m/s and may be explained by a desire to increase capacity factors. However, this hypothesis is not supported by trends in observed capacity factors over the period. Data show that capacity factors are, on average, highest for wind farms developed in the 2010–2013 period (approximately 33%–37%), with capacity factors of approximately 31%–32% afterward. These lower capacity factors may represent lower availabilities in the first year of operation because of commissioning problems or being constrained down due to local system congestion. Furthermore, the system operator has not distinguished between partly and fully commissioned wind farms in their reports so data for the early operational periods may be misleading.

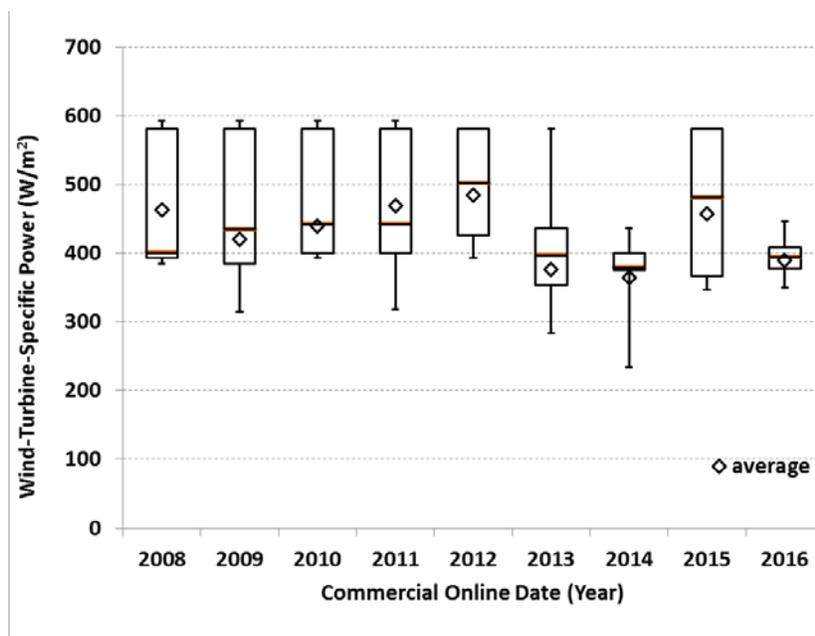


Figure 12. Specific power for wind projects installed in Ireland from 2008 to 2016

Wind farms in Ireland are frequently developed as special purpose vehicles so that filed company accounts identify CapEx and OpEx at a project level. For this reason, capital cost (CapEx) data were collected from filed audited company balance sheets that include all project-related expenditures. Results indicate that there is no apparent trend in real average CapEx over the study period, with figures varying from year to year, lying in the €1.4 m/MW to €1.9 m/MW range. Although these figures are slightly higher than other participating countries, it is possible that the source of the Irish data encompasses a greater scope of expenditure than other countries do. OpEx data were collected from profit and loss statements in filed company accounts. However, only a small sample size was obtained in this way since profit and loss reporting requirements apply only to large enterprises and many wind company special purpose vehicles did not fall into this category. Accounting operating costs often include components that do not represent cash expenditures on the day-to-day running of the wind farm (e.g., depreciation); these were removed where such data were identifiable and discarded where not. Therefore, reported Irish OpEx data should be treated with caution, although the results obtained were verified with industry professionals where possible. OpEx results gave an average of approximately 48€/kW/yr over the 2008–2016 period. There was significant variation from year to year, with no obvious trend apparent.

4.3 Cost of Wind Energy Generation in Ireland Since 2008

4.3.1 Sources and Assumptions

This section describes the results of LCOE calculations for the study period using CapEx, OpEx, energy output, tax, and financing cost data. The sources of CapEx (investment) and OpEx (operation and maintenance) costs are described earlier. Given the small sample sizes for OpEx data, the significant interannual variability and the absence of any obvious trends, the real 2016 average value of 48.26 €/kW/yr for the 2008–2016 period was used for all annual LCOE calculations. Energy output data were obtained for individual wind farms for the 2016 calendar year from the Irish Single Electricity Market Operator. Metered dynamic (half-hourly) energy generation by unit (“ex-post 2” data) postcurtailment⁴⁷ was obtained from the Single Electricity Market Operator Market Data portal for each available wind farm and summed to give annual outputs. These were corrected to reflect generation for a typical meteorological year using a 30-year wind index (ECA&D 2018) and the 2016 average national curtailment rate (2.8%). Full load hours and capacity factors were then calculated using total installed wind farm capacity data.

The cost of project financing involved estimating the WACC, which is a function of: cost of debt, cost of equity, inflation, and debt-to-equity ratio. Long-term inflation expectations were taken as the European Central Bank’s target rate of 2%. The cost of debt was estimated based on the sum of the risk-free rate, country risk, and project default spread, and verified through contacts with financial institutions as well as through the analysis of the financial statements of wind energy companies. The cost of equity was estimated using the capital asset pricing model; it was not possible to verify these results. Since there were no publicly quoted companies in Ireland which operate only wind farms, the debt-to-equity ratio was estimated by analyzing

⁴⁷ Wind energy generators are compensated for curtailed energy at the market price.

comparable publicly traded companies for which data were available. The data used and resulting WACC estimates are shown in Table 5.

Table 5. Financial Parameters and Resulting Weighted Average Cost of Capital in Ireland

Financial Parameter	Sources	2008–2012	2013–2016
Cost of debt (nominal)	Risk-free rate (ECB), CDS (Bloomberg), project spread (lenders)	7.0%	7.0%
Corporate tax rate	Irish tax authorities	12.5%	12.5%
Cost of equity	Capital asset pricing model (various data sources)	14.0%	14.0%
Debt-to-equity ratio	Equivalent publicly traded company	4:1	4:1
Nominal before-tax WACC	From above	8.4%	8.4%
Nominal after-tax WACC	From above	7.4%	7.4%
Real after-tax WACC	From above	5.2%	5.2%

Although renewable energy projects qualify for the Irish government’s Accelerated Capital Allowance scheme, which allows the entire capital cost of qualifying equipment to be written down in the year of purchase, large wind companies appear to depreciate assets using a 20-year straight-line model. Therefore, this approach is used in all LCOE calculations. Corporation tax in Ireland is chargeable at 12.5% and this rate has remained unchanged over the study period.

4.3.2 Trends Since 2008

Estimated LCOE values for Irish wind project investments for each of the years 2008–2016 are summarized here. Table 6 shows the input values used in each of the study years and the corresponding LCOE value. The sources of the input data are described earlier and it should be noted that these are average values (typically capacity- or generation-weighted) and that, in reality, there is a wide spread of LCOE values for each year as all wind farms have different performance, cost, and financing characteristics. Furthermore, significant input data uncertainties exist, as highlighted earlier.

Table 6. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed from 2008 to 2016 in Ireland

Parameter	Unit	Wind Project Year of Installation								
		2008	2009	2010	2011	2012	2013	2014	2015	2016
Net energy production ^a	Capacity factor %	29	29	35	33	37	34	32	31	31 ^b
	(Full load hours)	(2,535)	(2,556)	(3,050)	(2,892)	(3,207)	(3,017)	(2,827)	(2,710)	(2,710) ^b
Investment costs ^c	2016 €/kW	1,424	1,742	1,893	1,624	1,776	1,703	1,776	1,446	1,677
	(2016 \$/kW)	(1,575)	(1,927)	(2,094)	(1,796)	(1,965)	(1,884)	(1,965)	(1,599)	(1,855)
O&M costs ^c	2016 €/kW/yr	48	48	48	48	48	48	48	48	48
	(2016 \$/kW/yr)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
After-tax WACC ^d	% nominal	7.4	7.4	7.4	7.4	7.4	6.7	6.7	6.7	6.7
	(% real)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(4.6)	(4.6)	(4.6)	(4.6)
Corporate income tax rate	%	13	13	13	13	13	13	13	13	13
Depreciation schedule ^e		Linear, 20 year								
LCOE ^f	2016 €/MWh	69	79	71	66	64	63	69	62	69
	(2016 \$/MWh)	(76)	(87)	(78)	(73)	(71)	(69)	(76)	(69)	(76)

^a Net energy production in calendar year 2016: 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 8,784 hours in 2016.

^b Lower 2016 capacity factors might be influenced by commissioning problems, phased-commissioning, or curtailment/constraint.

^c Investment costs and O&M costs converted to real 2016 euros and US dollars. Details are [in the attached supplemental data appendix](#). O&M costs 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% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. 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.

Table 6 shows that there has been relatively little change in the real life cycle costs of producing one unit of wind energy in Ireland over the study period. The maximum and minimum LCOE for the period was 79€/MWh (\$87/MWh) and 62€/MWh (\$69/MWh), respectively, with a mean value of 68€/MWh (\$75/MWh). Given that O&M costs, inflation, depreciation, and amortization periods were constant throughout, and that WACC only varied slightly, changes in LCOE are almost completely explained by changes in capacity factors and investment costs over the period. The highest average investment cost occurred in 2010, but this was offset by the high average annual capacity factor (and, therefore, energy production) for wind turbines installed in that year, resulting in a near-average LCOE figure. The lowest investment cost was in 2015, which, when combined with a near-average capacity factor in that year, resulted in the lowest LCOE over the period. The low average investment cost observed for 2015 was significantly influenced by two large wind farms commissioned in that year. The mean LCOE for the 2008-2012 period was slightly higher than that for 2013–2016. It is possible that this is because of the lower WACC for the latter period.

To better understand the components of LCOE change over the period, a decomposition analysis was undertaken on the values for the years at the beginning and end of the study period: 2008 and 2016. The intention was to identify the relative impacts of changes in input variables on LCOE estimates for these 2 years. The results of this analysis are shown in Figure 13, where it

can be seen that there was no significant change in overall LCOE between the two years. Increased energy production and lower WACC in 2016 (compared to 2008) lowered LCOE by 4.4€/MWh (\$4.9/MWh) and 3.3€/MWh (\$3.6/MWh), respectively. However, these reductions were more than offset by higher capital costs that increased LCOE by 8.2€/MWh (\$9.1/MWh).

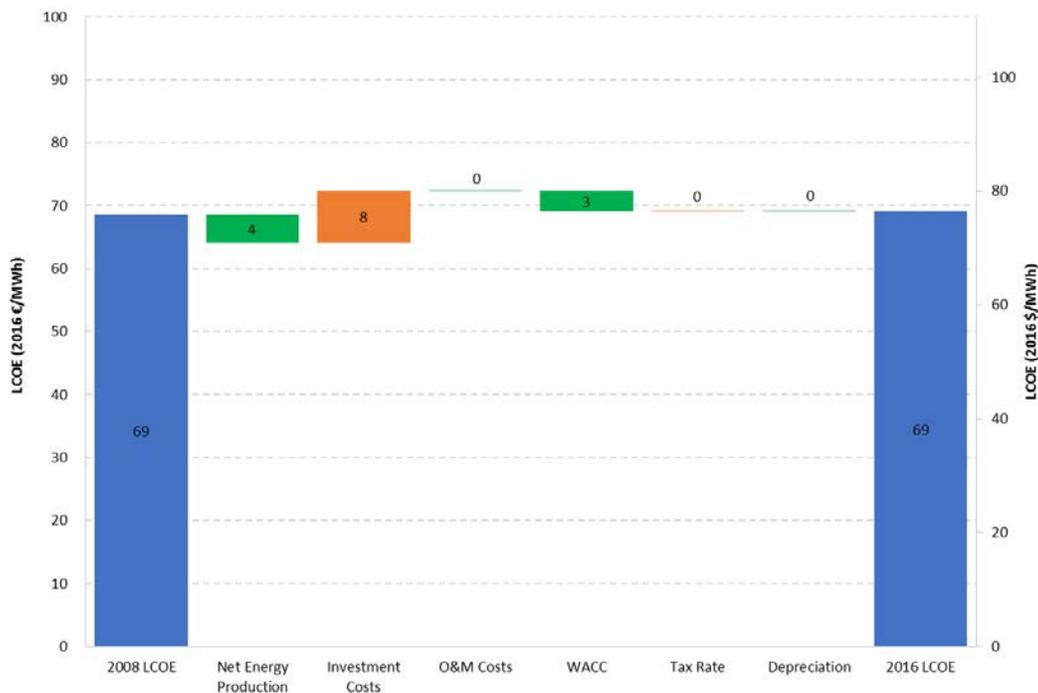


Figure 13. Sources of LCOE reduction in Ireland from 2008 to 2016

Note: green denotes reduction and orange denotes increase

4.4 Wind Energy in the Irish Electricity Market

Wind is becoming an increasingly important component of the Irish electricity market with wind energy generation targeted to meet over 35% of electricity needs by 2020. Given this level of deployment, it is important for any subsidies to be carefully designed and represent value for money for the consumer.

Figure 14 shows the estimated LCOE of wind energy generation in Ireland compared to both the wholesale market system marginal prices (excluding capacity payments that may account for approximately 7% of revenues for wind generators) and the minimum guaranteed feed-in tariff (REFIT, see Section 5.1.2) including both the reference (energy) price and balancing payment. It can be seen that while the LCOE has remained relatively steady, the average annual SMP for electricity has fluctuated; this is closely correlated with wholesale gas price over the period. As in other countries, higher wind energy outputs coincide with lower SMPs and, although annual differentials were not available at the time of writing, it is estimated that wholesale prices were 4%–5.4% lower in 2009 (Denny et al. 2017) than they would have been in the absence of wind generation; this downward pressure on wholesale electricity prices by wind generation is likely

to be higher in later years as wind capacity has grown. The wholesale prices (SMPs) shown, therefore, overstate the prices obtained by wind operators, although the omission of capacity payments may compensate for this effect.

4.4.1 Trends Since 2008

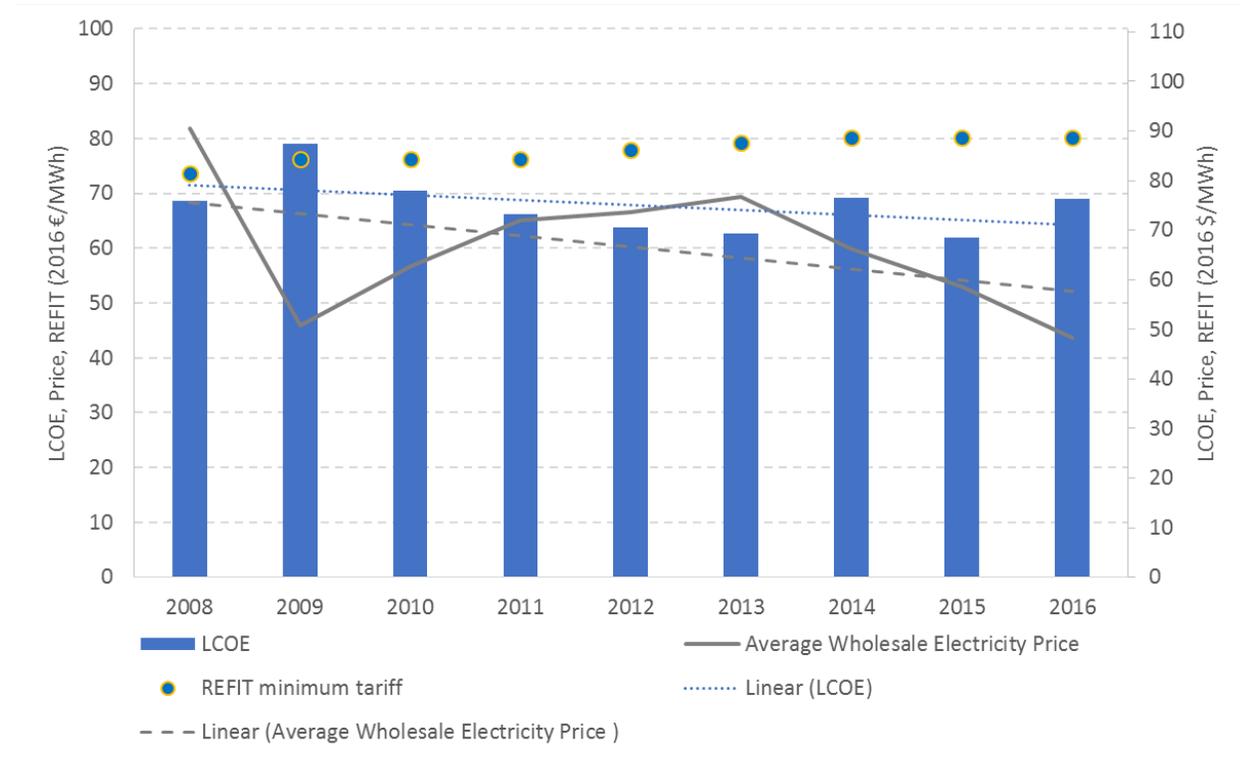


Figure 14. LCOE, average wholesale electricity price, and REFIT in Ireland from 2008 to 2016

Assuming that average monthly SMPs are representative of total earnings for wind farm operators, wind LCOE reached or exceeded grid parity in 2008, 2011, 2012, and 2013 (see Figure 15). However, in almost all years the average LCOE was below the REFIT price, suggesting that this price would have incentivized investment in an average project. The gap between the LCOE trend line and the REFIT price is increasing, which would make REFIT-contracted projects progressively more attractive if they were available; however, they are not, the scheme having closed in 2015. Finally, it is worth noting that the 9-year trend lines for annual LCOE and SMPs are diverging and, if this continues, land-based wind energy in Ireland will never reach grid parity. The falls in SMP have been largely driven by a combination of depressed electricity demand, increasing wind power contribution, and declining gas prices. Gas prices have increased rapidly since the latter half of 2017, perhaps arresting the downward SMP trend and reversing the divergence between SMPs and LCOE.

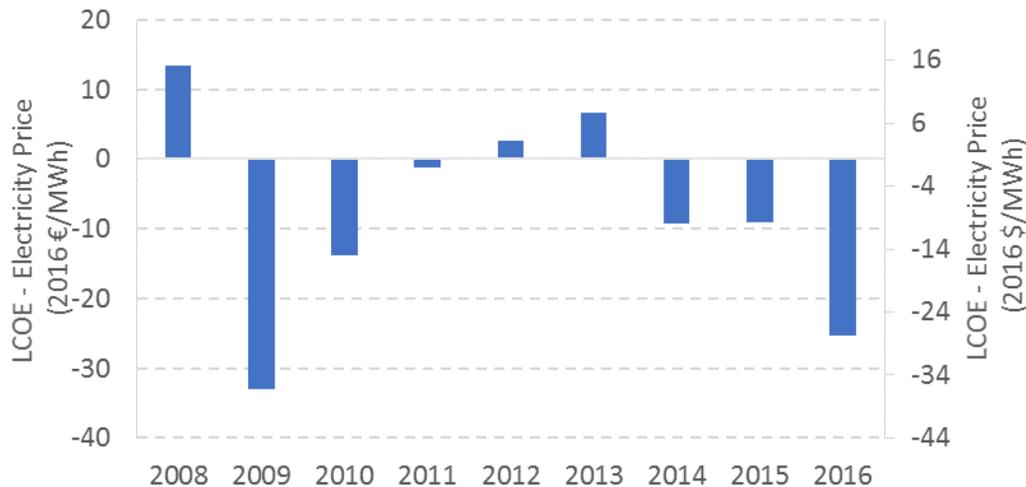


Figure 15. Difference between LCOE and market value of electricity in Ireland from 2008 to 2016

4.4.2 Expectations for the Future

LCOE trends indicate that technology developments, such as the move to larger-scale technologies with lower specific powers, are not resulting in significant life cycle cost reductions in Ireland. It appears that any reductions in the capital cost of equipment are being largely balanced by higher project development costs. Based on current trends, the outlook is therefore for very modest reductions in the LCOE of Irish land-based wind projects over the coming years. However, a recovery in electricity prices would change this situation.

The stagnation in LCOE and the recent relatively low wholesale electricity prices combined with their high variability means that land-based wind energy investment will require reliable price supports for the foreseeable future. Further risks posed by the introduction of wind farm balance responsibility in the new I-SEM electricity market further adds to the market-based revenue uncertainty for wind.

4.5 Summary

Over the 2008-2016 study period, the estimated annual LCOE for Irish land-based wind energy projects was largely unchanged, with a period average of 68€/MWh (\$75/MWh). Changes in capacity factors and WACC resulted in small reductions in LCOE, but these were offset by the impact of higher investment costs.

The average size of wind farms has almost doubled in the latter study years (2013–2016) to 15–30 MW while turbine capacities have increased from approximately 2 to 2.75 MW. Average rotor diameter and hub heights are now over 90 m and 80 m, respectively, whereas specific power has decreased from approximately 450 W/m² to 380 W/m². Capacity factors are, on average, highest for wind farms developed in the 2010–2013 period (at approximately 33%–37%) with capacity factors after this approximately 31%–32%.

The stagnation in LCOE and the relatively low wholesale electricity prices coupled with price volatility and future market uncertainty means that land-based wind energy investment may require reliable price supports for the foreseeable future.

5 Norway

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5.1 Wind Energy Development in Norway

Norwegian electricity production is based overwhelmingly on hydropower, though planning and deployment of wind power have increased dramatically in recent years.

The total electricity production in Norway in 2017 was 149.3 TWh. Renewable sources of electricity amounted to 97.7% of the national electricity production, with 1.9% and 95.8% of the electricity production coming from wind and hydropower, respectively. With electricity consumption in the country totaling 134.1 TWh for the year, there was a net electricity export of 15.2 TWh (Statistics Norway website).

5.1.1 Domestic Wind Energy Capacity, Production, and Targets

Total installed wind energy capacity in Norway was 1,188 MW at the end of 2017 (NVE 2018), and production of wind power in 2017 was 2,850 gigawatt-hours, compared to 2,125 gigawatt-hours in 2016. Further, 2017 was a record year for wind power deployment in Norway, with 324 MW of new wind capacity installed. Additionally, 1,600 MW of wind power was under construction at the end of the year.

Enova SF supported the development of over 700 MW of wind power commissioned between 2001 and 2013. Deployment of wind power in the first years of the electricity certificate scheme has been modest, with 529 MW of wind power approved in the scheme as of the end of 2017. Figure 16 shows the history of wind power deployment in Norway from 1997 to 2017.

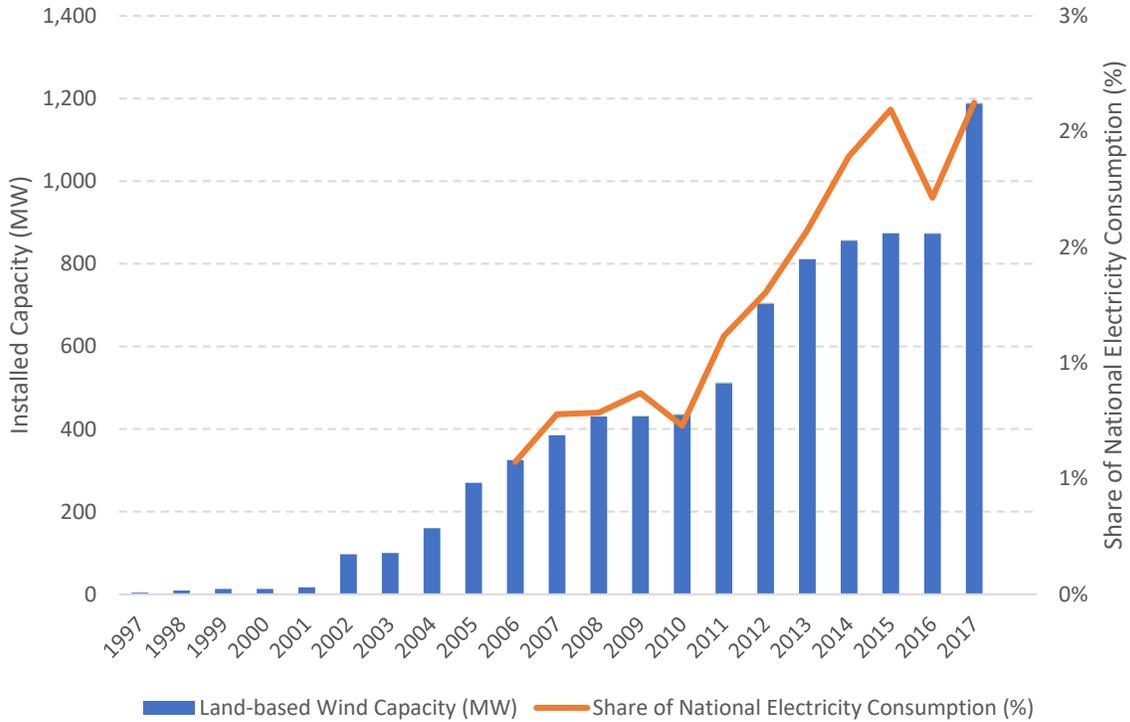


Figure 16. Wind power growth in Norway from 1997 to 2017

5.1.2 Revenue and Policy Incentives

Between 2001 and 2010, financial support for wind power projects in Norway was provided by the state-owned organization Enova SF, on a case-by-case basis with the goal of supporting projects just enough to make them commercially viable. This program ended in 2011, although the last projects to receive support were commissioned in 2012 and 2013.

From 1 January 2012, Norway and Sweden entered into a common electricity certificate market/scheme. The economic incentive provided by the electricity certificate scheme is to stimulate the combined development of 28.4 TWh/yr of new renewable power production in the countries by the end of 2020, of which 13.2 TWh is to be financed by Norwegian power consumers.

A key aspect of the certificate system is that it shifts the cost for supporting renewables from Enova to the electricity consumer. Approved power plants receive one certificate for every generated megawatt-hour from renewable energy sources, for a period of 15 years from commissioning. Hence, owners of approved plants have two products on the market: electricity and certificates, and these can be sold independently of each other. The demand for certificates is created by a requirement under the act that all electricity users purchase certificates equivalent to a certain proportion of their electricity use, known as their quota obligation. The price of certificates is determined in the market by supply and demand, and it can vary from one transaction to another.

In April 2017, an agreement was reached between the Norwegian and Swedish governments about the future of the electricity certificate scheme after the original cutoff for deployment in 2020. Norway will not expand its targets beyond the existing target to finance 13.2 TWh of new renewable energy by 2020, but the agreement extended the cutoff for Norwegian projects by 1 year, meaning that wind power in Norway must be commissioned by the end of 2021 to receive support from electricity certificates. There is no plan to subsidize new wind power in Norway after 2021, and wind power realized in Norway after then will thus have to be profitable based upon electricity sales alone. Sweden has elected to expand its target to add an additional 18 TWh of new renewable production by 2030, within the electricity certificate scheme. The agreement between Norway and Sweden is that certificates will continue to be traded in a common market even after the cutoff for Norwegian plants' eligibility for the scheme at the end of 2021. Because of the new target in Sweden, the demand and market for certificates will be extended until 2045.

5.2 Wind Energy Project Trends in Norway Since 2008

In this section, trends regarding wind projects in Norway are presented. With the relatively small number of existing wind farms in Norway, trends may not be as clear as in other countries, although some of the clearer trends are addressed here. The full data set can be visualized and downloaded in the [IEA Wind TCP Task 26 Data Viewer](#). The specific data used in this report and the data used to convert monetary values to real 2016 euros and U.S. dollars are compiled in [the attached supplemental data appendix](#).

Norwegian wind farms tend to be larger than in other European countries, with licenses typically being granted for 50–150 MW per wind farm, although several smaller wind farms are in operation or licensed.



Figure 17. Locations and sizes of wind farms in Norway that are constructed or under construction

Most existing and licensed wind farms in Norway are located on coastal mountaintops with high mean wind speeds and complex terrain. Wind turbines have tended to have a high rated capacity, and there has been a clear increase in turbine nameplate capacity, from 2.3 MW in 2008 to over 3 MW in 2016. Rotor diameters for wind turbines in Norway have increased more than capacity ratings since 2008, from an average of 75 m in 2008 to 113 m in 2017. Wind-turbine-specific power has decreased from around 530 W/m² in 2008 to 330 W/m² in 2017.

Increases in turbine-specific power have generally led to increased capacity factors, but there has been no clear temporal trend in mean wind speed or wind turbine IEC class at developed sites, which complicates this trend. Before 2011, all wind turbines in Norway were IEC Class I, and from 2012 to 2017, wind farms consisted of both IEC Class I and Class II turbines. Based on wind conditions at licensed projects, IEC Class I and Class II turbines are expected to dominate the market also in upcoming years, with only a few wind farms being built in areas suitable for IEC Class III turbines.

Average investment costs for Norwegian wind farms have not shown a consistent trend since 2008. Projects built in 2017 had similar investment costs to the levels seen in 2008 (about 1,100 EUR/MW), while average CapEx tended to be higher for projects realized from 2011 to 2015.

5.3 Cost of Wind Energy Generation in Norway Since 2008

In this chapter, trends in LCOE are presented based on both reliable data and more uncertain assumptions. Owners of wind projects in Norway report detailed information on investment costs to the Norwegian Water Resources and Energy Directorate (NVE), and reliable data for wind power production have been obtained from the Norwegian TSO Statnett. Lacking complete or reliable data, NVE has estimated O&M and financing costs, based on limited data and supplemented with knowledge gained through contact with the wind power industry.

To represent temporal trends in the cost of wind energy generation in Norway, capacity-weighted averages for wind projects in four different periods are used. Averaging across years was required for the periods 2006–2008, 2011–2013, 2014–2015, and 2016–2017, such that the data could be published without being traced back to individual projects. For simplicity in describing trends, projects from the different periods are hereafter referred to as 2008, 2012, 2014, and 2016.

5.3.1 Trends Since 2008

Input data and LCOE calculations for wind energy projects by commercial operation year from 2008 to 2016 are summarized in Table 7.

From 2008 to 2012, the LCOE for wind power projects in Norway increased slightly, from 56 €/MWh to 61 €/MWh (\$62/MWh to \$67/MWh).⁴⁸ The increase over this period was due almost entirely to higher investment costs for projects realized around 2012. Average LCOE for Norwegian wind projects have fallen sharply since 2012, first to 41 €/MWh (\$45/MWh) in 2014 and then further to 32 €/MWh (\$35/MWh) in 2016.

At a high level, reductions in LCOE after 2012 can be attributed to professionalization of Norwegian wind power development, incentivized by the market-based nature of the electricity certificate scheme, and aided by lower financing costs and improvements in wind turbine technology.

⁴⁸ Exchange rates used from NOK: 9.29 NOK/EUR and 8.40 NOK/USD.

Table 7. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed from 2008 to 2016 in Norway

Parameter	Unit	Wind Project Year of Installation								
		2008	2009	2010	2011	2012	2013	2014	2015	2016
Net energy production ^a	Capacity factor %	32	-	-	33	33	33	43	43	41 ^b
	(Full load hours)	(2,841)	-	-	(2,880)	(2,872)	(2,872)	(3,813)	(3,813)	(3,566) ^b
Investment costs ^c	2016 €/kW	1,106	-	-	1,574	1,574	1,574	1,475	1,475	1,127
	(2016 \$/kW)	(1,223)	-	-	(1,741)	(1,741)	(1,741)	(1,632)	(1,632)	(1,247)
O&M costs ^c	2016 €/kW/yr	46	-	-	46	46	46	41	41	38
	(2016 \$/kW/yr)	(51)	-	-	(51)	(51)	(51)	(45)	(45)	(42)
After-tax WACC ^d	% nominal	7.7	-	-	5.5	5.5	5.5	5.0	5.0	4.5
	(% real)	(5.6)	-	-	(3.4)	(3.4)	(3.4)	(2.9)	(2.9)	(2.5)
Corporate income tax rate	%	28	-	-	28	28	28	28	27	25
Depreciation schedule ^e		Linear, 20 year				Accelerated 5 year				
LCOE ^f	2016 €/MWh	56	-	-	61	61	61	41	40	32
	(2016 \$/MWh)	(62)	-	-	(67)	(67)	(67)	(45)	(45)	(35)

^a Net energy production in calendar year 2016: 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 modelled wind indices from Kjeller Vindteknikk. Full load hours based on 8,784 hours in 2016.

^b In 2016, a full year of energy production data was not available for projects installed during 2016. Therefore, the capacity factor associated with projects installed in 2016 is estimated using applications for electricity certificates.

^c Investment costs and O&M costs converted to real 2016 euros and U.S. dollars. Details are in [the attached supplemental data appendix](#). O&M costs 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% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. This assumption is used to convert nominal WACC to real WACC.

^e 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 in 2016.

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

To analyze the main drivers of the reduction of LCOE, a decomposition analysis was performed, which is shown in Figure 18. The analysis indicates that the main factors contributing to the LCOE reduction in Norway are increases in capacity factor and decreases in WACC and OpEx. Changes in these factors led to reductions of 10.7 €/MWh (\$11.8/MWh), 7.8 €/MWh (\$8.6/MWh), and 2.3 €/MWh (\$2.5/MWh), respectively. There were also reductions of around 3 €/MWh (\$3.3/MWh) caused by lowered corporate tax rates and the introduction of 5-year depreciation schedules for wind projects.

As mentioned earlier, there are no reliable data in the public domain for financing costs and structures for wind projects in Norway. Qualitative trends with financing for Norwegian wind farms since 2008 have been falling interest rates and foreign capital from, for example, European pension funds. Combined with increased revenue hedging for power and electricity certificates sales, and the security of long-term service agreements, these trends are expected to have

resulted in steep reductions in the WACC for wind projects in Norway over the period. To represent the sum of these drivers quantitatively over time, values for WACC in Table 7 are based on annual averages of long-term interest rates for government bonds (Norges Bank website), with an added risk premium of 3%. O&M costs are also assumed to be reduced between 2012 and 2016, based upon interviews with the industry and financial statements from a limited number of wind power companies.

Going toward 2020, average LCOE for Norwegian wind projects is expected to be reduced on the order of 5 €/MWh (\$5.5/MWh). Projects around this time are expected to consist of fewer, but even larger wind turbines, with a nameplate capacity of 4–5 MW. Analysis of detailed cost data for Norwegian wind farms has shown significant impacts of wind turbine scaling on CapEx, due to relative reductions in road, foundation, and other infrastructure costs. These effects may be particular to large wind farms being built in complex terrain, where construction costs for roads (for example) tend to be a more significant portion of the CapEx than in other countries. As with offshore, fewer but larger turbines can also lead to fewer maintenance operations and lower OpEx.

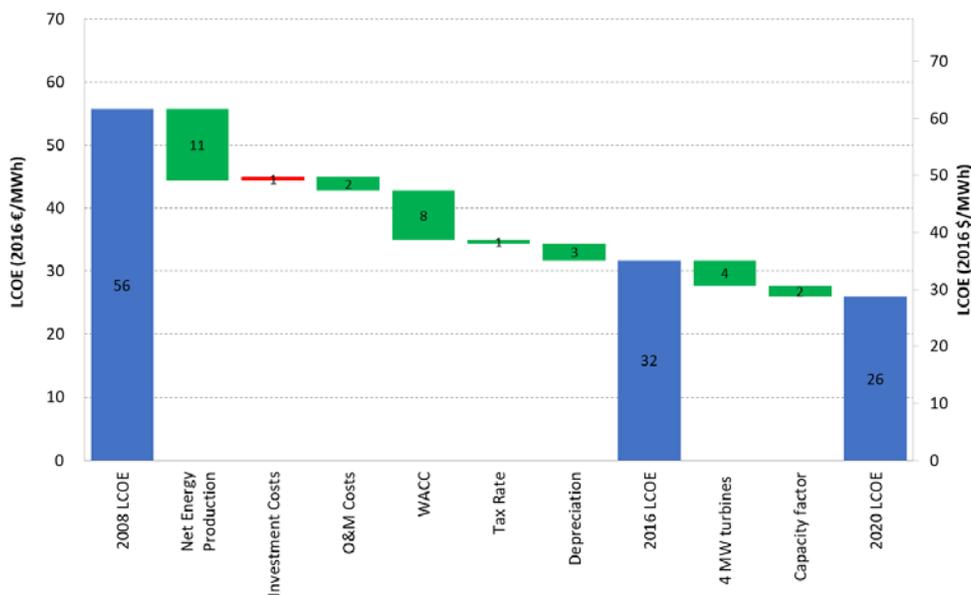


Figure 18. Sources of LCOE reduction in Norway from 2008 to 2016, with a projection of LCOE reduction to 2020

Note: green denotes reduction and orange denotes increase

5.4 Wind Energy in the Norwegian Electricity Market

Wind penetration in the Norwegian power system remains low but is expected to increase to 10% of power production sometime in the 2020s. Several modeling studies, including NVE’s long-term power market analysis (2017) suggests that the flexibility of the Norwegian hydropower system will limit the impact of wind power on prices in the country’s wholesale power market.

Power prices in Norway tend to have a strong seasonal profile, with higher power prices in the winter months because of increased consumption for electric heating and decreased runoff due to

freezing temperatures. This price-profile over the long term is favorable for the market value of wind power, since Norwegian wind farms tend to produce significantly more of their annual production during stormy winter months than in the summertime.

The market value of wind in this analysis is calculated as the ratio between the annual revenue of wind power in the market, and its annual generation, with the units €/MWh. The calculation uses historical hourly values of wind power production from the Norwegian TSO Statnett, and power prices per bidding zone from NordPool, as follows:

$$MV = \frac{\sum_t^T p_t \cdot E_t}{\sum_t^T E_t} = \bar{p}_{wind}$$

where t is the hour of the year ($1, \dots, T$), E is the wind energy production at the hour, t , and p is the market price at the hour, t , in the bidding area considered. To calculate a national average value for the five bidding zones in Norway, NO1-NO5, the total revenues are weighted using the total annual wind power generation in each zone. The national average electricity price has been weighted using the total demand in each area. The results are shown in Figure 19.

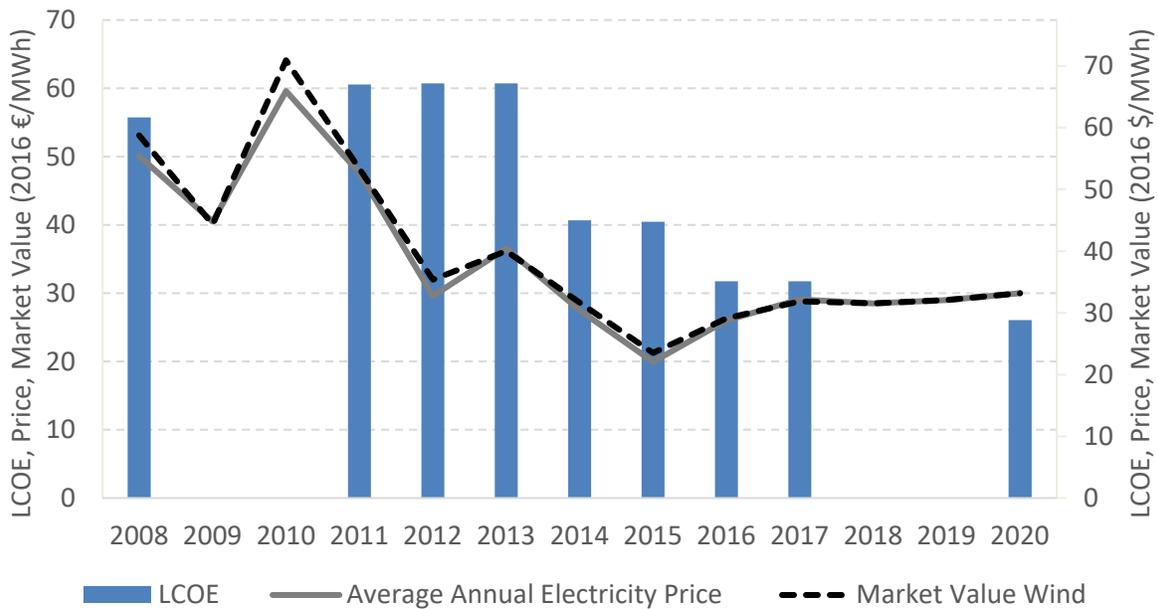


Figure 19. LCOE, average wholesale electricity price, and market value of wind in Norway from 2008 to 2016 with a projection to 2020

As shown in Figure 19, the market value of wind power in Norway has been near or slightly above the average annual power price. The figure also shows that despite significant declines in power prices since 2008, wind power LCOE is approaching the market value of wind, and with NVE’s projections of LCOE and power price is expected to achieve grid parity by 2020. Electricity certificate prices are not shown here, but these provide significant additional revenue to wind power projects in Norway built after 2012 that are eligible for the scheme, and they are shown and discussed in more detail in Chapter 6 of this report.

5.4.1 Expectations for the Future

The current pipeline of projects means that wind power deployment in Norway is expected to be high at least until the deadline for the electricity certificate scheme in 2021, with many wind farms currently under construction and many more in the process of making investment decisions. After the deadline for the electricity certificate scheme, there is considerable uncertainty about the rate of deployment of wind power in Norway, but low LCOE for wind power suggests that this will likely be more dependent on political will and other environmental factors than profitability for wind power projects.

The projection of wind power costs in this report is based upon a hypothetical project utilizing 4.2-MW turbines in an area with good wind resources. Further wind turbine scaling is expected to lead to higher capacity factors as well as savings in balance-of-plant and O&M costs compared with 3-MW wind turbines. The assumptions used for calculation of 2020 LCOE are presented in Table 8, and the power prices for 2020 are based upon NVE's base-case scenario, which is used to evaluate license applications.

Table 8. Input Values and Resulting Levelized Cost of Energy for Wind Projects Projected for Installation in 2020 in Norway

Commercial Online Date	2020
Installed capacity rating (MW)	4.2
Rotor diameter (m)	126
Hub height (m)	92
Capacity factor (%)	43
Investment cost (€/kW)	1,111
(\$/kW)	1,229
Variable O&M cost (€/kW)	8.6
(\$/kW)	9.5
After-tax nominal WACC (%)	4.5
National corporate tax (%)	22
LCOE (€/MWh)	26.1
(\$/MWh)	28.9

5.5 Summary

LCOE for wind energy decreased substantially in Norway from 2008 to 2016, from 56 €/MWh (\$62/MWh) in 2008 to 32 €/MWh (\$35/MWh) in 2016, a reduction of around 40%. The main drivers identified for this LCOE reduction are increased net energy production and decreased WACC and OpEx.

The market value of wind power in Norway is near the average annual electricity price, due to low wind power penetration and the flexibility of the Norwegian hydropower system. Wind power production also benefits from higher wintertime production when power prices tend to be higher.

The cost of wind energy in Norway is quickly approaching average power prices despite these having declined in recent years. This, along with expectations for larger and lower specific power turbines in the near term, suggest that wind power in Norway is very near grid parity already. This implies that significant deployments are plausible even after the end of the electricity certificate scheme in 2021.

6 Sweden

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6.1 Wind Energy Development in Sweden

Swedish electricity production is based largely on hydropower and nuclear power, which together account for fully 80% of electricity production. Starting in the 2000s, however, electricity production from wind power has rapidly increased.

After a general overview of the capacity installed for both land-based and offshore wind and the short-term and long-term targets for wind power, this analysis focuses on land-based wind from 2008 to 2016. Project-level data are available until 2016. However, when available, 2017 data will be added.

6.1.1 Domestic Wind Energy Capacity, Production, and Targets

The expansion of wind power started around 2008 in Sweden as shown in Figure 20. Total installed wind capacity in 2008 was 1,090 MW. At the end of 2017, the cumulative installed wind power capacity reached 6,611 MW. This means that the installed capacity increased by six-fold during this period. The annual additional installations during 2008–2017 varied between 199 MW to 894 MW. In recent years, the trend has been downward, with the lowest annual installation being in 2017 (199 MW). This can be explained by downward trends for both electricity prices and electricity certificates, resulting in smaller revenues for wind power projects and uncertainty about the prospects for renewable projects after 2020.

During 2017, however, there was a drastic increase in investment decisions concerning wind power projects, corresponding to 2,100 MW of new capacity (Swedish Energy Agency 2018a). The increase in investment decisions during 2017 is probably a result of the decision on a new target for renewable energy sources through 2030 within the electricity certificate system and an extension of the system through 2045, which created more stable conditions for investments in renewables.

Land-based wind power constitutes the vast majority of wind power installations in Sweden with 97% of the total installed capacity. Today, there are five small offshore wind farms in Sweden with a total wind capacity of 203 MW. Three of these wind farms were already in operation in 2008, with two offshore farms installed in 2009 and 2013 and one that has been decommissioned.

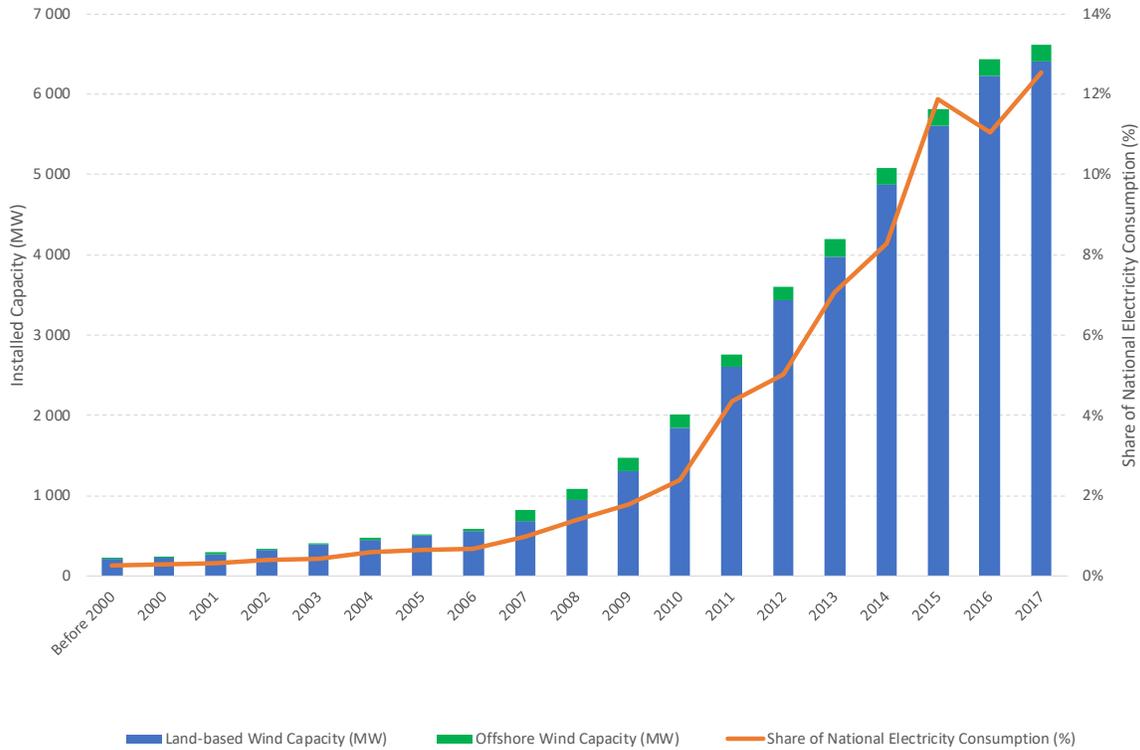


Figure 20. Wind energy growth in Sweden from 2000 to 2017

Source: Swedish Energy Agency (2018a, 2018b)

According to the Swedish Wind Energy Association’s latest forecast, the installed capacity of wind power will increase by more than 50% during the coming four years, resulting in approximately 10,000 MW, corresponding to 25 TWh of wind power production by 2020 (Swedish Wind Energy Association 2018). All this new capacity is assumed to be land-based wind power.

Looking further into the future, wind power production is expected to increase to 35 TWh by 2030 (corresponding to an installed capacity of 12,000 MW) and to 50 TWh by 2050 (17,800 MW), according to Swedish Energy Agency’s latest long-term forecast published in January 2017 (Swedish Energy Agency 2017b).

Because a large part of the wind power capacity in Sweden has been installed since 2008, only a few wind turbines have been decommissioned so far. Between 2008 and 2016, a total of 28 MW have been decommissioned.

In 2017, wind power production amounted to 17.6 TWh, which corresponds to 11% of the total electricity production in Sweden and 13 % of the electricity consumption (Swedish Energy Agency 2018a). The share of renewable energy in electricity production was approximately 65% in 2016 (Swedish Energy Agency 2018b).

The overall renewable energy target for Sweden is to have at least a 50% share of energy generated from renewable sources in gross final energy consumption by 2020. This target was

already achieved in 2011, and in 2016 the share of renewable energy was 54% (Swedish Energy Agency 2018b).

There is also a target for the electricity certificate scheme for renewable electricity generation, which is described in Section 6.1.2.

In 2016, the government and three of the parties in opposition have concluded an agreement on Sweden's long-term energy policy. The agreement consists of a common road map for a controlled transition to an entirely renewable electricity system, with a target of 100% renewable electricity production by 2040. It should be noted that this is a target, not a deadline for decommissioning nuclear power, nor does it entail closing nuclear power plants through political decisions. According to estimations made by the Swedish Energy Agency, about 80–120 TWh new renewable capacity will be required by 2040 to reach the target, of which a majority is assumed to be wind power, as the potential of wind power is significant in Sweden.

Another target in the long-term agreement is that Sweden is to have no net emissions of greenhouse gases into the atmosphere by 2045 and should thereafter achieve negative emissions.

6.1.2 Revenue and Policy Incentives

Since 1 May 2003, the electricity certificate system has supported renewable electricity production in Sweden. Although there have been several changes in the system since its inception, its fundamentals have been unchanged, which means that Sweden has one of Europe's most stable renewables regulatory regimes. The electricity certificate system is a market-based support system that aims to increase the production of renewable electricity and make production more cost efficient. Within the electricity certificate scheme, approved power plants receive one certificate for each megawatt-hour of renewable energy they produce over a period of 15 years. The system is technology-neutral; all renewable technologies receive the same number of certificates per megawatt-hour and there are no special quotas for wind power. Hence, owners of approved energy plants can market two products: electricity and certificates.

The demand for certificates is created by a requirement under the law that all electricity users purchase certificates equivalent to a certain proportion of their electricity use, known as their quota obligation. For 2016, Swedish market participants with quota obligations had to purchase electricity certificates corresponding to 23.1% of their calculation-relevant consumption. The quotas gradually increase until 2030, which results in increasing demand for electricity certificates.

Norway joined the electricity certificate scheme in 1 January 2012 and until the end of 2021, Sweden and Norway have a common electricity certificate market. By 2020, the two countries aim to increase their production of electricity from renewable energy sources by 28.4 TWh. This target represents approximately 10% of the current electricity production of the two countries. Sweden will finance 15.2 TWh and Norway 13.2 TWh. The market will determine when and where the new production will take place. The joint market will permit trading in both Swedish and Norwegian certificates and will receive certificates for renewable electricity production in either country. In Norway, plants must be commissioned before 1 January 2022 to be eligible for electricity certificates.

In June 2017, the Swedish parliament decided on a new target for electricity from renewable energy sources through 2030. The system will increase the production of electricity from renewable energy sources further by 18 TWh by 2030 and is extended through 2045.

6.2 Wind Energy Project Trends in Sweden Since 2008

In this section, trends regarding wind projects in Sweden are presented. The full data set can be accessed and downloaded in the [IEA Wind TCP Task 26 Data Viewer](#). The specific data used in this report and the data used to convert monetary values to real 2016 euros and US dollars are compiled in [the attached supplemental data appendix](#).

The size of land-based wind projects has grown five-fold since 2008. In 2008, the average size of a wind energy project was about 4 MW and consisted of 2–3 wind turbines. In 2016, the average size had increased to 20 MW and 7 turbines, respectively. The capacity rating of the turbines installed has also steadily increased during the period, from an average nameplate capacity of 1.4 MW in 2008 to 2.9 MW in 2016. Rotor diameter has grown substantially from 74 m in 2008 to 113 m in 2016 and the turbine height from 83 meters to 104 meters in 2016. During the same time the specific power has declined, from 378 W/m² to 298 W/m², which is a result of the fact that the growth in rotor diameter has been larger than the growth in the capacity rating turbines.

The overall trend during 2008–2016 has moved toward larger and more efficient projects. Figure 21 illustrates trends in rotor diameter, hub height and capacity factor over this period. Further, turbine models have been developed that fit very well with Sweden’s wind regime and planning environment: large rotors to capture more energy in Class III sites, and taller towers to tap into stronger winds at higher altitudes. These trends have resulted in a gradual increase of the generation-weighted capacity factors, from 26.8% in 2008 to 32.5% in 2016, corresponding to an increase in full load hours from 2,354 to 2,859 from 2008 to 2016. The 2016 wind resource in Sweden was 100% of a normal year,⁴⁹ which means that the wind-index-weighted full load hours were the same.

⁴⁹ The wind energy index in Sweden, both locally and nationally, has been calculated by Vindstat.com since 1991.

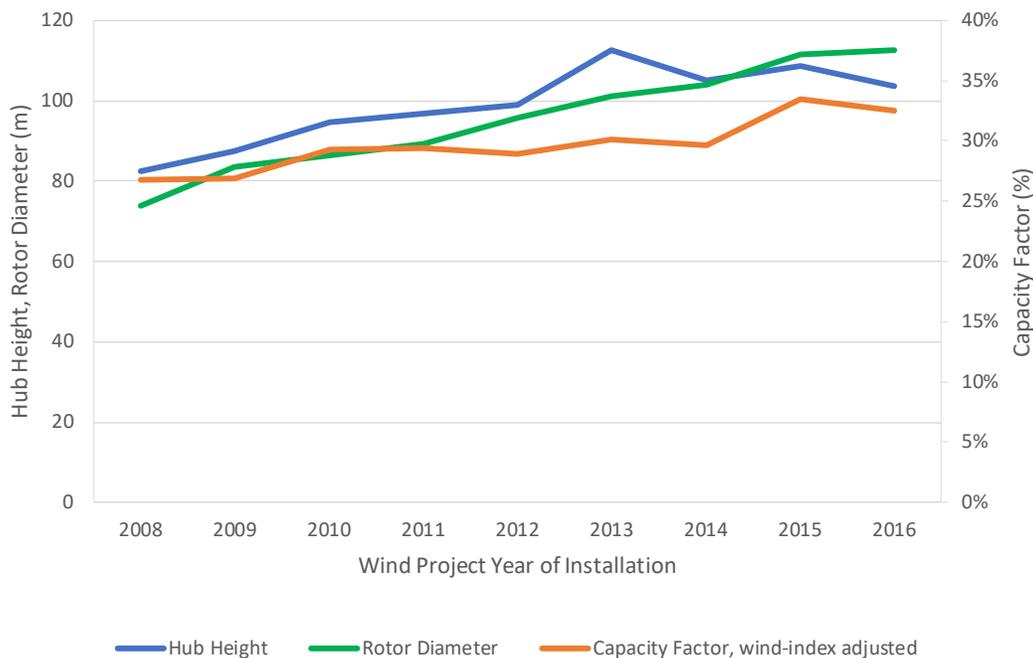


Figure 21. Capacity factor, hub height, and rotor diameter for wind projects installed in Sweden from 2008 to 2016

The prevailing wind directions are west and southwest in Sweden, which has made locations in the west and south part of Sweden the most feasible for wind power and the area where the first installations of wind power took place. In 2008, a national mapping of wind resources in Sweden was conducted for the first time by Uppsala University on behalf of the Swedish Energy Agency. This mapping showed that there is significant wind potential in forested areas, which were unknown before.⁵⁰ That was an important finding for wind power development in Sweden, as two-thirds of the land area in Sweden is covered with forest. Further, there are generally fewer conflicts with other land-use interests in these areas compared to the situation in more densely populated areas in the south of Sweden. Since the first wind mapping took place, many wind farms have been developed in forest areas all over Sweden, but with a majority in the central and northern parts of Sweden in recent years.

From 2008 and 2016 the average wind speed at the developed sites stayed relatively unchanged, with a slight decrease from 7.7 in 2008 to 7.5 m/s in 2016. As the wind turbine density in the country is still low, the decline likely does not indicate a lack of good sites.

Typical project investment costs in 2008 ranged from 1,117 €/kW to 1,779 €/kW (1,235 to \$1,968/kW) with a capacity-weighted average of 1,371 €/kW (\$1,517/kW).⁵¹ Investment costs

⁵⁰ Wind mapping with the MIUU-model: <https://www.geo.uu.se/forskning/luval/amnen/meteorologi/pagaende-forskning/vindenergi/vindkartering/version-2007/>.

⁵¹ Exchange rates used from SEK: 9.47 SEK/EUR and 8.56 SEK/USD

peaked in 2009 and have gone down by over 30% thereafter. In 2016, the capacity-weighted average investments cost amounted to 1,150€/kW (\$1,273/kW). From an international perspective, investment costs are relatively low in Sweden. This can probably be explained by the fact that both project developers and turbine manufacturers have had to adjust costs for new projects in Sweden after experiencing low revenues on the Nordic electricity market in recent years (PwC 2017).

The O&M costs include land use fees, maintenance, insurance, grid connection tariff, and real estate tax. Similar to the investment costs, the O&M costs peaked in 2009 and sank thereafter. Between 2009 and 2016, the O&M costs decreased by almost 40%. The capacity-weighted average costs were 61€/kW (\$68/kW) in 2008 and 41€/kW (\$45/kW) in 2016.

A trend toward reduced cost of financing for land-based wind in Sweden was assumed with the WACC decreasing from approximately 8% (nominal) in 2008 to 5% in 2016. The main driver for this reduction is the lower cost of debt, as well as the lower cost of equity.

6.3 Cost of Wind Energy Generation in Sweden Since 2008

To represent the cost of wind energy generation in Sweden, data on typical wind projects in Sweden from 2008 to 2016—the capacity-weighted averages of investment costs and O&M costs—were used. The typical project reflects the average figure for installations that year. Two main sources have been used to collect project data: the electricity certificate system registry, hosted by the Swedish Energy Agency and The Wind project database (Vindbrukskollen), hosted and updated by the County Administrative Board of Västra Götaland.

There are no published data on the costs of wind projects in Sweden. The investment costs and average annual fixed O&M costs were obtained from a survey of annual financial reports from a selection of wind projects (Sweco 2017). It should be noted that the sample size for O&M costs are limited. The O&M costs have been calculated as the average O&M costs of every year after the installation year, which means that the O&M costs for wind farms that were installed during 2015 and 2016 are based on one or two years of cost data, whereas wind farms installed in the beginning of the period are based on an average of several years of cost data.

Project-specific data were not available for financial structures, which were instead estimated based upon limited data and interviews with market players. The financial structures for wind power projects in Sweden have changed since 2008. In 2008, project financing with 75% debt was typical. After that, the debt fraction gradually dropped to a typical debt fraction of about 50% in 2016. Furthermore, the cost of lending decreased between 2008 and 2016. There has also been a change in the type of investors. Between 2008 and 2010, local energy companies accounted for a large part of the investments in wind projects in Sweden. These companies tend to have a relatively high return on equity, and levels of WACC at approximately 8% (nominal). From 2010 on, large financial institutions with long-term holding horizons, such as insurance companies and pension funds, have been the main source of private capital for Swedish wind projects. Such investors seek long-term and safe investments and tend to have a lower required rate of return than traditional energy companies. Based on these changes, WACC was assumed to have decreased from 8% in 2008 to 5% in 2016. In addition, the Swedish corporate tax rate was lowered in 2013, from 26% to 22%.

The depreciation schedule used in calculating the LCOE for wind energy projects in Sweden is a 20-year straight-line schedule, which is applied for all years in the analysis period.

6.3.1 Trends Since 2008

The input data for the LCOE calculation and LCOE for wind energy projects by commercial operation year from 2008 to 2016 are summarized in Table 9.

The LCOE for wind power in Sweden has sunk from year to year over the given time period, from 86€/kWh in 2008 to 44€/kWh in 2016 (\$95 to \$49/kWh), corresponding to a reduction of 48%. However, between 2008 and 2009, the LCOE increased, as a result of an increase in both investments and O&M costs, which is consistent with global cost trends for wind energy projects. Since 2009, both investments and O&M costs have gradually gone down.

Table 9. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed from 2008 to 2016 in Sweden

Parameter	Unit ^a	Wind Project Year of Installation								
		2008	2009	2010	2011	2012	2013	2014	2015	2016
Net energy production ^a	Capacity factor %	27	27	29	29	29	30	30	33	33 ^b
	(Full load hours)	(2,354)	(2,363)	(2,574)	(2,582)	(2,539)	(2,644)	(2,600)	(2,936)	(2,859) ^b
Investment costs ^c	2016 €/kW	1,371	1,718	1,571	1,580	1,449	1,319	1,321	1,203	1,150
	(2016 \$/kW)	(1,517)	(1,900)	(1,738)	(1,747)	(1,603)	(1,459)	(1,461)	(1,330)	(1,273)
O&M costs ^c	2016 €/kW/yr	61	67	57	60	61	54	44	42	41
	(2016 \$/kW/yr)	(68)	(74)	(63)	(66)	(67)	(60)	(49)	(47)	(45)
After-tax WACC ^d	% nominal	8.0	7.6	7.3	6.9	6.5	6.1	5.8	5.4	5.0
	(% real)	(5.9)	(5.5)	(5.1)	(4.8)	(4.4)	(4.0)	(3.7)	(3.3)	(2.9)
Corporate income tax rate	%	26	26	26	26	26	22	22	22	22
Depreciation schedule ^e		Linear, 20 year								
LCOE ^f	2016 €/MWh	86	100	81	80	75	62	58	46	44
	(2016 \$/MWh)	(95)	(111)	(89)	(88)	(83)	(69)	(64)	(51)	(49)

^a Net energy production in calendar year 2016: 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 8,784 hours in 2016.

^b In 2016, a full year of energy production data was not available for projects installed during 2015 and 2016. Therefore, the capacity factor associated with projects installed in 2015 and 2016 is estimated using applications for electricity certificates.

^c Investment costs and O&M costs converted to real 2016 euros and US dollars. Details are in [the attached supplemental data appendix](#). O&M costs 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% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. 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.

To analyze the main drivers of the reduction of LCOE, a decomposition analysis was performed, which is shown in Figure 22. The analysis indicates that the main factors contributing to the LCOE reduction in Sweden are net energy production and WACC, accounting for more than 60% of the reduction. Net energy production through more efficient turbines with higher

capacity factors have reduced LCOE by 16 €/MWh (\$18/MWh), and decreasing WACC has reduced LCOE by 10 €/MWh (\$12/MWh). Reduction in investment costs and in O&M costs has also contributed to the LCOE reduction, while changes to corporate income tax rates have had a minor effect on the LCOE during the period according to this analysis. Depreciation was unchanged over this period.

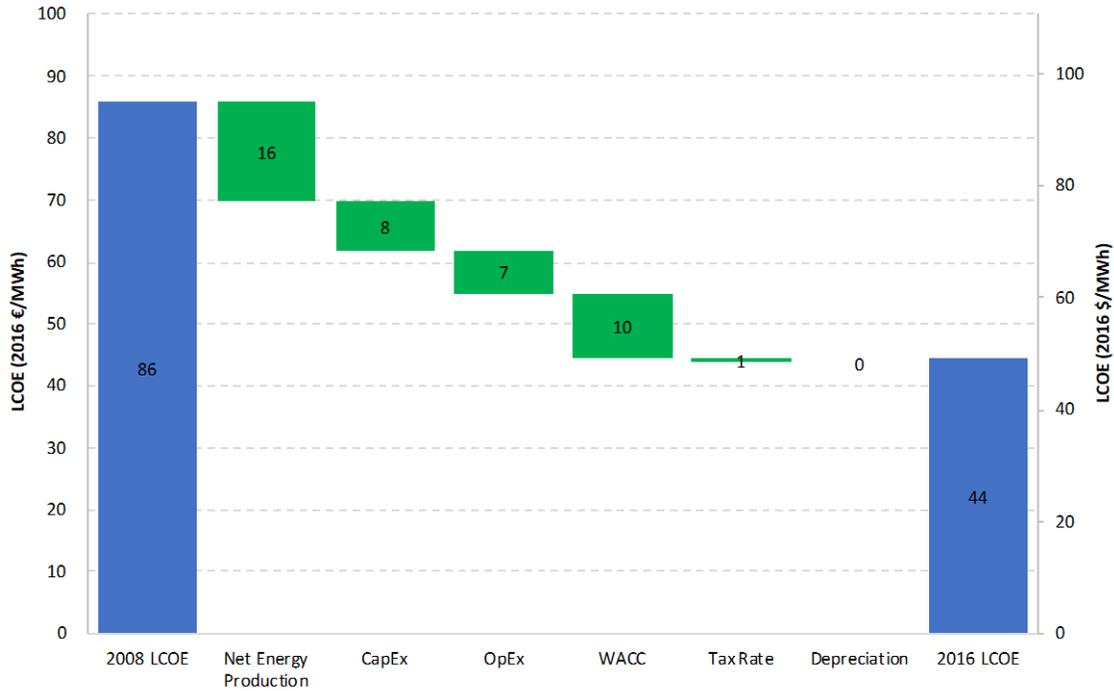


Figure 22. Sources of LCOE reduction in Sweden from 2008 to 2016

6.4 Wind Energy in the Swedish Electricity Market

Even though there has been a large expansion of wind power installations in Sweden since 2008, it has not reached a high penetration level in the Swedish electricity market. In 2017, wind power accounted for 13% of total power demand and 11% of electricity production (Swedish Energy Agency 2018a).

The market value of wind, referred to as the average electricity price that the wind producers receive, is generally lower than the average market price, at least when the penetration of wind is high. The market value of wind is calculated as the ratio between the annual revenue of wind power in the market and its annual generation. It has been calculated here using historical values from the Swedish TSO Svenska Kraftnät (SVK 2018) and NordPool (Nordpool.com 2018), as follows:

$$MV = \frac{\sum_t^T p_t \cdot E_t}{\sum_t^T E_t} = \bar{p}_{wind}$$

where t is the hour of the year ($1, \dots, T$), E is the wind energy production at the hour, t , and p is the market price at the hour, t , in the bidding area considered. To calculate an average value for the four bidding zones in Sweden, SE1-SE4, the total revenues have been weighted using the

total annual generation in each area. The average electricity price has been weighted using the total demand in each area. The results are shown in Figure 23.

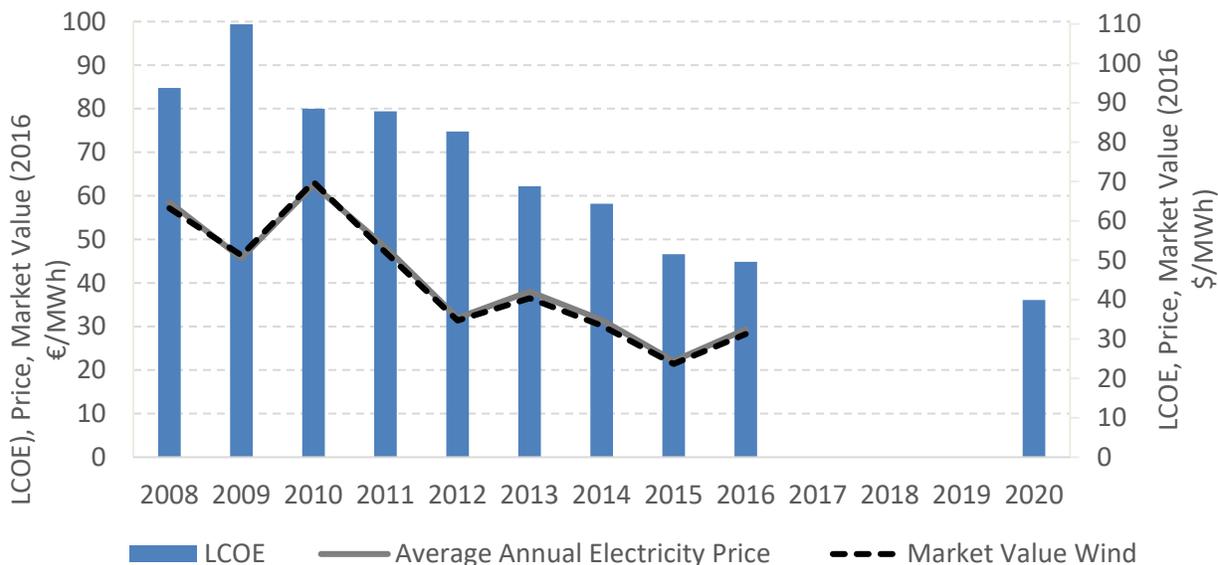


Figure 23. LCOE, average wholesale electricity price, and market value of wind in Sweden from 2008 to 2016, with projections to 2020

The market value of wind in Sweden differs very little from the average electricity price from 2008 to 2016. In 2016, the market value was 3% lower than the average price. This can be explained by the fact that wind power still accounts for a relatively small share of the total electricity production and that hydropower accounts for a large part of the electricity production in Sweden. In the long run, when the share of variable electricity production is expected to be larger, the market value of wind is assumed to decrease compared to the average electricity price. Calculations made by the Swedish Energy Agency indicate that the market value of wind will be approximately 12% lower than the average electricity price in the south of Sweden (SE4) when the target of 18 TWh new renewable capacity has been installed (Swedish Energy Agency 2017a).

Figure 28 shows both the LCOE of wind power and the electricity price decline from 2008 to 2016. As the LCOE has gone down more than the market value of wind, the gap between the LCOE for wind energy and the market value of wind has decreased since 2008. In 2016, the gap was 16 €/MWh (\$18/MWh), which can be compared to 9 €/MWh (\$32/MWh) in 2008. These calculations indicate that it will still be a number of years before Swedish wind power projects reach grid parity.

It should also be noted that the average price of electricity certificates in 2016 was 14 EUR/MWh (\$15/MWh), which indicates that the gap between the LCOE and market value of wind was not fully covered by the revenue from the subsidy scheme.

6.4.1 Trends Since 2008

The revenue streams for Swedish wind projects have varied substantially between 2008 and 2016, due to the fact that both the electricity price on Nordpool and the electricity certificates are

highly volatile, which is shown in Figure 24. The prices of certificates peaked in 2008 above 40€/MWh (\$44/MWh) and have thereafter steadily decreased. In 2017, the certificates reached their lowest level since the system began, with an average of 7€/MWh (\$8/MWh), but prices have increased slightly in the beginning of 2018. At the same time, the electricity price on NordPool has varied to a large extent. The total revenues from selling electricity and certificates from wind power projects have varied from a high of 140€/MWh (\$157/MWh) in 2010 to a low of 24€/MWh (\$27/MWh) in 2015.

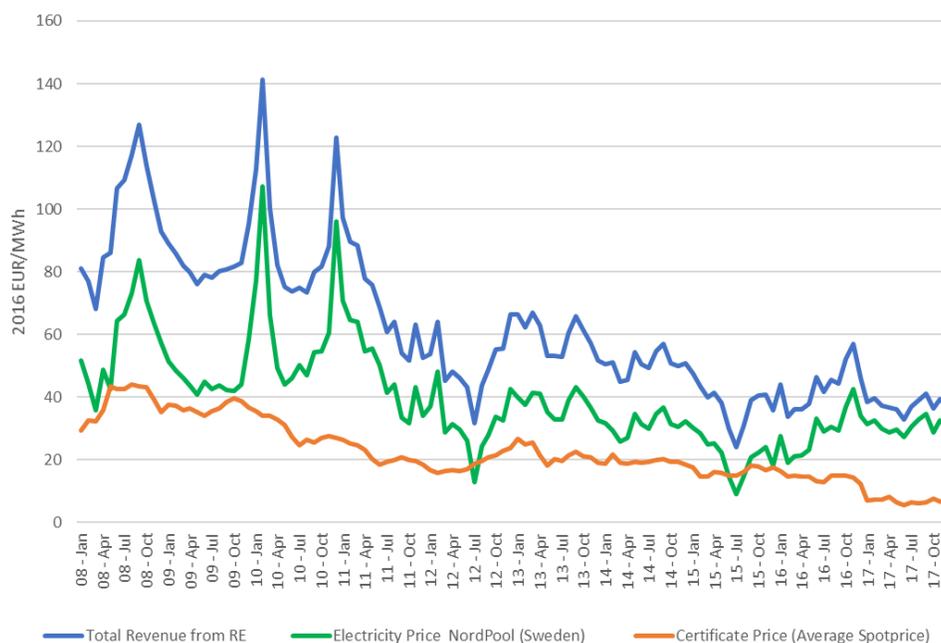


Figure 24. Electricity prices at NordPool (monthly prices Sweden), electricity certificate prices (monthly spot prices), and total revenue from renewable electricity production in Sweden from 2008 to 2016

Sources: Nordpool.com (2018) and Svensk Kraftmäkling (SKM.se 2018)

The overall trend during this period is of falling prices of both electricity and certificates, which has resulted in declining profitability for wind power investments in Sweden since 2008. The downward trend can be explained by a power surplus on the Nordic market and a surplus of electricity certificates during much of the period from 2008 to 2016.

The uncertainty regarding power prices and certificate prices, combined with the trend toward decreasing prices generally, have resulted in changes in the way wind projects are financed in Sweden. In the beginning of the 2000s, it was possible to finance wind projects without any price hedging. After the financial crisis, banks started to require price hedges for wind projects, especially for larger ones. Structures of short-term hedging contracts with 3–5-year contracts for electricity and 1 year for certificates were typical. Today, both banks and investors require power purchasing agreements (PPAs) for 10 to 15 years post financial close, mitigate the uncertainty. A PPA provides a fixed price for every kilowatt-hour produced regarding both power and electricity certificates. Normally, 70%–80% of the revenues from a wind project are price hedged.

6.4.2 Expectations for the Future

Future wind energy projects in Sweden are expected to continue to see reductions in LCOE. The estimated LCOE for 2020⁵² has been calculated assuming a linear development of investment costs and O&M costs, based on their development from 2008 to 2016. The assumption regarding technical parameters is based on information about turbine types and expected capacity factors in planned wind projects that are to be in operation in 2020. The assumptions used for the LCOE calculations are shown in Table 10.

Table 10. Input Values and Resulting Levelized Cost of Energy for Wind Projects Projected for Installation in 2020 in Sweden

	Unit	Commercial Operation Date in 2020
Installed capacity rating	MW	3.8
Rotor diameter	meter	140
Hub height	meter	110
Capacity factor	%	36
Investment cost	2016€/kW	1,077
	(2016\$/kW)	1,191
Fixed O&M costs	2016€/kW/yr	34.1
	(2016\$/kW/yr)	37.7
After-tax nominal WACC	%	5.0
National corporate tax	%	21.4
LCOE	2016€/MWh	36
	(2016\$/MWh)	40

These assumptions result in LCOE of 36€/MWh (\$40/MWh) in 2020, which corresponds to a 19% reduction between 2016 and 2020. This is in line with the cost reductions in the period 2008–2016.

With regard to revenues, experience has shown that both electricity prices and electricity certificate prices are quite unpredictable—today’s prices are substantially below past predictions. The published long-term forecasts for Nordic prices have varied widely (Pettinicchio 2017). However, there is a general expectation of higher electricity prices compared to today, driven by higher EU carbon prices and fuel prices. At the same time, several players on the market emphasize the risk of zero prices (0 €/MWh) on electricity certificates in the near future. These expectations are based on the recent, drastic increase in investments in renewable electricity production in the electricity certificate system, which is expected to contribute to meeting the 2030 targets earlier than expected. A higher electricity price could potentially mitigate the negative effects of zero prices on certificates by bringing wind power closer to grid parity and profitability without subsidies.

⁵² LCOE for 2020 represents the costs for wind energy projects with a commercial operation date by 2020.

There is an expectation of continued strong interest from investors in Swedish wind power. This can be explained by expectations on both higher electricity prices and continued reductions of LCOE for wind energy. The conditions on the market with unpredictable revenues are expected to lead to an optimization of financing structures—for example, more advanced corporate PPA solutions for new market entrants. It is also likely that we will see more large-scale new projects, from 150 to 200 MW and greater, to accommodate the relatively low levels of revenues. Thanks to Sweden’s low population density, there is room for establishing large-scale wind projects.

6.5 Summary

LCOE for wind energy decreased substantially during the period 2008–2016 in Sweden, from 86 €/MWh in 2008 to 44€/MWh in 2016 (\$95–\$49/MWh), a reduction of 48%. The main factors contributing to the LCOE reduction are net energy production and WACC, accounting for more than 60% of the total reduction. Net energy production accounts for the largest contribution, including increases in the capacity factors of turbines with large rotors capturing more energy in Class III sites, and taller towers that can tap into stronger winds at higher altitudes being installed. Furthermore, there has been a trend toward larger and more efficient projects. WACC is the second-largest driver, which is assumed to have decreased because of lower lending costs and changes in the type of investors investing in projects. A decline in investments and O&M costs has also contributed to a reduction of LCOE during the period analyzed.

7 European Union

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Another obvious trend on the market during this period is that both banks and investors today require price hedges for wind projects. PPAs for 10 to 15 years post financial close are typical now, in order to mitigate the uncertainty of electricity and certificate prices on the Swedish electricity market. The trend toward decreasing LCOE is expected to continue for projects commercially operating in the 2020 timeframe. A 19% reduction between 2016 and 2020 is projected, resulting in an LCOE of 36 €/MWh (\$40/MWh) by 2020.

7.1 Wind Energy Development in the European Union

In this chapter, a general overview of the development of wind energy in the European Union (EU) will be given. Some member states of the European Union are also part of IEA Wind Task 26 and detailed country chapters are available (Denmark, Germany, Ireland, and Sweden). All data used refers to the period between 2008 and 2016. Wherever available, data for 2017 was included as well.

7.1.1 Domestic Wind Energy Capacity, Production, and Targets

At the end of 2017, the installed capacity of wind energy in the European Union was 168.8 GW (153 GW land-based and 15.8 GW offshore) (Wind Europe 2018). Since 2005, the installed capacity increased at an average of 10.7 GW per year. Also, 2017 was a record year for wind in the European Union, with an installation of about 15.6 GW of new wind power (Wind Europe 2018). Wind power installations in 2017 were higher than all other energy technologies (followed by solar photovoltaics), accounting for more than half of total installations that year. The total production of electricity from wind amounted to about 336 terawatt-hours (TWh), which corresponds to about 12% of the total electricity demand in the European Union (Figure 25).

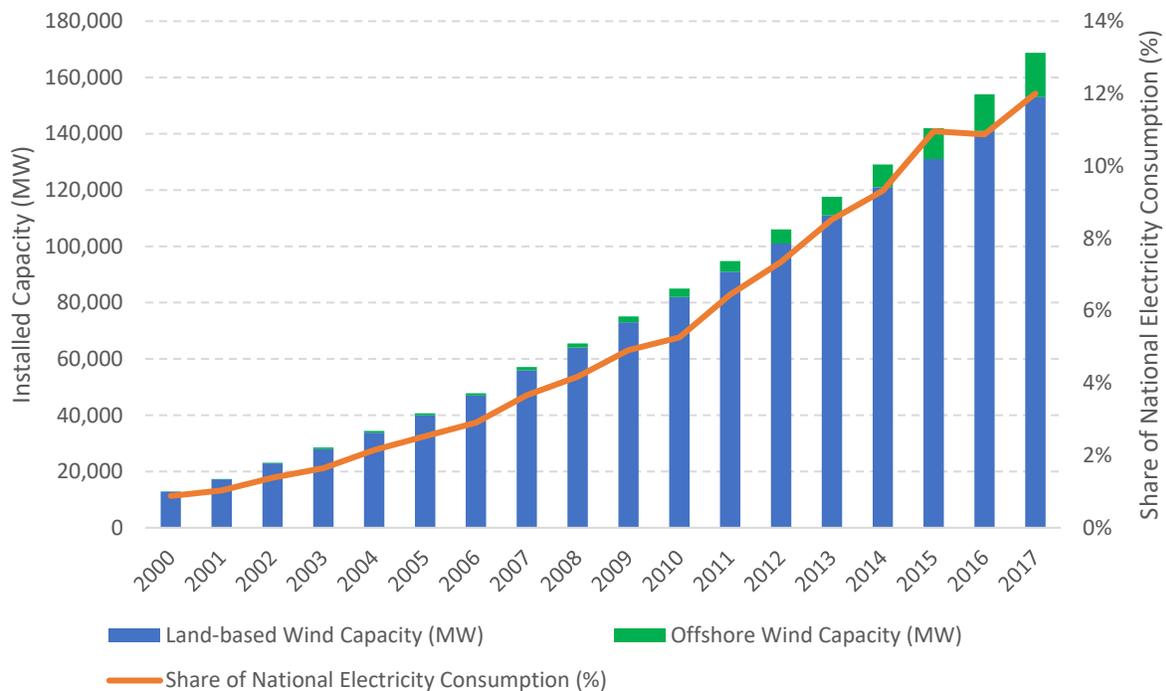


Figure 25. Wind power growth in the European Union from 2000 to 2017

Sources: Wind Europe (2018) and Eurostat (2018a, 2018b)

The European Union targets a 27% share for renewable energy by 2030.⁵³ This target is not translated in binding targets at the national level but member states are able to set national objectives. There is no target for specific renewable energy technologies such as wind.

The 2016 EU reference scenario presents a benchmark of the EU energy system, transport, and greenhouse gas (GHG) emission developments from 2016 to 2050 (Capros et al. 2016). It includes policies and measures adopted at the EU level and in the member states by December 2014 and foresees a great increase of wind energy (Publications Office of the European Union 2016). By 2030, land-based wind capacity would reach about 217 GW and 323 GW by 2050 while offshore wind would reach 38 GW and 45 GW, respectively.

7.1.2 Revenue and Policy Incentives

Current state aid guidelines for environmental protection and energy encourage EU member states to shift their wind energy regulatory framework toward schemes that will ensure higher market compatibility (European Commission 2014).

For many European countries, 2017 was a transitional year to new support schemes and tender mechanisms. A large number of projects were rushed to connect to the electricity grid while feed-in tariffs or feed-in-premiums still apply. The first land-based wind tenders took place in Germany, Spain, and France. The United Kingdom ended its Renewable Obligation Certificates. While some projects in Germany, France, and Belgium will continue accessing feed-in tariffs,

⁵³ On 14 June 2018, the Commission, Parliament, and Council agreed on a binding renewable energy target for the EU of 32% by 2030. The agreement still needs to be adopted by the European Parliament and the Council.

and Sweden persists with its Green Certificates, the policy support landscape in Europe changed to auction-based systems in 2017.

7.2 Wind Energy Project Trends in the European Union Since 2008

This section highlights some of the trends in EU wind power projects between 2008 and 2016. For the full data set, refer to the [IEA Wind TCP Task 26 Data Viewer](#). The specific data used in this report and the data used to convert monetary values to real 2016 euros and U.S. dollars are compiled in [the attached supplemental data appendix](#).

Current wind power projects in the EU have an average size of about 9 MW, compared to 14.2 MW in 2008 (Figure 26). The average turbine nameplate capacity has increased from 2.0 MW in 2008 to about 2.6 MW in 2016.

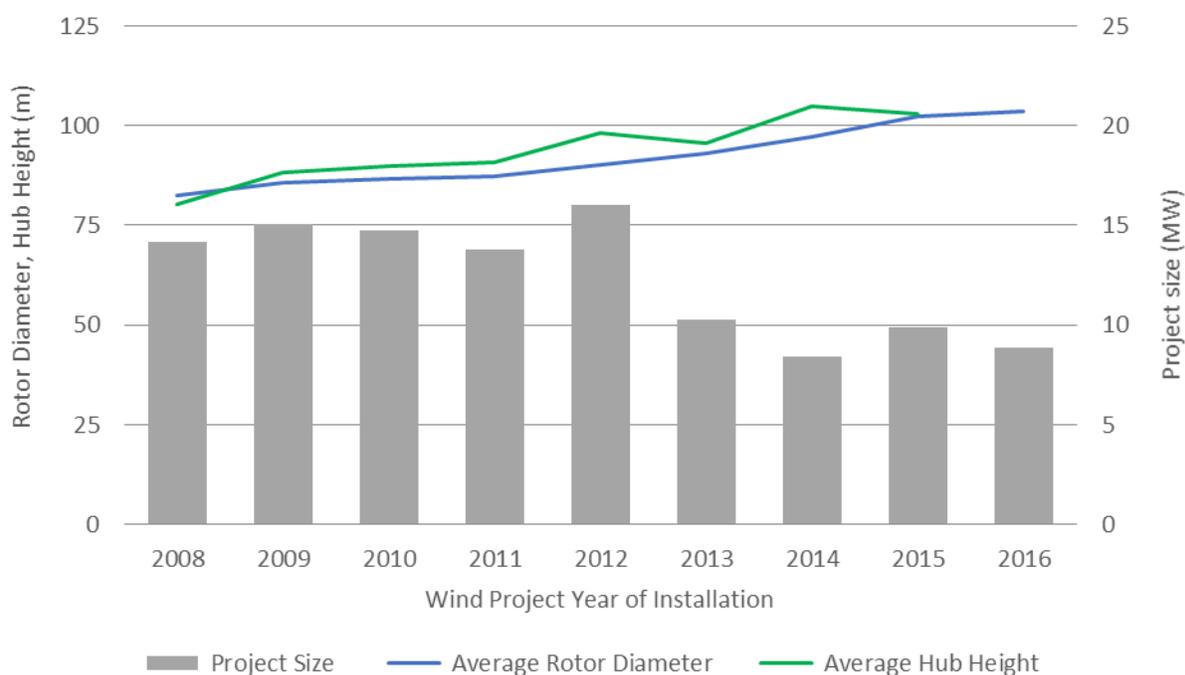


Figure 26. Specific power and capacity factors for wind projects installed in the European Union from 2008 to 2016

The average hub height of the installed turbines was about 100 m in 2016 and increased from 2008 (80-m average hub height). Similarly, average rotor diameters have increased from 82 m in 2008 to 104 m in 2016. As a result of those technological developments, the specific power of EU wind turbines has decreased from about 380 W/m² in 2008 to about 310 W/m² in 2016.

The main wind turbine classes in the EU in 2016 are IEC Class II (32%) and Class III (24%). In 2008, main wind turbine classes were Class II (32%) and Class I (27%), whereas Class III turbines only had a share of 9%. This seems to indicate that turbines are being installed more and more in sites with a lower wind resource quality.

7.3 Cost of Wind Energy Generation in the European Union Since 2008

7.3.1 Sources and Assumptions

The LCOE in the European Union has been assessed for 2008 to 2016 based on an average project for each year. We could not obtain cost data at a project level from individual wind power projects in the EU. Instead, the project database from Bloomberg New Energy Finance (BNEF) (2018) and a number of research notes were used (Grace 2014, 2015; Hostert 2016a, 2016b, 2017).

The sample size of the data available through the BNEF research notes used is relatively small and covers only a number of countries for 2014–2017. For the period before 2013, the BNEF project database was used. Data for investment costs and fixed O&M costs have been calculated based on BNEF using a simple average over all EU countries present in the sample.

The average capacity factor for the EU was calculated as follows: Eurostat provides data about the installed capacity and wind energy production per year and member state (Eurostat 2018a, 2018b). This information was used to calculate the average capacity factor for each country per year. Thus, the capacity factor represents the whole fleet and not only the respective capacity additions of a given year. For example, the capacity factor for 2015 includes the whole fleet in operation by the end of 2015 and not the capacity factor of the wind turbines installed in 2015. The wind index for each country was calculated based on the European Meteorological derived high resolution renewable energy source generation time series (EMHIRES) (Gonzalez-Aparicio 2016) and all capacity factors have been normalized by dividing each annual value by this factor. To account for the fact that the capacity factor of turbines installed in a certain year are not the same as the capacity factor of the whole fleet, a correction has been applied.⁵⁴ At the end, the capacity factors of all EU member states have been aggregated by weighting them according to the share of the country's wind power production over the total EU wind power production in a given year.

The structure of the project financing has remained relatively unchanged throughout 2008–2016, with two-thirds of annuity-based debt being typical in the EU. Debt rates of 2.3% to 3.1% and equity rates of 8.3% to 10.1% occurred. Following the general trend of a reduced cost of capital in Europe, financing cost for wind projects appears to have decreased in the last two years.

Table 11 shows the main financing parameters used to estimate the nominal, after-tax WACC associated with wind projects installed in each year from 2008 to 2016.

⁵⁴ We used the capacity factor of newly installed turbines for each year 2008-2016 from the [IEA Wind TCP Task 26 Data Viewer](#) for the EU countries that are part of IEA Wind TCP Task 26 and provide data on capacity factors for onshore wind (Ireland, Sweden, Denmark, Germany). Next, we calculated how much better the newly installed turbines perform compared to the average fleet for each country and year (in relative terms). Then, we calculated an average of the relative difference for each year across countries weighted by installed capacity) and applied this difference to obtain the capacity factor of the new turbines.

Table 11. Financial Parameters and Weighted Average Cost of Capital for Wind Projects Installed from 2008 to 2016 in the European Union

Parameter	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016
Debt/equity ratio^a		66/33	66/33	66/33	66/33	66/33	66/33	66/33	66/33	66/33
Return on equity^b	%	9	9	9	9	9	9	10.1	10.0	8.3
Return on debt^b	%	2.7	2.7	2.7	2.7	2.7	2.7	3.1	2.8	2.3
Corporate tax^c	%	20	20	20	20	20	20	20	20	20
WACC (after-tax, nominal)	%	4.6	4.6	4.7	4.7	4.6	4.4	5.0	4.8	4.0

a: According to BNEF research notes, average over a number of EU countries. Data before 2013: 66/34 assumed

b: According to BNEF research notes, average over a number of EU countries. Data before 2013: average

c: Big variations between countries exists: corporate tax rates range from 9% to 33%, with 20% assumed as an EU average.

For simplicity, a single depreciation schedule was assumed for the European Union. In reality, each country may treat capital assets such as a wind plant differently. In this analysis, linear depreciation of 100% of the initial capital investment over 20 years was assumed.

7.3.2 Trends Since 2008

The characteristics of the typical projects used for the calculation and the resulting LCOE for 2008–2016 is displayed in Table 12. The LCOE for the representative wind power projects in the EU is estimated using the methodology described in Appendix A.

The LCOE in the EU has decreased from about 83 €/MWh (\$92 USD/MWh) in 2008 to about 41 €/MWh (\$45/MWh) in 2016, corresponding to a reduction of about 50%. The LCOE did not decrease steadily but also shows fluctuations in consecutive years. This fluctuation is mainly a result of yearly variations in capacity factors and investment costs.

Table 12. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed from 2008 to 2016 in the European Union

Parameter	Unit	Wind Project Year of Installation								
		2008	2009	2010	2011	2012	2013	2014	2015	2016
Net energy production – whole fleet ^a	Capacity factor %	22	22	22	24	24	24	24	25	25
	(Full load hours)	(1,932)	(1,932)	(1,932)	(2,108)	(2,108)	(2,108)	(2,108)	(2,196)	(2,196)
Net energy production – new turbines ^a	Capacity factor %	24	26	28	28	29	31	34	34	35 ^b
	(Full load hours)	(2,151)	(2,276)	(2,432)	(2,490)	(2,562)	(2,684)	(2,947)	(2,968)	(3,077) ^b
Investment costs ^c	2016 €/kW	2,145	2,279	2,270	2,253	2,104	1,727	1,818	1,599	1,564
	(2016 \$/kW)	(2,373)	(2,521)	(2,511)	(2,492)	(2,327)	(1,911)	(2,011)	(1,769)	(1,730)
O&M costs ^c	2016 €/kW/yr	27	27	27	27	26	25	27	23	23
	(2016 \$/kW/yr)	(30)	(30)	(29)	(29)	(28)	(28)	(29)	(25)	(26)
After-tax WACC ^d	% nominal	4.6	4.7	4.7	4.6	4.4	5.0	4.8	4.0	3.9
	(% real)	(2.5)	(2.6)	(2.6)	(2.5)	(2.4)	(2.9)	(2.7)	(2.0)	(1.8)
Corporate income tax rate	%	20	20	20	20	20	20	20	20	20
Depreciation schedule ^e		Linear, 20 year								
LCOE ^f	2016 €/MWh	83	83	77	74	67	57	53	44	41
	(2016 \$/MWh)	(92)	(92)	(86)	(82)	(74)	(63)	(59)	(48)	(45)

^a Net energy production in calendar year 2016: 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. See 3.2.1. Full load hours based on 8,784 hours in 2016.

^b In 2016, a full year of energy production data was not available for projects installed during 2016. Therefore, the capacity factor associated with project installed in 2016 was estimated at 35%.

^c Investment costs and O&M costs converted to real 2016 euros and US dollars. Details are in the attached supplemental data appendix. O&M costs 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% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. This assumption is used to convert nominal WACC to real WACC.

^e Linear depreciation of 100% of the initial capital investment over 20 years. See 3.3.1

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

The decomposition analysis of the changes over time is shown in 27. In this analysis, the effects of a change of a single specific parameter over time were assessed. The results show that the LCOE reductions were mainly caused by improvements in capacity factors and investment cost reductions. Combined, these two factors are responsible for more than 90% of the LCOE reduction.

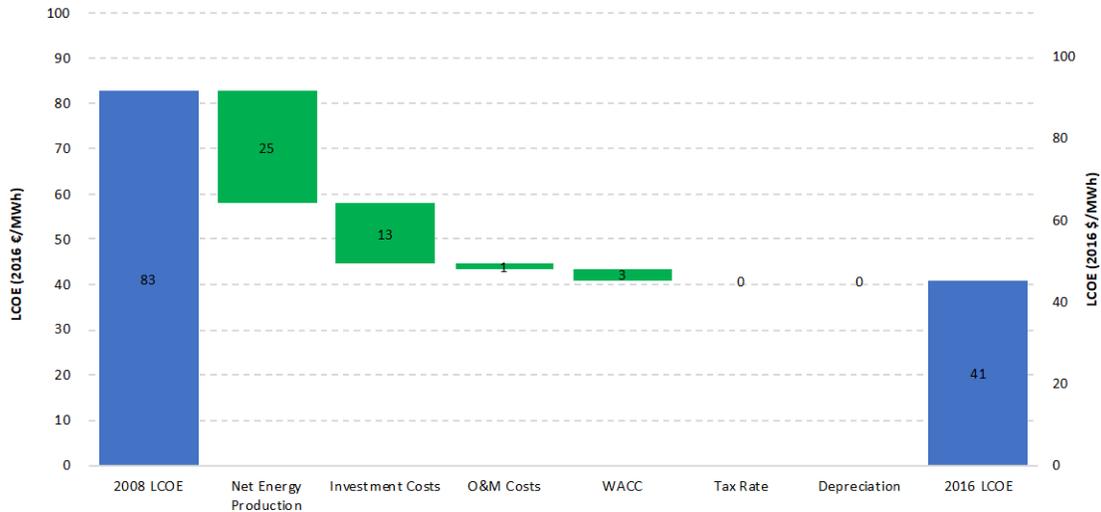


Figure 27. Sources of LCOE reduction in the European Union from 2008 to 2016

7.4 Wind Energy in the EU Electricity Market

Wind energy has covered 11.6% of the EU’s power demand in 2017. High levels of wind (and other variable renewable energy source) power might lead to declining electricity wholesale market prices. In general, the market “value of wind” is lower than the average market price of electricity.

The market value of wind is calculated as the ratio between the annual revenue of wind power in the market and its annual generation. It represents the average revenue per energy unit of wind produced and is computed as follows:

$$MV = \frac{\sum_t^T p_t \cdot E_t}{\sum_t^T E_t} = \bar{p}_{wind}$$

where t is the hour of the year ($1, \dots, T$), E is the wind energy production at the hour, t , and p is the market price at the hour, t , in the bidding area considered.

Hourly capacity factors at the bidding zone level for wind energy are available through EMHIREs, the generation time series for present and future scenarios of the JRC (Danish Energy Agency data catalogue). Data for electricity prices are coming from various sources and were provided through the European Commission’s Energy Market Observation System (Energy Market Observation System 2018). The system provides data from 2011 onward. For some countries, additional data from Energinet was included for 2008–2010.⁵⁵

To calculate an average value for a country with several bidding zones (e.g., Denmark and Sweden) and for averaging across all EU countries, the total revenues and total production for all of the zones has been calculated along with an average market value.

⁵⁵ Data coverage is about 50% of installed wind capacity from 2008 to 2010 and above 90% from 2011 onward.

7.4.1 Trends Since 2008

The LCOE of wind power decreased between 2008 and 2016 (Figure 28). In the same period, the electricity price also decreased (European Commission 2016). The gap between average price and market value has remained relatively constant over time.

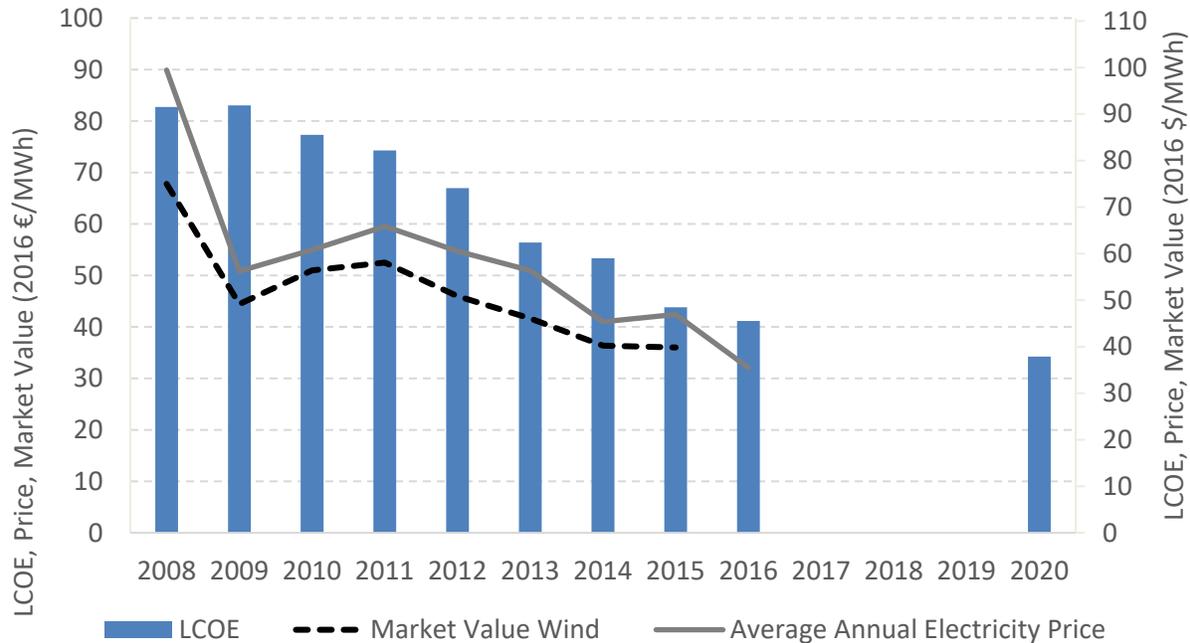


Figure 28. LCOE, average wholesale electricity price, and market value of wind⁵⁶ in the European Union from 2008 to 2016, with a projection to 2020

Figure 29 shows the gap with grid parity for the EU. This gap represents the required additional revenue on top of the wholesale electricity price to make a wind power project profitable. The year 2008 can be considered an outlier because of the fact that data availability was not very high, and electricity prices were relatively high during this year. Since 2009, the gap with grid parity is decreasing and was about only 8 EUR/MWh in 2015.

⁵⁶ Annual average electricity prices and market value have been converted to real 2016 terms.

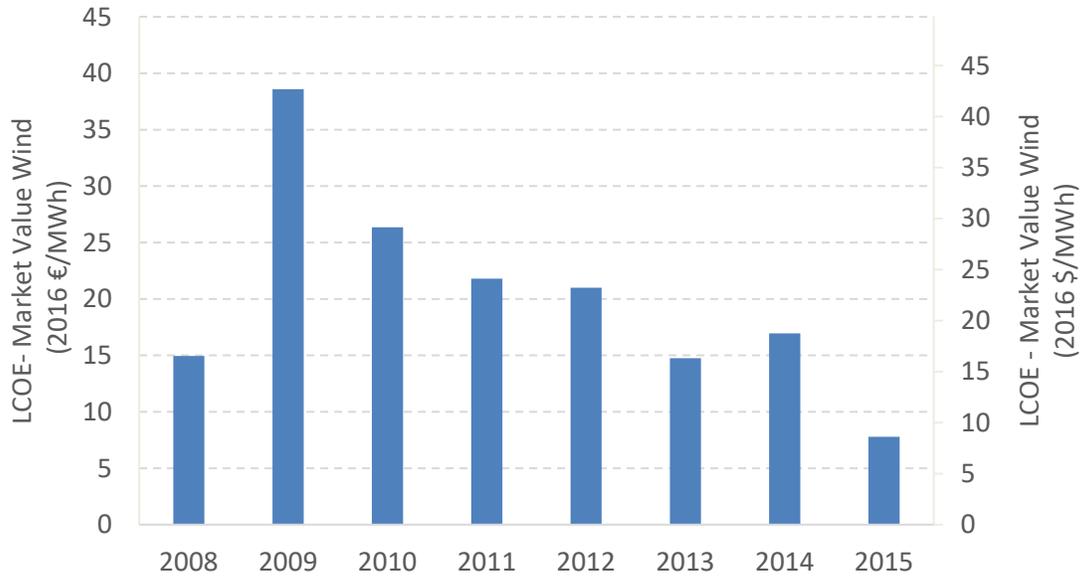


Figure 29. Difference between LCOE and market value of wind from 2008 to 2016 in the European Union

7.4.2 Expectations for the Future

The expected LCOE for 2020 is based on the BNEF New Energy Outlook (2017). Investment costs are assumed at 1,400 EUR/kW, with a capacity factor of 40% (about 3,500 full-load hours). O&M costs and other financial parameters (nominal WACC 3.9% and corporate tax 20%) were unchanged from the 2016 assumptions.

The estimated LCOE for 2020 is about 34 EUR/MWh. This amount is lower than the 2016 (41.2 EUR/MWh) level, but the reduction in the 4-year period is about 17%, compared to a reduction of about almost 40% between 2012 and 2016. The lower magnitude of the reduction can partly be explained by the fact that the increase of capacity factor and reduction of investment costs were estimated to be quite moderate.

7.5 Summary

The levelized costs of wind energy have declined in the EU from about 83 €/MWh (\$92/MWh) in 2008 to about 41 €/MWh (\$45/MWh) in 2016, corresponding to a reduction of about 50%. This reduction was enabled by efficiency increases of new turbines that led to higher capacity factors and a reduction of investment costs for new turbines.

The market value of wind in the EU is lower than the average electricity price. However, since 2009, the gap with grid parity has been decreasing, and amounted to about 8 €/MWh (\$9/MWh) in 2015. For the future, a further reduction of this gap might occur, depending also on the power price developments.

8 United States

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8.1 Wind Energy Development in the United States

When measured by installed capacity, wind power is the single largest source of installed renewable power in the United States. Projections anticipate wind power surpassing hydropower as the single largest source of renewable energy generation in the United States by 2019 (Energy Information Administration 2018). Like each of the preceding chapters, this chapter provides an overview of the U.S. wind industry before delving into more detailed data on technology, cost, and pricing trends for the 2008–2016 and including 2017 data where available.

8.1.1 Domestic Wind Energy Capacity, Production, and Targets

Domestic wind energy capacity and production in the United States has substantially increased since the late 1990s. The U.S. wind power capacity additions equaled 8,203 MW in 2016 and 7,017 MW in 2017, bringing the cumulative total to 88,973 MW by the end of 2017 (Figure 30). Wind constituted 6.3% of all electricity generation in the United States in 2017 (Wisler and Bolinger 2017, updated with 2017 data). The U.S. features only a single 30-MW offshore wind project—installed in 2016; the balance of the U.S. installed capacity is land-based wind.

Although the United States has no national target for wind power or renewable power deployments, the U.S. Department of Energy (DOE) (2017b) studied a scenario in which wind power provides 10% of the nation’s electricity demand by 2020 (increasing to 20% by 2030 and then 35% by 2050). Cumulative installed capacity by 2020 in that scenario is estimated at 113 GW. An average of projected deployment through 2020 from multiple sources compiled by Wisler and Bolinger (2017) suggest that actual installations through 2020 are anticipated to be comparable to the DOE scenario. Historically, for the United States, a patchwork of state-based mandates have driven much of the wind project installations, whereas more recently cost competitiveness and corporate procurement (in addition to others) are driving wind project installations.

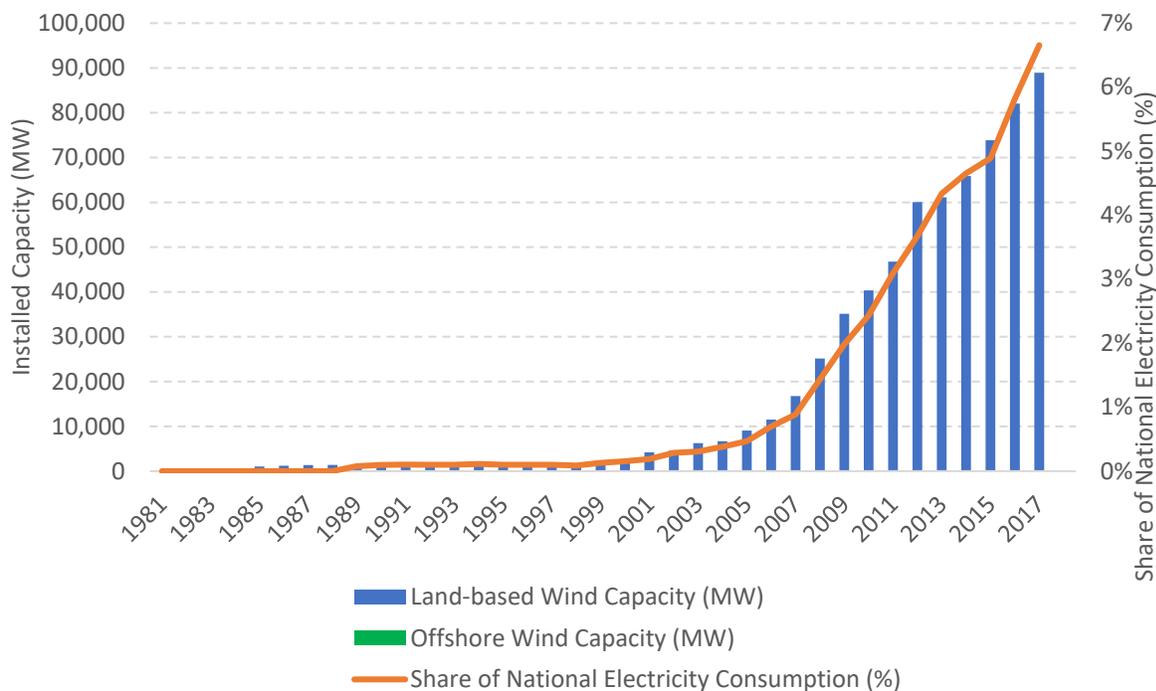


Figure 30. Wind power growth in the United States from 1981 to 2017

8.1.2 Revenue and Policy Incentives

PPAs are the typical energy contract transaction structure between electricity generation owners (sellers) and energy offtakers (buyers) in the United States. A PPA stipulates the commercial terms at which energy sales will be transacted from the buyer of electricity to the seller, principally the annual price at which the offtaker will purchase the energy (usually expressed in kilowatt-hour or megawatt-hour) and the length of time during which it will make such purchases (the term).⁵⁷ PPAs are typically negotiated bilaterally and often emerge from competitive solicitations. Also, they may be executed with utilities or directly with end users (e.g., corporations) as direct retail offtake. Historically, utilities have been the primary source of wind power PPAs in the United States, but direct retail offtake has become increasingly prominent in recent years. In locations with liquid wholesale power markets (e.g., the Electric Reliability Council of Texas) wind power projects may sell directly into the wholesale markets as “merchant” projects, oftentimes with hedging contracts to limit risk exposure. Also, electric utilities, at times, own wind projects, in which case no formal PPA is required. For projects installed in 2016, Wisner and Bolinger (2017) report that public and private utilities made up approximately 52% of U.S. offtake (either through PPAs or direct ownership), and direct retail or corporate offtakers made up 23%. Merchant or quasi merchant offtake mechanisms were utilized for 22% of projects installed in 2016.

The U.S. federal government incentivizes renewable energy projects principally through the tax code. As of this writing, wind technologies are eligible to receive either the production tax credit (PTC) or the investment tax credit (ITC), as well as 5-year accelerated tax depreciation through the Modified Accelerated Cost Recovery System (MACRS). Additional “bonus” depreciation

⁵⁷ The most typical term length is 20 years but can range from 5 to 30 years.

allowances have also sometimes been offered. Based on the *Consolidated Appropriations Act, 2016* (H.R. 2029, Sec. 301), projects that begin construction in 2017 through 2019 are only eligible for a reduced-value PTC or ITC, with those incentives phased out entirely for projects that begin construction in 2020 and beyond (Wiser and Bolinger 2017; Schwabe et al. 2017).

The PTC serves as an after-tax revenue stream for a period of 10 years from the project's commissioning. Historically, the PTC has been inflation adjusted to maintain a similar real tax credit value as was originally authorized in 1992, when it was first legislated. Because the PTC affects financial structures in the United States, its effective value varies based on each project's financial structure and the efficiency with which a project is able to monetize the tax credit. When levelized across a 20-year project life, the effective value of the full PTC has been recently estimated by Bolinger (2018) to be worth approximately 12€/MWh (\$13/MWh) (also see Bolinger 2014). As the PTC phases down in the years ahead, its value will decline; however, the PTC expiration is expected to alter the debt and equity ratios and will likely improve a wind project's WACC.

Looking ahead, the U.S. tax reform bill passed and signed into law in December 2017 (*Tax Cuts and Jobs Act*, H.R. 1) lowers the corporate tax rate from 35% to 21%. A reduced corporate tax pool could have secondary impacts on the value of the PTC for wind energy projects by potentially decreasing the availability and therefore increasing the cost of tax equity that is often needed to monetize the tax credits. In addition, the *Tax Cuts and Jobs Act* includes additional restrictions (in the form of the “base erosion anti-abuse tax,” or BEAT provision) on the types of corporate taxable earnings that are eligible for U.S. tax credits. Although the final tax law places a cap on the BEAT provision—as it applies to the PTC—that limits its effects to only 20% of the potentially impacted wind tax credits (this is also known as the “80% fix”), these more recent considerations may have some impact on the value of the PTC to wind power projects. At the same time, even with these additional dynamics at play, it is anticipated that the majority of the value of the tax credit will remain intact for most projects (CohnReznick Capital 2018). Meanwhile, the lower overall federal tax rate is, counterintuitively, expected to increase the cost of new wind energy projects to some degree, as a result of interactions with the value of MACRS depreciation and the effective cost of debt.

State governments also sometimes use the tax code to provide additional revenue streams or cost reduction opportunities for wind power projects. State PTCs, property tax abatements, and sales tax relief have all been used in the past by state governments as a means of incentivizing additional wind power development. The effects of these policies have been varied, local, and dependent on the specific circumstances of a local jurisdiction or state where the project resides. Along with these direct financial incentives, state policy in other forms—including most prominently the renewables portfolio standard—has supported state-level markets for renewable power including wind. As a result, some projects are able to sell renewable energy certificates separately from their power production, whereas in other cases electricity and renewable energy certificates are both sold in a consolidated manner via PPAs.

8.2 Wind Energy Project Trends in the United States Since 2008

The U.S. wind power industry and technology have evolved substantially since 2008. A sampling of key trends include project features such as wind turbine nameplate capacity, rotor

diameter, hub height, specific power, wind project performance, investment costs, O&M costs, and financing costs (including tax and depreciation). In addition, trends in state and federal policy, wholesale power prices, and the competitive landscape for power generation more broadly in the United States have significantly influenced the wind power industry. This section provides a description of the trends in each of these areas leveraging the data sets maintained by the Lawrence Berkeley National Laboratory (LBNL) and, in many cases, presented in the web-based data viewer published on the IEA Wind TCP Task 26 website (IEA Wind TCP Task 26 2018). Further details on the data sets (e.g., 25th to 75th percentile, minimum, maximum, and sample size) for these wind energy project areas are provided in the [IEA Wind TCP Task 26 Data Viewer](#). The specific data used in this report and the data used to convert monetary values to real 2016 euros and U.S. dollars are compiled in [the attached supplemental data appendix](#).

Since 2008, the average wind turbine nameplate capacity has steadily increased from 1.7 MW to 2.2 MW in 2016; a further increase to 2.3 MW occurred in 2017. Even with these increases, the United States continues to lag behind the typical turbine nameplate capacity levels of many European projects. Average rotor diameter has grown substantially since 2008, going from 79 m to 108 m in 2016 and with a further increase to 113 m in 2017. The resulting increase in rotor swept area is arguably the most noteworthy wind turbine trend in the country, and, coupled with the more modest increases in nameplate capacity, has led to significantly lower turbine-specific power ratings over this time period (reaching 233 W/m² and 231 W/m² in 2016 and 2018, respectively). The declining trend of turbine-specific power from 2008 to 2016 is shown in Figure 31. The average turbine hub height of 80 m is relatively standard in the U.S. market and has been holding relatively steady since 2008. In recent years, exceptions to the standard 80 m hub height have become more typical in the Great Lakes and Northeastern parts of the country, in particular to harness the better wind resource for those regions. Average hub height was 78 m in 2008, 84 m in 2016, and 86 m in 2017. Project performance as measured via average project capacity factor by project vintage or year of commissioning has increased, from approximately 33% for projects completed in 2008 to ~43% for projects completed most recently, with the most notable increase in recent years (i.e., since 2012). Capacity factor increases have been driven in large measure by increasing rotor size and the declining specific power of turbines deployed in the U.S. market (Figure 31).

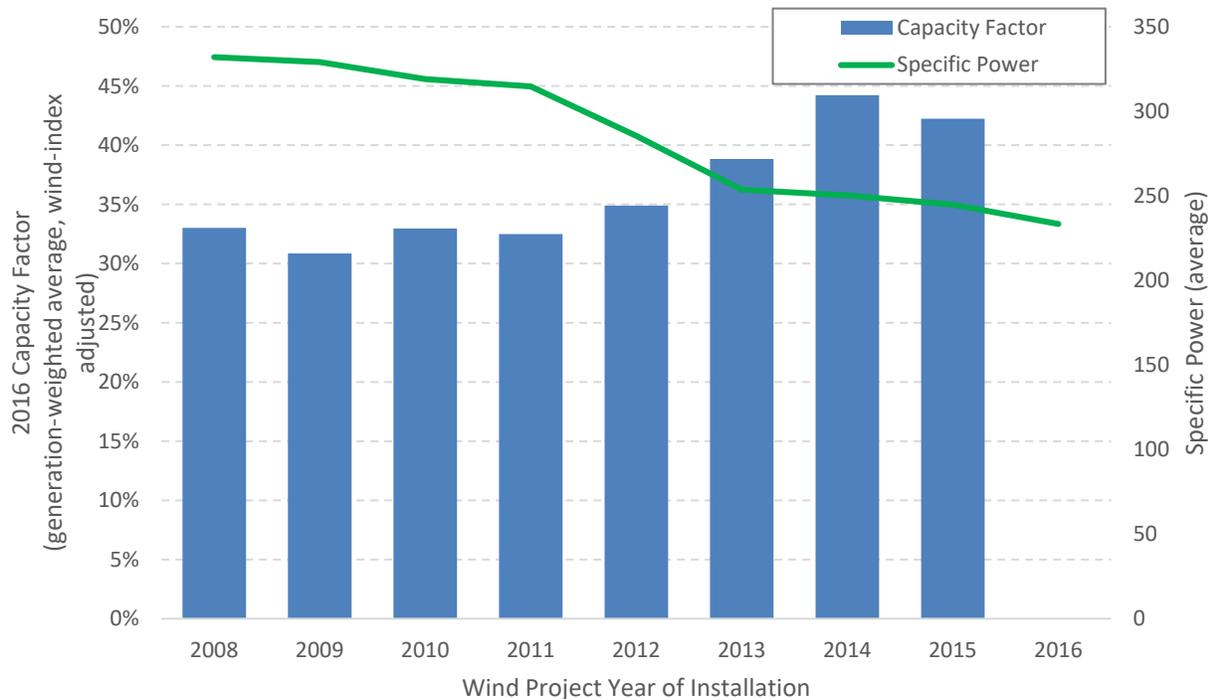


Figure 31. Specific power and capacity factors for wind projects installed in the United States from 2008 to 2016

Average investment costs of wind projects increased from 1,955€/kW (\$2,162/kW) in 2008 to 2,137€/kW (\$2,364/kW) in 2009 but have since declined steadily and substantially to 1,434€/kW (\$1,586/kW) in 2016. Based on recent industry interviews and other available data, total O&M expenditures (including all operational expenses) are estimated to have declined from 48€/kW/yr (\$53/kW/yr) in 2008 to 37€/kW/yr (\$41/kW/yr) in 2016. The cost of financing is represented by the WACC. Because LCOE values reported here exclude the value of the PTC, we developed an estimate for what the WACC might have been over time, were the PTC not available. As noted earlier, the actual historical cost of finance has been impacted by the PTC, with estimates of the PTC-impacted WACC reported in the [IEA Wind TCP Task 26 Data Viewer](#). The U.S. WACC estimates used for the LCOE calculations in this chapter, however, range from 6.4% to 5.7% during the period of analysis in nominal terms, while keeping capital structure fixed, and have generally declined over the period given reduced debt interest rates observed since the financial crises of 2008. Note that, as a result of our approach, the WACC used in this chapter differ from those reported in the [IEA Wind TCP Task 26 Data Viewer](#).

In combination with the wind technology and cost trends noted in this section, significant changes in wholesale power prices primarily as a function of the North American “shale gas revolution” were also evident in the 2008–2016 time period. This revolution came into being as hydraulic fracturing technology opened up vast volumes of low-cost natural gas and pushed down natural gas prices and price expectations. In turn, abundant low-priced natural gas significantly reduced average wholesale power prices during this period. Stagnant electricity demand and significant deployments of low marginal cost wind power and solar photovoltaics have resulted in additional downward pressure on wholesale power prices (DOE 2017a; Wiser et al. 2017).

Given these trends in reduced wind energy costs and increased project performance, but also increased pricing pressures from other resources, current PPA values for wind projects in the country's best wind resource areas are at levels on the order of approximately two U.S. cents per kilowatt-hour (Wiser and Bolinger 2017), or 20 U.S. dollars per megawatt-hour (Euro 18 per megawatt-hour) with the additional value of the PTC levelized over 20 years. This period also saw an expansion of state renewable portfolio standard policies (Barbose 2017), periods of significant uncertainty in the status of the federal PTC, and movement in state-level financial incentives in various directions and magnitudes. Ultimately, these trends have reduced the available revenue to new U.S. wind power projects.

8.3 Cost of Wind Energy Generation in the United States Since 2008

The cost of wind energy generation in the United States is calculated using four main wind-specific components: investment costs, WACC, O&M costs, and full load hours or capacity factor.

The data sources, sample size, and estimate methodologies vary for each wind energy cost or performance component. The investment cost and full load hour data are sourced from a data set maintained by LBNL and used to inform the annual DOE *Wind Technologies Market Report* (Wiser and Bolinger 2017), and the values used are the same as those shown in the [IEA Wind TCP Task 26 Data Viewer](#).⁵⁸ The sample size of the investment cost and full load hour data is illustrated in the Data Viewer by showing the percent of total yearly capacity additions that the sample represents by year. The O&M cost trend derives from recent industry interviews with developers, wind turbine manufacturers, and others, as well as from other available data. After-tax nominal WACC values are estimated based on historical data on the cost of debt from, in part, Bloomberg New Energy Finance, as well as estimates of the cost of sponsor equity and the debt-to-equity ratio under a non-PTC scenario. The O&M and WACC assumptions differ from those reported in the [IEA Wind TCP Task 26 Data Viewer](#).

The U.S. national tax rate since 2008 assumes a blended state and federal tax rate of 40%. However, in accord with the 2017 *Tax Cuts and Jobs Act*, the U.S. tax structure has changed to a lower blended tax rate of 26% (21% federal tax rate) starting in 2018. For this analysis and reporting, we used the historical tax rates and schemes to characterize wind power LCOE as these historical conditions represent the conditions that were anticipated at the point of final investment decision for projects commissioned during 2008–2016. The long-term inflation rate expectation since 2008 is assumed to be held constant at 2% for each year through 2016. The depreciation schedule for wind energy projects is assumed to be the 5-year MACRS schedule, which is applied to all years in the analysis period.

8.3.1 Trends Since 2008

Here we show the calculated U.S. LCOE values for each year for the 2008-2016 period. In addition, we describe the observed LCOE trends. The LCOE values presented do not include any direct wind energy policy support such as the PTC but do include the tax benefits of MACRS depreciation. The input data used for calculating LCOE relies on the data sets and WACC

⁵⁸ The capacity factor value for projects built in 2016 used in the subsequent analysis is calculated using an average for 2014 and 2015 projects as comprehensive wind project performance data are not yet available for 2016 projects; early data suggest that this assumption is valid, if not somewhat conservative.

estimates maintained by LBNL. The data necessary for calculating LCOE includes wind plant capacity factor, investment costs, O&M costs, after-tax nominal WACC (without the PTC), inflation rate, tax rate, depreciation schedule, and the project amortization period. The nominal and real input data and calculated wind energy LCOE by commercial operation year from 2008 to 2016 are summarized in Table 13.

Table 13. Input Values and Resulting Levelized Cost of Energy for Wind Projects Installed from 2008 to 2016 in the United States

Parameter	Unit	Wind Project Year of Installation								
		2008	2009	2010	2011	2012	2013	2014	2015	2016
Net energy production ^a	Capacity factor %	33	31	33	32	35	39	44	42	43 ^b
	(Full load hours)	(2,900)	(2,710)	(2,895)	(2,854)	(3,066)	(3,411)	(3,885)	(3,710)	(3,787) ^b
Investment costs ^c	2016 €/kW	1955	2137	2133	2042	1844	1729	1617	1462	1434
	(\$2016/kW)	(2,162)	(2,364)	(2,359)	(2,259)	(2,039)	(1,913)	(1,789)	(1,618)	(1,586)
O&M costs ^c	2016 €/kW/yr	47	46	45	44	43	42	41	40	39
	(\$2016/kW/yr)	(52)	(51)	(50)	(49)	(48)	(47)	(46)	(45)	(44)
After-tax WACC ^d	% nominal	6.4	6.8	6.8	6.7	6.3	6.4	6.2	6.0	5.7
	(% real)	(4.4)	(4.7)	(4.7)	(4.6)	(4.2)	(4.3)	(4.1)	(3.9)	(3.6)
Corporate income tax rate	%	40	40	40	40	40	40	40	40	40
Depreciation schedule ^e		MACRS 5 year								
LCOE ^f	2016 €/MWh	73	86	80	77	64	55	45	43	40
	(2016 \$/MWh)	(81)	(95)	(88)	(85)	(71)	(61)	(50)	(47)	(44)

^a Net energy production in calendar year 2016: 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. Based on the latest DOE *Wind Technologies Market Report* (Wiser and Bolinger 2017), NextEra estimates that the “wind resource index” for the United States, as a whole was 99% in 2016; as such, the generation-weighted average 2016 capacity factors are shown adjusted upward for a typical wind resource year by 1/0.99. Full load hours based on 8,784 hours in 2016.

^b In 2016, a full year of energy production data was not available for projects installed during 2016. Therefore, the capacity factor associated with projects installed in 2016 is calculated using an average for projects installed in 2014 and 2015.

^c Investment costs and O&M costs converted to real 2016 euros and US dollars. Details are [in the attached supplemental data appendix](#). O&M costs 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% based on the European Central Bank 5-year forecast and the U.S. Federal Reserve medium-term estimate in each year from 2008 to 2016. This assumption is used to convert nominal WACC to real WACC.

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

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

In general, the LCOE in the United States is reduced from year to year over the considered time period. In 2008, the calculated LCOE for the United States is 73 €/MWh (\$81/MWh), compared to 40 €/MWh (\$44/MWh) calculated for 2016, a 45% reduction for this period. Although there are a large number of variables that may impact the LCOE of a wind energy project since 2008, there are four primary sources identified that drive the LCOE reduction in the United States (Figure 32). These primary sources include net energy production, investment costs, O&M costs, and the cost of finance. Net energy production, 17 €/MWh (\$19/MWh) from 2008 to 2016,

accounts for the largest reduction in LCOE, and has primarily been driven by the lower-specific-power wind turbines being installed in the U.S. market. Next is the reduction in investment cost, decreasing LCOE by 12 €/MWh (\$13/MWh), which is consistent with global trends as competitive pressures continue to increase and drive installed turbine and balance-of-plant costs lower. Reductions in O&M costs decrease LCOE by an estimated 2 €/MWh (\$2/MWh)⁵⁹ and is informed by ongoing industry interviews and other available market data since there is limited project-level data for O&M available in the United States. Lower O&M expenditures over time are supported by larger turbine sizes, a growing and maturing wind sector, and increased competition among O&M service providers. Finally, the after-tax nominal WACC has reduced the LCOE by 2 €/MWh (\$3/MWh), as a consequence of reduced debt interest rates between 2008 and 2016. The LCOE impact for each of these LCOE components and the calculated subsidy-free LCOE in 2008 and 2016 is shown in Figure 32. There are no LCOE changes from tax⁶⁰ and depreciation⁶¹ because these inputs are held constant for the period considered.

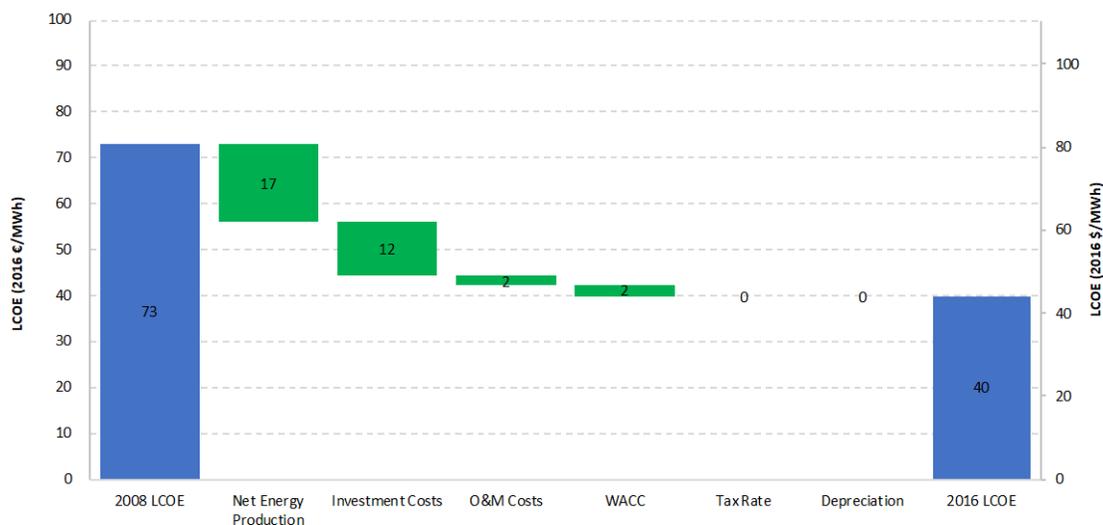


Figure 32. Sources of LCOE reduction in the United States from 2008 to 2016

Note: green denotes reduction and orange denotes increase

8.4 Wind Energy in the United States' Electricity Market

Although wind power LCOE is a useful metric, it is also critical to understand the broader context in which changes in LCOE are occurring. Further, it is important to understand the value that wind power offers to the broader electricity sector in terms of offsetting other electricity costs. This section integrates wind project LCOE trends with estimates of average wholesale electricity prices and wind power market value, as well as data on average wind power PPA price trends. These various additional metrics serve to contextualize the LCOE estimates. In addition to the focus period from 2008 to 2016, projections for wind projects commissioned in 2020 are included.

⁵⁹ EUR to USD conversion appear to be the same due to rounding.

⁶⁰ No change in tax rates between 2008 and 2016 at 40%; the United States restructured its tax rate in 2017 to 26%.

⁶¹ A 5-year MACRS depreciation schedule is utilized for each year over the analysis period.

8.4.1 Trends Since 2008

As depicted in Figure 33, LCOE trends show that the cost of wind energy, after increasing between 2008 and 2009, trended downward from 2009 to 2016.

As a point of reference for broader market conditions, the figure shows nationwide, simple average wholesale electricity prices from 2008 to 2016, considering both average energy and (where applicable) estimated capacity prices. Prices for specific nodes are weighted by the quantity of total generation capacity (considering all plants, not just wind) at each node. These data show that average wholesale electricity prices have fallen between 2008 and 2016, from approximately 64 €/MWh (\$70/MWh) to 26 €/MWh (\$29/MWh); prices rose in 2017 to 28 €/MWh (\$31/MWh). These prices are most directly impacted by the cost of fuel, and especially natural gas; therefore, the year-to-year trends largely follow the varying price of natural gas over time.

Of greater relevance to wind are estimates of the market value of wind generation. Wind projects in the United States are sometimes concentrated in areas with limited transmission, reducing the merchant market value of that wind generation as revealed through prices at local pricing nodes. The temporal profile of wind output is also not always well-aligned with system needs, impacting both energy value and (where applicable) capacity value, and wind may further push local wholesale prices lower when output is high. Figure 33 shows estimates of the combined energy and capacity value of wind in the United States on a nationwide average basis, considering the location of wind plants, their hourly output profiles, and any available capacity markets or requirement in which wind might participate. Prices for specific nodes are weighted by the quantity of wind capacity at each node. Overall, these estimates show that the market value (considering energy and capacity) of wind is considerably lower than time-weighted average wholesale electricity prices, and has declined from 48 €/MWh (\$54/MWh) in 2008 to 18 €/MWh (\$20/MWh) in 2016–2017.

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 PPAs. Those PPA prices, meanwhile, are affected not only by the LCOE of wind, but also by available federal and state incentives—the federal PTC being the largest of those incentives. Figure 33 shows average levelized wind PPA price data, based on the year of project installation and reflecting underlying data from individual contract terms and conditions levelized over the duration of the PPA and including escalation terms where applicable. Based on these data, PPA prices were observed to increase between 2008 and 2011 before falling precipitously from 2011 to 2014 and then declining at a more modest pace since that time. In the most recent years, levelized PPA prices have averaged roughly 19 €/MWh (\$21/MWh).⁶² PPA prices are well below estimated LCOE values primarily because of the presence of the federal PTC.

Comparing these various measures of the cost and value of wind 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. Second, the wind LCOE and PPA data

⁶² Average PPA prices updated from Wiser and Bolinger 2017; note 2018-2020 results are all the same because of a limited sample of only seven PPAs in total; as such, those seven PPAs are averaged and assigned to each year.

reflect long-term (often 20-year) estimates, whereas the average electricity price and market value estimates are single-year figures that may change over time.

With those caveats in mind, several notable observations might be made:

- The estimated market value of wind is considerably lower than the LCOE of wind. The magnitude of that “grid parity” gap has changed over time, and narrowed in more recent years, but remains sizable. This suggests that wind is not yet broadly competitive with other sources of electricity in the United States, and that policy incentives have been needed to support deployment growth.
- Wind PPA prices have been reasonably aligned with market value estimates since 2013. This suggests that wind power developers and offtakers are successfully contracting at levels that are generally comparable in terms of both cost and value, at about 2 cents (USD)/kWh or 18 €/MWh (\$20/MWh). Wind PPA prices are affected by the federal PTC, and the convergence between wind PPA prices and market value estimates since 2013 suggest that the PTC has enabled wind deployment on economic grounds since that time.
- Trends in the LCOE of wind and wind PPAs in the earlier years of the analysis period were affected by market conditions that were very different in the years leading up to 2008 than in the years following. Specifically, during this period, the market was affected by contracts that were signed in advance of the financial crises and at a time when natural gas and wholesale electricity prices were much higher. This was also a period of significant wind expansion in the United States, which may have also placed upward price pressure on wind power LCOE and PPA prices.

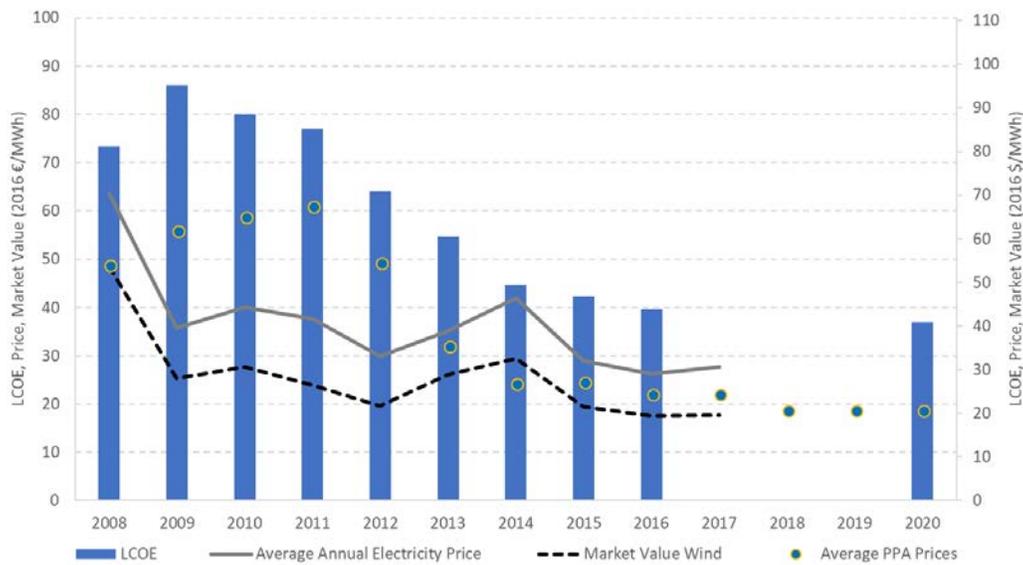


Figure 33. LCOE, average wholesale electricity price, and market value of wind in the United States from 2008 to 2016, with projections to 2020

8.4.2 Expectations for the Future

Future wind energy projects in the United States are expected to continue to see reductions in LCOE. The estimated LCOE in 2020 is calculated using a top-down methodology consistent with the cost reduction projections used in the National Renewable Energy Laboratory's (NREL's) *2018 Annual Technology Baseline* (NREL 2017). The *2018 Annual Technology Baseline* estimates a 6.9% LCOE reduction from 2016 to 2020. Applying this reduction to the 40 €/MWh (\$44/MWh) calculated for 2016 results in a 2020 LCOE estimate of 37 €/MWh (\$41/MWh).

Despite these encouraging wind LCOE trends, with the reduced value of the PTC and expectations for continued significant competition from photovoltaic and gas-fired electricity generation, the outlook for wind power revenue in the United States remains challenging. This is reflected in the gap between the 2016 LCOE reported in Figure 33 and the market value of wind also reported in that figure. As a result, Mai et al. (2017) suggest that without significant continued LCOE reductions to levels approaching 2 cents (USD)/kWh or 18€/MWh (\$20/MWh) by 2030, wind power deployments could stagnate in the United States for much of the 2020s and even into the 2030s. Notably, however, with very substantial continued cost reductions consistent with Dykes et al. (2017) or the aggressive cost reduction case presented in Wiser et al. (2016), continued wind power growth remains feasible, with deployment potentially expanding significantly throughout the country in the coming decades.

8.5 Summary

Since 2008, the calculated subsidy-free LCOE for U.S. wind energy projects has shown a 45% reduction from 73 €/MWh (\$81/MWh) to 40 €/MWh (\$44/MWh) in 2016. Improvement in wind project capacity factors from 33% to an estimated 43% is the primary driver for LCOE reduction, accounting for a 17 €/MWh (\$19/MWh) decline in LCOE. Reduction in average wind project investment costs from 1,955 €/kW (\$2,162/kW) to 1,434 €/kW (\$1,586/kW) is the second largest driver for LCOE reduction in the United States, resulting in a 12 €/MWh (\$13/MWh) LCOE decline. Reduction in O&M costs from 47 €/kW/yr (\$52/kW/yr) to 39 €/kW/yr (\$44/kW/yr) is the third driver, accounting for a 2 €/MWh (\$2/MWh)⁶³ LCOE reduction. Lastly, reductions in the cost of finance from a 6.4% nominal WACC to 5.7% reduced LCOE by 2 €/MWh (\$3/MWh). Continued reductions in the LCOE of wind are anticipated in the years ahead, resulting in an average LCOE of around 37 €/MWh (\$41/MWh) in the United States. As the market value outlook for wind energy continues to be relatively challenging, continued wind LCOE reductions beyond 2020 are expected to be critical to the continued growth and expansion of wind power in the United States.

⁶³ EUR to USD conversion appear to be the same due to rounding.

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Appendix A. LCOE Calculation

The levelized cost of energy (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 equal 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

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

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 ($E_n = E$)
- Operation and maintenance costs can be represented by an annual average value that does not change from one year to the next ($OM_n = OM$)
- 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 ($D_n=0$).

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:

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 described in each chapter 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 period, from 2008–2016. The after-tax, nominal WACC is computed as follows:

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

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

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.⁶⁴ Forward-looking inflation rate expectations that were reported by the U.S. Federal Reserve and European Central Bank from 2008 to 2016 were relatively consistent around 2%.

- 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, 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.

⁶⁴ Note that country- and year-specific data were used to translate all currency values (e.g., investment and operation costs) into real 2016 currency for this analysis. These values are included in the attached supplemental data appendix.