CHAPTER 7

# Offshore wind energy

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## Abstract

Offshore wind farms have been deployed since 1991, mainly in the North sea and Baltic sea but in recent years also in the United States and East Asia. Learning effects in offshore wind parks have been masked by various other developments over the past two decades, leading first to an increase in capital expenditures (Capex) and average levelized cost of electricity (LCOE) between 2003 and 2012, followed by a steep decline between 2015 and 2018. Based on changes in Capex, capacity factor, weighted average cost of capital (WACC), and operational expenditures (Opex), the LCOE increased from 120€/MWh in 2000 to 190€/MWh in 2015 and then decreased to about 100€/MWh at the end of 2018, with average projections for 2021 reaching 70€/MWh. Especially the increase in capacity factor has been a major driver in reducing the LCOE. Given the strong fluctuations in the past and many factors influencing the LCOE of offshore wind projects, it was not possible to derive meaningful one-factor experience curves and learning rates that would allow extrapolation for the future cost projections. Multifactor learning curves approach taking into account raw material costs, location-specific properties, and soft factors such as developments in WACC show more promise, but more deployment of offshore wind is needed to demonstrate whether such models can provide more accurate cost trend forecasts for the coming years.

## Chapter Outline



**Technological Learning in the Transition to a Low-Carbon Energy System.**
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## 7.1 Introduction

The first offshore wind park was installed almost 30 years ago in Denmark in 1991. The very first such wind farm in Vindeby, Denmark, comprised 11 turbines with a power of 450 kW each, resulting in a total capacity of 4.95 MW (Henderson, 2015). Since then, offshore wind farm deployment has grown exponentially, initially in the North and Baltic seas, but in recent years in new markets outside Europe. Putting wind turbines offshore has several advantages compared to onshore parks, such as a vast techno-economical potential; higher, more constant, and often "smoother" wind speeds; and in many cases less resistance from local stakeholders (depending on distance to shore, given visual impacts are minimal to none when parks are sited far offshore). Also, the possibility to transport turbines by ships rather than trucks has allowed for an impressive increase in turbine size, allowing for higher electricity production per turbine amortizing installation costs across greater output. On the other hand, offshore wind installation costs are higher, requiring dedicated equipment, and the environment is harsher, also making operation and maintenance more challenging.

Europe has been leading the development of offshore wind farms for the past three decades. In 2018 Europe connected 409 new offshore wind turbines to the grid across 18 projects. This brought 2649 MW of net additional capacity. Europe now has a total installed offshore wind capacity of 18,499 MW, as shown in Fig. 7.1 (WindEurope, 2019). The United Kingdom has the largest amount of installed offshore wind capacity in Europe, representing 43% of all installations, followed by Germany with 34%, Denmark with 8% (despite no additional capacity in 2017), the Netherlands 7%, and Belgium 6% (WindEurope, 2019). Combined, the top five countries cover 98% of all grid-connected offshore turbines in

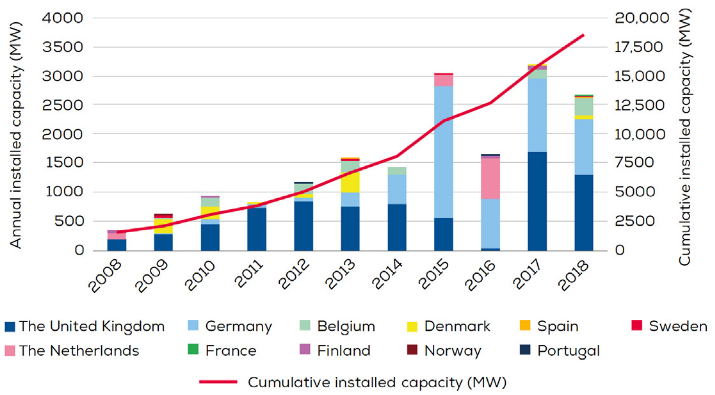


**Figure 7.1**
Offshore wind energy power installed in Europe in the period 2008–18. *Source: Reproduced with permission from WindEurope (2019).*

Europe and 80% globally. Outside Europe, a number of relatively small offshore projects have been developed in the United States and Asia (China, Japan, Vietnam), and projects are planned in Korea and Taiwan. In addition, China installed about 5 GW of offshore capacity in 2017 and 2018, bringing the global total to around 24 GW by the end of 2018 (IRENA, 2019). In this chapter, for historical developments, we focus mainly on the North and Baltic seas, as the vast majority of deployment (and most likely technological learning) has taken place in this region.

There are important differences between onshore and offshore wind farms. A clear difference with onshore park is the need for a more elaborate foundation, usually a monopile (in shallow water) or a tripod or lattice construction for waters up to 40 m deep (Fig. 7.2). The turbines are interconnected with an array of power cables that deliver electricity to an offshore substation that converts the electricity to a high-voltage current to minimize losses during transport to shore over the export power cable. A second substation connects the park to the conventional high-voltage grid.

## 7.2 Methodological issues and data availability

An overview of the general data collection issues applicable to wind energy is given in Table 7.1. For both on- and offshore wind, large sets of price data are available, but especially the upfront investment cost shows a large increase between approximately 2003 and 2012, making it difficult to devise meaningful experience curves that can be used to determine learning rates that reflect actual technological progress. Market dynamics, market maturity, technology evolution, and raw material prices have influenced the price

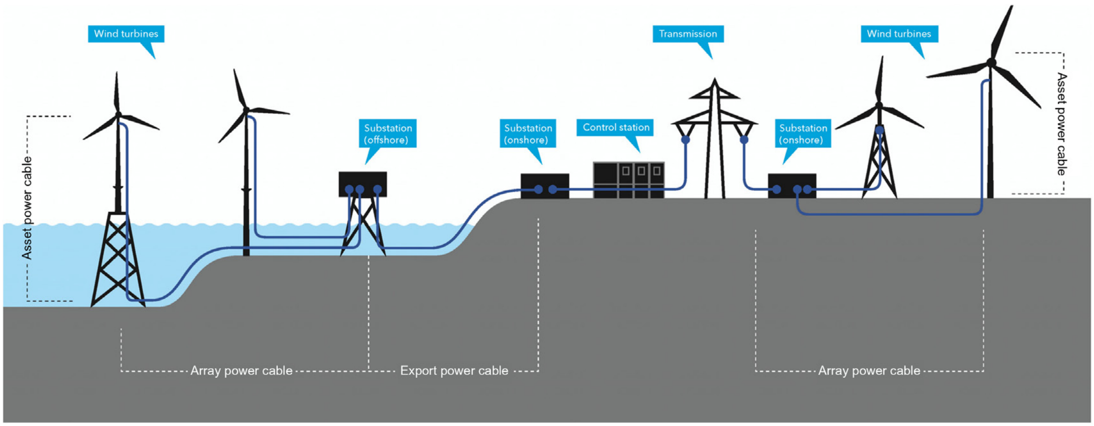


**Figure 7.2**
Typical layout of an offshore and onshore wind farm. *Source: Reproduced with permission from DNV GL (2015).*

**Table 7.1: General data collection issues for offshore wind power.**

| Issue | Resolution | Applicability |
|---|---|---|
| Historical data is not for cost | Price data is used | ☑ |
| Data not available for desired cost unit (LCOE) | Capex and capacity factors are known for most projects, WACC, and O&M usually need to be estimated | ☑ |
| Data is valid for limited geographical scope (five countries, covering North Sea and Baltic Sea) | Different datasets combined and compared | ☑ |

*Capex*, Capital expenditures; *LCOE*, levelized cost of electricity; *WACC*, weighted average cost of capital.

developments of wind turbines (Wiser and Bolinger, 2017). By taking into account these factors in a multifactor experience curve, a more accurate model to project future wind turbine, and on- and offshore wind farm prices, could possibly be established, as shown in Section 7.3.1.

Data for total installed costs, capacity factors, O&M, and costs of capital is required to calculate the levelized cost of electricity (LCOE) of offshore wind projects, with assumptions used in the absence of project level data. For many recent offshore tenders, only the complete, estimated costs for the wind farms as a whole are often available, and the price per unit of electricity may or may not reflect and LCOE equivalent depending on the contract terms. An additional complication is that the comparability of data between countries is often compromised due to different boundary conditions. For instance, costs reported for recent Dutch tendered wind farms do not include the grid connection to shore, while in the United Kingdom, the results do. In this chapter, all capital expenditures (Capex) include the cost of grid connection. An additional complication is that given the longer lead times of offshore wind farm developments, and continuing cost reductions, there are examples in recent years of projects' final budgets being lower than the currently estimated budgets.

Another issue is the fact that cost of offshore wind energy is often measured using the upfront investment cost (€/kW). Over time, the operation of wind farms has improved, in terms of O&M costs and capacity factors, and thus for a given wind farm capacity, the electricity generated has increased, and the operating costs have decreased relatively, resulting in lowered costs of electricity produced (LCOE). Furthermore, offshore wind farms are characterized by higher capital costs but in general have much higher capacity factors compared to most onshore wind farms. The increase of capacity factors is also the result of other improvements that might actually increase the costs of capacity (such as application of higher towers) yet still result in lower LCOE. In this chapter, all LCOE presented have been calculated as much as possible with project-specific data on Capex (including grid connection), capacity factor, and lifetime. The weighted average cost of capital (WACC) has been based on either project or (if not available) country-specific data, whereas operational expenditures (Opex) have been estimated based on general literature estimates. For more details, see Gomez Tuya (2019).

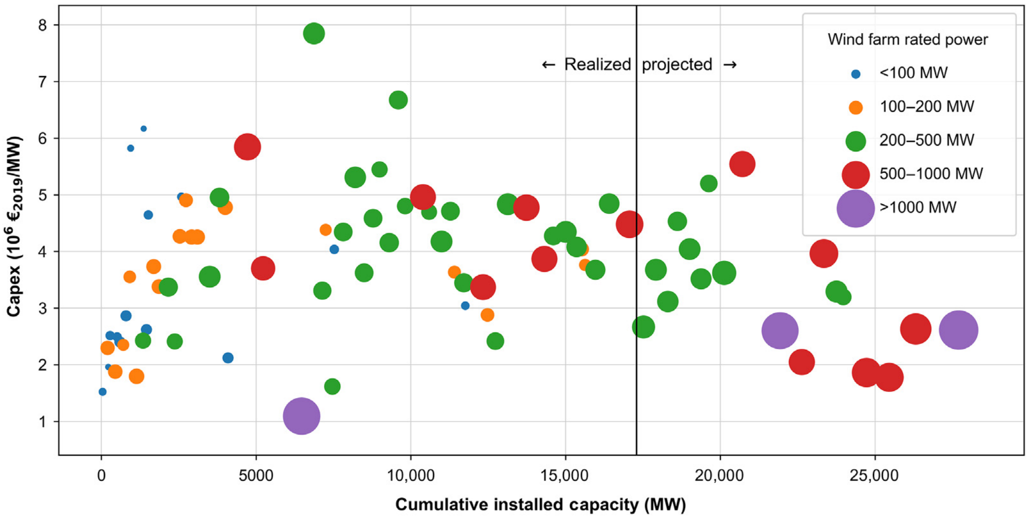


**Figure 7.3**
Development of global offshore wind park specific capital expenditures (Capex) between 2001 and 2018 (realized) and 2019–22 (projected). *Source: Based on own data collection by Gomez Tuya and Taylor.*

As shown in the previous research (Junginger et al., 2010; Voormolen et al., 2016), there can be large country-specific differences between wind system prices, due to differences in market maturity, regulatory requirements, government support schemes, and structural factors (e.g., labor and material costs). While recent offshore wind farm data (see Fig. 7.8) indicates that recent prices are becoming similar for four major European markets, further research should establish whether these price differences are still occurring for, for example, onshore wind farms.

## 7.3 Results

### 7.3.1 Experience curve analyses

For offshore wind farms, data was collected on all wind farms installed offshore in Europe between 2001 and 2018 and announced wind parks of 2019–22. The resulting specific Capex cost (including grid connection costs) is plotted against cumulative installed offshore capacity in Fig. 7.3.

As can be seen on the left side of Fig. 7.3, the general Capex trend increased between 2001 and about 2012. Especially around 2012, a wide divergence of Capex was found, with prices ranging from as low as 1.2 up to 8 M€$_{2019}$/MW. Many reasons can be attributed to this increase in Capex, which will be discussed in more detail in the next section. After

2013 a general declining trend can be observed, especially with some projected wind farms expecting to reach Capex under 2 M€/MW. Nevertheless, no meaningful experience curve could be fitted for the entire data series.

For the development of LCOE the picture looks very similar (see Fig. 7.4A–D)—based on the estimated LCOE of individual wind parks, no clear experience curve could be established, and only after correcting for a variety of factors, the following clear(er) trends could be found:

- Analog to onshore wind (see Chapter 6), using LCOE for experience curve analyses captures more factors than Capex-based analyses—especially the increase in capacity factor (see also the next section). Also, ultimately wind parks are designed to achieve lowest cost of electricity rather than lowest upfront investment cost.
- As shown in Fig. 7.4A, LCOE varied significantly for different countries: the United Kingdom saw a doubling of LCOE from 120 to 240€/MWh, and subsequently a sharp decline to 70–90€/MWh (projected). In contrast, in Denmark, with one exception, LCOE has always remained under 100€/MWh. This is likely due to differences in policy support schemes and other factors (see also next section).
- Typically, in experience curves, no difference between countries is made, and in Fig. 7.4B, all annual LCOE are averaged. Also, next to the one-factor experience curve, additional explanatory variables are introduced, such as the changes in WACC, water depth, and steel prices. However, meaningful experience curves can be derived.
- An additional factor that makes the application of the experience curve concept difficult is the small number of individual wind parks built, an issue earlier discussed by Junginger (2005). This means that in years with only one data point (especially in early phases of the technology), these can determine the fit of the experience curve to a large extent. In Fig. 7.4C an attempt is made to correct for this by only considering years with at least two data points.
- As a last step, in Fig. 7.4D, only offshore wind parks are taken into account with a size of 250 MW or larger, at least 20 km from shore, and in at least 20 m water depth, in order to ensure that wind parks can reasonably be compared with each other. This effectively limits the dataset to the period of 2014–21. As can be seen in Fig. 7.4D, this yields an experience curve with learning rates between 26.8% and 31.2%. Especially the inclusion of water depth as additional explanatory variable increases the quality of the fit.

Fig. 7.4D does show both single and multifactor learning curves with high quality of fit. Yet, we caution against the use this learning rate for any projections: especially Fig. 7.4D only describes a trend over a very limited time period with only two cumulative doublings of electricity generation (compared to more than nine doublings in Fig. 7.4B). It is highly unlikely that this steep decline in LCOE can be continued in the coming years, and also

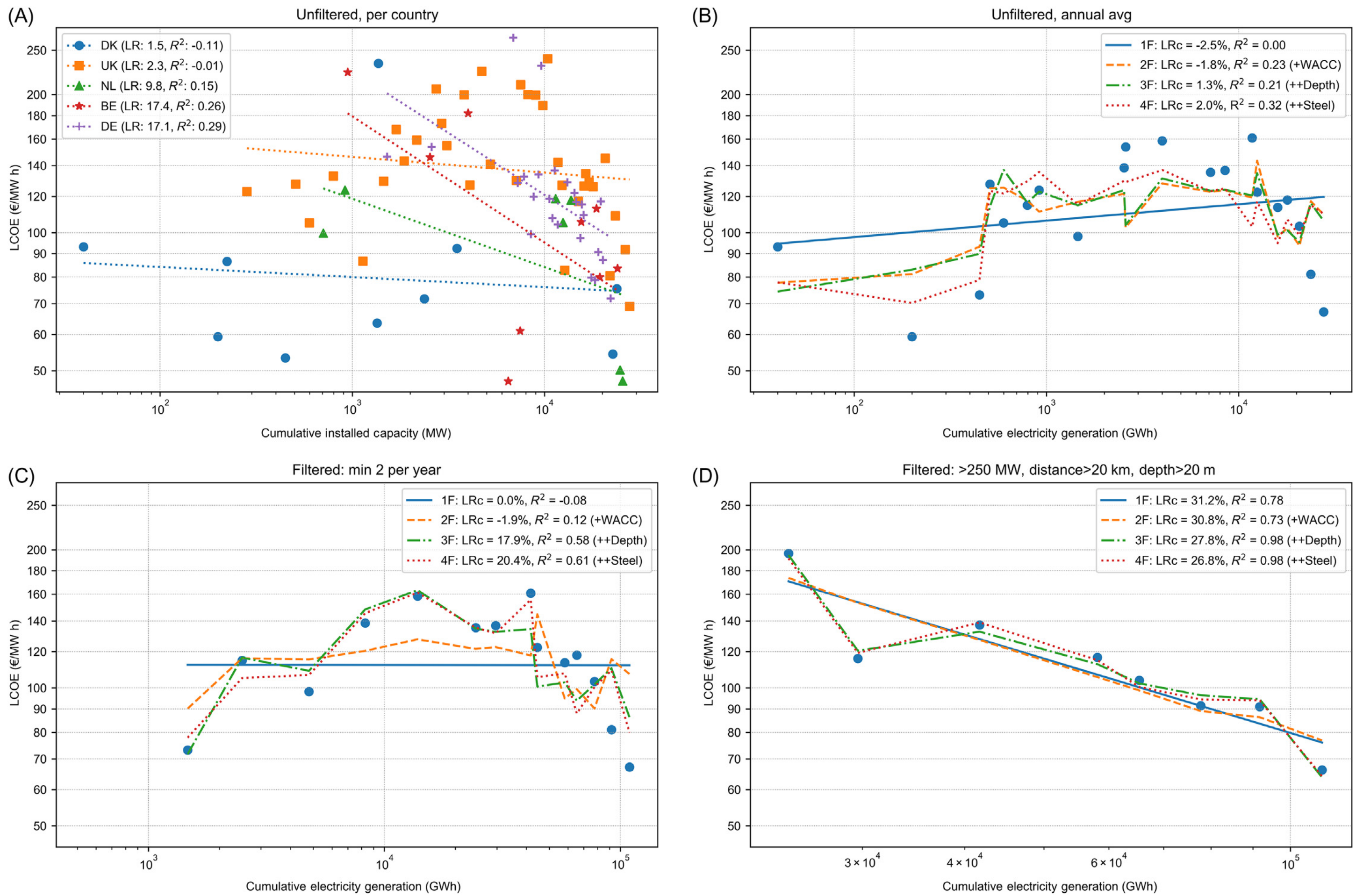


**Figure 7.4**

(A) Levelized cost of electricity (LCOE) for individual offshore wind farm in Denmark, the United Kingdom, the Netherlands, Belgium, and Germany; (B) annual averages, with additional explanatory variables weighted average cost of capital (WACC), water depth, and steel prices; (C) only annual data with at least two data points; (D) only considering wind parks of at least 250 MW, at least 20 km from shore, and a water depth of at least 20 m. *Source: Based on own data collection.*

when comparing it to the LCOE, learning rates found for onshore wind parks of 10%–12% (see Chapter 6).

### 7.3.2 Main drivers behind cost and price changes

When offshore wind parks were first installed in the early 1990s, it seemed to be a reasonable idea to use the same technology for offshore wind farm as the one used in onshore with slight adjustments. However, the needs for further offshore R&D and expertise were underestimated. Wüstemeyer et al. (2015) point out that competition for onshore products in the 2000s was high, and that most companies manufacturing components for wind farms were reluctant to divert R&D to specific offshore turbines, but this strategy failed. One example is the 160 MW Horns Rev 1 wind farm in Denmark with 80 Vestas V80 turbines that were adapted for offshore usage (Richardson, 2010). Two years after the commissioning, all wind turbines had to be removed for refurbishment, maintenance, and replacement works due to eminent transformer and generator problems (Sweet, 2008). Companies soon realized that offshore wind farms needed new turbine designs, specifically adapted to the harsh marine environment and not simply an adaptation of existing onshore turbines. However, optimizing products for offshore usage meant at the same time making them inefficient for onshore wind power, since additional features, such as an extended corrosion resistance, are unnecessary cost drivers (Wüstemeyer et al., 2015). Nevertheless, in the past decade, most manufacturers have set up separate R&D lines for offshore wind farms, and thus dedicated R&D has certainly added to LCOE reductions.

Since the establishment of the first offshore wind parks in the 1990s, the Capex and the price trend in general have been increasing, together with the size and rated power of the turbines, the water depth, and the distance from shore, as shown in Fig. 7.5.

This led in the period of 2000–15 to an increase of the Capex from around 1.5 M€/MW in 2000 to 4.0 M€/MW in 2010. A large number of factors have been mentioned in literature, which may all partly have contributed to this:

- Between 2001 and 2015, offshore wind parks have continuously been placed further offshore and in deeper water. Obviously, with increasing water depth to about 25 m in 2018, the cost of foundations increases. The same goes for the average cost of grid connection and installation costs with increasing distance to shore (the average distance of farms built in in 2018 was about 40 km). However, even when correcting for these factors, it can only partially explain the increase in Capex (Voormolen et al., 2016).
- A second factor is the increase of raw material prices such as steel (factor 2 between 2004 and 2009) and copper (factor 3–5 from 2004 to 2009–14). Yet again, these factors contributed to the overall Capex increase but cannot fully explain the increase.

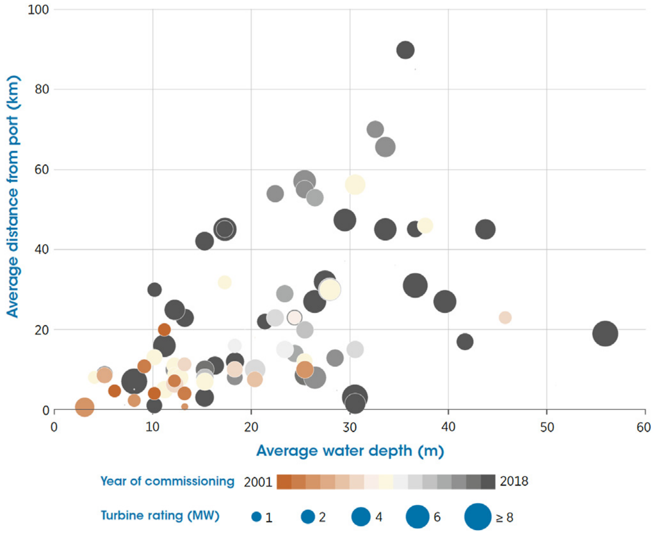


**Figure 7.5**

Average distance from port and water depth in commissioned offshore wind projects, 2001–18. *Source: Reproduced with permission from IRENA (2019)*

- Voormolen et al. (2016) find that also competition between turbine suppliers and other market actors was limited. For example, Siemens supplied turbines for 23 of the 45 projects surveyed by Voormolen et al., with a capacity of 5.2 GW (62% of total capacity assessed). In 2014 Siemens had a market share of 86% (EWEA, 2015). Under such monopolistic conditions, it is unlikely that market prices reflect production costs.
- Voormolen et al. (2016) also reported that in the United Kingdom, environmental permits specified the turbine size several years before the project was actually realized, requiring the project owners to use outdated technology at the point of construction.

Probably, a combination of these and other factors is responsible for the increase in Capex between 2000 and 2015. However, from 2015 onward, decreasing Capex can be observed. This is most likely again due to a number of factors, including technology improvements, greater experience among project developers, greater economies of scale in supply chains, as well as competition among suppliers, benefits from multiple wind farms in specified zones.

The improvements in offshore wind turbine technologies have been impressive. The first turbines installed had a diameter around 65 m and a capacity of 2 MW, while in 2018 the average rated capacity of new installed turbines was 6.8 MW (Fig. 7.6), and an average rotor diameter was 160 m. Since 2014 the average rated capacity of newly installed wind turbines has grown at an annual rate of 16% (WindEurope, 2019). For the commercialization of a 10 MW turbine (featuring a 164 m rotor diameter) has been

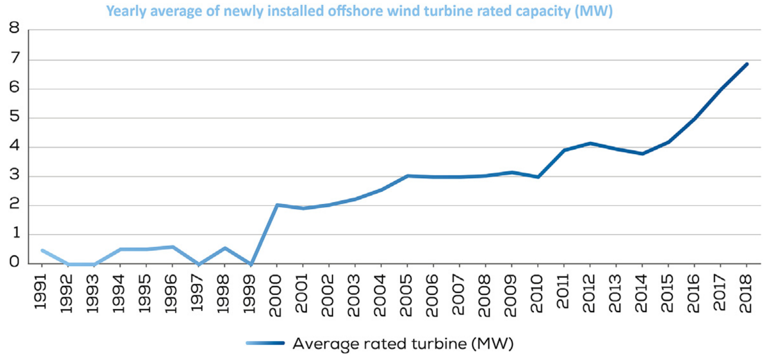


**Figure 7.6**
Yearly average rated capacity of newly installed offshore wind turbines (MW). *Source: Reproduced with permission from WindEurope (2019).*

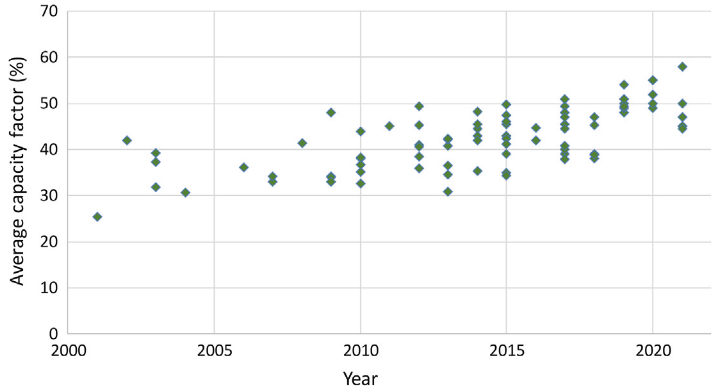


**Figure 7.7**
Capacity factor trend for European offshore wind farms; values from 2001 till 2021 (2019–21 projected). *Source: Based on (Wiser et al., 2016a) with permission from Springer Nature.*

announced by Vestas for the beginning of 2021, and a 12 MW turbine by Haliade-X is under development for 2022 (IRENA, 2018).

But the changes in Capex only tell part of the story: other factors also have significantly influenced the overall LCOE. Perhaps even more importantly, the average capacity factor has increased continuously over the years. While in the early 2000s, capacity factors of around 30% were common, by 2018, capacity factors had increased to 45% (with a range between 40% and 50% covering most projects) and are projected to increase further to 50% and more by 2022, as shown in Fig. 7.7. Similarly to the development for onshore wind, this impressive increase in electricity production is not reflected in the Capex but has played a major role in lowering LCOE in recent years.

But cost reductions appear to be an even more complex set of factors. In a report published by Vree and Verkaik (2017) the cost structures of three specific offshore wind farm projects were analyzed in detail. In this report, three offshore wind farms are discussed, which (in 2019) have not yet been built. The analyses reveal that a multitude of different factors not only led to overall significant reductions of LCOE, improved wind turbine and foundation design, increased experience in installation, and reduced steel prices (all impacting upfront Capex), but also increased availability (from 94% to 96%). Next to these technical improvements, also "soft" costs have been reduced, such as insurance cost, financing cost, return on equity, and permit and policy improvements. The impact of individual factors, however, varied between the three parks assessed. The report concludes that strong tender pressure (and competition), low raw material prices, low interest rates and equity costs, good policies in Denmark and the Netherlands (government as "project developer": risk reduction for the investors) resulted in LCOE reduction from 150–200 to 40–80€/MWh (depending on site condition, tax regulations, inclusion of exclusion of grid costs).
The range of 40–80€/MWh does not reflect current prices, but bids are made some years back for projects to be operational as of 2020 and beyond. Overall, based on some case studies, we estimate that about roughly 60% of the cost reduction can be attributed to institutional innovation, whereas 40% to "hardcore" technological innovation.

The cost of financing, and more specifically the WACC, has also likely played a role in past cost increases between 2003 and 2012. Gomez Tuya (2019) found an increasing trend in WACC between 2004 and 2012 in the United Kingdom, Denmark, Germany, and the Netherlands, but all sharply declined between 2014 and 2015. Interestingly, the WACC fluctuated much less in Denmark (always between 7.5% and 9% between 2001 and 2018) than in the United Kingdom, which displayed structurally higher WACC, ranging between 9% (between 2015 and 2017) and almost 14% (in 2009 and 2012). This is part of the explanation for the large differences observed between the United Kingdom and Denmark as shown in Fig. 7.4A. Possibly, the sharp decline in WACC in recent years is (partly) due to a perception by equity providers that offshore wind is less risky than it used to be. If so, then technological learning had an indirect impact on the LCOE, but this is speculation, and incorporating such effects in experience curves remains a challenge.

### *7.3.3 Future outlook*

Given the ambitious Paris climate goal, offshore wind is expected to continue to grow strongly over the coming years. Next to the main growth area in the European Union, also the United States and China are expected to invest increasingly in offshore wind parks. For the near future (2030), it is expected that global installed capacity will reach 130–140 GW (IEA, 2018), compared to less than 20 GW installed at the end of 2018. For 2050, EWEA expects a growth in Europe alone of 400 GW, and so globally installed capacity could increase up to well above 500 GW. Gernaat et al. (2014) show that integrated assessment models assume significant deployment of offshore wind, especially in scenarios with climate policies (e.g., to reach a 2°C target), showing deployment between 200 and 1500 GW by 2050. For the baseline scenario in the IMAGE TIMER model, 850 GW alone is deployed, with highest deployment in the rest of Asia (20% of global offshore capacity), Europe (15%), South America (14%), and China (12%). According to this projection, only 1% of the offshore technical potential will have been developed by 2050, increasing to 3% by 2100 (Gernaat et al., 2014).

Given this expected massive increase in installed capacity, it could be both expected and societal interest that the cost of offshore wind energy is further reduced. However, as discussed in the previous sections, it is very difficult to identify robust cost trends, given the fact that a large number variables influence the LCOE, and not all of them are linked to technological learning. Therefore based on the trends identified in this chapter, no estimates are made given future cost reduction prospects.

For comparison, elicitation surveys by several experts have been done before predicting the future development of wind costs. This method is widely in use and offers a close estimation of the future expectations as shown in Wiser et al. (2016a,b).

In Fig. 7.8 the baseline of 2014 and the middle point in 2030 were determined by consulting experts on the expected average LCOE and by requesting details on five core input components of LCOE: total upfront Capex to build the project (€/kW); levelized total annual Opex over the project design life (€/kW-year); average annual energy output

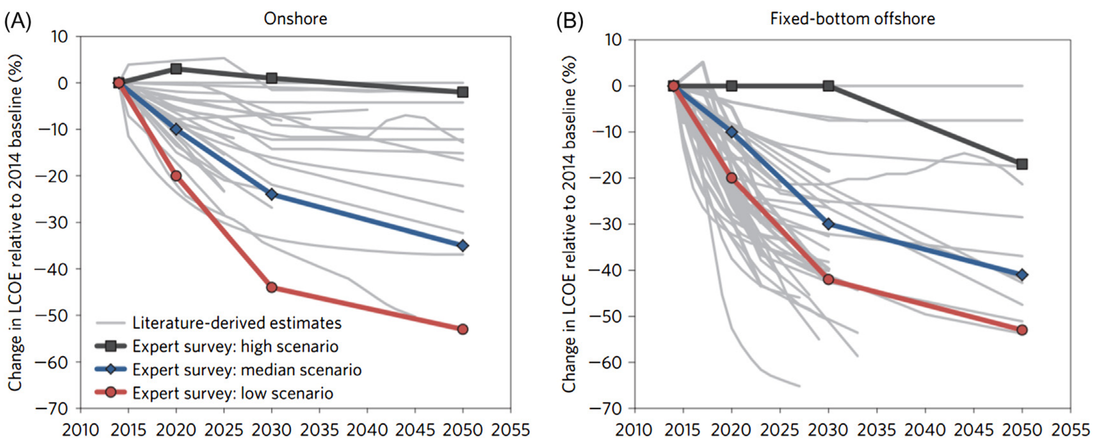


**Figure 7.8**
Estimated change in levelized cost of electricity (LCOE) for onshore wind parks (A) and fixed-bottom offshore wind parks (B); comparing expert survey results with other forecasts (Wiser et al., 2016a,b).

(capacity factor, %); project design life considered by investors (years); and costs of financing, in terms of the after-tax, nominal WACC % (Wiser et al., 2016a). As a 2015 starting point, an LCOE of 170 US$/MWh was taken, and for 2030, most experts expected a drop of LCOE to about 120 US$/MWh by 2030. This survey was taken at (or shortly after) the peak of LCOE in UK and German projects. But based on the latest bids, LCOE are expected to decline to 50−90€/MWh already by 2021. This elucidates again the difficulty to make sound projections for offshore LCOE.

For the future, we see several trends. First of all, with recent capacity additions outside Europe, the scenarios used in integrated assessment models are starting to materialize. In these regions the lowest cost sites are still largely unoccupied. In the North and Baltic seas, however, new sites will have to move ever further from shore, which may cause higher LCOE. Then again, we also observe that new technological concepts are emerging for installation and operation, such as hydraulic drivetrains, airborne wind, off-grid wind energy with $H_2$ production, and automated O&M—some expected before and some after 2030. These may bring down the LCOE. In the North Sea the intense use means that combination with interconnectors is likely to occur, energy islands with O&M stations are envisaged, etc. It is difficult to say how the interaction between depletion of geographic potential on the one hand and technological learning and new concepts on the other will ultimately impact LCOE, but they will typically be site specific and thus difficult to assess with experience curves alone.

One factor that has hampered the determination of actual LCOE is the lack of reliable data on WACC for individual projects but also of the actual electricity production and development of operation and maintenance cost of offshore wind farms. Publication of such data would also aid the more accurate assessment of current and future LCOE of offshore wind.

### *7.3.4 Conclusions and recommendations for science, policy, and business*

Almost three decades ago, offshore wind started as an experiment. The Vindeby was dismantled in 2016/17 after 25 year of operation (it was designed in 1991 for 20 years max), and so by now, a truly new generation of offshore wind farms is expected to power a large share of the renewable energy needs in the coming years. In order to reach a 100% renewable electricity system in the European Union, offshore wind will be essential (Zappa et al., 2018). Offshore wind is the backbone of the decarbonization strategy for many European countries, with plans to produce green hydrogen for transport and industry use. As such, the recently achieved reductions in LCOE are promising. However, due care should be taken when assuming further LCOE reductions and extrapolating recent trends. The geographic potential of offshore wind is ultimately limited, and locations further offshore will require floating foundations and longer cables for grid connections.

Also reductions in WACC achieved recently may just as well be canceled if interest rates increase again. Last but not least, in this chapter, only the production cost of electricity has been assessed, but not how electricity prices will develop. With increasing penetration of offshore wind and other intermittent renewables, prices may decrease as well (both yearly averages and during specific times of high wind speeds), and so profit margins may become smaller, and policy support may have to be maintained for longer periods. Then again, with increasing availability of low-cost electricity storage technologies (see chapter 8), and the increasing demand for green hydrogen may enable the development of new business models.

Given the strong fluctuations in the past and many factors influencing the LCOE of offshore wind projects, it was not possible to derive meaningful one-factor experience curves and learning rates that would allow extrapolation for future cost projections. Multifactor learning curves approach taking into account raw material costs, location-specific properties, and soft factors, such as developments in WACC, show more promise, but more deployment of offshore wind is needed to demonstrate whether such models can provide more accurate cost trend forecasts for the coming years. Ultimately, experience curves will likely remain more applicable to modular technologies (e.g., photovoltaics, batteries) or at least more standardized supply chains and homogeneous site conditions such as onshore wind.

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