UKERC Technology and Policy Assessment

Cost Methodologies Project: Offshore Wind Case Study

Working Paper

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This working paper was produced as part of the TPA Cost Methodologies project.

Contents

1. Introduction

Offshore wind is widely expected to play a major role in UK compliance with the EU Renewables Directive. Projections from a range of analysts suggest the UK may need at least 15 to 20 GW of offshore wind capacity by 2020 (HoL, 2008) . Though the government has not set a specific target, the central range in its Renewable Energy Roadmap is that up to 18 GW could be installed by 2020 (DECC, 2011) with aspirations to go well beyond that in the decades that follow.

Development rights in the UK have been awarded by the Crown Estate (the owner of the seabed) in 4 rounds to date. Rounds 1 and 2, which commenced in 2001 and 2003 respectively, granted rights for a total of circa 8 GW of development. Round 2.5 gave Round 2 developers the rights to an additional 1.5 GW, whilst Round 3 rights, awarded in 2010, were for over 30 GW of potential development (The Crown Estate, 2010a, The Crown Estate, 2010b, Douglas-Westwood, 2010).

Given the substantial ambitions for UK offshore wind deployment the issue of cost and cost reduction has therefore been the subject of considerable interest. Drawing heavily on the data and analyses of UKERC TPA's 2010 report (Greenacre et al., 2010), this paper examines cost trends in offshore wind energy, comparing past forecasts with outcomes to date, and analysing the main reasons for the disparity between them. The rationale for the study is to support and inform Chapter 5 of the UKERC TPA report 'Presenting the Future: An assessment of future cost estimation methodologies in the electricity generation sector'. The case study has three specific aims:

- Examine the key trends in contemporary costs and future cost projections (Section 2);
- Understand the drivers underlying these key trends and the reasons for differences between anticipated cost levels and actual out-turns (Section 3);
- Identify implications for cost estimation methodologies (Section 4).

2. Costs trajectories

In this section we analyse how future costs forecasts have so far compared with contemporary cost out-turns i.e. we compare past expectations about the future with the ‘reality’ of contemporary costs at any given time. Our analysis covers both offshore wind capital costs and levelised costs of generation.

2.1 Expectations of future costs

Early estimates of offshore wind cost trends were derived from engineering assessment, from experience curves adapted from the onshore experience, and from what data were available in the infancy of offshore wind development. The literature from the late 1990s onwards reflected a widespread expectation that costs would fall as deployment expanded (Greenacre et al., 2010).

Analysts also looked at the experience of the onshore sector for clues as to the likely trajectory. Onshore costs fell fourfold in the 1980s, and halved again in the 1990s. As a consequence, grounds for optimism appeared justifiable and informed UK government thinking in the early 2000s (Greenacre et al., 2010). In 2003 for example, the economics of offshore wind were reviewed for the DTI and The Carbon Trust (Garrad Hassan, 2003). Based on a range of assumptions, offshore wind capital costs were expected to reduce by around 15% over the next 5 years. Given that contemporary capex (capital expenditure) was estimated at £1.1 million – £1.35 million/MW, this should have resulted in a reduction to between £935,000 and £1,150,000/MW by 2008. The report further anticipated that over a 20 year timescale i.e. until the early to mid-2020s, capital costs could fall by 40% to between £660,000 and £780,000/MW.

In 2005, a report by BERR suggested a capex target level for 2010 of £750,000/MW of installed capacity (DTI, 2005). In the same year, the IEA projected 2010 capital costs in the range £860,000/MW to £1,120,000/MW, and expected generation costs in 2010 to fall to between £44 and £57/MWh (IEA, 2005). Meanwhile, (Enviros Consulting, 2005) anticipated that generating costs would decline rapidly so long as the then current build rates were sustained, and expected that by 2008 the cost of generation would fall to £60/MWh. Table 1 presents UK levelised cost estimate ranges for 2020 from several further studies in the early 2000s.

Study/group estimate	Date	2020 Cost (£/MWh)
PIU Energy Review	2002	20 – 30
Interdepartmental Analysts Group	2002	25 – 30
Future Energy Solutions for Markal modelling work	2002/2003 (figures originally appeared 1998)	39 – 57

Table 1 Cost estimates for offshore wind in 2020 in different UK studies from (Gross, 2004)

The general expectation that costs would fall over time as the industry matured is further demonstrated by Figure 1 below. This presents a summary of the capex value forecasts between 1990 and 2050 as reported in the literature. It shows the in-year average forecast costs for two groups, one consisting of those forecasts made up to 2005, and one consisting of those forecasts made from 2005 onwards.

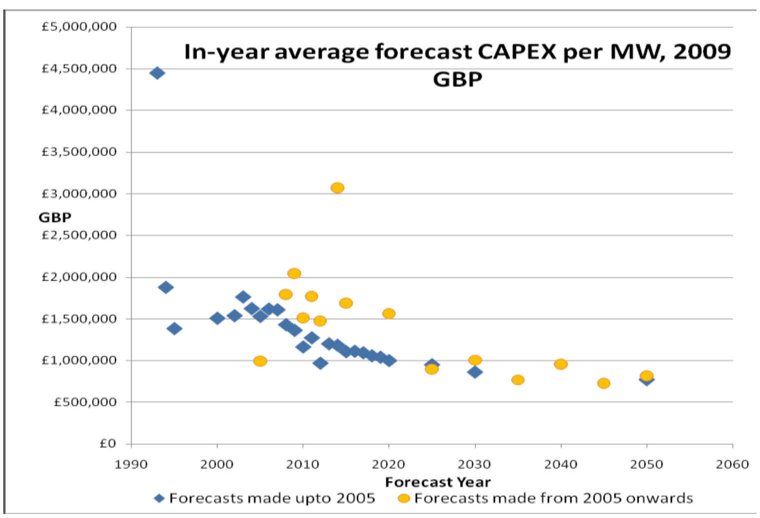

Figure 1 Forecast capex, comparing pre and post 2005 estimates (Greenacre et al., 2010)

The above data reinforce the message that analysts consistently expected costs to fall over time. After 2005 forecast costs in the relatively near future rose as it became clear capex had not fallen as originally anticipated. However, costs were still expected to fall in the longer term, returning to broadly the same level as earlier forecasts.

2.2 Actual cost trajectory experience

We now turn to what actually happened to costs trends in contrast to what had been expected to happen. Figure 2 below presents the in-year minimum, maximum, and average actual capex per MW installed for offshore wind projects reported in the literature from the early 1990s to the mid-2000s (Greenacre et al., 2010). From this it can be seen that the in-year average trend provided reasonable grounds to expect that costs in the medium to long-term future would be lower than contemporary levels. In the UK, typical capital costs during the period 2000 to 2004 had fallen to between £1.2m/MW and £1.5m/MW (BWEA and Garrad Hassan, 2009). By 2003, for example, the cost range was between £1.1 million and £1.35 million/MW installed.

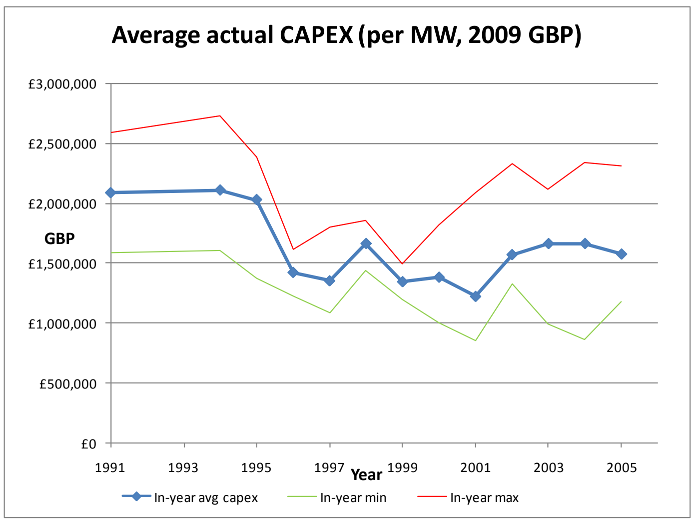

Figure 2 In-year average actual capex, up to 2005 (Greenacre et al., 2010)

However, against early expectations, the second half of the last decade saw costs escalate dramatically. The estimated levelised cost of energy generation rose from around £85/MWh in the mid-2000s to around £150/MWh by 2010 (DTI, 2006, Mott MacDonald, 2010). Contributing to this increase, O&M costs for a range of UK Round 1 and Round 2 projects were estimated to have risen from £38,000 per MW per annum to around £60,000 per MW per annum – a 58% rise over the five year period to January 2009[1] (Ernst & Young, 2009). Meanwhile, typical capital costs doubled from approximately £1.5 million/MW in 2005 to £3.0 million/MW in 2009 (see Figure 3 below). As shown by Figure 1 past expectations of future capital costs in 2009 were

[1] Reflecting projects achieving commercial operation date up to and including 2012.

approximately £1.25 million to £2.0 million per MW thus actual costs exceeded expectations by between approximately 50% and 150%.

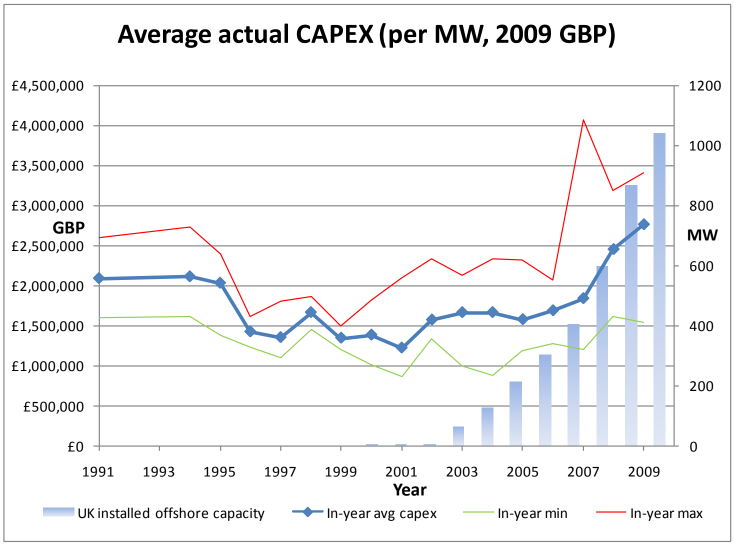

Figure 3 In-year average actual capex, 1990 to 2009 (Greenacre et al., 2010)

More recently, it has been suggested that there are signs that a plateau in costs may have been reached (Greenacre et al., 2010). In 2010, according to the majority of commentators, the typical capex of around £3.0 million/MW and typical energy costs at a little under £150/MWh were approximately the same as a year previously. However, arguing against this view, Mott Macdonald in 2011 estimated even higher energy generation costs at £169/MWh though the capital costs remained similar at around £3.0 million/MW (in a range between £2.8 million and £3.4 million/MW) (Mott MacDonald, 2011). Similarly, the (ARUP, 2011) report for DECC puts levelised costs at £174/MWh (large scale, medium scenario) though suggesting lower capital costs of approximately £2.75 million/MW.

3. Causes of disparity between forecasts & outcomes

The following three sub-sections examine the possible reasons for the gap between expectations of future costs and the reality of actual outcomes. The reasons are categorised into three groups (methodological issues; significant endogenous factors; and significant exogenous drivers) but it is acknowledged that there is some overlap between them. Following (Greenacre et al., 2010), the distinction between the latter two groups reflects the extent to which policymakers and offshore wind developers either were able in theory to influence or mitigate the causes (endogenous) or were not (exogenous).

3.1 Methodological issues

Application of experience curves using onshore data

At least until the mid-2000s there was little primary data from which to construct experience curves. Offshore wind was still in its infancy with only 13 offshore wind farms constructed worldwide between 1991 and 2004 totalling less than 550MW of installed capacity. By 2010, offshore wind still represented less than 2% of global installed wind capacity. Before the year 2000, the UK had no offshore wind capacity at all and four years on there were only three completed wind farms totalling just 124 MW of installed capacity. Consequently, early forecasters had little or no offshore wind data available and therefore experience curves were borrowed and adapted from the historically more mature onshore experience (Greenacre et al., 2010).

However the cost components, and the availability and resulting load factors of onshore and offshore are different and a comparison of the two is not like for like. For example, annual turbine availability for onshore wind farms has typically been 97% or above, and only 1% operate at less than 80% availability. By contrast, analysis of UK Round 1 offshore projects reveals that average availability was only 80.3%, falling well short of expectations (Feng et al., 2010). Table 2 below illustrates some of the significant cost-related differences between typical onshore and offshore projects.

Category	Onshore wind farm	Offshore wind farm
Average availability	> 97%	c. 80% for UK Round 1
Comparative cost of wind turbine generator (WGT)	c. 17% less than offshore equivalent	c. 20% more than onshore equivalent
Comparative cost of foundation/tower	60 – 70% less than offshore	150 to 200% more than onshore
% Cost of installed WGT	70 – 80% of total capex	35 – 50% of total capex
% Cost of installed foundation	4 – 7% of total capex	20 – 25% of total capex
% Cost of electrical infrastructure	9 – 12% of total capex	21 – 23% of total capex
Land rent/offshore consents	c. 4% of total capex	c. 7% of total capex

Table 2 Examples of cost-relevant differences between onshore and offshore wind energy. Sources: (Feng et al., 2010, ODE Limited, 2007, Greenacre et al., 2010, Blanco, 2009, Bilgili et al.)

Another factor relevant to the problem of 'borrowed' onshore wind data is the wide variation in onshore learning rates found in the literature. Many different experience curves for wind power have been presented over the years e.g. (Junginger et al., 2005, Neij, 2008) and therefore the cost trends suggested by such curves vary considerably. Learning rates in the literature reviewed have ranged from less than zero (where costs are rising not falling) to more than 30%, depending on factors such as differing data sets used and the time-frame or geographical boundary applied.

(McDonald and Schrattenholzer, 2001), for example, shows a wide range of onshore wind power learning rates (see Table 3 below). A review of the offshore literature also reveals a wide range of assumed learning rates derived from onshore wind experience being used to formulate offshore wind scenarios or project costs across a range of time periods. Capital cost learning rates have tended to be lower than energy cost ratios and range from 2.5% to 10%. Learning rates for levelised costs of energy range from 9% to 30% with a mean range of approximately 15% to 20% (Greenacre et al., 2010).

Country/region	Time period	Est. learning rate
OECD	1981 – 1995	17
US	1985 – 1994	32
California	1980 – 1994	18
EU	1980 – 1995	18
Germany	1990 – 1998	8
Germany	1990 – 1998	8
Denmark	1982 – 1997	8 (all turbine sizes)
Denmark	1982 – 1997	4 (55kW or larger)

Table 3 Estimated wind power learning rates adapted from (McDonald and Schrattenholzer, 2001)

The borrowing of data from the onshore wind experience was an understandable response to the relative infancy of offshore development in the early 2000s. However, it is plausible to suggest that experience curves were therefore applied inappropriately which in turn had implications for government policy and the allocation of national resources. For example, the UK's Department for Trade and Industry (DTI) developed experience curves in 2002 for the levelised cost of energy from offshore wind postulating three different scenarios (Figure 4).

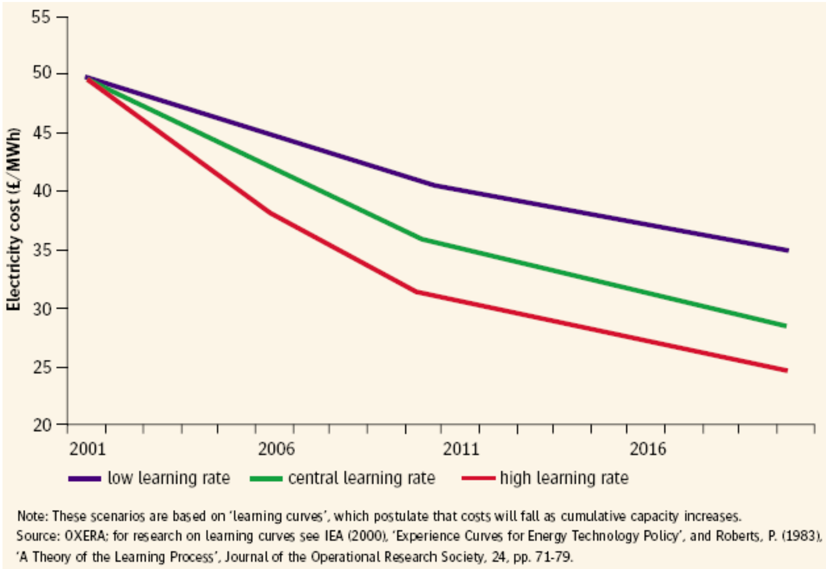

Figure 4 Scenarios for future offshore wind costs (DTI, 2002)

It is true that the above scenarios were not intended as actual predictions but use hypothetical experience curves to show the potential for cost reduction if a given learning rate were to be achieved. Nevertheless, (DTI, 2002) and other reports and journal papers such as (IEA, 2003, Dale et al., 2004, Junginger et al., 2005) were all representative of the view that investment and generating costs of offshore wind power would fall over the coming decade and beyond.

Some commentators did sound a warning note regarding the use of learning based assessments. (Chapman and Gross, 2001) for example, noted that then current offshore wind costs were based upon very limited experience, and were applied to an industry that was using turbines essentially developed for onshore generation. Nevertheless the downward trend in onshore costs appeared to offer most commentators reasonable grounds for optimism. However, if the converse had been true – with analysts in the early 2000s predicting serious escalations in future costs – it would be hard to imagine the same level of government enthusiasm for UK Rounds 2 and 3.

Engineering assessment optimism

The bulk of the early forecast data and predictive analysis regarding offshore wind costs would appear to have drawn upon experience curve methodology not engineering assessments (Greenacre et al., 2010). Indeed, the available literature reveals only very limited evidence of engineering assessment analysis. Here too, however, estimates of the future costs of offshore wind proved optimistic compared to the reality.

For example, in 2003 Garrad Hassan used a disaggregated component and engineering assessment-type approach to consider the potential for cost change. They concluded that capex for a nominal UK Round 2 project could be expected to reduce by around 15% over the following 5 years. In addition the report considered there to be more scope for higher than for lower reductions (Garrad Hassan, 2003). Other instances of future costs analysis from engineering assessment include (Milborrow, 2003) which also anticipated cost reductions from technological improvements and economies of scale; and also (Chapman and Gross, 2001) which used both engineering considerations and experience curve methodology to suggest a 2020 cost of energy range of between £20 and £30/MWh.

Comparing expectations with reality, average offshore wind capex in 2003 was around £1.7 million/MW and applying Garrad Hassan's 15% reduction by 2008 would result in capex of approximately £1.45 million/MW. In reality, average capex in 2008 had risen to around £2.5 million/MW and continued to increase thereafter. Confirmation of costs in 2020 is, of course, some years away. However, it is worth noting again that the (Mott MacDonald, 2011) estimate of the current levelised cost of offshore wind energy is close to £170/MWh and the (ARUP, 2011) figure is nearly £175/MWh (medium scenario).

Sub-sections 3.2 and 3.3 consider the main drivers for this significant escalation in costs and the resultant disparity between forecasts and out-turns.

3.2 Significant endogenous factors

Turbine prices and component supply squeeze

Several drivers contributed to an increase in turbine prices during the previous decade though evidence in the literature that disaggregates their individual effects is limited. Together with the increasing cost of commodities (see sub-section 3.3.1), the rise in turbine prices was due in part to the cost of engineering/marinisation improvements in the face of poor availability experience (Greenacre et al., 2010). In addition, (Gordon, 2006) notes that by the mid-2000s rapid growth in the US onshore wind industry caused by the US Production Tax Credit (PTC) scheme was resulting in a global shortage of turbine components, delaying European offshore projects and forcing up prices.

By 2007, turbine supply was the dominant bottleneck with the UK offshore sector squeezed by onshore turbine demand from China, India, and elsewhere in Europe as well as the US (BVG Associates, 2007). (Douglas-Westwood, 2008) reported that the combination of a strong market and constrained supply drove onshore turbine prices upwards by 30% between 2006 and 2008. Meanwhile, (Ernst & Young, 2009) studied the evolution of turbine costs over time for a range of UK Round 1 and Round 2 projects and reported that offshore wind turbine costs were likely to increase 67% from an average of

£0.9 million/MW to around £1.5 million/MW over the five year period to 2011 (see Figure 5 below).

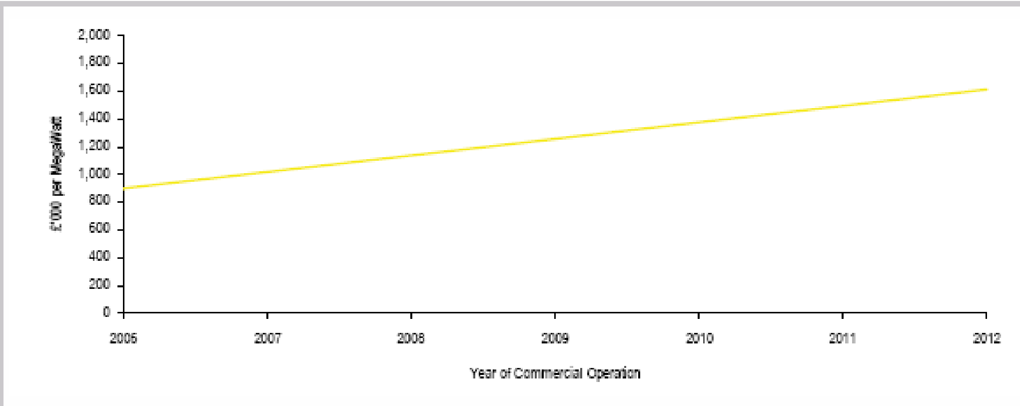

Figure 5 Wind turbine generator cost at COD – indicative trend line 2006–2012 (Ernst & Young, 2009)

Two others factors are significant. First, offshore turbines occupy a small niche relative to onshore turbine markets and it is understandable that a 'niche premium' would attach to the offshore market (Greenacre et al., 2010). Second, recent literature has noted the possible impact on competition given the limited number of companies engaged in turbine manufacturing for the UK offshore wind industry (BWEA, 2008, Carbon Trust, 2008, Ernst & Young, 2009, RAB, 2009). The market has been dominated by Siemens and Vestas who together accounted for 98% of offshore turbines installed in the UK up to 2009 (Ernst & Young, 2009) and have thus been in a position to pass on high commodity and component costs to developers with relative ease.

Depth and distance

It seems likely that early costs forecasts did not sufficiently allow for the effect of increasing depth and distance in offshore wind development. Collectively, UK Round 2 projects are more distant and in deeper waters than Round 1 projects. Table 4 shows the approximate average minima and maxima for depth and distance of Round 1 and 2 wind farms in operation, construction, or planning stage. At their maxima, Round 2 projects are on average nearly double the depth and more than double the distance of Round 1 projects.

	Average Depth (m)	Average Distance (km)
UK Round 1 wind farms	6 – 14	6.5 – 10
UK Round 2 wind farms	12 – 24	19 – 22

Table 4 Source: (4C Offshore Limited, 2010)

Unsurprisingly, an increase in depth and distance can have a significant impact on both capex and opex. Together they influence construction, installation, electrical infrastructure, and O&M costs. Depth is of course a primary factor in engineering design and foundation size during the construction and installation phase. For example, foundation costs can rise from approximately £400,000 – £500,000 per MW for 20m depth to £500,000 – £625,000 per MW for 35m depth (Ramboll Offshore Wind, 2010) – see Figure 6 below. Of particular relevance to UK Rounds 2.5 and 3, The Carbon Trust found that foundation costs for sites in 40 to 60m of water were 160% greater than for sites in 0 to 20m of water (Carbon Trust, 2008).

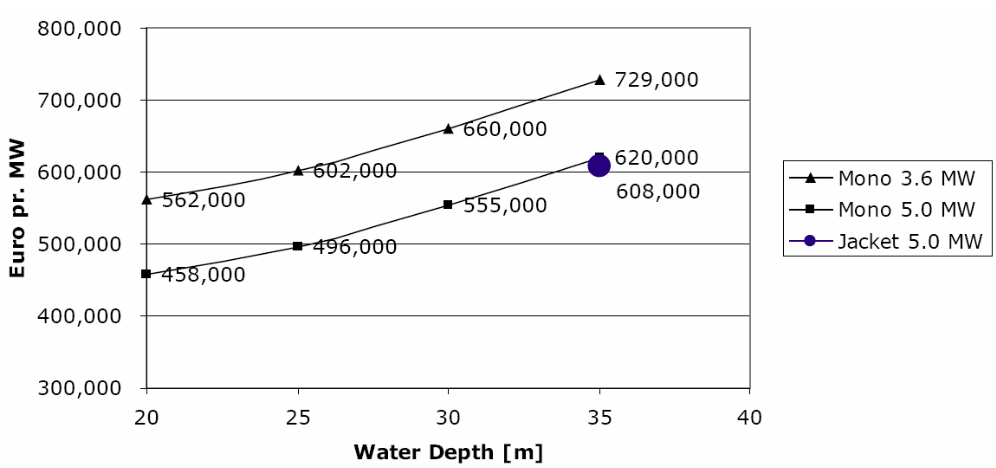

Figure 6 Foundation costs as a function of depth (Ramboll Offshore Wind, 2010)

Distance is a factor both at the installation stage and also during operation because of maintenance and repair requirements (see below). It also impacts on electrical infrastructure costs, in particular the amount of transmission cabling required. (Ernst & Young, 2009) analysed the evolution of electrical infrastructure costs versus distance from shore for a range of Round 1 and Round 2 projects and found a close correlation. Figure 7 shows how infrastructure costs doubled from around £300,000 – £400,000 per MW for projects less than 5km from shore to £800,000 per MW for projects 20km out.

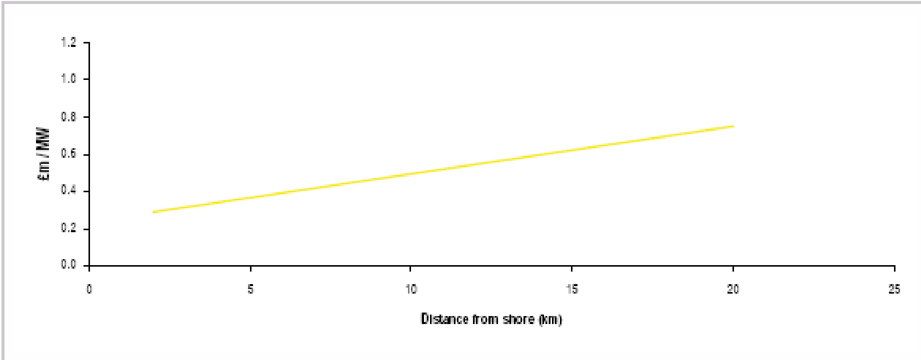

Figure 7 Electrical infrastructure cost vs. distance from shore (Ernst & Young, 2009)

Operation and maintenance costs

O&M costs increases since the mid-2000s have largely been a function of two drivers. First, costs in UK Round 1 were greater than expected, in part due to the inadequate marinisation of onshore machines (ODE Limited, 2007) leading to higher than anticipated levels of breakdown and repair, and consequently of non-availability (which affects load factor – see below). In addition, O&M costs have been increasing, at least since the mid-2000s, as projects have been built further from shore. Additional factors, according to (Ernst & Young, 2009), include more preventative but costlier strategies, higher labour and logistics costs, a stronger Euro, and some re-estimation of previously under-estimated O&M budgets in the light of experience gained from earlier projects.

Availability/reliability and load factor

The load factor of a wind farm is strongly influenced by two variables: wind conditions and availability of turbines and related equipment. In theory, a major advantage offered by offshore wind is that wind speeds are generally higher and more stable than onshore sites. Indeed, (Snyder and Kaiser, 2009) suggest that moving onshore to offshore should lead to an increase in the load factor from roughly 25% to 40%. However, UK offshore farms have experienced higher than expected loss of generation – in particular from gearbox failure (especially bearings); generator failures; subsea cable damage; and operator access limitations (BVG Associates, 2007).

As noted earlier, UK Round 1 projects experienced only 80.3% average availability. As a result, the annual average capacity factor for reporting UK Round 1 wind farms has been 29.5% (Feng et al., 2010) – higher than the average value of 27.3% reported in 2007 for UK *onshore* wind farms but lower than the expected 35.0% for UK offshore and the reported capacity factors of at least 40% for some Danish offshore wind farms (Wind Stats, 2009a, Wind Stats, 2009b). Again, actual out-turns have disappointed compared to prior forecasts – in this case the poor availability record was perhaps not anticipated in the UK because early European offshore farms proved to be relatively reliable. For example, the average annual availability of Denmark's well-established near-shore installation at Middelgrunden has been over 93% (Larsen et al., 2005).

3.3 Significant exogenous drivers

Commodity prices

Commodity prices rose significantly from the early 2000s until 2008 when the effects of the global credit crisis began to be felt. In the offshore wind sector, the most significant commodity is steel which has typically accounted for around 12% of total project cost (BWEA and Garrad Hassan, 2009). From 2002 to 2007 the steel index experienced growth of 47% CAGR (compound annual growth rate) although in 2008 it fell by 58% returning to the long-term historic trend (Ernst & Young, 2009).The increase in steel prices from the early 2000s was thus a likely contributing factor to turbine costs rising from £0.9 million to £1.5 million/MW (67%) in five years (RAB, 2009). Steel price rises played an even greater role in the escalating costs of foundations. Foundation structures are heavily reliant on steel and costs increased from around £250,000 to £700,000/MW (a 180% increase) over the five years to 2009 (Ernst & Young, 2009).

The cost of other relevant commodities, such as copper, also increased. Between 2002 and 2006 commodity prices grew at 19% (CAGR). However, between 2007 and 2009 with the onset of the global credit crisis, the commodity prices index fell by 5% CAGR although it remained substantially above the historical trend line. Analysis by The Carbon Trust in 2008 suggested that if commodity and materials prices were to return to 2003 levels, overall offshore wind power costs would fall by 11% (Carbon Trust, 2008).

Euro/Sterling exchange rate

The Euro/Sterling exchange rate also contributed significantly to the rise in costs borne by UK offshore wind developers. Around 80% of the value of a typical UK offshore wind farm is imported and has either been priced in Euros or priced in a currency tied to the Euro (Greenacre et al., 2010). Since 2000 when the exchange rate was approximately €1 = £0.60, the Euro gradually increased in value against the pound, reaching almost one-for-one parity in December 2008. Consequently, until 2009 UK developers experienced continued increases in component costs because of the Euro's gradual appreciation against Sterling.

As noted in sub-section 3.2.3, O&M costs were also affected by the strength of the Euro. In addition, vessels and support services have been largely sourced from continental Europe, hence installation costs also rose (Ernst & Young, 2009). Thus, whilst prices for commodities have fallen since 2008 as a result of the global downturn any positive effect on turbine prices had until recently been more than offset by the appreciation of the Euro against Sterling (Ernst & Young, 2009).

Cost of finance

A third exogenous driver has been the increased cost of financial capital. In theory, if an offshore wind developer were to use project finance, then the increasing experience in construction and operation should gradually reduce the risk premium for offshore installations resulting in a decreasing cost of capital (Greenacre et al., 2010).

However, utility developers, who have been responsible for the majority of capacity installed to date, have instead typically used balance sheet financing (Ernst & Young, 2009). The consequence of this was an increase in funding costs because of the 2007/2008 crisis in the global credit markets. Figure 8 below charts utility bond prices from January 2006 to January 2009 and shows the marked rise in spreads for utility bonds from mid-2007 onwards resulting in a higher cost of corporate debt (Ernst & Young, 2009).

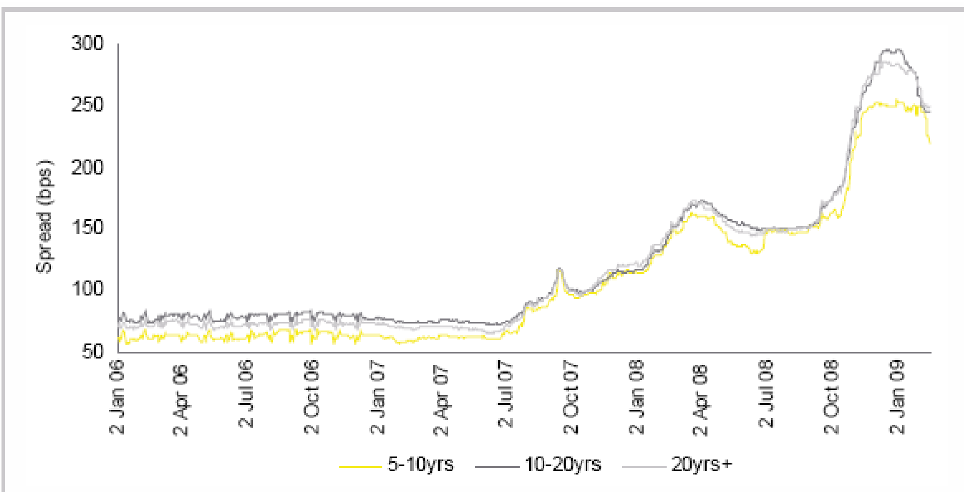

Figure 8 Sterling utilities bond indices (Ernst & Young, 2009). Source: Merrill Lynch indices, Bloomberg

4. Summary and conclusions

Estimates in the 1990s and early 2000s of future offshore wind costs have so far proved to be considerably over-optimistic in the light of actual out-turns from 2005 onwards. Whilst some commentators sounded a cautionary note, most appeared confident that innovation, learning effects and economies of scale expected from increasing deployment over time would indeed produce significant reductions in capital and levelised costs.

As we have seen, this has not been the case. On the contrary, the past experience of offshore wind in the UK demonstrates how the cost reductions anticipated by both experience curves and engineering assessment were overwhelmed by a variety of relatively high impact drivers. In terms of experience curve theory, it is therefore clear that cost reductions may be influenced by other variables than simply cumulative capacity, and that as noted by (Kahouli-Brahmi, 2009), the non-incorporation of such variables can leave forecasts prone to the overestimation of technological learning-by-doing effects and thus to a positive bias of estimated learning rates.

In the case of UK offshore wind, the sources of forecasting error may be broadly grouped into three categories – methodological issues, endogenous factors and exogenous drivers – summarised as follows:

Methodological issues

- Use of onshore wind data
- Premature application of experience curves
- Engineering assessment optimism

Endogenous factors

- Turbine prices and component supply squeeze
- Depth and distance
- Operation and maintenance costs
- Availability/reliability and load factors

Exogenous drivers

- Commodity prices

- Euro/Sterling exchange rate
- Costs of finance

Some of the above could not have been easily anticipated, if at all. Commodity price rises and the Euro/Sterling exchange rate are prime examples, as perhaps was the state of the turbine market from which offshore wind developers suffered both too much competition (for example, from competing onshore turbine demand in the US) and too little (only two offshore wind turbine manufacturers).

Nevertheless, whilst hindsight is a privileged point of view, it is reasonable to suggest that at least some of the sources of error should have been better anticipated, more rigorously scrutinised or more clearly factored into the forecasting analysis. The effect of harsh marine conditions and of increasing depth and distance might have been more thoroughly considered – on installation costs, O&M, electrical infrastructure, and load factors. In addition, the early application of experience curves using learning rates 'borrowed' from a related sector was arguably not questioned enough. This has important implications for other 'infant' technologies in the early stages of deployment such as novel PV technologies and, in particular, CCS where there is effectively no costs track record as yet and so learning rates are sometimes being borrowed from associated technologies such as flue gas desulphurisation (see section 3 of the report's allied case study on CCS).

It is likely that the over-optimistic cost forecasts seen in the offshore wind sector had important UK policy implications and that if analysts in the early 2000s had been predicting serious escalations in future costs it would be hard to imagine the same level of government enthusiasm for UK Rounds 2 and 3. However, this case study also demonstrates that there may be no easy solution to this given that several of the most important sources of error were all but impossible to anticipate.

Finally, this case study also reveals a potential irony concerning the timing of experience curve application. For analysts of a technology or sector which has moved beyond the nascent phase – and therefore has reasonably robust cost and capacity growth data – experience curves may be employed for corporate and policy strategising with relative confidence (recognising always that some uncontrollable events may overwhelm the forecasts). However, the corporate and governmental imperative to 'peer into the future' is likely to be greatest at the nascent stage – precisely the stage when there is not enough data to adequately support an experience curve. It is therefore worth considering whether analysts and policy makers can only become relatively confident about the application of experience curves at a point when there may be a less critical need for them.

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