UKERC Technology and Policy Assessment

Cost Methodologies Project: Onshore 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

By 2020, it is projected that there will be 170GW of onshore wind capacity in the European Union, and 120GW in China (IEA, 2011), whilst America is expected to deliver 12GW of wind per year on average within this decade (Emerging Energy Research, 2009). Meanwhile within the UK, the Department of Energy and Climate Change (DECC) envisages a total of 13GW of onshore wind capacity over the same timeframe (DECC, 2011) However, although not as expensive as its offshore counterpart, the cost-effectiveness of onshore wind has been challenged within the UK. In February 2012 over one hundred MPs wrote to the Prime Minister expressing their concern about the subsidies required to support the technology (Middleton, 2012).

This case study contributes to a UK Energy Research Centre (UKERC, 2011) project on electricity generation cost estimation methodologies by:

- Examining forecasts for onshore wind costs made in the past;
- Comparing these forecasts with how costs actually evolved;
- Understanding the key historical drivers of onshore wind costs; and
- Identifying implications for onshore wind cost estimation methodologies.

The analysis focuses on the capex costs and levelised cost of energy (LCOE) of onshore wind. The cost data was collected from over 40 sources from a range of countries, with full details found in the Appendix.

Consistent with the terminology of the main UKERC report and the report's other case studies, this study distinguishes between *exogenous, endogenous,* and *methodological* drivers of cost.

- <u>Exogenous drivers</u>: broad, macroeconomic drivers that are *external* to the power sector – which policymakers and industry have limited scope to mitigate.
- <u>Endogenous drivers</u>: drivers emerging from *within* the power sector – which policymakers and industry can potentially mitigate.
- <u>Methodological drivers</u>: drivers arising from the *way* in which costs are estimated – rather than reflecting 'real-life' phenomena.

The study begins by considering cost trajectory expectations from the past (Section 2), and then explores how costs actually evolved (Section 3). Following this, the drivers of changing costs are discussed (Section 4) and implications for onshore wind cost estimation methodologies identified (Section 5).

2. Cost trajectory expectations

This Section considers forecasts of the costs of onshore wind. Obtaining data for the 1980s and early 1990s proved difficult within the resources available, so the graphs focus on the mid-1990s onwards.

Levelised cost forecasts for onshore wind are presented in Figure 1 below.

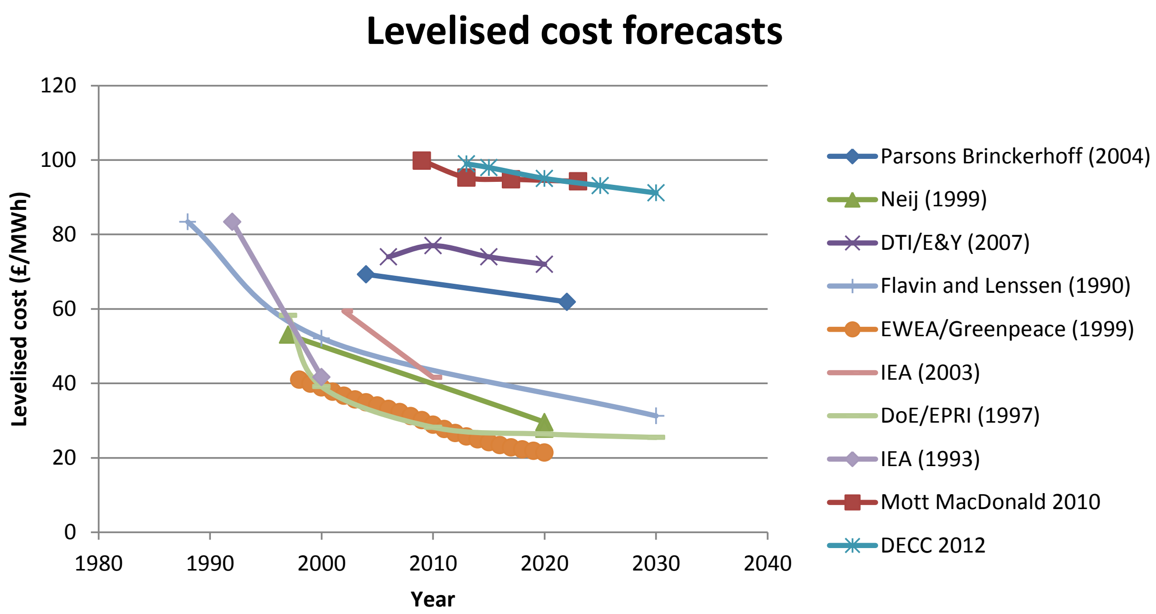

Figure 1: Levelised cost expectations for onshore wind.

The graph indicates the expectation during the early years of the wind industry of substantial cost reductions being achieved. The methodology underpinning cost forecasts varied. The U.S. Department of Energy based its cost forecasts on technical and engineering assessment i.e. detailed projections of how wind turbine technology was expected to evolve (DoE & EPRI, 1997). For instance, it described its expectations that wind turbines would evolve from the fixed speed generators in 1996 to variable speed generators in 2000, with larger, lighter rotors and towers. It then mapped out its expectations in 2005 that the technology would be further improved, to eliminate hydraulic systems, with smarter rotors and flexible turbine systems driven with interactive controls.

However, a more common forecasting approach was to form future projections based on past learning rates (or their converse, progress ratios). For instance, the UK Government projected that the LCOE of onshore wind would fall to 75% of its 1996 value by 2010 based on historical trends (DTI, 2002). There are numerous examples of studies devising variants of experience curves for onshore wind, applied to wind turbines, wind farms and wind-generated electricity. Based on experience curve analysis, Neij (1999) suggested progress ratios of 93-97%, and EWEA and Greenpeace proposed a progress ratio of 85% until 2010, with the rate of cost reduction slowing after this period. Junginger et al. (2005) were more optimistic in suggesting a global progress ratio for wind farms of 77-85%, emphasising the potential for cost reduction via mass production.

However, in response to the cost escalations experienced in the mid-2000s, projections for aggressive cost reductions were revised. Analysts were suggesting in 2007 that in the short-term, costs would rise during the period to 2010 to reflect current turbine supply constraints and steel prices (DTI/Ernst&Young, 2007). GL Garrad Hassan (2010)'s scenario analysis for UK onshore wind projects for 2010-2015 suggested that prices could move either upwards or downwards, though they reported that 'the potential cost increase is higher than the potential cost decrease'. Their methodology was based on identifying nine drivers of onshore wind costs, based on industry evidence and consultation, assigning a weighting to each driver, and then conducting scenario analysis. They argued that macro-economic and global industry drivers would continue to have a strong impact on project costs in the UK in the following five years. This emphasis on exogenous drivers is striking. Indeed, a fundamental difference between forecasts made pre-mid-2000s and those made post-mid-2000s is that the latter tend to explicitly address exogenous factors, whereas the former often solely focus on endogenous technological development. In addition, later forecasts tend to more explicitly address the uncertainty surrounding cost projections.

Recent cost projections suggest that longer-term, modest cost reductions are expected; for instance, Milborrow (2011a) suggests a 5-10% decrease by 2020, and possibly a further, similar decrease by 2030. However, the potential for further endogenous learning is recognised as being limited since onshore wind is now perceived to be a relatively mature technology (Mott MacDonald, 2010). Indeed, of the nine drivers of cost considered by Garrad Hassan (2010) 'scale, learning and innovation' is assigned the lowest magnitude.

3. Actual cost trajectory experience

This Section presents capex and levelised costs of onshore wind as they occurred in time, comparing these outcomes with the forecasts discussed in the previous section.

Figure 2 below presents capex costs of onshore wind from 1994 to 2011. Note that GL Garrad Hassan (2010) suggests that in general, UK project costs are comparable with project costs elsewhere in Europe.

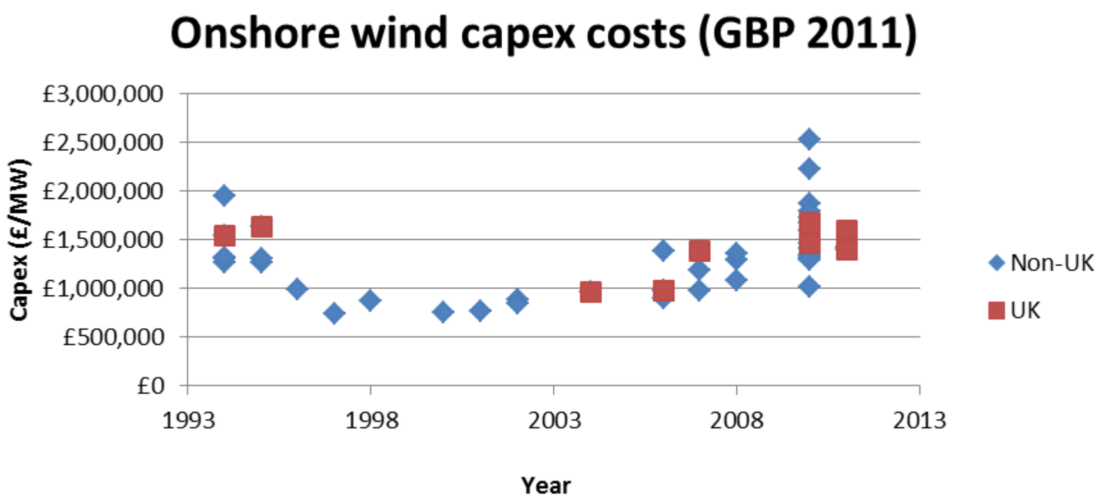

Figure 2: Capex costs of onshore wind 1994 – 2011 (details of data analysis are found in the Appendix).

Figure 3 below presents the levelised costs of onshore wind. The trend here is somewhat unclear, in part because levelised costs vary significantly depending on the wind resource available (María Isabel, 2009). Nevertheless, from the 1980s to the early 2000s, substantial capital and levelised cost reductions did occur. Wind turbine prices fell by a factor of at least three from 1981 to 1991, whilst the levelised cost of energy halved during the 1990s (EC, 1999). Overall, actual outcomes broadly conformed to expectations of cost reduction.

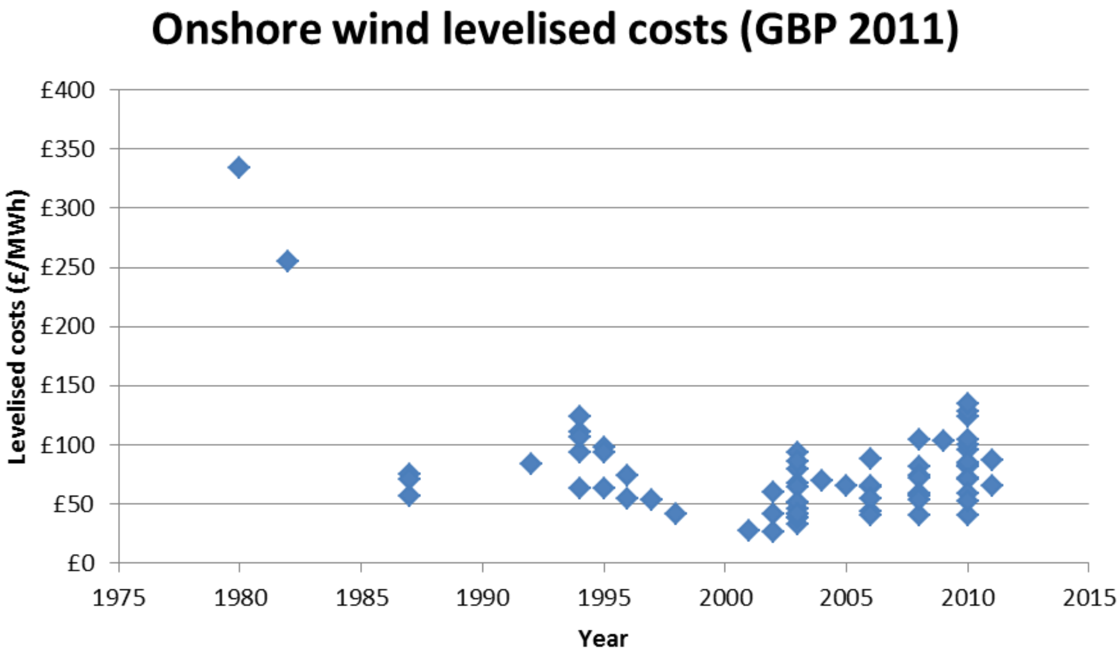

Figure 3: Levelised costs of onshore wind since 1980.

However, from the early 2000s onwards, installed costs began to diverge upwards from past cost trajectory expectations. Junginger et al. (2005), for example, had suggested a possible capex target of €463,000/MW by 2010 (though acknowledging that this was calculated on a very optimistic basis). In fact, actual capex outcomes in 2010 increased to a wide range between approx. £1,000,000/MW and £2,500,000/MW.

Nevertheless, projections made in 2007 (DTI/Ernst&Young, 2007) that costs would continue to increase were proved wrong. Average prices of wind turbine declined by around 20% from late 2008 to 2010 (Bolinger and Wiser, 2011) (see Figure 4), and fell further in 2011 (Milborrow, 2012).

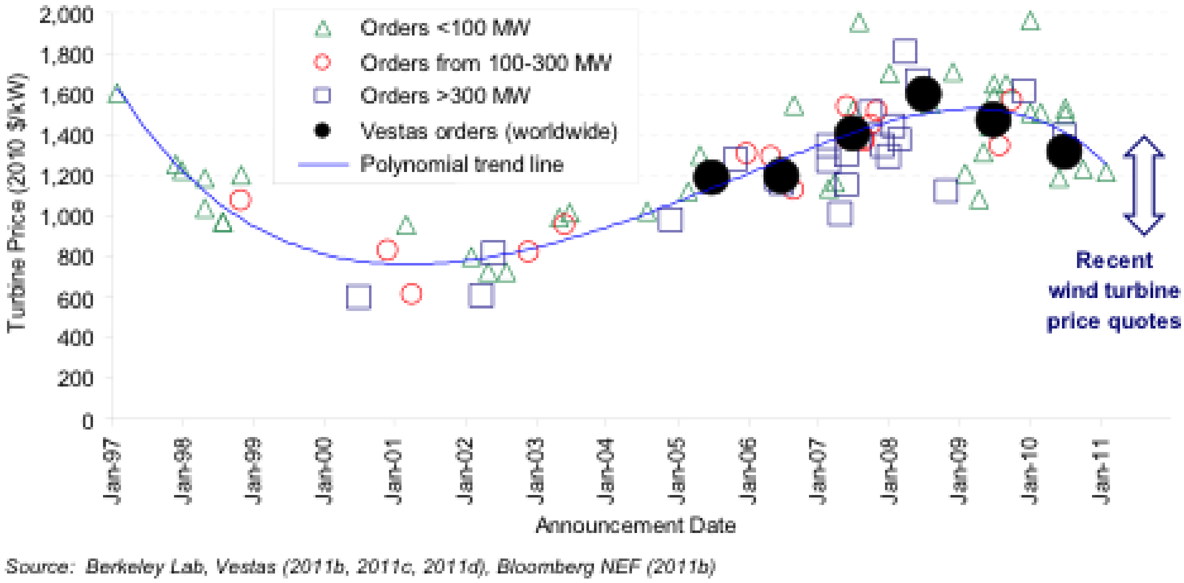

Figure 4: Wind Turbine Prices in the United States, taken from Bollinger and Wiser (2011: p. 5).

4. Discussion: 1980–mid-2000s

This section analyses the key drivers underlying changing onshore wind costs over time. Specifically, it focuses on understanding the drivers of cost reduction from the 1980s to the mid-2000s. Other than brief references to possible falling costs of raw materials, exogenous factors are rarely cited in discussions of cost reductions during this period (EC, 1999). Instead, the focus is centred on various endogenous factors. Firstly, turbine upscaling delivered substantial cost reductions throughout the 1980s to mid-1990s. The average size of wind turbines installed in Denmark increased from 71 kW in 1985 to 523 kW in 1996 (EC, 1999). The larger the machines the fewer are required for a given capacity. This brings savings in site costs (thus driving down capex) and in operation and maintenance costs (thus driving down levelised costs) (EC, 1999). The turbines are larger, with taller towers so they tend to capture more wind at higher altitudes. This results in increased generation, and thus lower LCOE (Lako, 2002).

Secondly, the development of the European Wind Atlas Methodology, which mapped wind resources in the 1970s and 1980s has been cited as crucial to delivering productivity gains thus reducing levelised costs. This is because the correct micro location of each wind turbine is crucial for the economics of a wind energy project and turbines are sited following computer modeling, based on local topography and meteorology measurements (María Isabel, 2009). Thirdly, the wind industry continued to make ongoing technical improvements. For instance, on average the rotor efficiency of turbines increased from 35-40% in the early 1980s to 48% in the mid-1990s (Neij, 1999). Drive-trains were optimised, and improved understanding of how loads affect turbines led to more accurate calculations of the physical limits of materials resulting in a lower weight (BTM Consult, 2001). Finally, from the 1980s, operations and maintenance costs fell (EC, 1999), and manufacturing processes benefited from economies of scale (Bellarmine and Urquhart, 1996).

It is perhaps due to the central role during this period of endogenous factors in determining wind turbine costs that projections based on experience curves (and indeed techno-engineering assessment) led to relatively accurate results. As we explore in greater depth in the main report, historical experience curves by definition reflect in the aggregate the variables that result in a cost curve (indeed the terms 'experience' and 'learning' in the context of experience or learning curves is quite misleading since historical cost trends reflect not only human learning (or lack thereof) but also all other variables). If exogenous factors have played a relatively minor role in cost reductions (i.e. past cost reductions are mostly attributable to technical, engineering and process learning) then experience curve extrapolations into the future may well prove reasonably accurate *provided that exogenous factors continue not to play a significant part in that future.* However, as we shall see in the next section, experience curves – and engineering assessment – are ill-suited to predicting significant exogenous changes should they occur (as indeed they can also be with some endogenous factors such as policy effects and supply chain constraints).

5. Discussion: Mid-2000s onwards

This section examines the drivers of cost escalation in the late 2000s, exploring why this escalation was not anticipated in cost forecasts.

Figure 5 below presents drivers of US wind turbine prices in the mid-2000s. This is useful in understanding the drivers of capex since wind turbine generators account for approximately 65% of total capex costs (Mott MacDonald, 2011). A key message is that cost escalation was driven by a range of factors, both exogenous and endogenous, of which currency movements and turbine upscaling were particularly important. The range of drivers is discussed below.

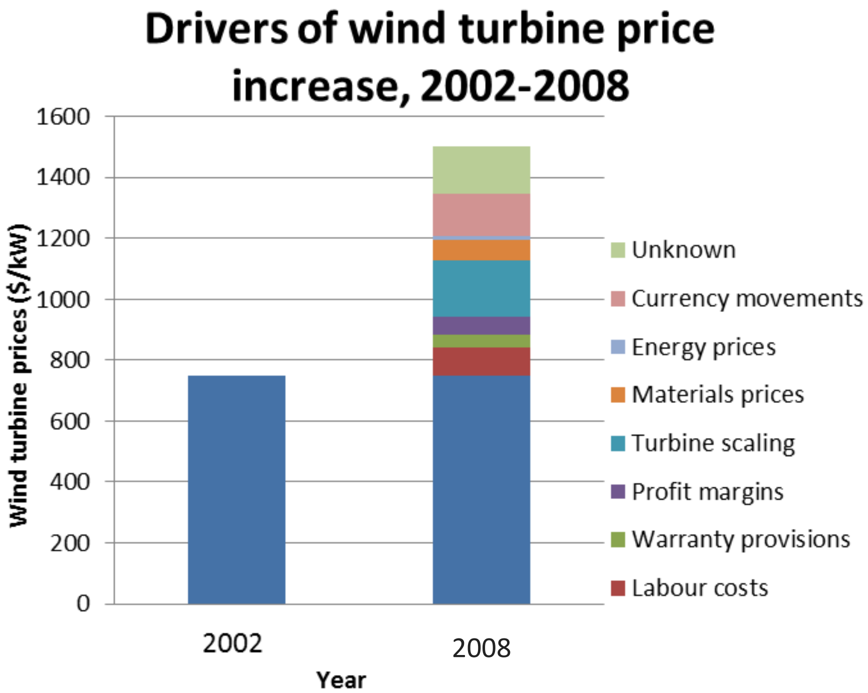

Figure 5: Drivers of wind turbine prices from 2002 to 2008, based on data from Bolinger and Wiser (2011).

Exogenous drivers

As Bollinger and Wiser (2011) highlight, one of the most significant exogenous drivers of increasing onshore wind costs in the late 2000s has been currency movements (ARUP, 2011). From a UK perspective, the weakening of the pound against the Euro since mid-2008 has significantly elevated prices for UK projects, which are typically dominated by European imports (GL Garrad Hassan, 2010).

Rising commodity prices have been a medium driver of onshore wind capex costs during this period, since wind turbines are material-intensive (EWEA, 2009). In particular, steel is used in towers, gearboxes and rotors, constituting around c.65-80% of total turbine mass, depending on the turbine model and manufacturer (Bolinger and Wiser, 2011, María Isabel, 2009). Other key materials which increased in price included copper, which is used in generators and cables, and cement, which is used in foundations (María Isabel, 2009). Although these commodity prices dropped back towards the end of 2008, there is a time lag before this feeds through to capex costs (Wiser and Bolinger, 2009). A smaller driver of onshore wind cost escalation has been energy prices, due to the effect on the costs of manufacturing and transporting turbines (Bolinger and Wiser, 2011).

These exogenous factors, being – by definition – beyond the immediate domain of the wind industry, were difficult to predict. This is why they were not factored into cost forecasts in the early 2000s.

Endogenous drivers

Firstly, turbines have continued to increase in scale, with average installed turbine capacity in the US rising from 0.9MW in 2001 to nearly 1.7MW in 2008 (EWEA, 2009, Bolinger and Wiser, 2011). This increased size has led to increased wind turbine prices on a £/MW basis, since mass scales more rapidly than height, with towers needing to be wider to support the extra height (Bolinger and Wiser, 2011). However, it is important to note the impact of increasing wind turbine costs on capex costs is mitigated to a certain extent by decrease balance of plant costs. The effect on LCOE is further mitigated by the higher capacity factors of larger and taller turbines (Bolinger and Wiser, 2011).

Secondly, supply chain constraints have played an important role in elevating capex prices, particularly during 2007 and 2008, although the congestion premium has since reduced (Mott MacDonald, 2010, Mott MacDonald, 2011). Shortages have been experienced for a range of components such as bearings, generators, hubs and main shafts (de Vries, 2008); the problem has been particularly pronounced for gearboxes (María Isabel, 2009). Bottlenecks were experienced by both turbine manufacturers and sub-contractors, and were compounded by difficulties in obtaining construction equipment such as cranes and vessels (de Vries, 2008, EWEA, 2009). A key cause of such bottlenecks has been the boom in demand for wind turbines, particularly in North America due to the US Production Tax Credit, and also in Europe and Asia (EWEA, 2009, GL Garrad Hassan, 2010, María Isabel, 2009). As such, there was insufficient turbine production to meet this strong demand (IEA, 2006). In addition, increasing turbine sizes added to supply chain challenges, since each new power rating typically requires a dedicated supply chain (de Vries, 2008). Bolinger and Wiser (2011) suggest that this tight supply and rapid pace of deployment also had the effect of causing short-term increases in labour costs as the supply of available labour struggled to keep up with demand.

Thus, along with certain unexpected exogenous drivers, there were also endogenous drivers – in particular policy effects – that cost forecasters did not anticipate. As one commentator noted, the shifting patterns of national incentive programmes are not always easy to predict (Aubrey, 2007).

Methodological drivers

Estimating costs based on experience curve analysis in particular led to over-optimistic cost forecasts. Experience curves are better suited to extrapolating endogenous change such as technical improvements and process learning and are less able to factor in exogenous risks which by their nature tend to be highly uncertain. In addition, there was also a tendency for cost forecasts to focus on *cost potential*, rather than on the *pragmatic challenges* of scaling up a supply chain, and avoiding bottlenecks.

6. Conclusion

From the 1980s to the mid-2000s, onshore wind broadly demonstrated the cost reduction predicted by experience curve analyses. Arguably a key explanation for why forecasts were realised during this period was that the key cost drivers were endogenous, and both technical/engineering assessment and experience curves are better suited to predicting (at least some aspects of) endogenous change as opposed to exogenous change.

However, from the mid-2000s onwards, the costs of onshore wind began to diverge from the cost forecasts. One explanation for why forecasts did not anticipate the experienced cost escalation is that their projections were focused on endogenous drivers of cost, rather than explicitly considering the exogenous risks – such as currency movements and commodity prices – which ended up exerting significant upward pressure on onshore wind costs. In addition, cost forecasts tended not to consider more 'pragmatic' endogenous drivers such as supply chain bottlenecks and the price escalation associated with meeting a boom in demand.

A further endogenous consideration is the increase in turbine prices experienced since the mid-2000s due to up-sizing of the turbines. However, this led to lower balance of system costs and increased capacity factors. A conclusion therefore is that it is perhaps best to assess the cost-effectiveness of onshore wind through LCOE not turbine prices (Bolinger and Wiser, 2011). That said, LCOE are also dependent on wind speeds, and the wind resource can vary significantly.

Due to the failure of experience curves to adequately anticipate the cost challenges faced in the second half of the last decade, revised approaches to estimating onshore wind costs are now evident in the literature. There appears to be a greater recognition of the uncertainties and contingencies of cost forecasts, and scenario analysis is being used to help anticipate the impacts of differing macroeconomic, exogenous possibilities. In other words, there is greater appreciation that wind costs are not just driven by technical improvements (such as better wind mapping, improved rotor efficiency etc), but also buffeted by global forces such as currency and commodity prices.

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Appendix

Data characterisation

Numerical data was drawn from over 40 studies, which was not limited geographically: (ARUP, 2011, PB Power, 2006, Mott MacDonald, 2010, Mott MacDonald, 2011, PB Power, 2004, María Isabel, 2009, Milborrow, 1994, Marafia and Ashour, 2003, Lazard, 2008, NREL, 2011, Neij, 1999, DTI/Ernst&Young, 2007, Noord et al., 2004, Lako, 2002, GL Garrad Hassan, 2010, Milborrow, 2011b, EC, 1999, Milborrow, 1995, Milborrow, 2012, DTI, 2006, Flavin and Lenssen, 1990, EWEA et al., 1999, DoE & EPRI, 1997, Enviros, 2005, DoE, 2008, NREL, 2008, Allen and Bird, 1977, Department of Energy, 1979, Kammen, 2004, IEA, 1998, IEA, 2003, Awerbuch and Berger, 2003, DoE, 2006, NGC, 2004, Delene et al., 1999, HoC, 2006, IEA, 2005, White, 2006, IEA, 2010, EERE/DoE, 2004, Dale et al., 2004, Wiser and Hand, 2009, IEA, 1992). These sources are diverse, ranging from grey literature reports which report the costs of multiple technologies, to narrowly focused academic studies. Readers should be aware that a minority of sources are from the wind industry (e.g. WindPower Monthly) or commissioned for wind trade associations (RenewableUK). They assume a range of deployment scenarios. Most of the cost data takes the form of current cost estimates, though are averages of actual reported figures. Costs data did not typically factor in the system costs associated with the intermittent electricity generation of wind turbines.

Treatment of data

<u>Normalisation:</u> All cost estimates were converted into 2011 GBP (an average of Jan–Nov 2011 since December figures were not available at the time of calculation). The data was *not* normalised to account for differences in discount rate, load factors, carbon price etc.

<u>Selection of representative cost estimates:</u> Some data sources provided multiple data estimates. In order to prevent any particular source (i.e. a source with extensive sensitivity/scenario analysis) from dominating the data and thus skewing the results, efforts were made to select key ‘representative’ cost estimates from each source. Where the same source provided multiple cost estimates resulting from sensitivity or scenario analysis, the ‘medium’ or ‘baseline/reference’ figure was selected, or – where this did not exist – an average was calculated. However, where the source provided estimates for multiple countries, a representative figure for each country was plotted.

Estimate year: For current cost estimates, often the year to which the estimate applied differed from the year of publication. This typically occurred with academic papers, due to the time lags entailed by the peer review process. Where this difference occurred, the data analysis was based on the year to which the cost estimate applied, rather than the publication year.