Great Expectations:

The cost of offshore wind in UK waters – understanding the past and projecting the future

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The cost of offshore wind in UK waters – understanding the past and projecting the future

A report produced by the Technology and Policy Assessment Function of the UK Energy Research Centre

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Preface

This report was produced by the UK Energy Research Centre's (UKERC) Technology and Policy Assessment (TPA) function.

The TPA was set up to inform decision-making processes and address key controversies in the energy field. It aims to provide authoritative and accessible reports that set very high standards for rigour and transparency. The subject of this report was chosen after extensive consultation with energy sector stakeholders and upon the recommendation of the TPA Advisory Group, which is comprised of independent experts from government, academia and the private sector.

The primary objective of the TPA, reflected in this report, is to provide a thorough review of the current state of knowledge. New research, such as modelling or primary data gathering may be carried out when essential. It also aims to explain its findings in a way that is accessible to non-technical readers and is useful to policymakers.

The TPA uses protocols based upon best practice in evidence-based policy, and UKERC undertook a systematic search for reports and papers related to this report's key question. Experts and stakeholders were invited to comment and contribute through an expert group. For this review, additional experts were also consulted directly. The project scoping note and related materials are available from the UKERC website, together with more details about the TPA and UKERC.

About UKERC

The UK Energy Research Centre carries out world-class research into sustainable future energy systems.

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Overview

This report by the UKERC Technology and Policy Assessment function is concerned with recent cost escalations in offshore wind. It documents early expectations and policy goals, explains recent cost escalations and assesses future prospects.

The reasons for cost escalation are well documented. In common with other energy technologies, UK offshore wind has been affected by commodity and currency movements. In addition, offshore wind has been subject to particular supply chain bottlenecks and cost escalations associated with making offshore turbines reliable and installing them in deeper more distant sites. As a result, cost reductions anticipated in the late 1990s and early 2000s gave way to dramatic increases in the period from 2005 – 2009.

This report finds evidence that cost increases may have peaked, but does not foresee any meaningful reductions in the period to 2015. It disaggregates the cost of offshore wind into key components and tests sensitivity to feasible ranges in the cost of key factors. In the period to around 2025 the report finds grounds for cautions optimism. There is potential for innovation to reduce costs, for supply chain pressures to ease and for new market entrants to provide competitive pressure on costs. However, there are still a number of factors placing upward pressure on costs, not least the implications of moving to even more challenging locations.

The UK is currently leading the world in offshore wind installation, with aspirations to become a world leading centre for the technology. Yet as much as 80% of a typical offshore wind farm built in the UK in the last five years will have been imported from elsewhere in Europe. Bringing more of the supply chain into the UK offers benefits in terms of reduced exposure to currency movements as well as helping build a 'green' manufacturing economy. The UK currently lacks capacity in key parts of the supply chain. This requires investment and the development of UK offshore wind is likely to require policy to continue to engage actively in supporting the development of docks and other facilities.

Offshore wind is still in its infancy, the UK is still building the equivalent of the first conventional power station. Cost escalations stand in some contrast to the optimism of early analysts. However it is not particularly surprising that we have arrived at a point in the history of a particular emerging technology when costs have increased. Many technologies go through such a period, and still go on to offer cost effective performance in the long run. The particular challenge faced by offshore wind is that its role in meeting UK and EU targets gives rise to a widespread expectation of rapid deployment.

Overall, there are grounds to be optimistic about offshore wind, tempered with *realism* about the challenges associated with its development and the need for policy to engage effectively with *all* the factors that will affect its success. Policy will need to create clear, long term signals that costs must decrease over time. It is also important for policy to continue to support innovation, reduce problems with planning and grid connection and support the development of the UK supply chain.

Executive Summary

Introduction

In December 2008, the EU Renewables Directive committed the European Union to satisfying 20% of its energy consumption via renewable sources by 2020. The UK's national target is 15%. This may mean that the UK will have to find 40% of its electricity generation from renewable sources by the end of this decade. Offshore wind is widely expected to play a major role in contributing to this target. The government has not set a specific target for offshore wind, but projections from a range of analysts suggest the UK will need 15 to 20 GW of offshore wind by 2020, with aspirations to go well beyond that in the decades that follow[1].

The UK's ambitions for offshore wind reflect the size of the potential resource and difficulties associated with public opposition to onshore wind. They also reflect a widespread expectation in the late 1990s and early 2000s that costs would fall as deployment expands. However, in the last five years costs have escalated dramatically, with capital costs doubling from approximately £1.5m/MW to over £3.0m/MW in 2009.

All the main electricity generation technologies have been subject to cost increases in the last five to eight years. Exogenous factors such as commodity prices that affect offshore wind also affect the construction other generation options. Moreover, fossil fuel price increases have led to additional increases in the levelised costs of conventional power stations. For example, the cost of electricity from gas turbine (CCGT) plant has almost doubled; it now stands at approximately £80/MWh compared to approximately £42/MWh (inflation adjusted) in 2006. Coal, nuclear and onshore wind all experienced large cost increases over the same period.

However offshore wind has been subject to particular difficulties and the cost escalations in offshore wind have been considerably larger than those for onshore wind. Onshore wind has recently been estimated to be the *lowest* cost large scale, commercially available low carbon generator applicable in the UK. In contrast, offshore wind is the most expensive (though costs for CCS and new nuclear in the UK remain hypothetical at the time of writing). Whilst some commentators remain optimistic and see the potential for creating significant economic benefit from offshore wind development, others anticipate a relatively high cost future for UK offshore wind, at least in the short to medium term.

It is important to understand why early commentators were wrong about cost trends in offshore wind. Offshore wind is still very much in its infancy, representing less than 2% of global installed wind capacity. Yet in the UK roll-out of offshore wind is more advanced than any other major emerging low carbon generation option, notably new nuclear and carbon capture and storage. Will cost projections made for other emerging options prove equally optimistic? Finally, we need to assess what the future is likely to hold for offshore wind, whether costs are now declining, by how much, how rapidly and what needs to be done to help this happen.

1 See main text for sources of all data, comment and analysis cited in the Executive Summary.

Costs in the early years

Until the mid-2000s the consensus in the offshore wind arena was that costs in the future would be significantly lower than then contemporary levels. Actual cost data from the early offshore wind farms were supportive of the idea of a downwards experience curve and reducing costs. In Denmark, for example, Vindeby offshore wind farm was constructed in 1991 at a cost of €2.6m/MW (£1.82m) whilst Horns Rev was built for €1.67m/MW (£1.05m) in 2002. In the UK, North Hoyle was completed in 2003 at a reported cost of £1.35m/MW and Scroby Sands was built the following year for a reported £1.26m/MW.

Analysts of offshore wind costs also looked at the experience of the onshore sector for clues as to the likely cost trajectory. The costs of onshore wind energy fell fourfold in the 1980s, and halved again in the 1990s through a combination of innovation and economies of scale. Grounds for optimism were further supported by positive engineering assessments and extrapolation of learning rates into the medium and longer term future. Such cost estimation techniques indicated that the capital and levelised costs of the nascent offshore wind industry would be likely to fall over time.

Big ambitions

Cost optimism informed government thinking in the early 2000s. Moreover, it coincided with climate change becoming more prominent on the policy agenda. Round 1 of UK offshore wind development commenced in 2001 with aspirations for nearly 2 GW of installed capacity. This was followed in 2002 by the introduction of the Renewables Obligation (RO) and a year later by Round 2 which aimed to develop nearly four times as much offshore wind capacity as the first Round.

In 2007, the case for even greater offshore wind expansion in the UK became more compelling with the advent of the EU Renewables Directive described above. Round 3 was launched in 2008, resulting in nine development zones totalling approximately 32GW of potential capacity. Meanwhile the RO was successively modified such that currently it runs to at least 2037 and all offshore projects accredited up to March 2014 qualify for 2 ROCs/MWh.

Cost escalations and emerging problems

UK offshore wind development has been slower than originally expected and has proved to be significantly more costly than much of the literature anticipated.

By June 2010, eleven Round 1 wind farms had been completed with a total capacity of just below 1 GW. Around half the proposed capacity for Round 1 is either still in development or has been lost to downsizing or withdrawals. Round 2 is still in the relatively early stages of development with only one project fully completed and another four under construction. Currently, the typical timeline for a large UK offshore project is estimated to be between seven and nine years, in large part due to the complexity of the planning process (recent changes may have improved matters, as we discuss below).

From the mid-2000s onwards, the costs of offshore wind development have been escalating. For projects coming online in 2008, capital costs were more than double the 2003 level. As of June 2010, the industry consensus is that capital and energy costs are approximately £3.0m/MW and £150/MWh respectively.

The factors that drove the costs escalations from the mid 2000s are well understood and reviewed in Chapter 4. A wide range of factors had an impact and detailed quantification of the contribution of each cannot be substantiated by the available data. However, it is possible to form a view of the *relative* contribution from these past major drivers; they were (in descending order of impact):

1. Materials, commodities and labour costs
2. Currency movements
3. Increasing prices for turbines over and above the cost of materials, due to supply chain constraints, market conditions and engineering issues
4. The increasing depth and distance of more ambitious projects, affecting installation, foundation and operation and maintenance (O&M) costs
5. Supply chain constraints, notably in vessels and ports
6. Planning and consenting delays

In 2009, key industry actors considered that the likely medium term trajectory of offshore wind costs would be for only a modest fall from 2009 levels out to 2015. Recent evidence suggests that costs in 2010 are no higher than 2009, suggesting costs may have 'peaked'. There is some evidence that a turning point may have been reached; the agreed price of the latest Round 2 project was reported as £2.9m/MW.

Future costs

UKERC has considered the prospects to 2025 using a disaggregated approach, examining each of the drivers or factors that impact on the cost components of offshore wind power:

Turbines represent the largest single cost item in an offshore wind farm, up to around half of overall capital expenditure. Turbine prices have gone up in part because of increasing commodity prices, particularly steel. However the total impact of materials, commodity and labour cost increases explains only around half the rise in turbine costs. The remainder may be explained in part by improving reliability in response to problems with early farms. There is also evidence that turbine prices in the early 2000s did not properly represent production costs, since many turbine makers were not making economic returns. However many analysts and industry experts believe that low levels of competition had an important impact. Moreover, offshore wind is a small element of wider turbine manufacture, and although long term benefits may emerge for 'first movers' as this grows, it is to be expected that, at first, serving such a 'niche' will require a premium.

Looking ahead, new market entrants, scale effects, innovation, recent movements in exchange rates and lower commodity prices bode well for the future price of turbines. Technology experts expect a range of design improvements, continued upscaling and other innovations to emerge in the coming decade. Given the uncertainties, a downside risk remains and if a range of problems are not addressed the price of turbines could even rise. It does not appear likely that turbine prices will fall rapidly; indeed they are likely to remain at or around their current level until around 2015 or so. However, provided a range of drivers move in the right direction together and assuming no further adverse currency effects (ideally because production moves to the UK) cost reductions could be significant in the period 2010 to 2025. We suggest that turbine cost reductions of up to perhaps 40% could be achieved in that timeframe, with an implication for overall levelised costs of a reduction of up to around 15%.

Foundations are subject to a similar set of drivers to turbines. With the exception of the Beatrice development, there has been no UK manufacture of foundations. Most have been sourced from Holland and have therefore been subject to Sterling-Euro currency fluctuations. Steel prices have also had a significant impact, and moving to deeper waters creates a significant challenge that is likely to increase costs in the short run. Whilst we did not find evidence of insufficient competition in foundation supply, several commentators highlight supply chain constraints. There is considerable potential for innovation, which many believe to offer substantial potential for cost reduction. Overall, we believe that there is a considerable spread of possible outcomes for foundations hence the range is from a 20% cost increase to a 30% reduction. The impact on levelised costs is moderated by the fact that foundations account for a relatively small share of total costs, and lies in a range of less than 5% either way.

Depth and distance are of particular relevance to future UK offshore wind development given the more challenging ambitions of UK Round 3. We provide crude estimates of the cost levels for the nine Round 3 zones relative to the capital and levelised costs of a typical mid-depth/mid-distance site more typical of Round 2. Levelised costs increase in all cases but one by between 5% and 24%. Whilst innovation and learning in installation, foundations, maintenance and a range of other factors ought to mitigate the impacts of going to more inherently costly locations, on the whole we believe that depth and distance are likely to place upward pressure on costs. It appears unlikely that better wind speeds will be sufficient to compensate for additional costs associated with going further offshore. Assuming no mitigating factors, a range of up to around 15 to 20% *increase* in the cost of energy is possible.

Load factor is another key intrinsic factor. This has been given particular attention by developers and manufacturers, and improved turbine reliability and better O&M should improve turbine availability. A downside risk remains, since it is possible that the greater distances associated with some Round 3 sites will negatively affect availability, due to greater access restrictions. If Round 3 sites are only able to achieve availability and load factors that are at the lowest end of the plausible range then levelised costs may rise by around 9%. If availability problems are resolved then better wind conditions and optimisation of turbines has the potential to reduce levelised costs. If UK Round 3 developments are able to secure load factors similar to those achieved in several Danish developments, other factors being equal, levelised costs could be reduced by up to around 15%.

O&M costs. The relationship between improving O&M and optimising availability is important. Whilst a range of learning effects are likely to improve effectiveness and decrease relative costs, absolute increases in O&M costs are not unlikely, given both more challenging conditions and the importance of improved availability. However, a 25% increase or decrease in O&M spend will respectively increase or decrease levelised costs by less than 3%.

Currency movements are obviously outside the control of project developers (currency hedging aside) or direct policy support for offshore wind. Whilst we do not speculate on the future of sterling, it is important to note how large an impact currency movement has had on offshore wind prices. Appreciation/depreciation of 20% has the potential to increase/decrease costs by around 12%, assuming that around 80% by value of an offshore wind farm is imported. Increasing the UK built, sterling denominated, proportion of offshore wind farm costs therefore has considerable merits in terms of reducing uncertainty as well as bringing wider economic benefits to UK companies and regions. Bringing more of the supply chain to Britain will also maintain downward pressure on costs if the pound remains relatively cheap by historic norms, in line with recent UK government expectations.

Commodity price movements had a big impact on the price of some of the key components of offshore wind farms, notably turbines and foundations. However, the impact of any single material input on the overall costs of offshore wind should not be overstated. Steel for example accounts for only around 12% of the capital cost of an offshore wind farm. We do not speculate on commodity prices out to 2025, though it is worth noting that the price of steel returned to its historic mean in 2008 and there are few reasons to expect dramatic increases in commodity prices in the short term. We illustrate the impact of steel over the longer run by testing sensitivity to a 50% increase/decrease in costs. Fluctuations of this magnitude only change levelised costs by around 5% in either direction.

Docks and ports are already inadequate to the task and considerable investment is needed. Better facilities exist in mainland Europe, in part because of public investment in docks. Sustained commitment, and perhaps further public spending, is likely to be needed to support an emerging UK supply chain.

Vessels and the wider installation supply chain are also tightly constrained at present and the wind industry must often compete with offshore oil and gas. Longer term, increasing confidence in the stability of the offshore market especially from Round 3 would be expected to lead to increasing supply. Investment in vessels and associated capabilities is expanding.

Planning delays have had a substantive impact on Rounds 1 and 2. We have not attempted to quantify this, but in terms of both absolute costs and revenue foregone it has a substantial and material impact on project finance and economics. It also places further strain on the supply chain, since lengthy delays undermine confidence. The IPC promised to improve matters, and it is essential that the Coalition government's revised arrangements do not compromise these improvements.

Conclusions about future costs

Whilst there a few reasons to expect meaningful costs reductions by 2015, many of the factors that drove costs up have either moderated or have the potential to be remedied. Looking ahead to the mid 2020s there are grounds for optimism.

To illustrate the range of possibilities, UKERC used sensitivity analysis to develop a range of plausible developments in key cost factors in the period to 2025. Because of the uncertainties that currently surround offshore wind costs we do not attempt to apply a learning curve based approach, instead we recommend expert market and engineering based assessment. This approach informs UKERC's analysis of costs, reported in Chapter 5. In our worse case, the costs rise from a current level of around £145/MWh to around £185/MWh. If favourable developments take place in all of the main factors, then costs could fall to under £95/MWh.

Cost projections have to be tentative at this current stage in the history of the offshore wind industry. However, we believe a gradual fall in the cost of offshore wind is a reasonable possibility over the period between now and 2025, particularly if policy can place downward pressure on costs and support the emerging UK supply chain.

Our 'best guess' figure for the mid 2020s is a fall of around 20% from current levels to just over £115/MWh, with continued falls thereafter.

Greater reductions are possible, but would require most, if not all, of the major cost drivers to move decisively in the right direction at once. A significant downside risk remains and it is possible that the costs of offshore wind could continue to go *up*, particularly if supply chain problems are not addressed.

Implications for policy

Our analysis suggests that achieving overall costs which are consistent with reducing support from the Renewables Obligation Certificate (ROC) multiple back down to 1.5 ROCs/MWh will require capital cost reduction of the order of 17-18%, assuming no major change in other factors.

Several key developments could help place downward pressure on costs:

Long term signals and cost monitoring capabilities

Concern has been expressed by some commentators about the relationship between the emergence of the 2 ROC multiple and the market power of some in the offshore wind supply chain, with limited competition in some areas and strong demand from a booming onshore market. A range of factors conspired to drive up costs and the government made the decision to provide 'emergency' 2 ROC support in response. Without additional support it is likely that offshore wind development would have faltered. Industry representatives will obviously wish to alert policymakers to cost escalations when development depends in part on policy subsidies. However, industry 'capture' of regulatory change is clearly a danger if support levels are in some part the product of a *negotiation* between policymakers and industry, particularly where industry structure is relatively concentrated.

Detailed development of a process for setting ROC multiples or Feed in Tariff (FiT) rates is beyond the scope of this report. Nevertheless we believe that it is essential for such arrangements to create clear, long term and binding signals that costs need to be reduced. Periodic 'reviews' cannot set long term signals and may be amenable to lobbying by special interests, particularly where key cost data is allowed to reside solely within the private sector. One means by which this might be achieved would be for the government to establish clearly specified regression in support levels over time. This is common in FiT regimes overseas, a feature of the micro-generation FiT, and whilst simplest in FiT systems could apply to either FiT or ROC based support for UK offshore wind in future. In order to better inform this it may also be desirable for the government to support the development of an independent, non-commercial cost monitoring capability, perhaps in collaboration with other countries, international bodies and academia. Such a capability could shape expectations ahead of time.

Planning and transmission

It is essential that the government's proposed changes to planning rules do not undermine progress made towards accelerating planning. 'Join-up' is essential, since the benefits of a streamlined system for offshore assets would be undermined by a slower process for substations and other onshore assets. Similar concerns relate to Offshore Transmission Owners (OFTOs) and connections to the national grid – though we have excluded these aspects from this review.

Support for innovation

Given the importance of continued innovation to cost reduction we also recommend that support for innovation in offshore wind continues to be given a priority in research, development and redeployment (RD&D) programmes. Important research on innovative, cost-reducing solutions is already a focus of the Carbon Trust's offshore wind 'accelerator', the Energy Technologies Institute (ETI) offshore wind work and the European Wind Energy Technology Platform.

Support for the UK supply chain

Our analysis also suggests that building a UK industry offers benefits in terms of transport costs and currency stability. Since UK consumers foot the bill for offshore wind a case can also be made that policy should seek to maximise benefits to UK companies, helping build a 'green' manufacturing economy. This will require investment, particularly in dock facilities, since there is little point in making turbines and other large components in the UK if we lack the wherewithal to install from UK bases. Direct and targeted support lower in the supply chain, in addition to the overarching incentive provided by the RO (or a FiT), is likely to be a cost effective way to secure UK based offshore wind. Failing to do this effectively risks both a higher cost trajectory for offshore wind and that UK developments are built out of ports in other parts of Europe. It is beyond the scope of this report to speculate further about the role of policy in securing UK manufacture, but doing so is likely to be key, both to cost reduction and perhaps to maintaining support from consumers.

Further work could investigate the potential to explicitly target a fraction of the support coming through the RO to the UK supply chain and perhaps UK RD&D.

Conclusions

Offshore wind offers lessons for policymakers and technology analysts alike. This report charts the progress with offshore wind – and the aspirations for it – from its beginnings in Denmark in the 1990s to present developments in Britain, now the world leader in offshore installation. Our review suggests that early, small scale, developments did not give a good guide to future costs and indicates that rapid upscaling of an emerging technology can create supply chain constraints, amplify design flaws and cause costs to rise whilst progress is slower than expected. External economic factors can also, at least for a while, overwhelm intrinsic learning or other effects.

It is important not to lose sight of the fact that offshore wind *is still in its infancy* – in terms of energy output we are still building the equivalent of the UK's *first* conventional power station. So-called 'first of a kind' costs still apply in large part to offshore wind. It is also important to avoid 'dogged optimism'; extending the timeframe in order to reconcile emerging evidence of cost escalation with a desire to demonstrate that costs can be attractive, eventually. However, we should not be particularly surprised that we have arrived at a point in the history of a particular emerging technology when costs have increased and problems mounted. Many technologies go through such a period, and still go on to offer cost effective performance in the long run. Overall, there are grounds to be optimistic about offshore wind, tempered with *realism* about the challenges associated with its development and the need for policy to engage effectively with *all* the factors that will affect its success.

Glossary

AG	Advisory Group
BWEA	British Wind Energy Association (now RenewableUK)
CAGR	Compound Annual Growth Rate
Capex	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CF	Capacity Factor
COD	Commercial Operation Date
DC	Direct Current
DECC	UK Department of Energy and Climate Change
DEFRA	UK Department for Environment, Food, and Rural Affairs
DoE	US Department of Energy
DTI	UK Department of Trade and Industry
EAC	UK House of Commons Environmental Audit Committee
E&Y	Ernst & Young
ECU	European Currency Unit
ETI	Energy Technologies Institute
EU	European Union
EWEA	European Wind Energy Association
FiT	Feed-in tariff
GBP	Pounds sterling
GDP	Gross Domestic Product
GW	Gigawatt
HLV	Heavy lift vessel
HVDC	High voltage direct current
ICEPT	Imperial College Centre for Energy Policy and Technology
IEA	International Energy Agency
IPC	Infrastructure Planning Commission
kW	Kilowatt
kWh	Kilowatt hour
L/C	Levelised cost of energy
LF	Load Factor

LPC	Levelised production cost [of energy]
LR	Learning rate or ratio
m/s	Metres per second
MW	Megawatt
MWh	Megawatt hour
NETA	New Electricity Trading Arrangements
NFFO	Non-Fossil Fuel Obligation
O&M	Operation and maintenance
OECD	Organisation for Economic Co-operation and Development
Ofgem	Office of the Gas and Electricity Markets
OFTO	Offshore Transmission Owner
ONS	Office of National Statistics
OPEC	Organisation of the Petroleum Exporting Countries
Opex	Operating expenditure
OSW	Offshore wind
PIU	Performance and Innovation Unit
PTC	US Production Tax Credit
PR	Progress ratio
RAB	Renewables Advisory Board
R&D	Research and development
RD&D	Research, development and deployment
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
TPA	UKERC Technology and Policy Assessment
TWh	Terrawatt hours
UKERC	UK Energy Research Centre
WTG	Wind turbine generator

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1. Introduction

1.1 Context and aims of the report

In December 2008, the EU Renewables Directive committed the European Union to satisfying 20% of its energy consumption via renewable sources by 2020. The UK's national target under this legislation is 15%. Depending on the contributions made by the heat and transport sectors this may mean that the UK will have to find 40% of its electricity generation from renewable sources by the end of this decade. Offshore wind is widely expected to play a major role in contributing to this target. Exactly how much offshore wind is needed has not been specified precisely by the government and will depend on the contribution of other renewables and success with efforts at demand reduction. Many commentators have suggested that the UK will need to build in the region of 15 to 20 GW of offshore wind by 2020 (HoL, 2008). Some commentators describe this as a challenge similar in scale to developing North Sea oil and gas in the 1960s and 1970s (Carbon Trust, 2008). However, the escalation in capital costs (capex) and levelised costs of energy in recent years has made the future development of offshore wind power look increasingly expensive.

The UK's ambitions for offshore wind reflect the size of the potential resource and difficulties associated with public opposition to onshore wind (DTI, 2002). They also reflect a widespread expectation that costs will fall as deployment expands. Using a combination of experience curves and engineering assessments, the consensus in the literature from the late 1990s onwards has been an expectation of falling costs. In fact, during the period 2000 to 2004, offshore wind power costs in the UK were relatively stable with typical capex ranging from around £1.2m/MW to £1.5m/MW (BWEA and Garrad Hassan, 2009a). However, in the last five years costs have escalated dramatically. According to the majority of industry observers typical capex has doubled from approximately £1.5m/MW to £3.0m/MW, and as a result estimates of the levelised cost of energy generation have risen from around £85/MWh to around £150/MWh (DTI, 2006, Mott MacDonald, 2010).

All the main electricity generation technologies have been subject to cost increases in the last five to eight years. Exogenous factors such as commodity prices that affect offshore wind also affect the construction of other generation options. Moreover, fossil fuel price increases have led to additional increases in the levelised costs of conventional power stations. For example, the cost of electricity from gas turbine (CCGT) plant has almost doubled; it now stands at approximately £80/MWh compared to approximately £42/MWh (inflation adjusted) in 2006. Coal, nuclear and onshore wind all experienced large cost increases over the same period (DTI, 2006, Mott MacDonald, 2010).

However offshore wind has been subject to particular difficulties and the cost escalations in offshore wind have been considerably larger than those for onshore wind. Onshore wind has recently been estimated to be the *lowest* cost large scale, commercially available low carbon generator applicable in the UK. In contrast, offshore wind is the most expensive (though costs for CCS and new nuclear in the UK remain hypothetical at the time of writing) (Mott MacDonald, 2010). Whilst some commentators remain optimistic and see the potential for creating significant economic benefit from offshore wind development (BCG, 2010), others anticipate a relatively high cost future for UK offshore wind, at least in the short to medium term (Mott MacDonald, 2010).

Recent estimates of the short to medium term cost outlook are that in the absence of extreme movements in macro-economic conditions and/or the onshore wind power market, offshore wind capex is not expected to alter dramatically over the next five years (BWEA and Garrad Hassan, 2009a). In fact, the industry consensus in 2009 regarding future trends was for a slight rise in the next two years followed by a slight fall out to 2014/2015. Such short to medium term projections are, of course, by definition uncertain. Even more uncertain is the longer term. Nevertheless the question of what may happen to costs beyond 2015, and what potential there is for costs to return to predicted trends, is extremely important.

Given the EU renewables targets and the aspirations for offshore wind development, the trajectory of future costs is therefore of considerable significance, both to the offshore wind industry itself and to the UK government. It is also important to understand why early commentators were so wrong about cost trends in offshore wind. Development in offshore wind is more advanced than new nuclear and carbon capture and storage. Given the more muted increases for onshore wind developments, we need to assess whether the factors that caused costs to rise offshore were unique or generic, hence whether projections made for nuclear or carbon capture might be subject to similar escalations. Finally it is important to assess how policy can bear down upon costs; whether and how it can address the factors that caused costs to rise.

The aims of this report are as follows:

(i) It examines the historical context of offshore wind costs and future cost estimates, charting the optimistic expectations of early analysis and the policy support that this garnered.

(ii) It reviews the literature exploring subsequent cost escalations, and the drivers behind these.

(iii) It considers the likely costs trajectory going forward, in particular during the UK Round 3 period i.e. from 2015 out to the mid 2020s when the nine Round 3 zones should be fully operational.

(iv) Finally, the report assesses implications for policy.

The report does not consider the range of grid connection issues that relate to the development and economics of offshore wind. Of particular relevance are delays and uncertainties related to the Offshore Transmission Operator licences (OFTOs) and the timeline and processes affecting onshore transmission upgrades or extensions. Like planning, these aspects have the potential to slow down development. They may also create direct costs. However we exclude them from scope both in order to focus more directly on costs of offshore wind farms and because the OFTO arrangements are still in flux at the time of writing.

1.2 Methodology

1.2.1 TPA Approach

The report is authored by the Technology and Policy Assessment (TPA) function of the UK Energy Research Centre (UKERC). The TPA function was set up to address key issues and controversies in the energy field and aims to provide authoritative inputs to decision-making processes in this arena, using an approach which learns from the practice of systematic review, which aspires to provide more convincing evidence for policymakers and practitioners, avoid duplication of research, encourage higher research standards and identify research gaps. This *evidence-based* approach is common in areas such as education, criminal justice and healthcare.

The goal is to achieve high standards of rigour and transparency. However, energy policy gives rise to a number of difficulties for prospective systematic review practitioners and the approach is not common in energy. We have therefore set up a process that is inspired by the evidence-based approach, but that is not bound to any narrowly defined method or techniques.

1.2.2 Assessment sequence

This assessment follows a generalised approach developed for all TPA work. The TPA has identified a series of steps that need to be undertaken in each of its assessments. These steps, derived from the practise of *systematic review* in non-energy policy analysis, give rise to the specific process for this study, outlined in Figure 1.1 below.

Figure 1.1 Process for TPA studies

	Scoping prospective issues	Solicit expert input	Define criteria for assessment	Review literature	Synthesis and analysis	Prepare draft report	Consult, peer review and refine	Publish and promote
Questions/issues	• What are key problems and issues?	• Need to reflect a range of informed opinion	• Ensure transparent, rigorous and replicable process	• Need to review literature thoroughly	• Need to apply rigorous criteria to evaluation of relevant studies	• Need to identify key issues and discuss initial findings with stakeholders	• Need to seek peer review and gain wide ranging criticism of initial work	• Need to ensure report reaches key audience
Actions	• Write scoping note • Seek feedback from advisory group • Seek feedback from online listing of initial scoping	• Appoint expert group • Hold expert stakeholder workshop	• Develop assessment protocols • Discuss with expert group and AG • Place protocols in public domain	• Apply protocol to literature search • Detailed and transparent 'trawl' • Identify relevant sources	• Apply protocol to evaluation and synthesis of literature • Detailed and transparent assessment of evidence base	• Write preliminary draft assessment	• Host stakeholder workshop to discuss draft report • Send draft report for peer review • Make appropriate revisions to draft report	• Design and graphics • Publication • Launch events
Outputs	• Scoping note	• Web publication of expert group	• Assessment protocols			• Draft report	• Final report	• Published report

1.2.3 Systematic review, expert elicitation and sensitivity analysis

The majority of the data used in this report is sourced from a systematic review of the available literature most directly relevant to offshore wind power costs. The project team also consulted extensively with industry experts, including wind farm developers and financiers, see Annex 3 for details of the expert group and industry interviewees.

The systematic review set out with a set of key words and search terms was determined that provided the basis for the creation of specific search strings using Boolean terminology. A systematic search was then carried out for reports and papers related to the subject in academic and other targeted research sources (see Annex 1).

The challenge was to keep the number of search strings to a manageable level without losing relevant papers from the review process. The project team therefore selected those combinations of terms deemed to provide the appropriate coverage (see Annex 1) and the systematic search revealed approximately 1150 evidence hits. However, a great many of these were duplicates across the databases and removal of these reduced the results total to approximately 450. This number was then approximately halved by removal of any hits that, judging from their title or abstract, were immediately obvious as being of little or no relevance. The total was then increased by the addition of evidence from following 'citation trails' and from specific recommendations, and also from non-academic sources such as industry publications (e.g. Wind Power Monthly) and relevant websites (e.g. Renewable UK (previously BWEA)).

This process produced a total of approximately 350 pieces of evidence that have been rated for relevance (see Annex 1). In the writing of this report, the majority of the evidence used is rated 1 or 2 with only very limited contextual use made of evidence rated 3 and 4.

The TPA team also undertook its own disaggregated quantitative analysis to examine the sensitivity of the levelised costs of offshore wind energy generation to key cost drivers. This analysis used a simple model of cost allocation between the various components of wind turbines, their installation offshore and performance, to assess the impact of a range of cost reducing and cost increasing trends derived from expert inputs and our analysis of the literature.

1.3 Report structure

The structure of this report is as follows:

- Chapter 2 examines the early costs of offshore wind. It reviews the development of *actual costs* up to the mid-2000s. The focus here is empirical in terms of capex, operating expenditure (opex), and levelised energy generation costs. Following this, it reviews the same time period but focuses on the development of contemporary *expectations* concerning likely future costs and cost trajectories.

- Chapter 3 considers the development of offshore wind in the UK from the point of view of government policy and major industry developments over the last decade. In particular, it examines the evolving policy and industry context in terms of a number of key drivers and responses that chart the UK's growing enthusiasm for offshore wind energy.

- Chapter 4 examines the problems, challenges and expectations in UK offshore wind development that have emerged since the middle of the 2000s. It looks at the delays to Rounds 1 and 2 and the cost escalations that have characterised the second half of the decade and also analyses the possible drivers behind these increases. In addition, it considers recent costs expectations for the medium term out to 2015 and for the longer term as far as 2050.

- Chapter 5 provides analysis and conclusions as to what the outlook for costs might be out to the mid 2020s. This is considered using a disaggregated approach, examining each of the drivers or factors that impact, positively or negatively, on the cost components of offshore wind power using sensitivity analysis. It also presents conclusions regarding the historical experience and potential future of offshore wind costs and discusses implications for future policy.

2. Costs in the early years: experience and expectations

2.1 Introduction

Chapter 2 examines the costs of offshore wind from two perspectives. First, section 2.2 reviews the historical development of offshore wind costs from the first Danish wind farms in the early 1990s through to the completion of the UK's Round 1 projects in the mid-2000s. The focus here is empirical i.e. on actual cost experience in terms of capex, opex, and levelised energy generation costs. Section 2.3 reviews the same time period up to the mid-2000s but focuses instead on the development of contemporary *expectations* concerning likely future costs and cost trajectories. Here, a combination of continuing technological advances, falling costs to date (particularly in onshore generation), and a convincing body of literature on experience curves, learning rates and engineering assessments suggested that cost trajectories would be downwards and that grounds for optimism were well-founded.

2.2 A brief history of costs

During the 1990s, the first country to begin to experiment with offshore wind was Denmark. The roots of the modern development of wind energy in Denmark can be found in the OPEC induced oil price shocks of 1973/4 and in the burgeoning green movement of that era (Danish Energy Ministry, 1999). The 1973 oil crisis resulted in the first Danish energy strategy, *Danish Energy Policy 1976*, followed five years later by *Energy 81*, which by then had been given added urgency by the second oil crisis of 1979/80.

Area resources for wind farms on land are limited in Denmark and by 1991 the first of Denmark's offshore projects – Vindeby, a 5MW demonstration program - was operational. This was followed in 1995 by a second 5MW installation at Tuno Knob (Danish Energy Ministry, 1999). Both projects had similar investments costs at approximately 2.1 – 2.2 million ECUs/MW (£1.43 million/MW)[2]. However the costs of energy differed significantly – 0.085 ECU/kWh for the 1991 farm and 0.066 ECU/kWh for the 1995 farm (Cockerill et al., 1998); (Barthelmie and Pryor, 2001). The difference may arise from the relative wind speeds/availability (Tuno Knob is four times the distance from shore) and from improvements in turbine efficiency between 1991 and 1995.

In the Netherlands, the 1994 2MW Lely offshore project carried an investment cost of only 1.7 million ECUs/MW (£1.1 million/MW) (Cockerill et al., 1998). Situated just 1 km from shore, its energy cost was comparable to the Danish Vindeby farm at 0.083 ECU/kWh. Note however that discrepancies in cost figures are not untypical in the literature and Barthelmie and Pryor (2001) reported a much larger investment cost (quoted in Euros) of €2.2 million/MW and a cost of energy of €0.112/kWh. However, Shikha et al. (2005) suggested that generation costs of early Danish offshore farms were around 6p/kWh which assuming a 2001

2 Note that all cost figures are taken 'as found' from the evidence reviewed and, unless specifically stated, have not been converted from original currencies into British pounds nor revised to account for inflation. The exception to this is the data appearing in cost charts produced by the UKERC TPA team for this report. In these cases, conversion to sterling and adjustment for inflation have been undertaken.

exchange rate of approximately £1 = €1.6 gives a lower cost of energy figure of around €0.096/kWh.

In 1996, a second and larger Dutch offshore project came online. The Irene Vorrink farm had installed capacity of 16.8MW and carried an investment cost of €1.2 million/MW – almost half the cost of the earlier project (using the figures from (Barthelmie and Pryor, 2001)). Energy costs showed a similarly impressive reduction down to €0.054/kWh.

In 1997 a plan of action for offshore wind farms in Denmark was submitted to the Danish Minister of Environment and Energy. The main conclusion of the action plan was that the technology for a commercial offshore development could be expected to be available after the year 2000 and that the economic prospects looked good in comparison with onshore installations. The government reached an agreement with the Danish utilities to develop the first 750MW of offshore wind power from five large wind farms during the period 2001 to 2008. Together, these five wind farms would produce about 8% of Denmark's electricity consumption.

Government approvals of the specific sites were given in June 1999 together with the approval of a 40MW site at Middelgrunden close to Copenhagen harbour (Jones et al., 2001). Middelgrunden was installed in 2000 and based on data from several commentators, capital costs were in the approximate range US$1 million/MW to US$1.3 million/MW (Jones et al., 2001); (IEA, 2003a); (Beurskens and de Noord, 2003). The cost of energy according to Barthelmie and Pryor (2001) was €0.053/kWh.

2000 was a landmark year in the UK that saw both the launch of the Round 1 offshore development bidding process by The Crown Estate and the completion of the UK's first offshore wind farm near Blyth Harbour, Northumberland. Installed capacity was 4MW and the project capex was between €1.5m/MW and €1.6m/MW (approximately £1.1m/MW) (Beurskens and de Noord, 2003); (Barthelmie and Pryor, 2001). The cost of electricity production was in the range €0.07 – 0.08/kWh (Barthelmie and Pryor, 2001). Round 1 is explained in more detail in Chapter 3.

In 2002, the first large scale Danish farm came on line at Horns Rev in the North Sea with 160MW of installed capacity at a cost of €1.675 million/MW. In the UK, 2002 marked both the introduction of the Renewables Obligation and the DTI's three month consultation on a strategic framework for the UK offshore wind industry. Shortly afterwards in February 2003, The Crown Estate initiated Round 2 of the UK's offshore wind exploitation which identified three key areas as appropriate for development: the Thames Estuary; the Greater Wash; and the North West (BWEA, 2009).

Table 2.1 below summarises capital costs for UK Round 1 and other European offshore projects, either already constructed, or to be constructed in the time period 2003 to 2005.

With the exception of Vorrink – comparatively a much larger project which possibly benefitted from significant economies of scale – the early projects cost as much or more than the later ones. Cost data such as this was therefore

Table 2.1 Published total technical capital costs for offshore wind farms derived from (Garrad Hassan, 2003). See original evidence for notes and qualifications.

Project	Date	Capacity (MW)	Depth (m)	Distance (km)	Capex (£m/MW)
Vindeby	1991	4.95	2.5 – 5.0	1.5 – 3.0	1.45
Lely	1994	2.00	2.5 – 5.0	0.8	1.58
Tuno Knob	1995	5.00	3.0 – 5.0	3.0 – 6.0	1.45
Irene Vorrink	1996-97	16.80	2.5 – 3.0	0.8	0.85
Bockstigen	1997	2.50	6.0 – 9.0	4.0 – 5.8	1.32
Blyth	2000	4.00	5.0	1.0	1.11
Utgrunden	2000	10.00	13.0 – 14.0	4.2 – 7.3	0.97
Middelgrunden	2000-01	40.00	2.0 – 6.0	2.0	0.90
Horns Rev	2001-03	160.00	6.0 – 14.0	14.0 – 20.0	1.31
Samsoe	2002-03	23.00	10.0 – 13.0	4.0	1.07
North Hoyle	2003	60.00	5.0 – 11.0	7.2 – 9.2	1.35
Nysted	2003	158.40	6.0 – 9.0	10.8	1.19
Scroby Sands	2003-04	60.00	13	2.3 – 3.6	1.26

logically supportive of the idea of a downwards experience curve and a reducing cost trend.

Understandably, Garrad Hassan (2003) considered the Horns Rev, North Hoyle, Nysted and Scroby Sands wind farms to be more representative of that generation of projects in terms of turbine size and project nature, and hence the report considered these the best cost references. On that basis the cost range appeared to be around £1.1 – £1.35 million/MW installed[3]. This was approximately the same as the costs in 2000/01 but cheaper than the first projects in the early/mid nineties.

Table 2.2 from Gross et al. (2007) broadly supports the range suggested by Garrad Hassan (2003) and also provides levelised costs of energy. Note that the cost of Danish output is considerably cheaper than the UK installations. This is partly due to currency and load factor differentials. However it also suggests that Danish developers had been able to attract finance with a relatively low cost of capital.

3 Several industry experts have suggested subsequently that some suppliers to early Round 1 projects made losses and therefore the capital costs reported at the time may have been unrealistically low. It is unlikely that this information was available in 2003 however, and not clear how large the impact of this loss making might have been.

Table 2.2 Cost estimates and real costs for offshore wind (Gross et al., 2007)

Development/estimate	Capital cost (£/kW)	O&M* (£/kW)	O&M* (p/kWh)	Life (years)	Cost of capital (%)	Load factor (%)	Levelised cost (£/MWh)
Future Offshore (DTI 2002)	1000		1.2	20	10	35	51[a]
Energy Review (DTI 2006d)	1500	46		20	10	33	79[a,c]
Danish Wind Industry (see footnotes)	1100		0.7	20	7.5	47[0]	33[b]
Horns Rev (DK)	1310[1]		0.7[2]	20	7.5	45[3]	40[a]
Nysted (DK)	1190[1]		0.7[2]	20	7.5	37[3]	42[a]
North Hoyle (UK)	1350[4]	35[5]		20	10	37[4]	60[a]
Scroby Sands (UK)	1250[6]	25[6]		20	10	34[6]	58[a]

Notes:

Exchange rates: £1 GBP = 10.9766 DKK

Discount rate:

a. 10% nominal (DTI 2003) and (DTI 2006d)

b. 5% real, assumed to be 7.5% nominal (as quoted in Danish Wind Industry 2003 and by assumption for Horns Rev and Nysted)

c. All costs in this table calculated 'overnight' – for simplicity neglecting interest during construction.

DTI 2006 published levelised costs include interests during construction, and on this basis their central estimate of costs is £83/MWh.

Technical data:

0. Approximation implied by data published by Danish Wind Industry – see http://www.windpower.org/en/tour/econ/offshore.htm

1. From (Garrad Hassan 2003)

2. From Danish Wind Industry (see above)

3. Operational data. Published by Wind Stats Newsletters (Vols. 18 – 20, 2005 – 2007 – see http://www.windstats.com), quoted figure averaged from the following quarterly data: Winter 2005 (0.57 Horns Rev, 0.5 Nysted), Spring 2005 (0.40, 0.33), Summer 2005 (0.30, 0.27) Autumn 2005 (0.54, 0.4), Winter 2006 (0.45, 0.35), Summer 2006 (0.27, 0.23), Autumn 2006 (0.58, 0.54)

4. npower 2006 report to DTI - http://www.dti.gov.uk/files/file32843.pdf

5. Long run estimate from npower's 2nd report to DTI http://www.dti.gov.uk/files/file32844.pdf.

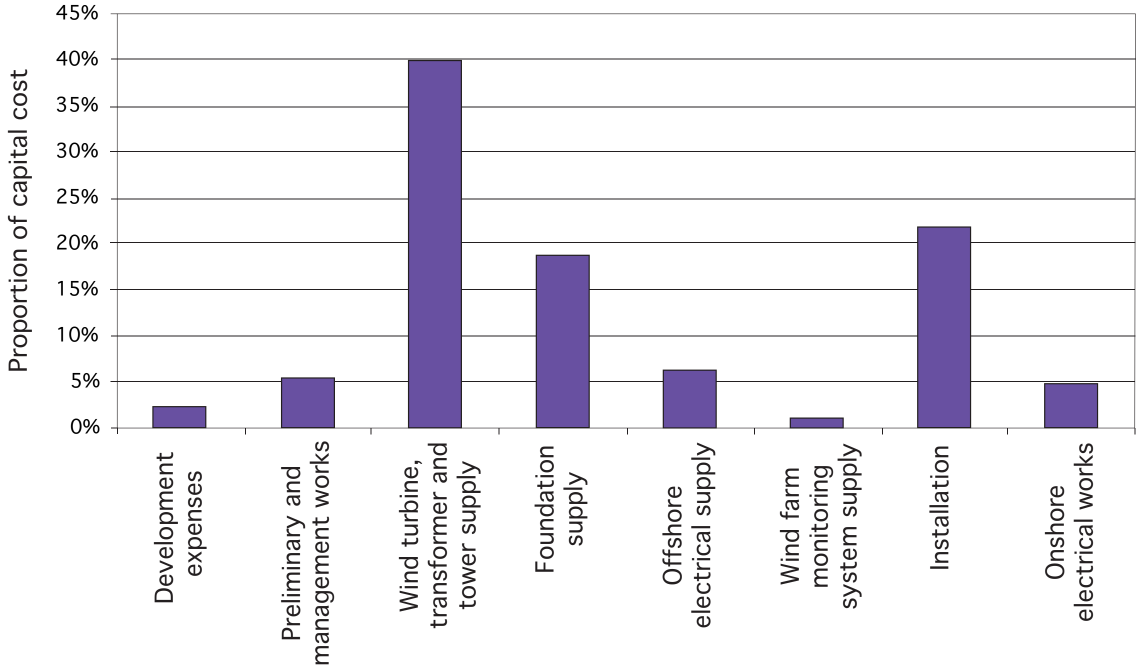
6. Scroby Sands report to DTI, 2005: http://www.dti.gov.uk/files/file34791.pdf

* O&M costs may be annualised, capitalised or expressed per unit. We have used two conventions here following the relevant studies. In principle each convention can be converted to the other.

Figure 2.1 provides a typical breakdown of UK Round 1 capital costs.

At this time, the data on O&M costs were particularly sparse. Garrad Hassan (2003) suggested that the first project that could serve as a reference was Horns Rev (though acknowledging that it had not yet completed a year of full operation). All earlier projects were either too small or too favourably-located (e.g. in very sheltered waters) to be a useful reference. A figure of £70,000 per turbine per annum was deemed reasonable and this included scheduled and unscheduled maintenance, owner's operating costs, and insurances (the latter are not included in some

Figure 2.1 Typical breakdown of capital costs (UK Round 1) (Garrad Hassan, 2003)



definitions of O&M). It did not however include lease payments to The Crown Estate or Transmission Network Use of System charges.

2.2.1 Summary of reported actual capital costs up to 2005

Figure 2.2 presents the in-year average actual capex per MW installed for offshore wind projects reported in the literature reviewed by the UKERC TPA team. Amounts have been converted from the original reported currency into GBP at the exchange rate prevailing at the year of the estimate, and inflated to 2009 values using ONS indices.

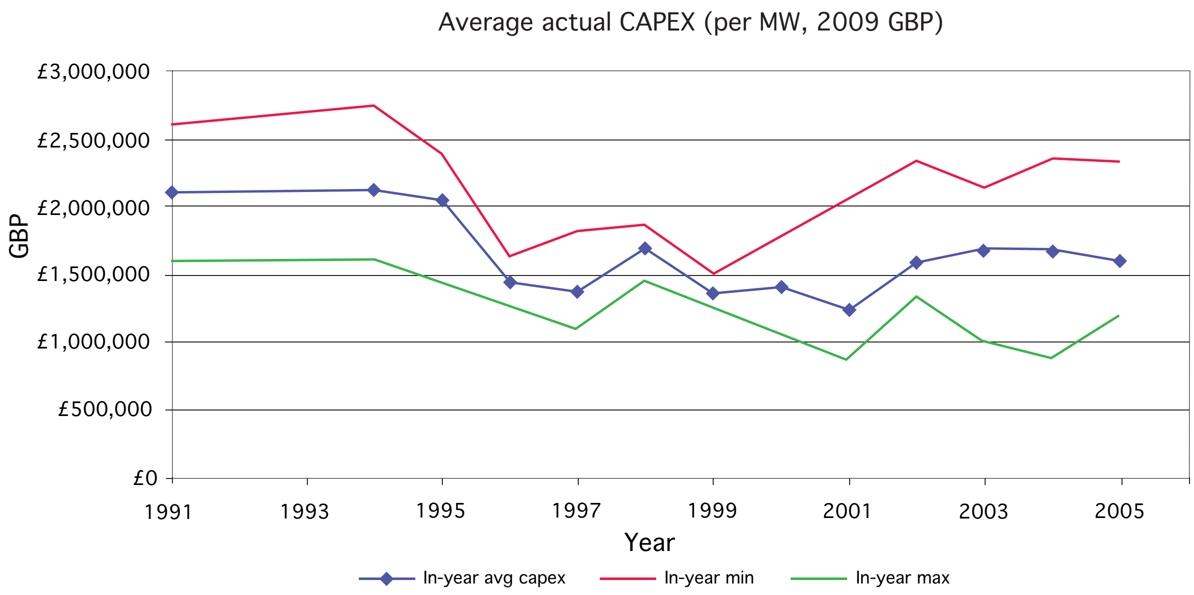
For the period up to 2005, the in-year average follows a trend that is roughly in line with that discussed above. The averages do however mask a significant range of reported costs within each year, with the difference between the highest and lowest in each year up to 2005 being between approximately £0.5M and £1.0M per MW. See Annex 2 for the full plot of the underlying data.

2.3 Grounds for optimism

Between the late 1990s and the early 2000s the consensus amongst observers of the offshore wind arena was that investment and generating costs in the medium to long-term future would be significantly lower than contemporary levels. Cost experience to date, as described in the previous sub-section, broadly supported this expectation.

Understandably given the lack of historical experience, the offshore wind industry looked in major part at the experience of the onshore sector for clues as to the likely

Figure 2.2 In-year average actual capex, up to 2005 (from UKERC TPA analysis)



offshore cost trajectory. The costs of onshore wind energy fell fourfold in the 1980s, and halved again in the 1990s (PIU, 2002b). Cockerill et al (1998), for example, noted that the cost of onshore wind plants had fallen substantially during the previous fifteen years, and that analyses of contemporary data indicated that this trend was continuing. The overall trend in Danish wind energy prices over the previous decade (including an assumption of 5% interest rate and 20 year life), showed an 8% per annum fall in prices. Meanwhile, the minimum prices for wind energy under the UK non-fossil fuel obligation (NFFO) scheme also showed a similar rate of fall, although it is suggested by some commentators that prices under the later NFFO rounds were too low and did not reflect the true costs (Mitchell and Connor, 2004).

The first generation offshore farms of the 1990s, however, were still relatively expensive, being prototypes that were often over-engineered or required optimisation after installation. Moreover, the turbines deployed were typically in the range 220-600 kW rather than the early 2000s generation of 2 to 2.5MW and the number of units installed was usually less than 20 per cluster (Barthelmie and Pryor, 2001). Indeed, analysis carried out for the Danish utilities showed that the use of larger wind turbines - up to 1500 kW rated output - would realise substantial savings (Cockerill et al., 1998). Assuming a wind farm was sited around 6 km from the coast, in a depth of 5-6m, the electricity price might be expected to fall from around 6 ECU cents/kWh (as at Tuno) to around 3.8 ECU cents/kWh.

Thus, based on information available at the time, it appeared that the above considerations combined to promise significant potential for cost reductions in the future. Cockerill et al. (1998)

concluded that "offshore wind energy prices are now moving down rapidly and will probably continue to do so, as new installations are commissioned. There is considerable scope for future price reductions, supported by several studies." At least for a while this view proved to be correct. Section 2.3.1 examines some of the methods used to make such judgements, their advantages and limitations, before we review early projections in this chapter. More recent projections are reviewed in Chapter 4.

2.3.1 Estimating cost reductions

The grounds for optimism considered above were further supported and validated by the use of experience curves to calculate and extrapolate learning rates and progress ratios into the medium and longer term future, and by engineering assessments of likely technical and cost reduction progress. The following sub-sections explore both approaches in more detail.

2.3.2 Experience curves, learning rates, and progress ratios

Experience curves - also referred to as 'learning curves' - document the quantitative relationship between cumulative production capacity and the price or cost of a given technology (Candelise, 2009). The learning curve model operationalizes the explanatory variable 'experience' using as its proxy a cumulative measure of production or use. Changes in cost (and/or price) typically provide a measure of learning and technological improvement, and represent the dependent variable.

Note that implicit within the explanatory variable 'experience' is both the idea of potential gains resulting from learning and also potential returns to scale where average unit cost may decrease as the level of production and installation increases (Kahouli-Brahmi, 2009).

The central parameter in the learning curve model is the exponent defining the slope of a power function. This parameter is known as the learning coefficient and can be used to calculate the progress ratio (PR) and learning ratio (LR) (Nemet, 2006). The progress ratio expresses the effect on cost (or price) for each *doubling* of production capacity. For example, if a cost has reduced from 100 to 80 as production has doubled then the progress ratio equals 80%. The learning rate is the complement of the progress ratio, i.e. (100 minus the progress ratio).

An experience curve is thus a tool for describing, analysing and extrapolating cost trends and performance of technologies. The extrapolated outcomes of experience curves are subject to two basic variables: the slope of the learning curve which may be more or less steep; and the rate of market deployment in the industry under study, which may be more or less rapid. Thus, a steep learning curve with relatively weak market growth may achieve a unit cost reduction in approximately the same time as a shallower learning curve with strong growth.

In theory, experience curves can be used to show the investment and capacity needed to make a technology such as offshore wind competitive (though it does not forecast *when* the technology will break-even unless assumptions are made regarding deployment rates) (IEA, 2000). However, Ferioli et al. (2009) is one of several commentators who argue that extrapolating cost reductions over long-time frames or capacity expansions, while providing valuable insight, requires caution if it is to be used as a reliable tool for strategic planning in the energy sector. The following sub-section explores this in more detail.

Experience curves: uncertainties and caveats

There are a number of arguments in the literature for the limitations of experience curves and why future projections derived from them should therefore be considered carefully. Particularly problematic in the case of offshore wind was the early application of learning curves, since the amount of installed capacity was still too small and thus the market data were inadequate (Chapman and Gross, 2001) (see also the next sub-section). Candelise (2009) summarises some of the other main issues (adapted in this report where appropriate to reflect the context of offshore wind power):

- Progress and learning is not constant over time and experience curves cannot predict discontinuities in the learning rate (citing IEA, 2000, Nemet, 2006).
- The timing of future cost reductions is sensitive to small changes in learning rates (citing Neij, 1997, Nemet, 2006).
- Whilst learning curves can provide cost reduction projections, they are less suited to predict potential technology breakthroughs.
- Learning curve theory assumes each firm in an industry will benefit from the learning-by-doing and experience of all firms, i.e. homogenous spillovers among firms, which is not always the case in reality (citing Albrecht, 2007, Nemet, 2006).
- Offshore wind technology is a compound learning system containing several elements such as turbines, foundations, installation, grid-connection, and O&M. But different elements can have different learning rates and are affected by different learning and cost reduction factors. A single experience curve ignores information on such sub-systems and their potential evolution.
- Experience as the only factor of cost reductions (i.e. the only explanatory variable) ignores the effect of knowledge acquired from other sources (citing Nemet, 2006), such as from other industries, e.g. oil and gas, and from R&D.

Notwithstanding the above caveats, Ferioli (2009) suggests that learning curves can nevertheless provide insight into future cost trends for energy technologies and are, once the limitations of the methodology are taken into account, an attractive tool for both scientific analysts and public policy-makers. The following sub-section considers the evidence in the literature derived from experience curves regarding the potential future trajectories of offshore wind costs.

Experience curves and the wind power industry

The most critical factor to consider in the use of experience curves for offshore wind cost trajectories is that at least until the mid 2000s there was little primary data from which to construct such curves. Offshore wind was still in its relative infancy. Consequently, the curves were often borrowed and adapted from the more historically mature onshore experience. However the cost components and load factors of onshore and offshore are different. A comparison of the two is not like for like and simply extrapolating from onshore experience curves may well be problematic.

It is also important to note that onshore learning rates vary quite considerably in the literature depending on region and time period. McDonald and Schrattenholzer (2001) shows a wide range of wind power learning rates in Table 2.3. Similarly, Junginger et al. (2005) presents a list of 20 widely divergent wind power progress ratios ranging from 68% to over 100% (where costs are rising not falling).

Our review of the offshore literature revealed a range of progress ratios that were being used to formulate scenarios or project costs across a range of time periods. Capital cost progress ratios tended to be higher than energy cost ratios (i.e. assumed *learning rates* for capex tended to be lower than for energy costs) and ranged from 90% to 97.5%. Assumed progress ratios for levelised costs of energy ranged from 70% to 91% with a mean range of approximately 80% to 85%.

Writing in 2001, Chapman and Gross (2001) argued that it was still too early to construct meaningful experience curves for offshore wind from actual data and emphasised the need for caution in extrapolating trends from the onshore wind industry. Subsequent experience validates this cautionary note and with the benefit of hindsight it appears that learning curves indeed *were* applied to the

Table 2.3 Estimated wind power learning rates adapted from (McDonald and Schrattenholzer, 2001)

Country/region	Time period	Estimated 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)

offshore wind sector at a premature and unrepresentative stage.

Nevertheless, in the early 2000s the downward trend in onshore costs gave commentators at the time reasonable grounds for optimism regarding offshore learning rates. Chapman and Gross (2001), for example, did develop offshore learning curve projections based upon the projections for high-cost sites onshore, but where development offshore was effectively 5 years 'behind'. The study concluded that a 15 – 20% learning rate for offshore wind was a reasonable expectation (subject to its overall note of caution).

In the following year, Lako (2002) constructed learning curves for one of the few studies to make a distinction between 'near-shore' wind power (i.e. sheltered, shallow sites) and 'true' offshore (such as the harsher environments of the Baltic and North Seas). Based on assumptions about cumulative growth, Lako (2002) presented 'reference' and 'low' experience curves for near-shore wind and offshore wind as a function of time (Figure 2.3 and Figure 2.4).

By 2010, the cost of an offshore wind farm was projected to fall to between €1.3m and €1.4m/MW. Looking further out to 2030, Lako (2002) estimated that near-shore investment costs could come down from €1,375/kW (in 2000) to €885/kW (reference) or possibly €755/kW ('low'). Near-shore wind could thus become nearly as competitive as onshore wind by virtue of its relatively high capacity factor compared to onshore wind (possibly approximately 36% vis-à-vis approximately 24% for onshore wind). Meanwhile, true offshore investment costs could reduce from €1,700/kW (in 2002) to €1,140/kW (reference) or possibly €970/kW ('low') in 2030. The capacity factor assumed here is approximately 40%.

Figure 2.3 Specific investment cost of a near-shore windfarm, 2000-2030 (Lako, 2002)

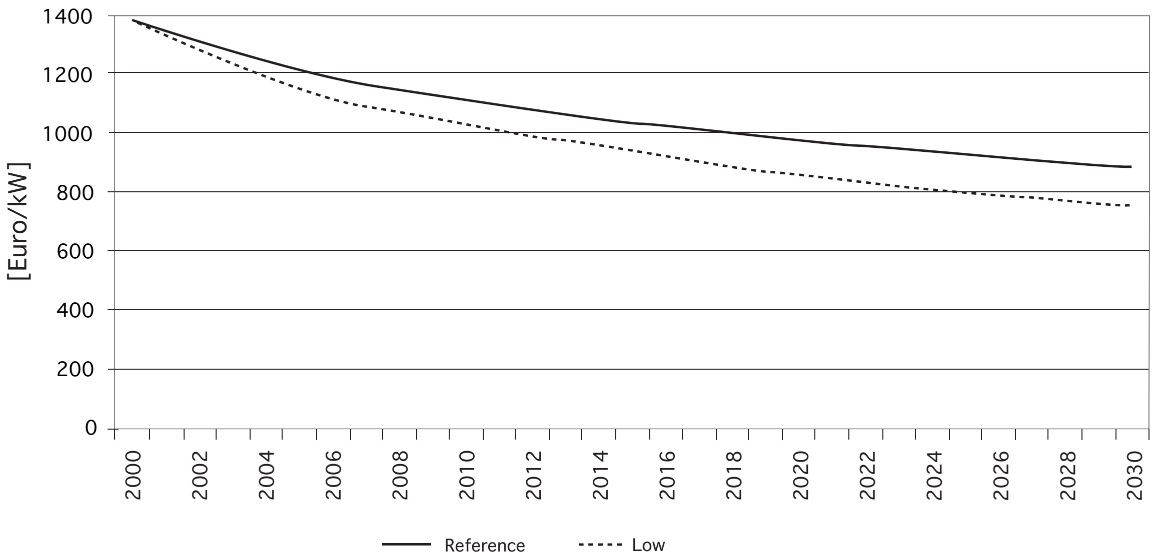
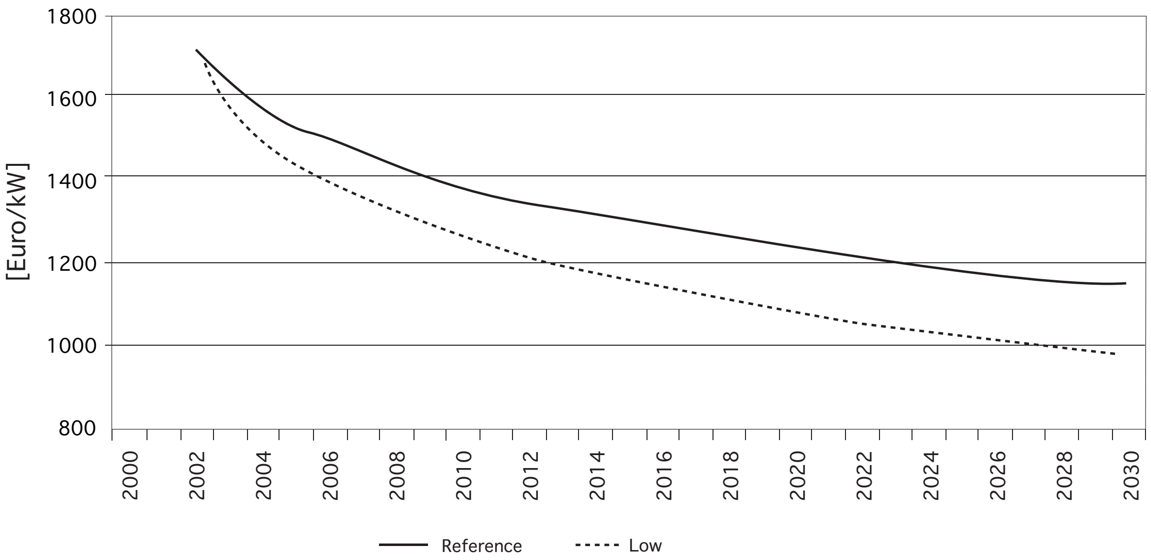


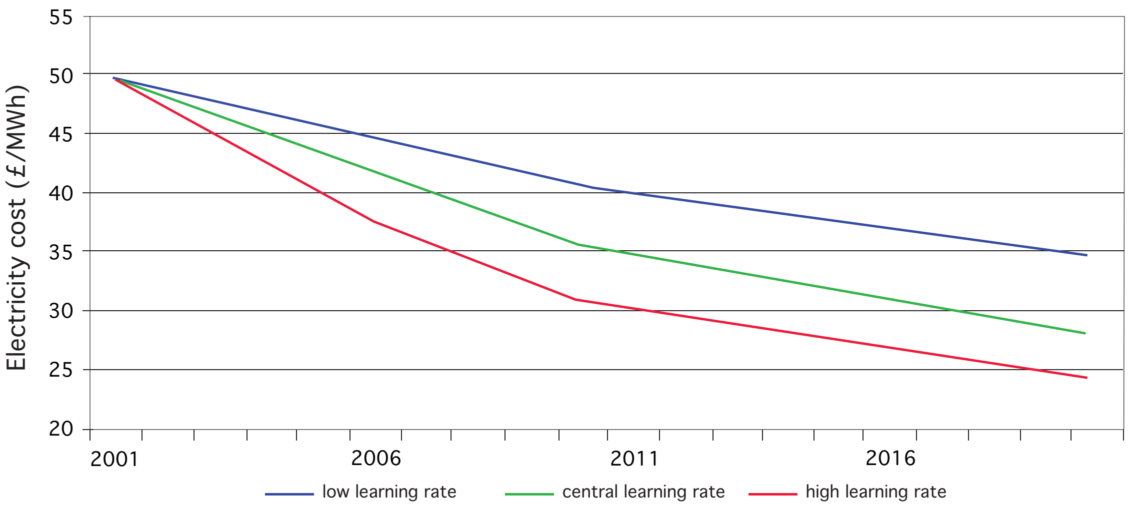
Figure 2.4 Specific investment cost of offshore windfarms, 2000-2030 (Lako, 2002)



The same year the DTI developed learning curves for the levelised cost of energy from offshore wind postulating three different scenarios (Figure 2.5).

Note that the scenarios are not intended as actual predictions but use hypothetical learning curves to show the potential for cost reduction *if* a given learning rate is achieved. Nevertheless, DTI (2002) and other reports and journal articles such as ICEPT (2002), IEA (2003b), Dale et al. (2004), Gross (2004), and Junginger et al. (2005) were representative of the understandable view that investment and

Figure 2.5 Scenarios for future offshore wind costs (DTI, 2002)



Note: These scenarios are based on 'learning curves', which postulate that costs will fall as cumulative capacity increases.
Source: OXERA; for the research on learning curves see IEA (2000), 'Experience Curves for Energy Technology Policy', and Roberts, P. (1983), 'A Theory of the Learning Process', Journal of the Operational Research Society, 24, pp. 71-79

generating costs of offshore wind power would fall over the next decade and beyond. Sub-sections 2.4 and 2.5 describe such expectations in more detail. First, however, we consider the role of engineering assessment in estimating potential cost reductions.

2.3.3 Engineering assessment

Because of their aggregate nature, learning curves do not offer detailed explanatory information regarding technological and concomitant cost improvements. Engineering approaches, by contrast, disaggregate a given technology system into components 'from the bottom up' thus providing a more detailed analysis of individual contributions to efficiency and cost (Mukora et al., 2009). This analysis may be qualitative or quantitative. The use of expert judgement is one approach employed, with predictions of likely future costs based on experience in estimation.

Typically, assessment of technologies places them on a spectrum that ranges from 'mature' to 'emerging' (Chapman and Gross, 2001). In contrast to mature technologies, emerging ones are those considered to have significant potential for further development and cost reduction through innovation. In the late 1990s and early/mid 2000s, offshore wind power seemed an obvious example.

The main advantage of the engineering assessment approach is that it need not rely upon previous trends in cost reduction – that may turn out not be repeatable, or (as in the case of offshore wind) are not yet available because market experience is very limited. The main disadvantage is that engineering assessments based on expert opinion can differ, and may be open to interpretation and manipulation (Chapman and Gross, 2001).

In addition, Mukora et al. (2009) cautions that estimating costs in the early stages of development is inevitably difficult and that whilst engineering assessment methods involve more detailed technology–specific approaches, on their own they do not offer the long-term forecasts required for policy making. Indeed, the bulk of the early forecast data and predictive analysis revealed in our evidence search would appear to have drawn upon learning curve methodology not engineering assessments. Nevertheless, some instances of engineering assessment analysis do occur.

Chapman and Gross (2001), for example, noted that then current offshore wind costs were based upon very limited experience, using turbines essentially developed for onshore generation. There were therefore two key areas for technology development and learning:

(i) The development of turbine technologies explicitly designed for the offshore environment.

(ii) Offshore engineering of wind farm installation.

The key question was thus the extent to which learning and technology development could offset rising engineering challenges, and how rapidly. As for all technologies, this would depend upon both installation rates and the learning rate.

Chapman and Gross (2001) considered what could be inferred from onshore wind development – and what could not – and assessed the extent to which offshore wind could draw upon existing practice in marine engineering in other areas. Their conclusions at the time were that:

- There is clearly 'spillover' between learning investments in onshore technologies and in development offshore. However the move offshore offers opportunity for additional technological development – for example, turbines may be larger and need not be designed to minimise noise, tip speeds may thus rise, raising conversion efficiency.
- The contention that follows from this is that turbine designs for offshore wind will continue to exhibit learning rates at least as high as the historical average for onshore.
- Whilst offshore wind engineering would appear closely related to other offshore industries, the devil is in the detail, and as a result the potential for innovation and learning remains high and the direct application of learning rates from other industries difficult to justify.
- Continued learning and considerable cost reductions should be expected as developments offshore take place on a significant scale. How to best to characterise and quantify this is less clear however.
- Overall, given both engineering considerations and learning curve methodology a cost range of 2.0 – 3.0 p/kWh by 2020 seems reasonable. The upper end of this range is conservative in comparison to the historical developments in wind energy onshore and in the light of the engineering evidence considered by Chapman and Gross (2001).

Two years later, Garrad Hassan (2003) estimated the costs for a nominal UK Round 2 project installed in 2008. A disaggregated component and engineering assessment-type approach was used to consider the potential for cost change. Based on the assessment, they concluded that capital costs could be expected to reduce by around 15% over the following five years on a per MW basis. In addition the report considered there to be more scope for higher than for lower reductions.

Gross (2004) referred to engineering assessments to consider the scope for innovation in offshore wind. Potential areas identified as likely to offer continued cost reductions were as follows:

- Turbines that spin faster thus increasing output for a given size of machine, and reduced blade size and loadings on bearings and structures relative to onshore machines of similar capacity.
- The emergence of dedicated industry with associated dock facilities, marine installation plant, and expertise in offshore wind installation.
- Innovation in turbine tower design and installation to reduce weight and ease construction, transport and installation.
- A variety of turbine refinements and innovations: larger turbines, variable speed direct current (DC) drives, and improved cabling and forecasting techniques.

Engineering assessment that combined all of the above, and considered the cost reduction potential for each cost component of offshore wind, suggested that these factors could deliver a capital cost reduction of around 40% by 2012 compared to the 2002 Danish development at Horns Rev (Milborrow, 2003).

The analysis of Milborrow (2003) postulated a hypothetical offshore wind development in excess of 500 MW in size that could be as much as 100 km from the shore. This was because moving further offshore in order to accommodate much larger developments would, it was argued, bring considerable economies of scale. Wind speeds would also be higher, around 1 m/s increase in average wind speed, for an additional 100 km from shore, and this would yield around 20% energy cost reduction, holding all other factors constant. These cost savings would not be significantly offset by the higher cost of cabling longer distances: cabling costs would remain around 10% of total capital expenditure for larger farms further off-shore. Thus, argued Milborrow (2003), any assumption that greater distances to shore would automatically lead to increased costs appeared mistaken.

Similarly, with regard to depth Gross (2004) noted that very large areas of relatively shallow water were available around the UK (citing DTI, 2002c), and approximately 150,000 km2 were available at less than 35 m in the North Sea. Thus, Gross (2004) argued that the assumption that shallow water, near shore locations would be used up appeared unlikely to be the case in the timeframe to 2020. These mitigating factors regarding distance and depth tended to undermine the assumption that progressively higher costs would necessarily accompany the expansion offshore.

2.4 Cost reduction expectations in the late 1990s and early 2000s

In (Neij, 1999) two scenarios for global growth in wind power (aggregating on and offshore) are postulated using an experience curve with a 95% progress ratio (i.e. a 5% learning rate). The results show that the average cost of wind-generated electricity would be reduced by 44% and 48% over the time period 1997–2020, for 15% and 20% per annum market growth scenarios, respectively.

In its chapter on Renewable Energy Technologies the 2000 World Energy Assessment cited two future scenarios for global wind power capacity growth and cost reductions (UNDP and WEC, 2000). A 'business as usual' scenario assumed a 15% - and later a 12% and then 10% - cost reduction, for each doubling of cumulative capacity. By 2020, the cost of generating has fallen on average to US$0.032/kWh (1998 level), ±15% (depending on wind speed, connection costs to the grid, and other considerations). A faster growth scenario with a different learning curve but the same starting conditions postulated a lower cost of US$0.027, again ±15% (see Figure 2.6).

No distinction was made between on and offshore generation and given the date of the report it must be assumed that the analysis was based substantially on onshore experience. Nevertheless, cost reductions of up to 45% appeared feasible within 15 - 20 years and the scenarios are indicative of the confidence in future cost achievements that would also inform offshore projections.

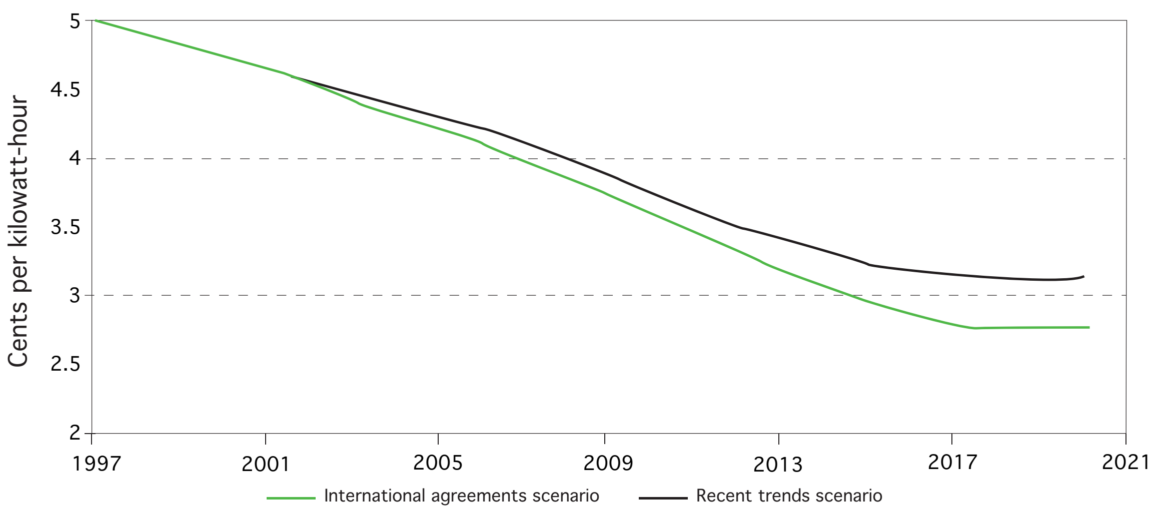
Of course a variety of opinions and judgements arise in the literature, with even short-range cost estimates proving variable in accuracy. For example, Cockerill et al. (2001) modelled the levelised costs of a range of offshore wind farms including Horns Rev which became fully operational in 2003. The model predicted costs of between 5 and 7 ECU cents/kWh. Four years on Gross et al. (2007) reported that the levelised cost at Horns Rev was £40/MWh or 4p/kWh which is in the range predicted. However, Barthelmie and Pryor (2001) also reported estimated future generation costs for Horns Rev but states a figure in euros of €0.047/kWh that is anywhere between 6% and 33% lower than the modelled range and in any case is 30% lower than the Gross et al. (2007) figure. See Table 2.4 for a list of cost projections from Barthelmie and Pryor (2001).

Table 2.5 presents UK cost ranges for 2020 from different studies in the early 2000s.

By 2002, the DTI noted that it was now 'cheaper than ever' to build wind farms offshore. Based on a hypothetical offshore wind farm, the DTI estimated the total cost of electricity to be around £50/MWh or 5p/kWh. This was based on capital costs of £1 million/MW and assumed a 20 year lifetime with either a 10% cost of finance and a 35% load factor or a 12% cost of finance and a 40% load factor (DTI, 2002). The breakdown of costs is shown in Table 2.6.

Whilst the DTI report acknowledged that offshore wind was still a relatively expensive way to generate electricity, it expected costs to fall quickly. On the basis of several learning curve scenarios (see Figure 2.5), the report suggested that the cost of offshore wind could fall by up to 50% over the next two decades to between 20 and 30 £/MWh i.e. 2 to 3p/kWh. Encouraged by the rapid global expansion of onshore wind capacity the UK government would therefore make preparations to enable a large scale development of the offshore industry to take place beginning with Round 2 (DTI, 2002).

Figure 2.6 Potential cost reductions for wind power 1997 – 2020 (UNDP and WEC, 2000)



Source: BTM Consult, 1999

Table 2.4 Planned offshore farms where economic assessments available (Barthelmie and Pryor, 2001)

Name	Turbines	Total	Year	Eurocent /kWh	Projected production MWh/y	Reference
Horns Rev, DK	80 Vestas 2MW	160	2002	4.7		Madsen (1997), DEA/ CADDET (2000)
Rødsand, DK	72 Bonus 2.2MW	158	2002	4.8		Energistyrelsen (1997), Madsen (1997), DEA/CADDET (2000)
Breedt, FR		7.5	2002	6.4		http://www.espace-eolien.fr/lille/Ofshore/centrbreedt.htm
Læsø Syd, DK[1]		150	2003	4.8	396,000	Madsen (1997), DEA/ CADDET (2000), Hartnell and Milborrow (2000)
Nearshore, NL		100	2003	7-8	300,000	Requires subsidy of NLG 60 m Hartnell and Milborrow (2000),
Omø Stålgrunde, DK[1]		150	2004	5.0	434,000	DEA/CADDET (2000) Hartnell and Milborrow (2000), Madsen (1997)
Gedser, DK[1]		150	2006	5.1		Anonymous (1998) Energistyrelsen (1997), Madsen (1997) DEA/CADDET (2000)

1. In January 2002, the newly-elected Danish Government called for further review of these proposed offshore developments.

Table 2.5 Cost estimates for offshore wind in 2020 in different UK studies from (Gross, 2004)

Study/group estimate	Date	Cost range (£/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 2.6 Estimated costs for a hypothetical UK offshore wind farm (DTI, 2002)

Hypothetical UK Wind Farm	
General information	
Capacity (MW)	100
Load factor (%), (a)	35
Depreciation period (years)	20
Cost of capital (%)	10
Capital cost per MW (£m)	1
Investment cost for 100MW installation (£m)	
Turbines	51
Foundations	16
Cable and network connection	25
Other capital costs	8
Total (b)	100
Annuity, per annum, (c) = calculated from (b)	12
MWh per MW per annum, (d) = 24x365x(a)	3,066
Capital costs, £/MWh, (e) = (c) / (d)	38
Total unit costs, (£/MWh)	
Capital costs, (e)	38
Operating and maintenance	12
Crown Estate rent	0.88
TOTAL	**51**

2.5 Cost reduction expectations in the mid 2000s

Medium term expectations

In 2003, the economics of offshore wind were reviewed in detail by Garrad Hassan (2003). One of the aims was to estimate costs for a nominal UK Round 2 project installed in 2008. Based on a range of assumptions, capital costs were expected to reduce by around 15% over the next 5 years on a per MW basis. Given that current capex was estimated at £1.1 - £1.35 million/MW, this results in a reduction to between £935,000 and £1,150,000/MW by 2008.

A further aim of the study was to investigate the longer cost trends in offshore wind. The analysis used a 92% progress ratio but expressed a number of caveats concerning the transfer of experience curves from the onshore to offshore wind context. Nevertheless, it 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.

Garrad Hassan was also charged by the DTI and the Carbon Trust with identifying and assessing critical parts of the supply chain. The specific question examined was whether "existing companies will have the resources, skills and time required to install in excess of 1GW per year from 2008, given the annual window for construction in the North Sea" (which was also taken to include the Thames Estuary and the Irish Sea). The conclusion at the time was broadly optimistic.

Other studies during this period also remained positive though expectations varied considerably. The IEA, for example, saw offshore wind capex reduction potential in the range 5 – 10% over the next decade i.e. to 2013 (IEA, 2003a). A report by BERR in 2005 set the target level for 2010 at £750,000/MW of installed capacity with O&M costs at £10/MWh (BERR, 2005). The IEA, in the same year, was more cautious, projecting 2010 capital costs in the range £860,000/MW to £1,120,000/MW (IEA, 2005).

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. The IEA was even more positive, expecting generation costs in 2010 to fall to between £44 and £57/MWh depending on the discount rate used (IEA, 2005). Junginger (2005) was similarly optimistic, concluding that the data might indicate more rapid price reduction opportunities than had so far been assumed. In the future, it was argued, such reductions were likely to emanate less from increases in turbine capacity and more from increased size of wind farm array and from mass production returns to scale.

Longer term expectations

The DTI modelled offshore wind costs in 2020 to produce a cost of energy of 3.05p/kWh (upper limit 4.6p/kWh (IEA, 2005)) assuming a 10% discount rate (DTI, 2003b). Junginger (2004) used both onshore experience curves and offshore engineering assessment to formulate a cost reduction in 2020 of between 25% and 39%. This resulted in a capital cost range of €980,000 to €1,300,000/MW (approximately £680,000 to £900,000/MW). Assuming a capacity factor of 38% and an interest rate of 8%, the levelised costs of electricity are reduced to €0.042 to €0.054/kWh (i.e. approximately 2.9p to 3.75p/kWh).

The Carbon Trust was more optimistic, projecting an energy cost of 2.2p/kWh by 2020 though with the caveat that reductions would depend on building installations of 1000MW or more, using standardised equipment to achieve economies of scale, and assuming engineering constraints related to layout and location, foundation structures and off-shore O&M could be overcome (Carbon Trust, 2003). Meanwhile Morgan and Peirano (2004) saw the potential for a 60% drop in capex by 2020 from 2003 levels. Assumptions here were a 20% annual growth in installation rate and a learning rate of 8%.

On an even longer timescale, the IEA estimated capital costs out to 2030.

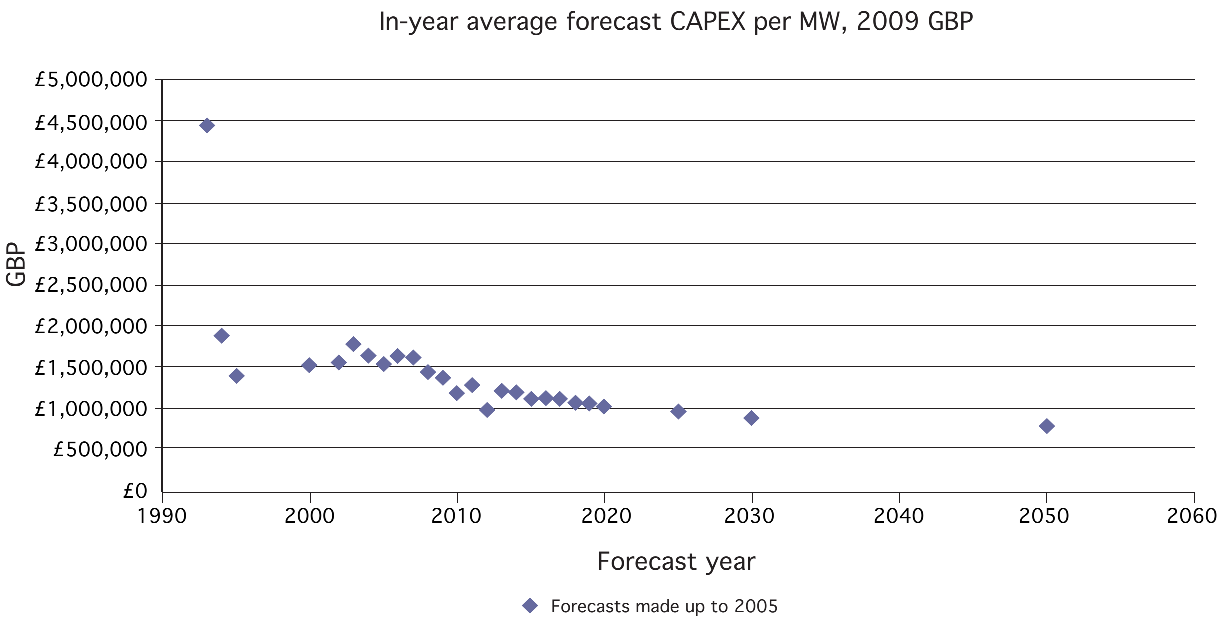
Starting from a 2001 baseline of approximately US$1.7 million/MW, offshore wind capex drops to under US$1 million/MW by 2030. This assumed a learning rate of 10% between 2001 and 2020, and a rate of 5% between 2021 and 2030 (IEA, 2003b).

Figure 2.7 below shows the in-year average of forecast capex for estimates made up to 2005, and clearly demonstrates the expectation that costs would fall over time as the industry matured. See also Figure 4.8 in Chapter 4 which compares these earlier estimates with those made post-2005.

Note however that Gross (2004) emphasised the considerable uncertainty regarding estimating future offshore wind costs, pointing out that different studies take different approaches for different purposes and a straightforward comparison is not necessarily valid. Gross (2004) cites the example of one approach which was based on a simple learning function for energy costs (citing PIU, 2002a) whilst another study by Future Energy Solutions (FES) used a range of values for capital cost, availability (load factor) and operating costs (DTI, 2003b). Gross (2004) observed that the FES data was therefore amenable to sensitivity analysis, and that changes to some variables could have profound impacts. For instance, wind costs are highly sensitive to financing assumptions and reducing the discount rate from 15% to 10% reduces the cost of a first 'tranche' of offshore wind to approx 3.0 p/kWh.

Finally, it is unlikely that few, if any, of these analyses from the 1990s and early 2000s envisaged the scale and pace of offshore wind development now being attempted. It is unclear whether their estimates might have been materially different if they had.

Figure 2.7 Forecast capex, pre-2005 estimates (from UKERC TPA analysis)



2.6 Summary

Between the late 1990s and the mid-2000s the consensus amongst observers of the offshore wind arena was that investment and generating costs in the medium to long-term future would be significantly lower than contemporary levels. Cost estimation techniques such as engineering assessment and learning curves strongly suggested that, based on the experience of other emerging energy technologies (especially onshore wind), the capital and levelised costs of the nascent offshore wind industry would be likely to fall over time.

Moreover, actual cost data from the early offshore wind farms completed in the 1990s and early 2000s were also broadly supportive of the idea of a downwards experience curve and reducing costs trend. In Denmark, for example, Vindeby was constructed in 1991 at a cost of €2.6m/MW, Tuno Knob cost €2.3m/MW in 1995, and Horns Rev was built for €1.675m/MW in 2002 (Beurskens and de Noord, 2003). In 2003, a typical UK offshore installation carried capital costs of around £1.1 – £1.35 million/MW (although some analysts have suggested subsequently that reported capital costs may have been unrealistically low, due to loss making in the supply chain).

Grounds for continued optimism appeared justifiable, such that a range of commentators during the first half of the decade estimated that by 2020 capex would fall to between £700,000 and £900,000/MW and levelised costs would be between approximately £20 and £60/MWh. With the benefit of hindsight it now appears that learning curves were applied to the offshore wind sector at a premature and unrepresentative stage. Whilst long term projections made in the early 2000s could of course still prove to be correct, the reality is that by the middle of the decade costs were actually starting to increase with generation costs for new plant estimated to come in at around £80/MWh. This new trend of cost escalation is explored in more detail in Chapter 4.

3. Big ambitions: policy goals, instruments and milestones

3.1 Introduction

This chapter considers the development of offshore wind in the UK from the point of view of government policy and major industry developments over the last decade. In particular, it examines the evolving policy and industry context in terms of a number of key drivers and responses which chart the UK's growing enthusiasm for offshore wind energy. The major milestones of UK offshore wind development are assessed beginning, in section 3.2, with Round 1. Subsequent sections consider the Renewables Obligation, the 2003 Energy White Paper, Round 2, the 2007 EU Directive, ROC banding and Round 3. A chronology of significant events is presented in Table 3.5.

3.2 UK offshore wind development

3.2.1 Round 1

After an initial 4MW test site at Blyth Harbour in 2000, the UK commenced offshore wind development in earnest in December 2000 when The Crown Estate announced so-called 'Round 1' of UK seabed site leases in order to assess the interest of wind power developers (Beurskens and de Noord, 2003).

In April 2001, 18 companies were awarded agreements for Round 1 leases by The Crown Estate. Under the agreements, the companies were given a three-year period in which to obtain the necessary consents for a lease to be granted (ODE Limited, 2007). The first consents were issued in April 2002, and in December 2003, North Hoyle became the first Round 1 project to start generating with 60MW of installed capacity.

By June 2010, 11 Round 1 wind farms had been completed with a total capacity of nearly 1GW. However, so far this falls significantly short of the original planned capacity for Round 1 of nearly 2GW. Progress has been slower than expected with nearly 500MW still in construction, pre-construction or dormant phase and approximately 425MW 'lost' to project withdrawals or downsizing (but see also sub-section 3.4.4 regarding extensions to Rounds 1 and 2).

Table 3.1 shows the current status and capacity of UK Round 1 wind farms.

Problems onshore

At the time of Round 1, aspirations to move offshore were fuelled, in significant measure, by the problems associated with securing planning permission for onshore wind farms. By the early 2000s the planning process was emerging as a major factor limiting the rate of deployment of onshore wind projects. The difficulties and costs experienced by many onshore developers in gaining planning permission stemmed from concerns amongst some sections of local communities about the impact of wind turbine siting – especially aesthetic objections but also concerns about noise (PIU, 2002b).

By the beginning of the decade it was becoming clear that the offshore option might ease the constraints on wind power developers in the UK and that a particular advantage offshore was the potential for

Table 3.1 Status and capacity of UK Round 1 wind farms (May 2010)

Round	Site	Start date or status	Planned MW	Actual MW (May 2010)
Pre- R 1	Blyth	2000	4	4
Round 1	North Hoyle	2003	90	60
Round 1	Scroby Sands	2004	60	60
Round 1	Kentish Flats	2005	90	90
Round 1	Barrow	2006	90	90
Round 1	Burbo Bank	2007	90	90
Pilot	Beatrice	2007	10	10
Round 1	Lynn	2008	97	97
Round 1	Inner Dowsing	2008	97	97
Round 1	Rhyl Flats	2009	90	90
Round 1	Gunfleet Sands I	2010	108	108
Round 1	Robin Rigg A	2009	90	90
Round 1	Robin Rigg B	2009	90	90
Round 1	Teeside	Approved	90	0
See note	Ormonde	Construction	150	0
See note	Tunes Plateau	Dormant	250	0
Round 1	Cromer	Withdrawn	108	0
Round 1	Scarweather Sands	Withdrawn	108	0
Round 1	Shell Flats	Withdrawn	180	0
Total R1			1892	976

Source: (4C Offshore Limited, 2010) and (Wind Power Monthly, 2010)

Note: Ormonde and Tunes Plateau were outside the original Round 1 process but conform to its terms.

greater public acceptability, chiefly because of the lower visual impact (PIU, 2002a). This in turn meant that it would be possible to build much larger turbines than might be acceptable on land, a benefit enhanced by the higher wind speeds typically encountered at sea (DTI, 2002).

3.2.2 The Renewables Obligation

In 2002, the NFFO was replaced by the Renewables Obligation (RO) which remains the UK government's principal mechanism for supporting the generation of renewable electricity. The RO is a certificate trading scheme and places a mandatory requirement on electricity suppliers in the UK to source an increasing proportion of electricity from renewables (see for example (DTI, 2007)).

As noted later, the targets, termination date and the specific ROC award for offshore wind generation have subsequently been revised as sector experience and policy thinking have evolved. The RO, together with the 2001 Offshore Wind Capital Grants Scheme and the 2002 policy programme 'Future Offshore' designed specifically to accelerate offshore wind development, helped develop an emerging market in offshore wind energy.

3.2.3 'Future Offshore' 2002 Green Paper

In its 2002 Green Paper, 'Future Offshore', the UK Department of Trade and Industry (DTI) noted that notwithstanding the many uncertainties, the UK had a vast resource of potentially suitable seabed that could theoretically provide several hundred GW of electricity from offshore wind farms (see Table 3.2) (DTI, 2002). This was based on research by the Energy Technology Support Unit and Future Energy Solutions in 1998 that estimated a theoretical potential generation from UK offshore wind of 3500 TWh/year and an economically practical potential of 100 TWh/year (DTI, 1998). This represented nearly one-third of then UK electricity demand (or approximately one quarter of current demand).

In addition to premier wind and site resources, the UK was also judged to have the financial, entrepreneurial, and skills resources needed to exploit the offshore potential on a large scale. In 2003, the Carbon Trust noted that UK companies had experience in design, installation and operations in off-shore environments and could convert its oil and gas experience to create a globally-competitive position in offshore wind. UK companies were well positioned for export growth in areas including the provision of installation and maintenance vessels and offshore operations and maintenance services overseas. Assuming a suitably ambitious investment programme, UK businesses could establish themselves across much of the value chain and aim to achieve a market share of as much as 80% by value (Carbon Trust, 2003).

3.3 The 2003 Energy White Paper

The RO and Round 1 were indicative of the way in which climate change – and the mitigating role of low carbon, renewable energy – had by then begun to work their way up the policy agenda. The interest in the subject of the then Prime Minister, Tony Blair, and the resultant 2002 Energy Review made climate change one of four 'pillars' of UK energy policy – together with security, competitiveness and fuel poverty. In the words of the PIU report, "…the issue of climate change has been identified as a key challenge for our future energy system" (PIU, 2002a).

February 2003 saw the publication of the Energy White Paper itself. The remit of the White Paper was very broad, covering all aspects of energy use including transport, efficiency, and progress towards a low-carbon economy. In terms of more specific relevance to offshore wind, it endorsed a

Table 3.2 Potential offshore wind resource in proposed Round 2/3 regions (DTI, 2002)

Water depths	5 to 30 metres				30 to 50 metres			
Region	**Area sq.km**	**%**	**MW**	**TWh/yr**	**Area sq.km**	**%**	**MW**	**TWh/yr**
Within territorial waters								
North West	2,748	17	32,976	115	634	3	7,608	27
Greater Wash	2,037	12	24,444	85	202	1	2,424	8
Thames Estuary	2,068	12	24,816	87	812	4	9,744	34
Other	9,769	59	117,228	410	18,371	92	220,452	771
Sub total	16,622	100	199,464	697	20,019	100	240,228	840
Outside territorial waters								
North West	597	6	7,164	25	1,433	5	17,196	60
Greater Wash	5,354	50	64,248	225	744	3	8,928	31
Thames Estuary	31	0	372	1	36	0	432	2
Other	4,662	44	55,944	196	27,070	92	324,840	1,136
Sub total	10,644	100	127,728	447	29,283	100	351,396	1,229
All waters								
North West	3,345	12	40,140	140	2,067	4	24,804	87
Greater Wash	7,391	27	88,692	310	946	2	11,352	40
Thames Estuary	2,099	8	25,188	88	848	2	10,176	35
Other	14,431	53	173,172	606	45,441	92	545,292	1907
Total	**27,266**	**100**	**327,192**	**1,144**	**49,302**	**100**	**591,624**	**2,069**

10% renewable electricity target set for 2010 and included an "aspiration" to double this by 2020 though at the time it fell short of setting a firm target (DTI, 2003a).

Whilst offshore wind power had not yet gained the pre-eminent position in government renewable energy policy that it has since the EU's 2007 Renewable Energy Directive, nevertheless it fitted the bill in a number of ways:

- it could make a significant contribution to emissions abatement
- as already discussed, it provided a solution to onshore planning problems
- the size of the potential resource was very large

- and, as described in Chapter 2, there was considerable optimism about the potential for cost reductions over the medium to long term.

In the summer of 2003, the Secretary of State for Trade and Industry requested that The Crown Estate invite developers to bid for site option agreements under a second round of the offshore wind development programme.

3.3.1 Round 2

'Round 2' of site leases consisted of a further 7 - 8GW of sites, mostly off the east coast plus some significant developments in the north west and in the Thames Estuary (Carbon Trust, 2008). 15 projects were proposed - to be developed between 2008 and 2014 - and supported by the then prevailing ROC incentives. By now, the government's ambitions for offshore wind were both clear and substantial:

"There is clear evidence that the biggest new contributor to our renewables target is going to be offshore wind and the government has a strong interest in encouraging it to develop quickly and successfully." (Bower (2003) citing DTI General Question and Answer Briefing 14 July 2003).

In terms of installed capacity, the situation to date is that Round 1 has produced nearly 1GW and Round 2 has one operational project (Gunfleet Sands II) with 64MW of capacity. The original Round 2 capacity aspiration between 2008 and 2014 was approximately 7500MW (but see also sub-section 3.4.4 regarding extensions to Rounds 1 and 2). Currently, another four Round 2 projects are under construction totalling an approximate installed capacity of 1300MW (see Table 3.3 for the current status and capacity of UK Round 2 wind farms).

With regard to implementation costs, at the time of the launch of Round 2, it was anticipated that capex would be up to 20% less than for the Round 1 projects, reflecting the learning effects, R&D and other factors since the inception of Round 1 (ODE Limited, 2007). Actual experience however has proved to be rather different for reasons that will be explored in more detail in Chapter 4.

3.4 Responding to problems and raising the stakes

3.4.1 Changes to the RO

By 2006, government energy strategy in general was under close scrutiny due to increases in UK carbon emissions since 2002, because of concerns about future reliance on imported gas, and because of a greater awareness of the scale of investment required in new (and in part, renewable) generating plant in the face of a potential electricity capacity shortfall in 2016 (HoC, 2006). There was thus an increased focus on those low carbon technologies that could also contribute on a large scale relatively quickly. Off-shore wind was an obvious leading contender with the government declaring that "the prospects for offshore wind were promising" (DTI, 2006).

However, at the time a variety of observers including the House of

Table 3.3 Status and capacity of UK Round 2 wind farms

Round	Site	Start date or status	Planned MW	Actual MW (May 2010)
Round 2	Gunfleet Sands II	2010	64	64
Round 2	Docking Shoal	Submitted	500	0
Round 2	Race Bank	Submitted	620	0
Round 2	Sheringham Shoal	Under construction	317	0
Round 2	Humber Gateway	Submitted	300	0
Round 2	Triton Knoll	Planning	1200	0
Round 2	Lincs	Approved	270	0
Round 2	Westermost Rough	Planning	240	0
Round 2	Dudgeon	Submitted	560	0
Round 2	Greater Gabbard	Under construction	504	0
Round 2	London Array I	Approved	630	0
Round 2	London Array II	Approved	370	0
Round 2	Thanet	Under construction	300	0
Round 2	Walney I	Under construction	184	0
Round 2	Walney II	Approved	184	0
Round 2	Gwynt y Mor	Approved	738	0
Round 2	West Duddon	Approved	500	0
Total R2			**7481**	**64**

Source: (4C Offshore Limited, 2010)

Commons Environmental Audit Committee (EAC) judged that progress so far in deploying key low carbon technologies was inadequate. It accused the government of failing to address the core issue of whether the policy and regulatory framework then in place was sufficient to stimulate the growth of lower-carbon generation on the scale required.

One of the EAC's recommendations was a modification of the RO to provide a range of different incentives – 'so-called ROC banding' – for different technologies (HoC, 2006). This would ultimately result in a boost for offshore wind and a reversal of the idea that policy should be technology neutral though this recommendation did not become a reality until 2009 (see section 3.4.3).

3.4.2 The 2020 targets

The case for offshore wind development in the UK became stronger in March 2007 when the European Union proposed a target that 20% of energy consumed across Europe would need to come from renewable sources by 2020. Under a burden-sharing agreement different countries took on different targets, based on both their existing renewables capacity and relative GDP per capita. Legally committed as of December 2008, the UK needs to achieve a target of 15% of final energy consumption from renewable sources by 2020 shared across the three main energy consumption categories: transport; heat; and electricity (Carbon Trust, 2008).

Offshore wind is widely expected to play a major role in contributing to this target. Exactly how much offshore wind is needed has not been specified precisely by the government and will depend on the contribution of other renewables and success with efforts at demand reduction. Many commentators suggest that the UK will need to build in the region of 15 to 20 GW of offshore wind by 2020 (HoL, 2008).

Domestically, the Climate Change Act enacted in 2008 made the UK the first country in the world to have a legally binding long-term framework to cut carbon emissions. This set a new level of ambition for UK climate policy with an initial goal of reducing emissions 34% by 2020 compared to 1990 levels (Appleyard, 2009).

3.4.3 Round 3

In December 2007 the UK government began planning for a massive expansion of offshore wind capacity by conducting a Strategic Environmental Assessment of additional offshore sites. The existing plans dating back to 2001 and 2003 for approximately 8GW of offshore wind under Rounds 1 and 2 were insufficient, both to achieve the EU targets and to meet expected market demand for new offshore wind development rights (DECC, 2009).

It was estimated that the UK would have to find nearly 30GW of electricity from offshore wind plant but whilst recognising this to be extremely challenging, the Carbon Trust considered that it was technically feasible, pointing out that 29GW of offshore wind farms only needed 0.5% of total UK sea floor, a combined space the size of the county of Somerset. Not only was there sufficient room in UK waters, even with all the current constraints on where plant can be located, but up to 40GW of wind (on and offshore) could be incorporated into the UK's electricity system without compromising security of supply[4] (Carbon Trust, 2008).

In June 2008, Round 3 was formally launched when The Crown Estates invited applications for exclusive rights to develop projects in specified zones. Bidding closed in March 2009 and nine successful applicants were announced in January 2010 totalling over 32 GW of installed capacity (see Table 3.4). Actual construction is not expected to commence

4 But the system would have to operate with a reduced load factor of conventional generation and an increased need for balancing services.

Table 3.4 Status and capacity of UK Round 3 wind farms

Round	Site	Start date or status	Planned MW	Actual MW
Round 3	Moray Firth	Planning	1300	N/A
Round 3	Firth of Forth	Planning	3500	N/A
Round 3	Dogger Bank	Planning	9000	N/A
Round 3	Hornsea	Planning	4000	N/A
Round 3	Norfolk Bank	Planning	7200	N/A
Round 3	Hastings	Planning	600	N/A
Round 3	Isle of Wight	Planning	900	N/A
Round 3	Atlantic Array	Submitted	1500	N/A
Round 3	Irish Sea	Planning	4200	N/A
Total R3			32200	N/A

Source: (4C Offshore Limited, 2010)

until 2014 at the earliest with the first phases of the new wind farms becoming operational in 2015 or 2016 (DECC, 2009).

RO extension and the 2 ROC multiple

2008 also saw the government announce that the RO would be extended until at least 2037. Alongside the RO, a number of other government support mechanisms have been announced, including the £10 million Low Carbon Energy Demonstration Fund which is aimed at accelerating the technology needed to see more large-scale offshore turbines. Moreover, in order to further boost its development, offshore wind generation became eligible for an additional 0.5 ROC per MWh from April 2009 and during the course of 2009 the ROC incentive was further extended. Currently, all offshore projects accredited up to March 2014 will qualify for 2 ROCs/MWh[5]. The government has said that this would provide an extra £400m in support for the offshore sector and allow the development of a further 3 GW in capacity (Backwell, 2009).

Other factors affecting Round 3

The launch of Round 3 was also given added support by The Crown Estate's decision that it would co-invest with consortia in the development risk up to the point of site consent (Carbon Trust, 2008). In addition, The Crown Estate commissioned a detailed connection study

5 The value of one ROC to a generator depends on the size of the ROC buyout fund which is redistributed (recycled) to ROC holders each year, and the ROC buyout price which is set by the regulator. In turn the size of buyout fund depends on the 'headroom' between the RO target and actual qualifying renewable electricity generation. The precise value cannot therefore be known in advance, but using the current buyout price of £37/MWh and the central estimate of the ROC recycle value from (Ernst & Young, 2009) suggests that each 2 ROC multiple is worth around £100 per MWh of offshore wind generated.

examining the potential requirements of offshore transmission connections for Round 3 wind farms. It also explicitly recognised that supply chain constraint has been one of the most significant issues facing developers. The Crown Estate's strategic approach to Round 3 is intended to provide turbine manufacturers and other links in the supply chain with greater visibility and certainty of future demand. It is hoped that this will allow them to make the necessary investments to meet that demand and reduce constraints (The Crown Estate, 2009, BVG Associates, 2009a).

UK port capacity is another crucial factor. In February 2009 the Department of Energy and Climate Change (DECC) published an independent report into the ability of UK ports to meet the demands of future offshore wind expansion and to attract inward investment from overseas turbine manufacturers and component suppliers (BVG Associates, 2009b). The report argued that there was plenty of potential port capacity in the UK, both in terms of location and land availability, but that investment in infrastructure would be required. According to DECC, UK ports have started to realise the potential opportunities in this sector, and have been showing interest in investment[6]. Overall, the government suggested that the UK was well placed to meet many of the bottlenecks in the offshore wind supply chain, such as gearboxes, generators, blades, electrical and control systems (DECC, 2009).

One final issue of significance is availability of project finance. In the April 2009 Budget, the government announced measures designed to improve the prospects for wind development, with renewable and energy projects generally standing to benefit from up to £4 billion of new capital from the European Investment Bank, which the government says will remove blockages in financing (Appleyard, 2009). The issue of finance availability is one to which we return in Chapter 5.

3.4.4 Extensions to Round 1 and 2

In the summer of 2009 The Crown Estate offered Round 1 and 2 developers the opportunity to tender for site area extensions to their existing projects (or planned ones subject to certain conditions). Known colloquially as Round 2.5, its purpose was "to take advantage of the possible accelerated delivery of project extensions, in order that construction could be underway before development starts on Round 3 projects" (The Crown Estate, 2010a). It is anticipated that this will help to deliver a stable flow of projects to the supply chain as it gears up for Round 3.

The awards were made in May 2010 with five Round 1 and 2 projects gaining site extensions. The additional capacity amounts to 285MW for Round 1 and 1.4 GW for Round 2 and will help replace capacity lost to project downsizing or cancellation (partially in the case of Round

6 In 2010 £60m of government investment in one or more UK ports was announced in the March budget *Wind Power Monthly* (2010) Special Report June 2010. Wind Power Monthly. Haymarket Business Media, London.

1 and more than fully in the case of Round 2 – see sub-sections 4.2.1 and 4.2.2).

3.5 Summary

Round 1 of UK offshore wind development was launched in 2000/2001 and in 2002, the NFFO was replaced by the Renewables Obligation. Both the RO and Round 1 were indicative of the way in which climate change had begun to work its way up the policy agenda such that the 2002 Energy Review made climate change one of the four 'pillars' of UK energy policy.

Offshore wind was seen as an obvious large scale, low/zero carbon solution. Not only does the UK have a vast resource of available wind and potentially suitable seabed, but it was also judged to have the financial, entrepreneurial, and skills resources needed to exploit the offshore potential on a large scale. Moreover, a combination of continuing technological advances, falling onshore wind costs, and convincing experience curves suggested that cost trajectories would be downwards. Such optimism understandably informed government thinking with, for example, DTI analysis in 2002, suggesting that the capital costs of offshore wind could fall by up to 50% over the next 20 years (DTI, 2002). An additional factor was the planning permission constraints for onshore wind farms and hence the potential for the offshore option to ease the pressure for land use.

In consequence, the government began making preparations to enable a large scale development of the offshore wind industry to take place and in July 2003 a second round of leasing for offshore sites was announced. Four years later, the case for a major change in offshore wind expansion in the UK became more compelling with the advent of the EU Renewables Directive in March 2007. In 2008, Round 3 was formally launched and the government also announced that the RO would be extended until at least 2037. During the course of 2009 the ROC incentive was further enhanced and currently all offshore projects accredited up to March 2014 will qualify for 2 ROCs/MWh. Bidding on Round 3 closed in March 2009 and 9 successful applicants were announced in January 2010 totalling over 32 GW of installed capacity.

By June 2010, eleven Round 1 wind farms had been completed with a total capacity of nearly 1GW. The original planned capacity for Round 1 was approximately 1900MW but progress has been slower than expected with nearly 500MW still in construction, pre-construction or dormant phase and approximately 425MW 'lost' to project withdrawals or downsizing (see Table 3.1). Round 2 is still in the relatively early stages of development with one operational project (64MW) and another four under construction with an approximate installed capacity of 1300MW. This compares to an original Round 2 capacity aspiration of nearly 7500MW. Site extensions to Rounds 1 and 2 have since increased their joint capacity potential by nearly 1.7GW.

The chronology of significant policy and industry developments beginning with Round 1 is summarised in Table 3.5.

Table 3.5 Offshore wind milestones and dates

Year/Month	Event
2000 December	Round 1 development phase launched by The Crown Estate. UK's first offshore wind farm commissioned off Blyth Harbour (installed capacity approximately 4MW).
2001 April	Successful Round 1 applicants announced: 18 sites, 13 locations. New Electricity Trading Arrangements (NETA) begin.
2002 April	Introduction of the Renewables Obligation (RO). Obligation level set to rise from 3% in 2002/2003 to 10.4% by 2010/2011.
2002 November – 2003 February	The DTI hold 'Future Offshore' consultation on the development of a strategic framework for the UK offshore wind industry.
2003 February	Publication of 2003 Energy White Paper. The Crown Estate seeks expressions of interest for Round 2.
2003 March	Interest from 29 companies at 70 locations around UK coastline.
2003 December	North Hoyle, 1st Round 1 farm commissioned, is switched on (installed capacity 60MW).
2003 December	RO expanded from 10.4% by 2010/11 to 15% by 2015. Results of Round 2 announced: right to develop 15 sites totalling over 7GW awarded to 10 companies or consortia.
2004	Energy Act 2004 creates a legal framework for development outside of UK territorial waters.
2004 December	Scroby Sands Round 1 farm is switched on (capacity 60MW).
2005	RO level extended to rise from 10.4% in 2010/2011 to 15.4% in 2015/2016 and then remain at that level until 2027.
2005 December	Kentish Flats Round 1 farm is switched on (capacity 90MW).
2006 January	Publication of Energy Review by DTI including announcement of an additional RO target of 20% renewable electricity by 2020-21 (but 40% in Scotland). Agreement to consult on ROC banding.
2006 July	Barrow Round 1 farm is switched on (capacity 90MW).
2007	Energy White Paper 2007: 'Meeting the energy challenge'.
	Agreement by UK to EU target of generating 20% of energy supply from renewables by 2020. UK's allocated target is 15%.
2007 August	Completion of Beatrice wind farm (capacity 10MW).

Continued overleaf

Table 3.5 continued

2007 October	Completion of Burbo Bank Round 1 farm (capacity 90MW).
2007 December	Government plans massive wind expansion by conducting SEA of 25 GW of offshore sites in preparation for Round 3.
2008 January	Energy Bill updates UK's energy legislative framework.
2008 June	The Crown Estate invites applications for Round 3 – up to 25 GW additional to existing/planned 8 GW from Rounds 1 and 2.
2008 October	Completion of Lynn and Inner Dowsing Round 1 wind farm (capacity 194.4MW).
2008 November	Climate Change Act passed into law. 2008 Energy Act includes ROC banding from April 2009. RO extended to at least 2037.
2009 January	2007 EU targets formalised by EU Renewables Directive.
2009 March	Round 3 bidding closes.
2009 April	Start of ROC banding introduced in 2008 Energy Act – offshore wind 1.5 ROC subsequently revised upwards to 2 ROCs in response to concerns over steeply rising costs.
2009 July	Publication of UK Low Carbon Transition Plan stipulating 40% of electricity to come from renewables, nuclear and clean coal.
2009 Autumn	Gunfleet Sands commissioned (installed capacity 172.8MW between Gunfleet I and II). Tendering for so-called 'Round 2.5' site extensions.
2010 January	Round 3 successful applicants announced.
2010 May	Round 2.5 awards made.

4. Emerging problems, expectations and cost drivers

4.1 Introduction

Chapter 4 examines both the problems and challenges in UK offshore wind development that have emerged since the middle of the 2000s and more recent expectations regarding future offshore wind cost trends, and discusses those factors which have driven the cost increases. Section 4.2 looks at the delays to Rounds 1 and 2 and the cost escalations that have characterised the second half of the decade. Section 4.3 considers costs expectations in 2008 and 2009 for the medium term out to 2015, whilst section 4.4 considers expectations in the longer term as far as 2050. Section 4.5 examines the reasons why costs have risen.

4.2 Delays and cost escalations from the mid 2000s

4.2.1 Clouds on the horizon: Round 1 delays

Successful Round 1 applicants were announced in April 2001 and the first project, North Hoyle, began generating in December 2003. However, it was a year later before Scroby Sands went online in December 2004 and a further year before the third Round 1 wind farm at Kentish Flats was completed. By 2006, installations were due to increase substantially with the UK set to become the world leader in installed capacity. The situation changed, however, when three large projects due for construction encountered major contracting problems, with Centrica's Lynn and Inner Dowsing projects and Eon's Solway Firth projects all failing to agree terms with their preferred contractors (Westwood, 2005).

Thus, by 2006, progress on the 18 UK Round 1 projects allocated in 2001 was slower than expected. By that year, all Round 1 should have been completed but in fact only four were operational, three had not even received planning approval, and one had been abandoned (HoC, 2006). The remainder were in varying stages of development though two of these would also subsequently be withdrawn.

Reporting in the same year, Westwood (2006) noted that contracts should have been progressing on larger wind farms and costs should have been falling, yet neither was the case. Contract negotiations on future projects were stalling and the costs of offshore wind development were escalating. Only one full UK project would be completed in 2006 and only one more the following year. By the end of 2007, the installed operational capacity of Round 1 was less than 400MW and at least one developer had switched focus from Round 1 to Round 2 (reflecting the desire for larger installed projects) to Round 1's detriment (BVG Associates, 2007).

By 2007 the typical timeline for a large UK offshore project was estimated to be seven years with three years in planning/consenting[7] (BVG Associates, 2007). The wind farms at Lynn and Inner Dowsing did not start generating until 2008 whilst 2009 finally saw the

7 Industry commentators expect Round 3 timelines to be shorter, in particular because of improvements to the planning and consents process

completion of Rhyl Flats. By June 2010, Round 1 projects totalling approximately 500MW have still to be completed and another 400MW of initially planned capacity has been withdrawn (see Table 3.1 of Chapter 3, section 3.2.1). However, this shortfall should be partially made up by the additional 285MW of Round 1 capacity planned under Round 2.5.

4.2.2 Progress in Round 2

The results of Round 2 were announced in December 2003 and gave 15 companies or consortia the rights to develop over 7GW of offshore wind capacity. However, as early as 2005 many Round 2 projects were already facing delays (Douglas-Westwood Limited and ODE Limited, 2005), and a year later only four of the 15 projects had got as far as making planning applications to the DTI (HoC, 2006).

By the time the government's 2006 Energy Review was published, there was a growing realisation of the technical difficulties, rising costs, and supply chain limitations of offshore wind development (BVG Associates, 2007). The increase to 1.5 ROCs for offshore wind power in the 2007 Energy White Paper was generally well received. However, major issues regarding planning uncertainties and timescales were compromising both onshore and offshore aspects of offshore development.

Industry commentators argued that the economic gap between capital costs, expected operational costs and revenue for most projects remained too large for substantial industry commitment (BWEA, 2006). The report noted that under the existing RO and capital grants regime, Round 1 projects had been built at an average rate of only one per year, and that there were still no signs of the stable pipeline of projects required by the supply chain to drive forward investment in Round 2 (BWEA, 2006). Despite this, some commentators remained optimistic. ODE Limited (2007), for example, suggested that the target for the commencement of the first Round 2 projects remained 2007 and it was anticipated that costs for implementation would be up to 20% less than for Round 1 projects.

The reality however was that by 2008 some 5GW of Round 2 projects were still to even clear the planning system (BWEA, 2008) and the time it was taking for projects to move through the site assessment and consenting procedure was considerable. Aubrey (2008) noted with regard to Round 1 that the duration from the award of a site lease to actual installation was rising to 8-9 years for many proposals, sometimes more. In the opinion of the Carbon Trust the planning process for both onshore and offshore wind was unsatisfactory given the time taken to go from application to approval and the complexity of dealing with multiple planning bodies (Carbon Trust, 2008). The result was not only long delays for building new capacity but also developers withdrawing from projects entirely[8]. In consequence, Round 2 capacity delivery was predicted (i) to have a longer 'tail' than previously foreseen with the BWEA projecting around 1.5GW still to be built after 2015; and (ii) to fail

8 But see sub-section 4.3.2 'Planning and consent' for information on more recent changes to the planning process.

to reach planned levels, falling approximately 1GW short of the original nominal figures announced in The Crown Estate's Round 2 leasing process (BWEA and Garrad Hassan, 2009b). This shortfall could be made up by the additional 1.4GW of Round 2 capacity planned under Round 2.5.

In addition to consent/planning issues the 2009 report by the BWEA and Garrad Hassan also identified several other sources of delay including developer resource limits; waiting for transmission grid upgrades; weak economics; construction delays; and shortage of wind turbines (BWEA and Garrad Hassan, 2009b). Together, these have been either a source or symptom of the cost escalations experienced in the offshore wind industry from the mid-2000s onwards and provide the context in which plans for Round 3 are being prepared. It is to these cost escalations that the report now turns.

4.2.3 Cost escalation from the mid-2000s

By 2005 it was becoming evident that offshore wind costs were increasing. This was contrary to early expectations and, as noted in Chapter 2, it now appears that learning curves were applied to the offshore wind sector at a premature and unrepresentative stage where the amount of installed capacity was too small and thus the market data were inadequate.

Costs had risen since the first of the Round I projects were installed and contractors were becoming increasingly aware of the realities of undertaking large contracts bearing high risk. Indeed this in itself led to project delays (Westwood, 2005). Approximate costs per MW installed were now running at between €1.6m and €1.75m, well above the contemporary target figure of €1.4m/MW.

For 2006/2007, a range of capital, O&M and generating costs were reported in the literature. Capex was between £1,236,000/MW and £1,731,000/MW (PB Power, 2006); (HoC, 2006); (DTI, 2006); (E&Y, 2007); (ODE Limited, 2007). O&M costs were estimated to be between £45,000 and £66,000/MW/yr (excluding transmission use of system charges) (E&Y, 2007). Levelised costs ranged between:

- £55 and £72/MWh estimated by EDF; £55 and £70/MWh estimated by Centrica; £62 and £84/MWh estimated by E.ON (HoC, 2006)
- £56 and £88/MWh estimated by 2006 Energy Review (DTI, 2006)[9]
- £55 and £90/MWh estimated by (PB Power, 2006)
- £81 and £101/MWh estimated by (E&Y, 2007).

Costs continued to escalate in 2007 with the Rhyl Flats wind farm (completed in 2009) costing over £2 million/MW installed. Costs had risen to the point where the biggest owners/developers (the major utilities) were re-assessing the rates

9 An extended range reflecting full sensitivities to capex, discount rate, O&M costs, load factor and interest rate margin was estimated at between £55 and £110/MWh. Assumptions underlying the above values were capital costs of £1,532,000/MW, O&M costs at £46/MWh, a 20 year lifetime and generating availability of 33% (DTI, 2006).

of return on their development portfolios (Douglas-Westwood, 2008).

By 2008 capex had escalated to between £2.18m and £3.05m/MW installed whilst energy costs ranged from £76 to £118/MWh (Carbon Trust, 2008). This compared with an average cost of energy for the first four Round 1 projects (completed between 2003 and 2006) of £69/MWh (Feng et al., 2010). By this time offshore generation was at least 60% more expensive than onshore (Carbon Trust, 2008).

The following year, Ernst & Young (2009) reported that average capital costs had doubled over the previous five years to more than £3.2m/MW in 2009 (for projects due to be completed in 2012). Ernst & Young (2009) noted that total capital costs had increased by approximately 30% over the period 2006-2008 (contracted costs) and that this trend had continued through to 2010-12 (current 2009 quoted costs). Levelised energy costs showed a 58% increase between 2006 and 2009 from £91/MWh to £144/MWh (E&Y, 2009).

In 2009, following a review by the government, the ROC multiple for offshore wind was increased to 2 ROCs per MWh. Offshore developers had been claiming that a combination of falling brown power prices and several years of rising costs meant that future investments could fail to make hurdle rates of return consistent with offshore risk profiles. Nearly 3000MW of already consented capacity was believed to be in this situation (RAB, 2009).

In 2010, the majority of industry commentators were content that capex figures reported by Ernst & Young a year previously were still broadly in line with current prices. On this basis a typical mid-depth, mid-distance UK project is £3.2m/MW with levelised costs at £144/MWh. A recent report by Mott MacDonald (2010) suggests a current capital cost range between approximately £2.3m and £3.6m depending on whether the project is 'first of a kind' (FOAK) or 'nth of a kind' (NOAK). Levelised costs range from approximately £149 to £161/MWh assuming a 10% discount rate.

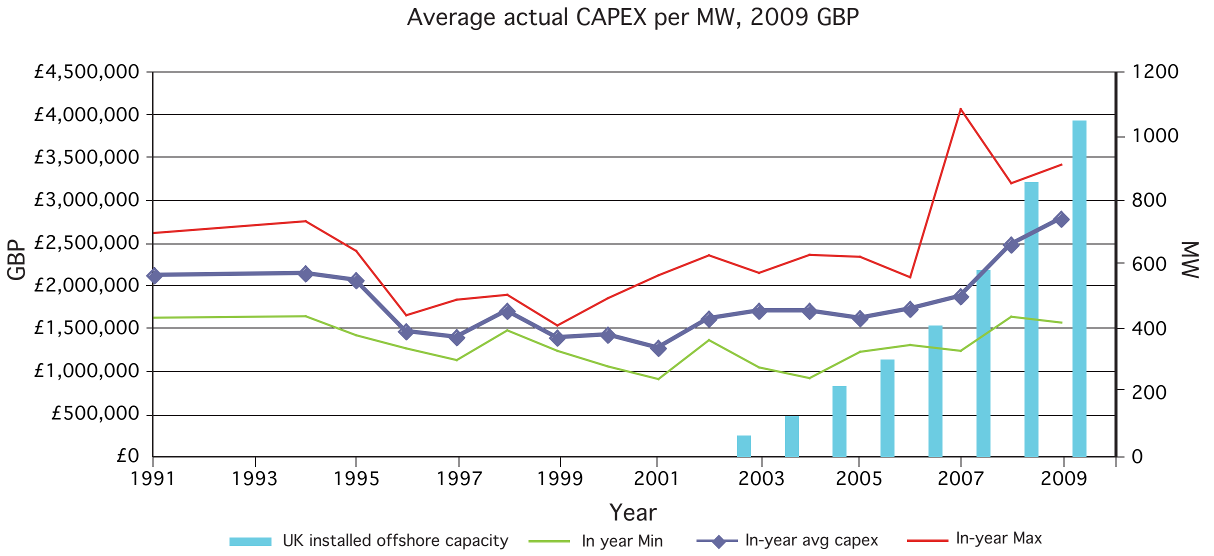
The costs of offshore wind farms differ according to circumstance, but the range of data reviewed above suggests that a cost range of between £3.0 and £3.5m/MW and £140 - £150/MWh is not unreasonable as an approximation. Levelised costs of £150/MWh approximate to an inflation-adjusted rise of around 50% from the mid-2000s, and can be contrasted with an increase in levelised costs of roughly a third (from and inflation-adjusted £66/MWh to £88/MWh) for onshore wind during the same period (DTI, 2006) and (Mott MacDonald, 2010).

It is too early to detect clearly the trend going forward. However the reported cost of a recent Round 2 project, Gwynt Y Mor, agreed in June this year (approximately £2.9m/MW including export cabling) (RWE, 2010), provides some evidence of a 'peak' and possible slight fall relative to 2009 levels.

4.2.4 Summary of reported actual capital costs from 2005

Figure 4.1 presents the in-year average actual capex per MW installed for offshore wind projects reported in the literature

Figure 4.1 In-year average actual capex, (from UKERC TPA analysis)



reviewed by the UKERC TPA team. As for Figure 2.2 in Chapter 2, amounts have been converted from the original reported currency into GBP at the exchange rate prevailing at the year of the estimate, and inflated to 2009 values using ONS indices.

As was also noted in Chapter 2, the averages mask a significant range of reported costs within each year, with the difference between the highest and lowest in each year from 2005 being between approximately £1m and £2m per MW (compared with a £0.5m to £1.0m range for up to 2005). The cumulative installed capacity of UK offshore wind is shown on the right hand axis. See Annex 2 for the full plot of the underlying data.

4.3 Recent estimates of medium term costs

4.3.1 Estimates in 2008/9

In 2008, the Carbon Trust estimated that contemporary offshore wind levelised costs lay in a range between £76 and £118/MWh depending on depth, distance and load factor (Carbon Trust, 2008) with an average of just over £100/MWh. Capital costs ranged between £2.18m and £3.05m/MW installed with an average of approximately £2.6m/MW. Using three different learning rate scenarios, the Carbon Trust estimated that by 2015 levelised costs could fall by 13-14% (with a 9% learning rate), by 19-21% (13% learning rate), and by 35-37% (15% learning rate). Using a 2008 average of £100/MWh produces modelled projections of £86-87/MWh, £80-81/MWh, and £63-65/MWh respectively.

The following year the report by the BWEA and Garrad Hassan used a higher capex figure of £3.1m/MW (for projects recently contracted or likely to be contracted shortly) from which to estimate future costs. The report noted that the consensus in 2009 of key industry players was for a slight rise in the next two years followed by a slight fall by 2015 (BWEA and Garrad Hassan, 2009a). Whilst acknowledging the increasing technical demands, especially on foundations and installation activities, the main factors cited for an anticipated reversal of recent costs escalations were:

- Increased wind turbine supply arising from both additional investment by existing suppliers and from new entrants to the offshore market.
- Longer-term contractual arrangements in place.
- Eased commodity prices.
- General increase in contractor competition.
- Increasing efficiency including standardisation.

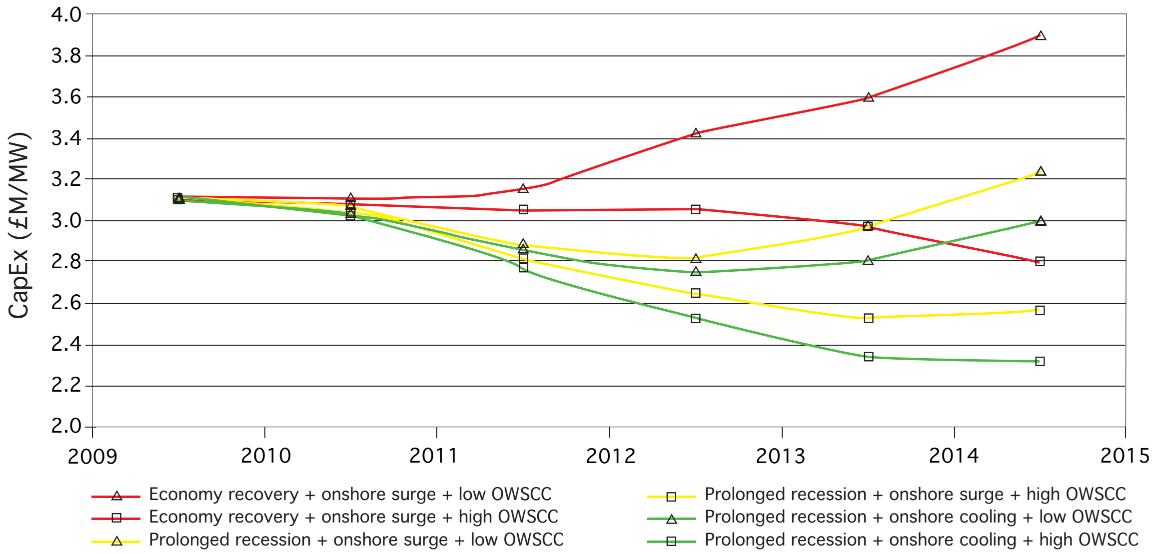
The BWEA/Garrad Hassan report integrated a range of industry views canvassed through a consultation exercise with historical data on cost trends and their own analysis of the sensitivity of capital costs to various industry drivers. Using a capex model, they projected five-year future cost trends under various macro-economic and industry assumptions. The relationship between macro-economics and industry supply chains was considered to be fundamental to formulating an outlook of future capital costs as was the interaction between the supply chain for the offshore wind industry and those of other industries, especially onshore wind. Hence the cost trend scenarios were formulated with reference to the global economic outlook in general, the outlook for onshore wind, and the overall level of confidence in the supply chain for offshore wind. The scenarios modelled were:

- Economic recovery with onshore wind surge: "Green-driven growth"; with either low or high offshore wind supply chain confidence.
- Prolonged recession with onshore wind surge: "European utilities look landwards"; with either low or high offshore wind supply chain confidence.
- Prolonged recession with onshore wind cooling: "European utilities look seawards"; with either low or high offshore wind supply chain confidence.

All prices were considered at 2009 levels and the influence of the move towards offshore transmission regulation (the OFTO regime) was taken to be neutral for the purposes of the study. The results are summarised in Figure 4.2.

Figure 4.2 shows a significant level of divergence between the various scenarios with the difference between the most optimistic and pessimistic being 51% at mid-2014. This 'spread', said the report, was a reflection of both the uncertainty over macro-economic and industry specific factors as well as the high level of sensitivity to which offshore wind capex is subject. One striking finding from the scenario results is that offshore wind capital costs are inversely proportional to both economic recovery and the growth of onshore wind.

Figure 4.2 Summary of five year capex projections (BWEA and Garrad Hassan, 2009a)



Notes: OWSCC – Offshore Wind Supply Chain Confidence; assumes a base case 2009 Capex of £3.1m/MW

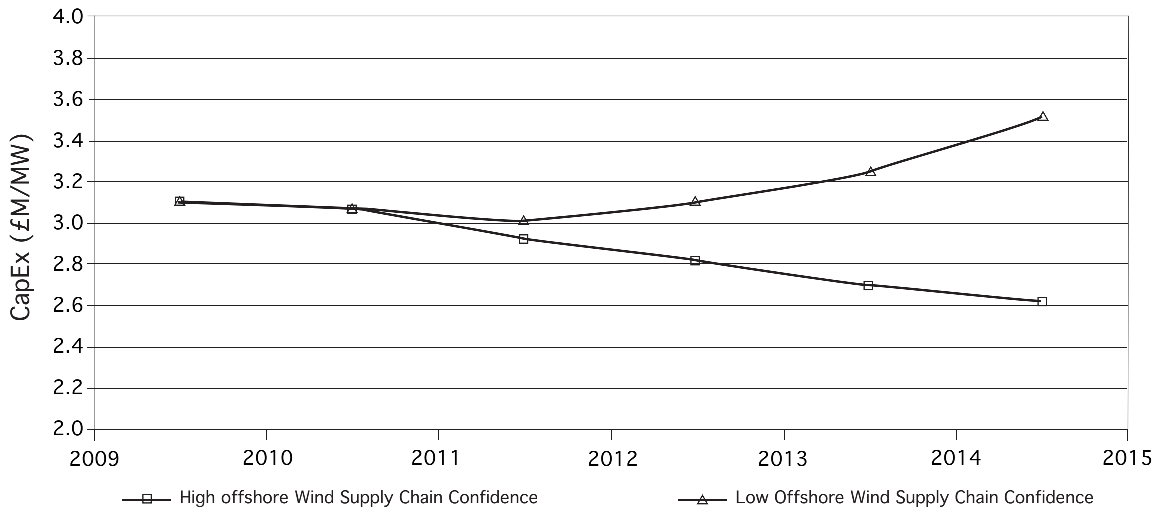
The results also demonstrate the high importance of the offshore wind supply chain response to shifts in macro-economics and onshore wind growth trends. For example, the average mitigating effects of high confidence is 24% at mid-2014 with two of the three high confidence scenarios leading to an overall reduction of capex.

However, because both macro-economic conditions and the development of the onshore wind industry are outside the control of the offshore wind sector, the BWEA/Garrad Hassan report also considered it useful to consider the scenario results with a 'neutral' outlook focusing simply on the level of supply chain confidence within the offshore wind arena. The results demonstrated the criticality of supply chain confidence when considering the costs outlook for offshore wind (Figure 4.3).

The 'high confidence' scenario implies the beginnings of a successful bifurcation of the onshore and offshore supply chains, thus creating a dedicated industrial base for the offshore sector. The projections suggested that such a shift could reduce capital costs to the range £2.3m to £2.8m/MW by 2015. By contrast, if industrial momentum were lost due to the supply chain losing confidence in the viability of the sector, project capex is likely to rise over the next five years, with the projections suggesting a range of £3.0m to £3.9m/MW by 2014 (BWEA and Garrad Hassan, 2009a).

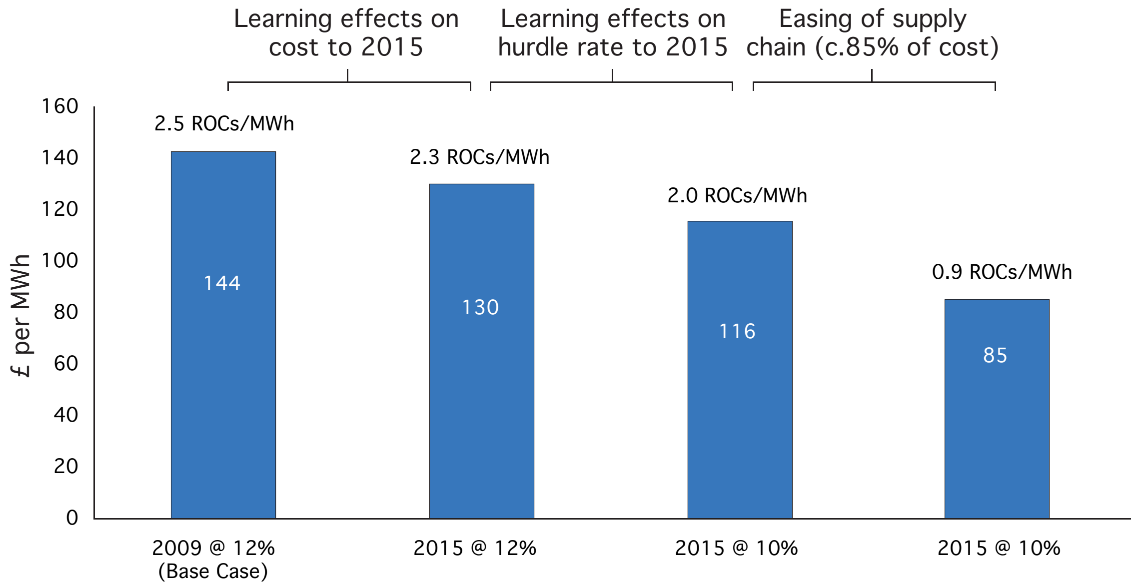
Also in 2009, Ernst & Young produced a report for DECC on the 'Cost of and Financial Support for Offshore Wind' (E&Y, 2009). Using estimated current and future project costs (calculated in January 2009 real terms), E&Y created a discounted cash flow model to derive levelised costs for projects reaching financial close in 2009 and in 2015.

Figure 4.3 Environment-neutral capex projections (BWEA and Garrad Hassan, 2009a)



As more offshore wind capacity is built and operational experience increases over the next five years the E&Y report has anticipated learning effects to lead to a reduction in levelised cost. However, this expectation is contingent upon supply chain issues not pushing prices in the other direction – a critical factor already noted on several occasions herein. By applying learning effects to the current cost of offshore wind, Ernst & Young (2009) suggested that the levelised cost could reduce by around 10% by 2015. Figure 4.4 shows the possible decrease in

Figure 4.4 Cumulative decrease in levelised cost on current Round 1 and 2 projects if learning effects are included (at specified hurdle rates) (E&Y, 2009)



Note that all modelling has been performed using post-tax real discount rates. Post-tax nominal rates are approximated by adding 2% to all post-tax real numbers. Source: E&Y analysis levelised costs (and RO banding levels) on contemporary projects (i.e. those near or at financial close in January 2009) as a result of learning effects and the easing of supply constraints in the offshore wind sector. The analysis models two discount rates – 12% and 10%.

The European Wind Energy Association also published a report in 2009, which estimated the medium-term cost development of offshore wind power also using learning curve methodology, though relative to a 2006 baseline (EWEA, 2009a). These medium-term cost predictions were made under the following conditions:

- Manufacturing capacity constraints for turbines will continue until 2010. A more balanced demand and supply is not expected to occur before 2011.
- The total capacity development of wind power is assumed to be the main driving factor for the cost development of offshore turbines, since most of the turbine costs are related to the general development of the wind industry.
- Thus, the growth rate of installed capacity is assumed to be a doubling of cumulative installations every three years.
- For the period between 1985 and 2004, a learning rate of approximately 10% was estimated (citing Neij, 2003). In 2011, this learning rate is again expected to be achieved by the industry up until 2015.

Based on the above, the average cost of offshore wind capacity was expected to decrease from €2.1m/MW in 2006 to €1.81m/MW in 2015, or by approximately 15% (Table 4.1). Note that the EWEA's cost figures are substantially lower than the UK experience where, for example, current capex is over £3.0m/MW. Whilst there is a considerable spread of costs, from €1.55m/MW to €2.06m/MW, the highest EWEA figure (forecast in 2015) is fully one third less than current UK capital costs.

Finally, it is worth noting that the UK government's view in 2009 was that the increase in offshore wind costs would be short term (DECC, 2009) and costs would reduce over time as the technology is industrialised, due to:

- increasing competition in the supply chain
- reducing risk due to technology developments and standardization
- economies of scale.

DECC acknowledged that site selection would also play a critical role in progressing economic offshore wind

Table 4.1 Estimates for cost development of offshore wind turbines until 2015, constant 2006-€. (EWEA, 2009a)

	INVESTMENT COSTS, MILLION €/MW			O&M	CAP. FACTOR
	Min	Average	Max	€/MWh	%
2006	1.8	2.1	2.4	16	37.5
2015	1.55	1.81	2.06	13	37.5

development, and suggested that sites might be situated in shallower, closer to shore areas.

4.4 Estimates of long term costs

4.4.1 Estimates in 2008

In estimating possible offshore wind costs in 2020, the Carbon Trust's 2008 report on offshore wind also emphasised the primary importance of optimal project siting as well as the role of RD&D funding to develop technology and reduce costs. At its most optimistic, the report suggested that the investment required to deliver 29GW of offshore wind could be reduced by as much as 40% by 2020 – from £75bn to £45bn. This implies a very best case capital cost in 2020 of approximately £1.55m/MW. With regard to levelised costs, depending on site and load factor, and assuming a conservative 9% learning rate, the report estimated a reduction of 19% to 21% by 2020 i.e. resulting in a range between approximately £77 and £95/MWh (Carbon Trust, 2008).

The middle and high scenarios see the supply chain prioritise offshore wind and hence increase RD&D and maximise economies of scale, thus fulfilling potential technology cost reduction. The offshore turbine demonstrates a learning rate of 13% and 15% respectively for the middle and high scenarios, whilst the foundations and installation components exhibit learning effects of 10 - 20% derived from economies of scale. The middle scenario proposes a reduction of 29% to 30% by 2020, resulting in a levelised cost range between approximately £68 and £83/MWh. In the high scenario, the cost of energy reduces by 42% to 44% i.e. a range between £54 and £68/MWh.

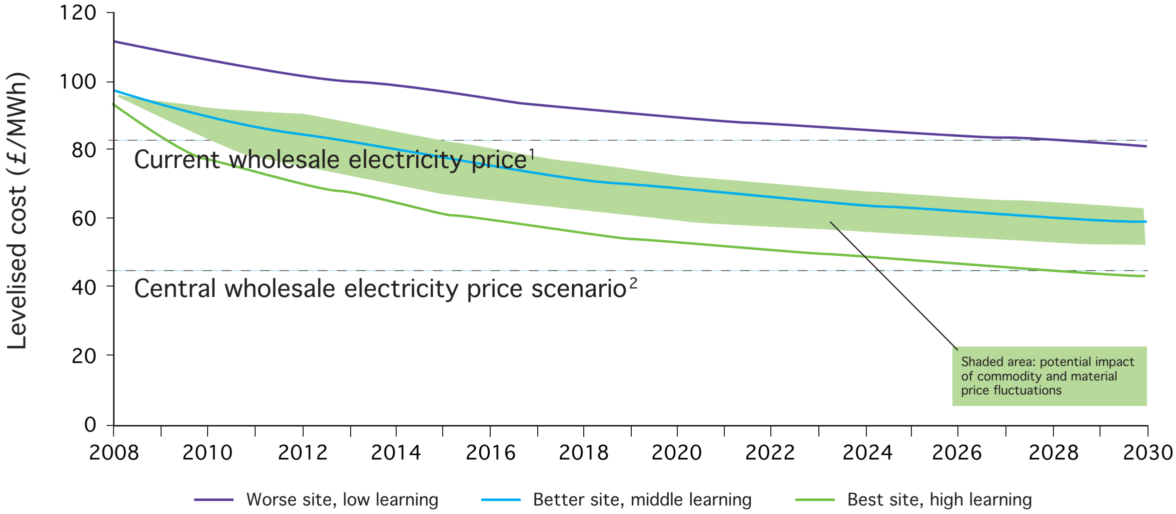
In addition, the Carbon Trust extrapolated different learning rates, based on different installation sites, in order to extend the forecast range out to 2030. The resultant levelised cost of energy ranges between approximately £40/MWh and £80/MWh (Figure 4.5).

As we have seen with the Carbon Trust's scenario work, the spread of costs can be considerable. Figure 4.6 shows a range of levelised costs estimated in recent literature. All costs shown relate to 2020 except for UKERC costs which are based on a systematic review of costs from a range of years (and German FITs (onshore wind section of graph) which are based on 2008 levels) (CCC, 2008).

4.4.2 Estimates in 2009

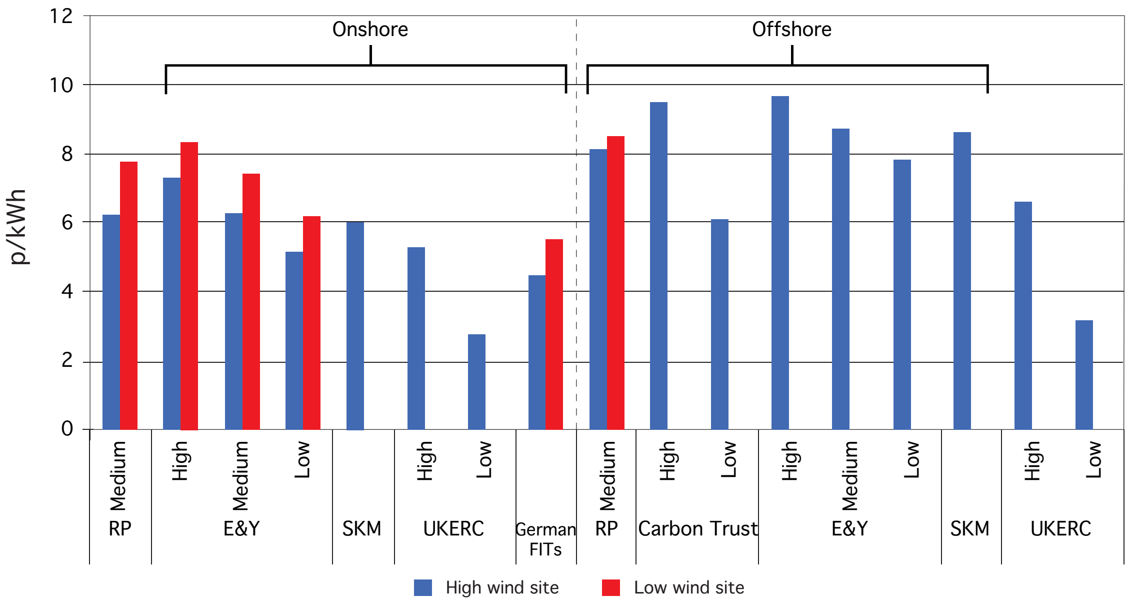
In 2009, the Committee on Climate Change estimated levelised costs in the year 2020 at £69 to £77/MWh, on the basis of a social discount rate (CCC, 2009). This is somewhat lower than its conclusions the previous year when the Committee reported that its forecast of likely levelised costs in 2020 lay towards the upper end of the estimates reviewed in the literature between £85 and £90/MWh (CCC, 2008). Meanwhile, the EWEA projected offshore capital costs of €1.3m/MW in 2020 and €1.2m/MW by 2030 (based on an assumption of €2.3m/MW in 2007) (EWEA, 2009b).

Figure 4.5 Offshore wind costs – site and learning scenarios (Carbon Trust, 2008)



Notes: 1. EnergyQuote, 27 June 2008; 2. BERR central energy price scenario
Original data from BCG analysis

Figure 4.6 Estimates of levelised costs for wind (CCC, 2008)



Source: SKM (2008), Ernst & Young (2006), UKERC (2006), Redpoint et al (2008), Carbon Trust (2008). Calculations of German feed-in-tariffs (FITs) based on www.wind-energie.de.and www.windworks.org

Note: £ 2008.

Looking further out, the IEA projected cost reductions in the longer term (see scenario map (Figure 4.7) below) (IEA, 2009). On the basis of a 9% learning rate, offshore investment costs would fall:

- 27% by 2030 implying capex of US$2.19m/MW at that time (and assumes O&M[10] costs fall by 25%).
- 38% in 2050 implying capex of US$1.86m/MW at that time (and assumes O&M[11] costs fall by 35%).

Note however, the starting assumption of US$3.0m/MW for capital costs whereas the current UK experience (expressed in US dollars) is over US$4.5m.

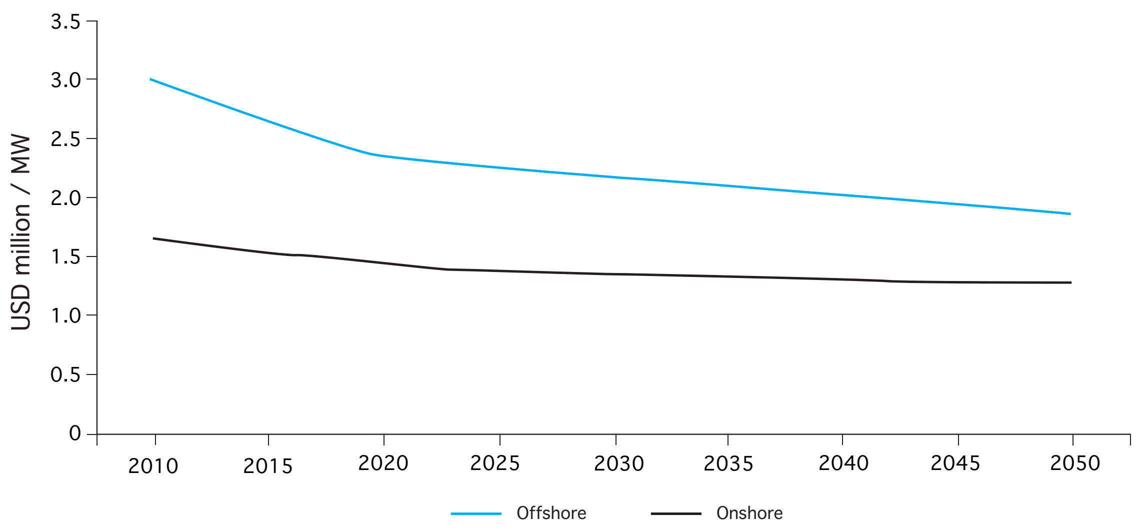
Also looking at mid-century, the European Commission's PRIMES capital cost model assumes capex of €1.16m/MW in 2050 (Blanco, 2009).

Finally, modelled scenarios in the UK Energy Research Centre's 'Energy 2050' report used a capex range between approximately £500,000 and £850,000/MW by mid-century. The higher baseline figure assumes an annual cost reduction rate of 1% up to 2020 and 0.5% thereafter. The lower 'accelerated technological development' figure assumes an annual cost reduction rate of 3% up to 2020 and 1% thereafter (UKERC, 2009).

4.4.3 Summary of forecast capital costs

Figure 4.8 presents a summary of the forecast capex values reported in the literature reviewed by the UKERC TPA team, and shows the in-year average

Figure 4.7 Scenario projections for development of onshore and offshore wind investment costs (USD/MW) (IEA, 2009)



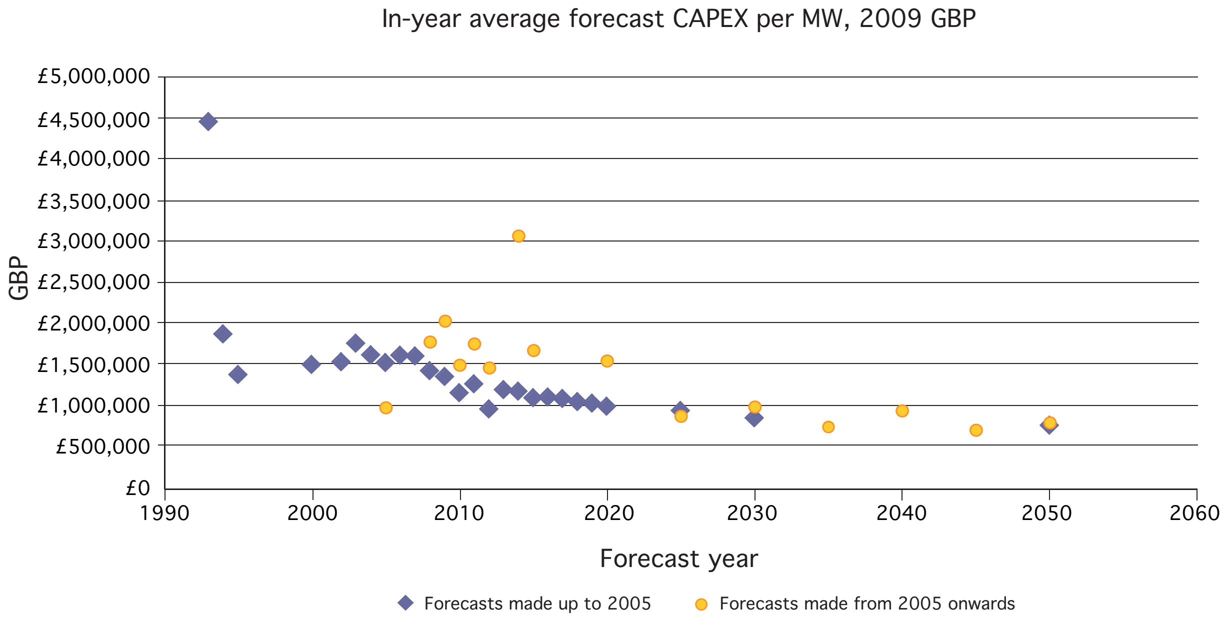
Source: SKM (2008), Ernst & Young (2006), UKERC (2006), Redpoint et al (2008), Carbon Trust (2008). Calculations of German feed-in-tariffs (FITs) based on www.wind-energie.de.and www.windworks.org

Note: £ 2008.

10 The IEA 'O&M' definition includes service, spare parts, insurance, administration, site rent, consumables and power from the grid.

11 As per footnote 10.

Figure 4.8 Forecast capex, comparing pre- and post-2005 estimates (from UKERC TPA analysis)



forecast costs for two groups, one consisting of those forecasts made up to 2005, and one of those forecasts made from 2005 onwards. Amounts have been converted from the original reported currency into GBP at the exchange rate prevailing at the year of the estimate, and inflated to 2009 values using ONS indices. See Annex 2 for full details.

The data reinforce the message that analysts have consistently expected costs to fall over time. What *changed* after 2005 is that forecast costs in the relatively near future were higher, but were still expected to fall in the longer term, returning to broadly the same level as earlier forecasts. Since this implies a higher rate of cost reduction, it raises the question as to what is influencing these expectations. There may be good reasons to hope that long run costs can be reduced a great deal, but it is important to ensure that this is based in reasoned analysis. It may be that long run costs become clearer in the period to 2015, when a better grounded basis for assessment becomes available.

4.5 Cost escalation drivers

4.5.1 Overview

In section 4.2 we saw how early optimism regarding future offshore wind costs gave way, from the mid-2000s onwards, to significant increases in actual costs. Section 4.5 now examines the drivers behind these cost escalations.

For obvious reasons, offshore wind generation is inherently more expensive than onshore - indeed, a recent report by Mott MacDonald (2010) shows that onshore wind is the cheapest of the low carbon technologies being deployed at scale in the UK. Foundations for offshore wind are more substantial and the laying of them is far more complex. Installing wind farms at sea is a much greater challenge, usually limited to summer periods but still exposed to severe weather risks - and the windier the site, the greater the risk. Accessing turbines for operation and maintenance also entails challenges and risks. Moreover, the wind turbines themselves are more expensive than onshore ones (approximately 20% more) (ODE Limited, 2007) and need to operate in a more or less continuously hostile environment where reliability is of even greater importance, given the difficulty of maintaining wind turbines at sea (Carbon Trust, 2008).

Nevertheless, over and above such considerations, offshore wind costs have increased dramatically since the mid-2000s. Even during the post-boom credit crisis of 2007/2008, costs continued to rise although there is now some signs that a possible plateau has been reached. In recent years, offshore wind commentators have suggested a range of reasons for the increase in capital, O&M, and energy generation costs[12]. These drivers may be categorised as either (i) 'intrinsic' or (ii) 'external', reflecting the extent to which offshore wind developers and energy policymakers are able to influence them.

Intrinsic drivers include:

- depth (especially for foundation costs) and distance
- availability/reliability and load factor
- lack of competition in production of key components
- supply chain/infrastructure bottlenecks
- planning and consent
- operation and maintenance costs.

External drivers of cost escalation include:

- cost of finance
- exchange rates
- commodity prices.

The division between 'intrinsic' and 'external' is to some degree open to debate. For example, supply chain and infrastructure could be considered as external issues driven by market forces. However, we include such factors within the intrinsic grouping because the UK government has the potential to influence them through, for example, grants or regional subsidies.

4.5.2 Intrinsic drivers

Depth & distance

The need to develop and service installation sites that are further from shore and in deeper waters creates additional risk and technology challenges and, where not compensated by higher wind speeds and load factors, will increase costs. Snyder and Kaiser (2009b) point out that the distance to shore influences both construction and O&M costs. During construction ships will have to make a number of trips to load equipment therefore the closer an offshore site is to

12 Some industry commentators have suggested that in addition to the drivers explored in this chapter the increased ROC multiples have also contributed to recent cost rises.

port, the less expensive installation will be. During operation a maintenance crew will need to make regular trips to monitor and/or maintain the foundations, towers and turbines.

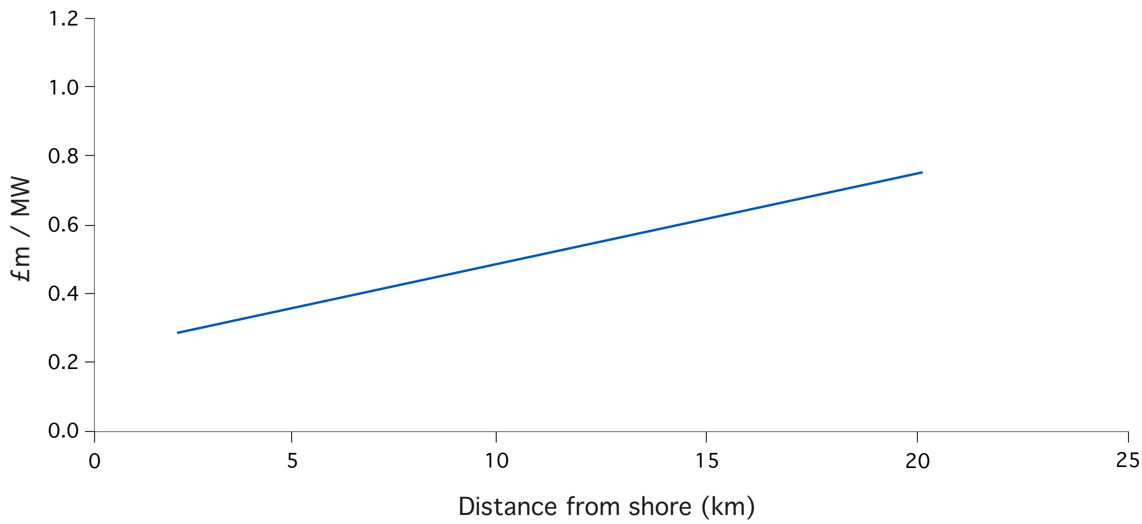
The distance to shore also dictates the amount of transmission cabling required. Figure 4.9 shows the evolution of electrical infrastructure costs versus distance from shore for a range of Round 1 and Round 2 projects, and indicates that the cost of electrical infrastructure is closely correlated to a project's distance (E&Y, 2009). Since more recent projects are located further offshore they incur higher electrical infrastructure costs than earlier near-shore projects. The impact of other factors on the cost of electrical infrastructure has been found to be relatively small by comparison (for example, Ernst & Young (2009) found little evidence of tight supply for electrical infrastructure components in 2009).

As in the oil and gas industry, water depth is also a primary factor and will play an increasingly important role in determining costs as wind farms are installed in ever deeper water. Figure 4.10 provides an example of how greater depth increases foundation costs.

Increasing depths increase the price of construction by making monopile and gravity foundations impractical and potentially requiring the use of more expensive, jacketed foundations and more expensive marine vessels for installation. On the other hand, Snyder and Kaiser (2009b) notes that depth and distance costs are likely to be (at least partially) mitigated by the increased turbine size typically associated with recent, more distant installations.

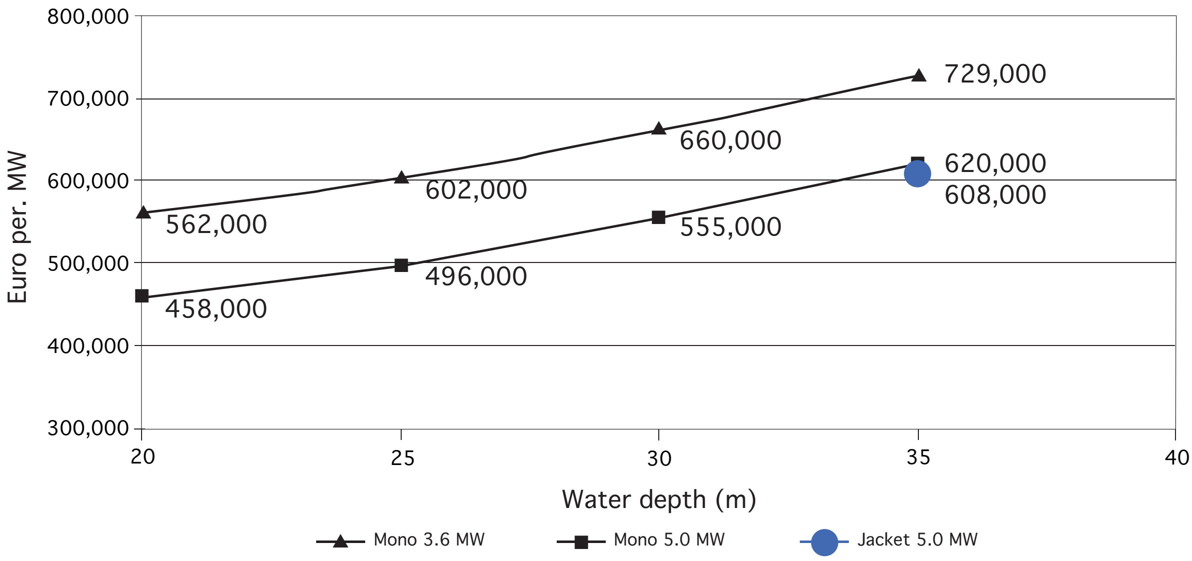
The Carbon Trust summarised the key depth and distance cost drivers as follows (Carbon Trust, 2008):

Figure 4.9 Electrical infrastructure cost vs. distance from shore (E&Y, 2009)



Source: Ernst & Young, DECC reference project data

Figure 4.10 Foundation costs as a function of depth (Ramboll Offshore Wind, 2010)



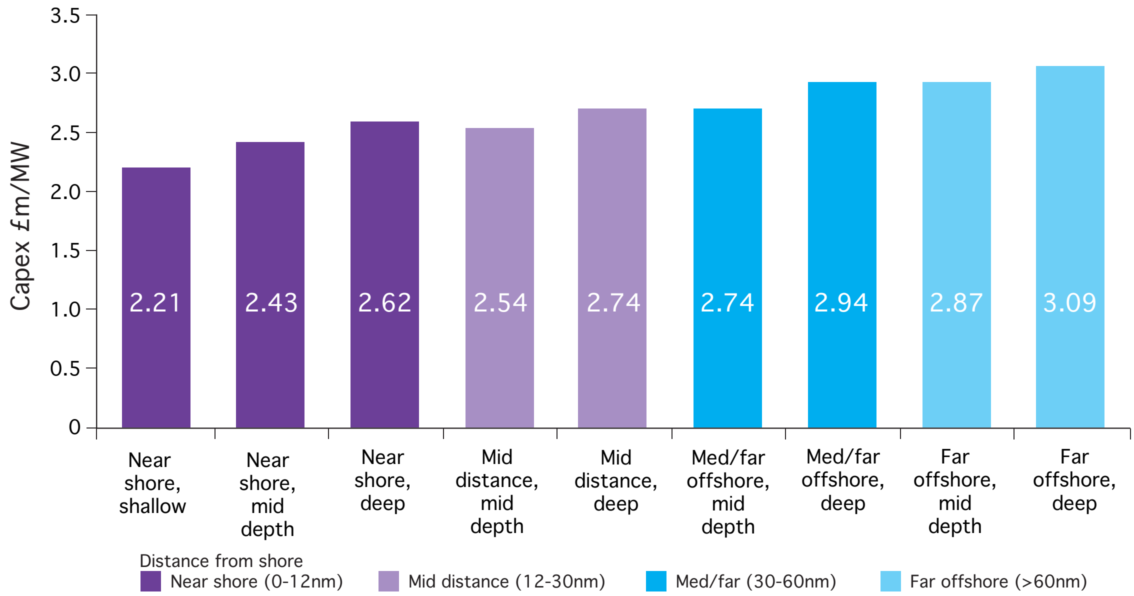
- *Installation* costs increase with both distance from shore and water depth; costs for sites more than 60 nautical miles (nm) from shore and in 40 to 60m of water are expected to be 230% higher than for sites less than 12nm from shore and in 0 to 20m of water.
- *Foundation* costs for sites in 40 to 60m of water are expected to be 160% greater than for sites in 0 to 20m of water.
- *Grid connection* for sites more than 60nm from shore may be by HVDC connection. Total grid connection costs for these sites may be 200% higher than for the sites less than 12nm from shore.
- *Operation and maintenance* costs vary with the expected replacement cycles of all the major components and as a result will increase over the lifetime of the wind farm, and also increase with distance from shore.

Site location is thus critical to the economics of an offshore wind development. The capex of different sites can vary by up to 40% (Carbon Trust, 2008) but revenues increase with wind speed because the power available from the wind is a function of the cube of the speed. If the wind speed doubles, its energy content will increase eight fold. A major advantage offered by offshore wind therefore is that wind speeds are generally higher and more stable than onshore wind sites. Turbines can be expected to operate at high capacity for a larger percentage of the time and this should give offshore wind a significant advantage over onshore generation in terms of energy productivity (ODE Limited, 2007).

Figure 4.11 and Figure 4.12 show 2008 capex and levelised costs for the main available UK site types.

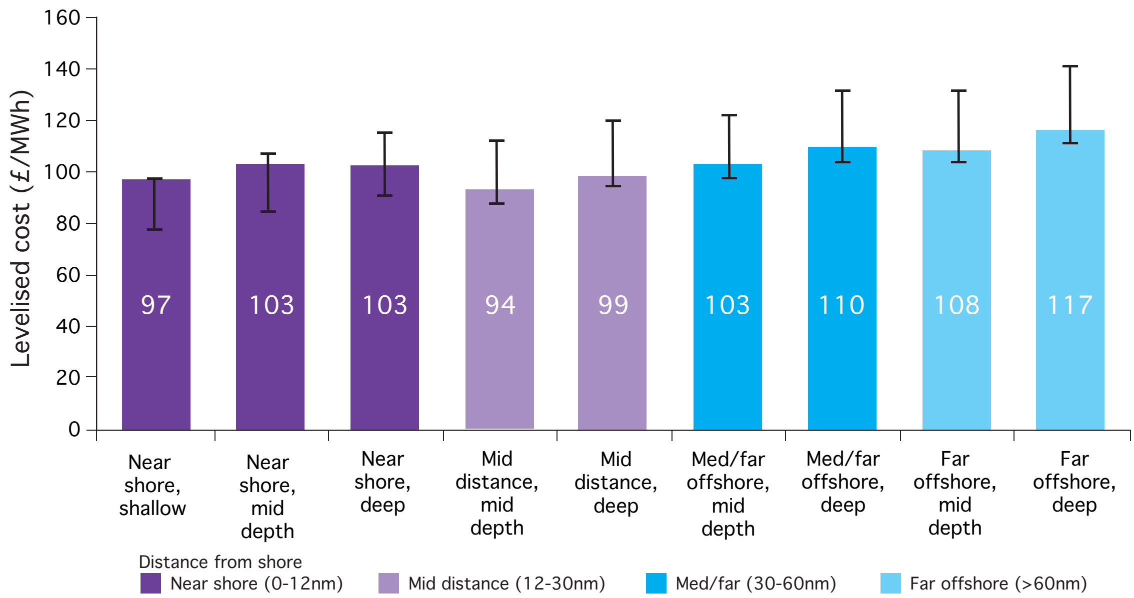
In terms of the sensitivity of the levelised cost to key drivers, the most important factor is the wind speed, followed by depth

Figure 4.11 2008 capex for 5MW turbines at different sites (Carbon Trust, 2008)



Note: Capex/MW includes offshore grid connection costs. Original data from SKM, BCG analysis

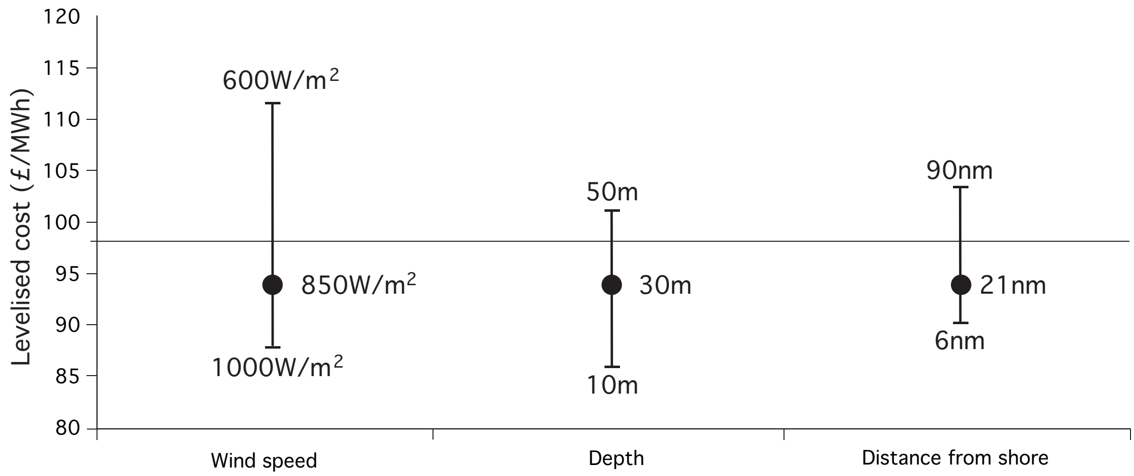
Figure 4.12 2008 average levelised costs for 5MW turbines at different sites, weighted by site/wind resource availability (Carbon Trust, 2008)



Original data from SKM, BCG analysis

and then distance (see Figure 4.13 for sensitivities to cost and revenue drivers). Thus the two most attractive site types as per Figure 4.11 and Figure 4.12 above are the near-shore, shallow water site with relatively lower capital costs (similar to

Figure 4.13 Sensitivities to main revenue and cost drivers (Carbon Trust, 2008)



Original data from SKM, BCG analysis

early Round 2 sites) and the mid-distance, mid-depth site that has higher costs but greater wind speeds. The latter has a higher capex of £2.54/MW versus the former's capex of £2.21/MW but lower levelised cost of £94/MWh versus £97/MWh thanks to the higher wind speeds of these sites (Carbon Trust, 2008). This illustrates the trade-off between increased costs at greater depth/distance and the (typically) greater resource availability at such sites.

Availability/reliability and load factor

As noted above, a major advantage offered by offshore wind is that wind speeds are generally higher and more stable than onshore sites. Snyder and Kaiser (2009a) suggests that moving onshore to offshore should lead to an increase in the capacity factor from roughly 25% to 40%. However, the load factor of a wind turbine is determined by two variables: the wind conditions and the *availability* of the wind turbine and related equipment – a measure of a wind farm's readiness to generate should wind conditions permit. For onshore farms, annual availability has typically been 97%, or above, and only 1% operate at less than 80% availability (Feng et al., 2010). 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). Feng et al. (2010) analysed the operational experience of UK Round 1 projects and found that at only 80.3% the average availability had indeed fallen well short of expectations.

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 approximately 40% for the Danish offshore wind farms (Wind Stats, 2009b, Wind Stats, 2009a). There is a direct correlation between availability data and reported load factors. Simple arithmetic indicates that if availability is reduced from 95% to 80% and wind conditions held constant then load factor will decline from approximately 35% to 30%. Moreover, the higher the theoretical load factor, the worse the impact of poor availability.

Poor availability was perhaps not anticipated because early farms proved to be reasonably reliable, the average annual availability of Denmark's well-established near-shore installation at Middelgrunden, for example, is over 93% (Larsen et al., 2005).

Competition in turbine manufacture

Turbine prices went up between the mid 2000s and 2009 for a range of reasons. Improving reliability to remedy the problems described above is one factor. As we discuss below, offshore turbines occupy a small niche relative to onshore markets and with strong demand from the US and elsewhere it is likely that a considerable 'niche premium' will attach to the offshore market. The supply chain constraints experienced by turbine makers will also have served to drive up costs and as we discuss in Section 4.5.3, UK offshore turbine prices have been profoundly affected by materials costs and currency movements.

Notwithstanding all the factors outlined above, much of the recent literature has noted the importance of the relatively small number of manufacturers engaged in turbine manufacturing for supply to the UK offshore wind industry (Carbon Trust, 2008), (E&Y, 2009), and (RAB, 2009).

The market has been dominated by Siemens and Vestas, until recently the only two turbine suppliers with significant offshore capability. Together they have accounted for 98% (48% and 50% respectively) of offshore turbines installed in the UK up to 2009 (E&Y, 2009) and have thus been able pass on high commodity and component costs to developers with relative ease. In addition, competition was further reduced in early 2007 when Vestas withdrew its 3MW marinised turbine from the market following gearbox problems. The Vestas turbine was not reintroduced until May 2008, thus making Siemens the sole supplier to the sector throughout 2007 and much of 2008 (Carbon Trust, 2008).

More recently, turbine manufacturers REpower and Multibrid have won large contracts with leading European utilities to supply their offshore wind projects (E&Y, 2009). Specifically designed for offshore use, their 5MW turbines are currently being tested at the Alpha Ventus site, Germany's first offshore wind park (Alpha Ventus, 2010). Additional manufacturers such as GE, Mitsubishi and Clipper are now entering or are expected to enter the market (BWEA and Garrad Hassan, 2009a). It is however, still too early to tell whether the increasing number of entrants to the turbine manufacturing market will significantly improve turbine costs for developers. Moreover, industry experts have stressed that it will take time for new entrants into the offshore turbine market to gain the confidence of UK developers and financiers.

Supply chain bottlenecks

Overview

Offshore wind power is still a relatively nascent industry that currently relies on both the onshore wind turbine supply chain and general offshore industries. Bottlenecks have been a symptom not only of a supply/demand imbalance across all the markets that these supply chains deliver to but also of the offshore wind market not being a strategic priority to them (Carbon Trust, 2008). With only 1 GW of UK offshore wind power delivered so far, for most companies in the supply chain to developers (e.g. turbine and other component manufacturers, vessel owners, and ports) offshore wind power has represented at most 10% of sales revenue. To date therefore, the offshore wind market has not been attractive enough for most companies in the supply chain to warrant the required level of investment. Instead, turbine manufacturers, for example, have focused on the onshore wind market (especially in the US), and for much of the rest of the supply chain offshore wind has represented less than 5% of sales (Carbon Trust, 2008).

This may be set to change with Wind Power Monthly (2010) anticipating a significant expansion in the supply chain, in particular in UK-based manufacturing capacity. So far, however, the relative immaturity of the supply chain for offshore wind components and support services appears to have resulted in market inefficiencies and contributed to significant cost increases particularly relating to the cost of procuring and installing wind turbines and foundations (E&Y, 2009). The sub-sections that follow identify and examine issues of delay and cost in the different parts of the supply chain.

Supply of components

By the mid-2000s, rapid growth in the US onshore industry was causing a global shortage of turbine components, delaying European offshore projects and forcing up prices. Noting that almost all UK Round 1 projects had been delayed by costs issues or problematic contract negotiations, Gordon (2006) suggested that significant responsibility could be directed towards the US Production Tax Credit (PTC) scheme.

This federal scheme gives a tax credit of $0.02/kWh of produced electricity for the first ten years of production from any renewable source, including wind (Snyder and Kaiser, 2009b). This fostered a low-risk, high-margin market in the US for turbine suppliers to sell into. Since inception, the PTC scheme has periodically expired leaving the US onshore wind market in the doldrums, but each revival of the incentive has created a surge in demand for turbines. The impact of the 'boom and bust' nature of the US market has been to encourage European turbine suppliers to target the US as a priority whilst the PTC is in play, effectively diverting turbines which might otherwise have been destined for the UK market (Westwood, 2006); (Aubrey, 2007).

By 2007, turbine supply was the dominant bottleneck (BVG Associates, 2007) with the UK offshore sector squeezed by onshore turbine demand from China, India, and elsewhere in Europe as well as the US, and by insufficient competition between turbine manufacturers (BWEA, 2008). Lead times for turbine delivery could be as much as two to three years and turbine supply was seen by developers as the major hurdle in achieving successful project completion (ODE Limited, 2007).

For their part, turbine manufacturers cited the supply of turbine components as key pinch points in the supply chain (BWEA, 2008). The increasing size of turbines had significant implications in terms of the number of gearbox suppliers who could reliably satisfy demand. The same problem, noted Aubrey (2007), applied to blades and bearings and towers - as well as to generators and transformers, and also to foundations. BVG Associates (2007), for example, reported that there were only two or three European suppliers of monopole foundations but also cautioned that if more entered the market this was likely to increase the competition for the steel plate used in their production.

In 2008, the Carbon Trust was still reporting supply chain bottlenecks in gearboxes, bearings, and forgings (as well as in cables, substations/transformers and vessels). Lead times could be up to three years for some components. The longest lead times were found in the supply of blades, bearings and generators. By then, some blade manufacturers, including market leader LM Glasfiber were reporting lead times of two to three years. Bearing manufacturers were quoting up to 32 months. No improvement to lead times was anticipated before 2010 although most of the major turbine manufacturers claimed to have already secured supply chain capacity to then (Carbon Trust, 2008); (Douglas-Westwood, 2008).

Douglas-Westwood Limited (2008) reported that the strong market and constrained turbine supply situation drove turbine prices upwards by 30% between 2006 and 2008. This is supported by Ernst & Young (2009) which studied the evolution of wind turbine costs over time for a range of UK Round 1 and Round 2 projects (see Figure 4.14). Turbine costs increased 67% from an average £0.9m to around £1.5m/MW over the five year period to 2011 (i.e. where financial close is expected in 2009).

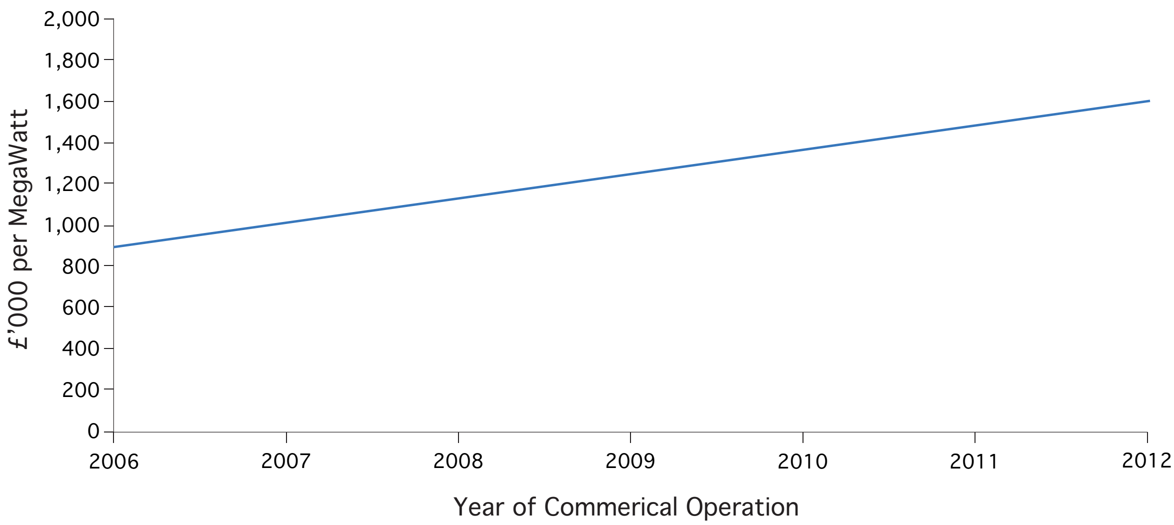
Port facilities

Whilst UK supporting infrastructure will naturally be a major issue for Round 3 developers given the huge size of the undertaking, port availability and quality are existing areas of concern for the industry. In the past UK ports have been judged as under-developed and expensive in comparison to continental ones and in need of local agency funding (Douglas-Westwood, 2008) and (BVG Associates, 2007). In the March 2010 budget, however, the government launched a £60m competition for investment in one or more UK ports (Wind Power Monthly, 2010).

Installation vessels

Offshore installation of foundations and wind turbines requires heavy lift vessels (HLV) and cable laying also requires installation craft. Although this part of the supply chain was not seen as a significant bottleneck in 2007, there was still insufficient confidence in the prospects for the offshore wind industry to stimulate the long charter of such vessels or the 'spec' construction of them (BVG Associates, 2007).

Figure 4.14 WTG cost at COD – indicative trend line 2006-2012 (E&Y, 2009)



Source: Ernst & Young, DECC reference project data

By 2008, the lack of available installation vessels was having an impact. New installation capacity for larger turbines in greater water depths was becoming paramount, but 'new builds' for the offshore industry were encountering significant delays due to high demand for vessels whose capabilities could span multiple marine industries including oil and gas (Douglas-Westwood, 2008). The result was that installation vessel companies were tied up with full order books and long-term contracts. A2Sea, for example, had a two-year waiting time; Oceanteam had ordered four new vessels with long term contracts already signed; and MVO had to charter back the 'Jumping Jack' installation vessel it had sold in order to complete its orders (Carbon Trust, 2008). Moreover, the market leader in turbine installation vessels was now booked until 2013 (Douglas-Westwood, 2008). In the previous five years vessel build costs had doubled, new vessel build time had extended to up to four years, and the lead times for cable installation vessels were expected to rise significantly in the next decade.

Electrical infrastructure

Between 2006 and 2007 the lead time for cable supply increased to 18 – 24 months. Meanwhile, the lead time for transformers – a key element of offshore substations –increased from 12 to 30 months over the same period (BVG Associates, 2007).

The problem continued into 2008 with the BWEA reporting developers experiencing difficulty in securing supplies of cables both for inter-array and connection to shore (BWEA, 2008). Douglas-Westwood (2008) noted that two suppliers currently dominated the cable supply sector and that new specialist players were finding it difficult to access the market. An additional issue was the UK's requirement for 3-metre cable burial depth which significantly increased time and costs because of the need for seabed ploughing.

Skills and labour

Some commentators have identified a shortage of skills as an industry concern, caused in part by competition for installation and service crews from the oil and gas industries and other offshore activities worldwide (BVG Associates, 2007); (BWEA, 2008). Analysts suggested that by 2008, a significant increase in the number of people with appropriate knowledge and experience would be required or lack of skills could very quickly become a major problem as the industry scales up (Douglas-Westwood, 2008).

Planning and consent

Planning and consent is one of the earliest issues – and first cost drivers - that a developer must face. The Round 1 consents process took considerable time, ranging from several months to, in the extreme case, a few years (ODE Limited, 2007). This consents process has been going through a learning curve as more is learned about the impact on the marine environment, navigational issues, grid connection and other aspects. Moreover, until late 2009, there have been three main consenting authorities applicable to offshore wind: DEFRA; the DTI and its successors; and the relevant local council's planning authority (ODE Limited, 2007). These factors have led to an increase in complexity and developers have therefore had to expend significant time and money in order to obtain consent.

Writing in 2008, the BWEA argued that sufficient resourcing across the government's departments and advisors was particularly urgent in relation to planning. The industry association noted that having consented approximately 3GW in the seven years since 2001, ten times that amount would now have to pass through the system in ten years in order for the government and the industry to meet its capacity objective by 2020 (BWEA, 2008).

However, one of the provisions of the 2008 Planning Act should significantly improve the situation. The Act is intended to streamline and improve the planning process for nationally significant infrastructure projects in England and Wales, including renewable energy proposals. It provides for a single consents regime with an independent Infrastructure Planning Commission (IPC) to take decisions. In the case of offshore wind farms, "nationally significant" is defined as any English and Welsh proposals with the capacity to generate over 100MW of electricity (DECC, 2009). The IPC was established in October 2009 and given the go-ahead to receive applications from March 2010. This should dramatically reduce the timeline for offshore wind farm approval from as long as ten years to less than three years in the future (Carbon Trust, 2008). At the time of writing (summer 2010) the coalition government intends to replace the IPC with a system that directs requests to the Secretary of State. It retains an ambition to streamline planning, however, and minimise delay (Douglas-Westwood, 2010).

Operation and maintenance costs

Operational performance and resultant maintenance requirements are especially important to the economics of a wind farm but in Round 1 operating costs have been greater than expected (and availability worse than expected). Much of this was due to the inadequate marinisation of onshore machines for the offshore environment (ODE Limited, 2007).

In Figure 4.15 below, Ernst & Young (2009) shows the evolution of forecast O&M costs over time (against Commercial Operation Date – COD) for a range of UK Round 1 and Round 2 projects. Total forecast O&M increase from £38,000 to around £60,000 per MW per annum – a 58% rise over the five year period to January 2009 (which reflects projects achieving COD up to and including 2012).

Ernst & Young (2009) suggested that increases in O&M costs may largely be driven by:

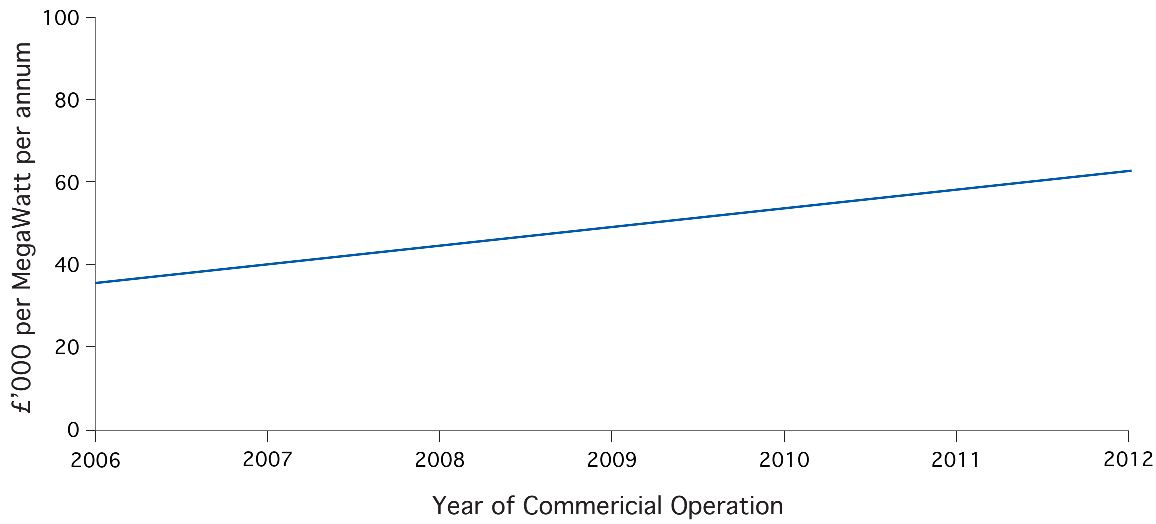
- Improved budgeting reflecting track record and experience gained from operating early projects where costs had perhaps been underestimated at first (e.g., better handling of post-installation repair work, frequency of parts replacement, performance and availability levels, accessibility).
- Evolution of O&M strategies which were historically formulated assuming a 20-year project life with limited preventive maintenance. With The Crown Estate lease periods now lasting 40 or 50 years, some participants are seeking to develop more proactive O&M strategies to extend asset and project life.
- Materials and services for O&M which have been affected by increases in labour, steel, and other commodity prices, as well as by the more recent strengthening of the Euro against Sterling (E&Y, 2009).

4.5.3 External drivers

Costs of finance

A significant development since 2007 has been the crisis in the global credit markets. Utility developers, who represent

Figure 4.15 Forecast O&M costs (years one-five) – indicative trend line 2006-2012 (E&Y, 2009).



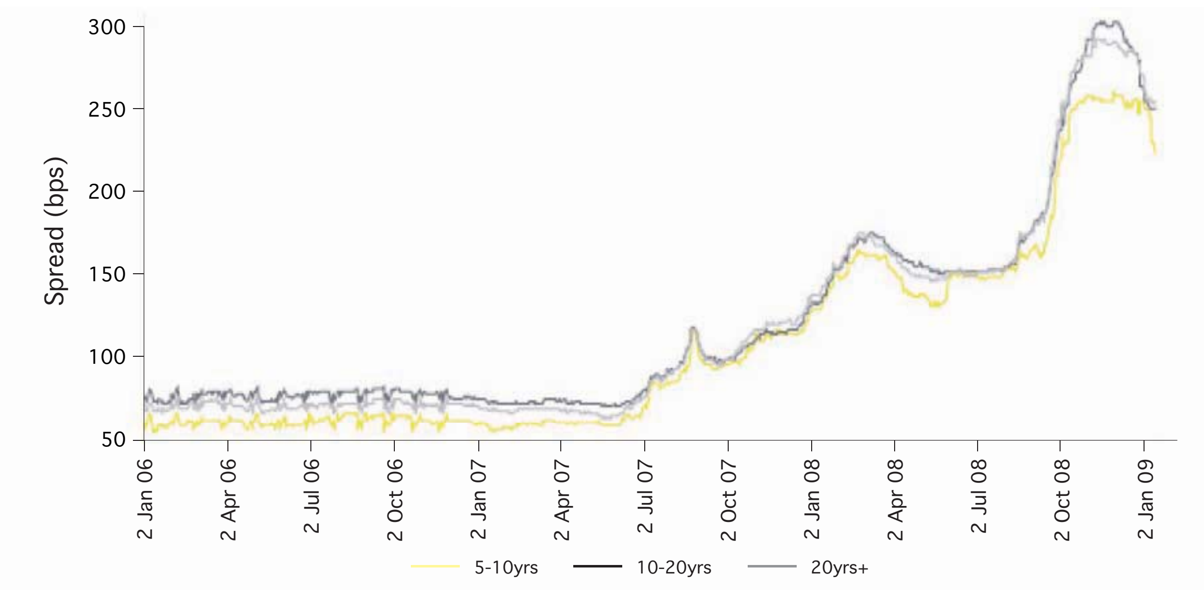
Source: Ernst & Young, DECC reference project data the majority of offshore wind capacity installed to date, have typically financed offshore wind projects using balance sheet financing (E&Y, 2009). Figure 4.16 below, charts utility bond prices from January 2006 to January 2009 and suggests that recent increases in the costs of financing new capital projects are a result of a higher cost of debt for these companies. Under normal expectations increasing experience in construction and operation should gradually reduce the risk premium for offshore installations resulting in a decreasing cost of capital. However, the significant rise in spreads for utility bonds since summer 2007 has led to a general rise in the cost of capital for these projects (E&Y, 2009).

With regard to future project financing, according to industry commentators the financial scale of Round 3 means that developers will be unlikely to be willing or able to fund construction of projects largely or entirely on balance sheet hence actual availability of capital could become a concern. Whilst the role of the proposed Green Investment Bank (GIB) is still under discussion, the GIB Commission has suggested that its focus should be on lowering investor risk, which may well improve access to capital for low-carbon projects including offshore wind developments. More far-reaching proposals include bringing investment in low-carbon infrastructure under the umbrella of a regulated asset base, with tax concessions for private and pension fund investors (Helm et al., 2009).

Commodity prices

Steel has been estimated to contribute approximately 12% of overall project costs (BWEA and Garrad Hassan, 2009a). The turbine nacelle is estimated to comprise 90% steel, and the transition piece (the section fixed to the foundation which carries the turbine tower) is primarily composed of steel (ODE Limited, 2007).

Figure 4.16 Sterling utilities bond indices (E&Y, 2009)



Source: Merrill Lynch indices, Bloomberg

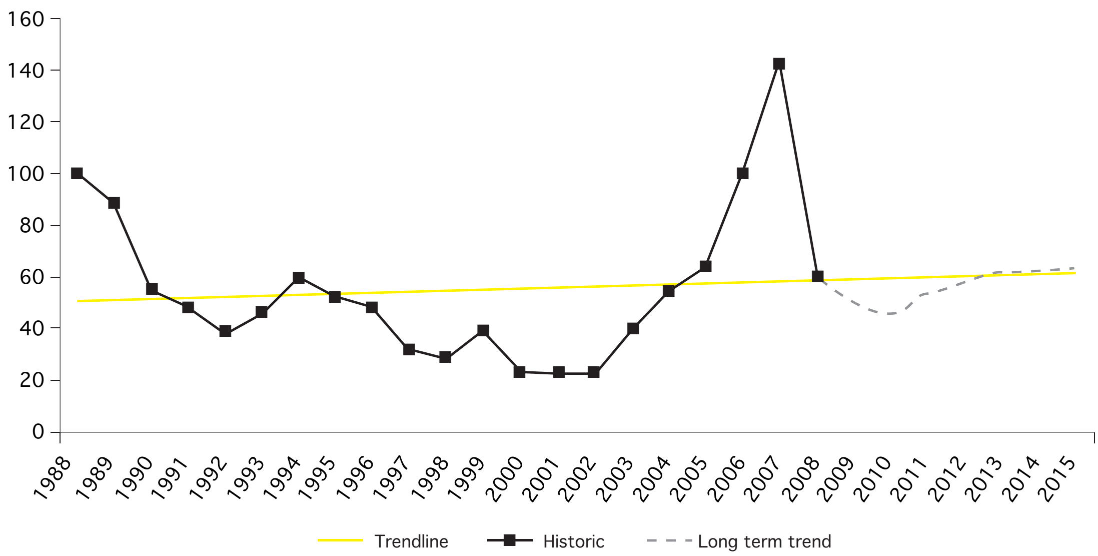
The increase in steel prices from the early 2000s to 2008 was thus a contributory factor to turbine costs rising from £0.9m to £1.5m/MW (67%) in five years (RAB, 2009). An historic analysis of steel prices is shown in Figure 4.17 below. From 2002 to 2007 the index experienced growth of 47% CAGR although in 2008 the steel price index fell by 58% returning to the long-term historic trend (E&Y, 2009).

In addition to the wind turbine itself, steel is used extensively in typical offshore wind foundations. Around three quarters of foundation costs relate to material costs and much of this is steel (E&Y, 2009). In consequence, a contributing factor to increased foundation costs (together with the strengthening of the euro against sterling) has been the rapid rise in steel prices in the second half of the decade. Figure 4.18 shows the evolution of foundation costs over time for a range of Round 1 and Round 2 projects. It shows that foundation costs have increased from around £250k to £700k/MW (a 180% increase) over the five years to 2009.

The cost of other commodities also increased from the early 2000s. Between 2002 and 2006 prices grew at 19% compound annual growth (CAGR). However, between 2007 and 2009 the commodity prices index fell by 5% CAGR although it was still substantially above the historical trend line. Analysis by the Carbon Trust suggests that if commodity and materials prices were to return to 2003 levels, overall offshore wind power costs would fall by 11% (Carbon Trust, 2008). Historic commodity prices are shown in Figure 4.19 (E&Y, 2009).

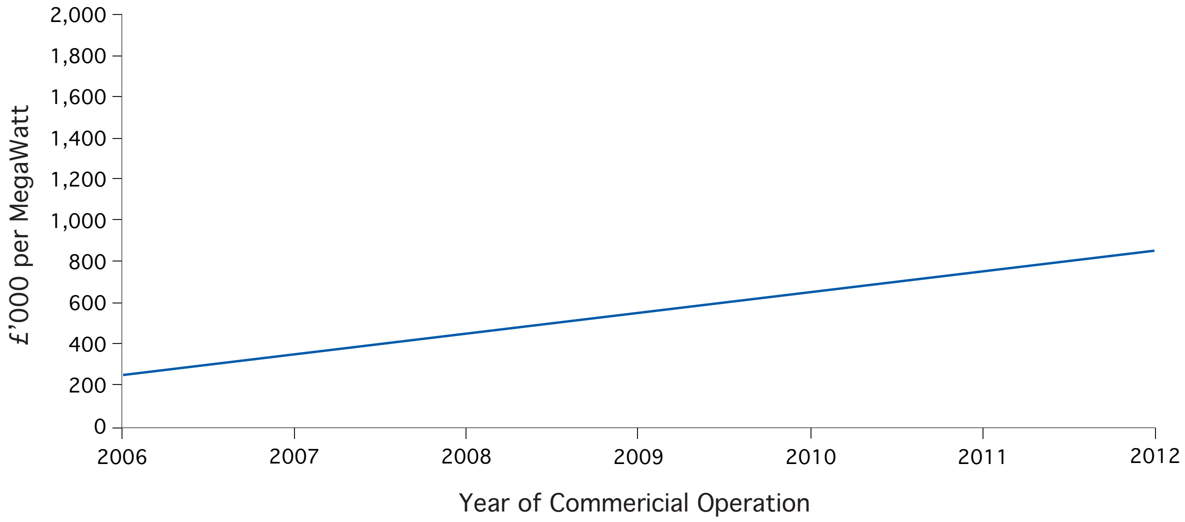
Globally rising commodity and materials costs between 2003 and the global credit crisis in 2007/2008 account for around half of the increase in turbine prices (Carbon Trust, 2008). Figure 4.20 shows the relative rise since 2003 in the main input prices. Figure 4.21 illustrates the proportional contribution of each of those

Figure 4.17 Steel prices – historic index rebased to 1988 (E&Y, 2009)



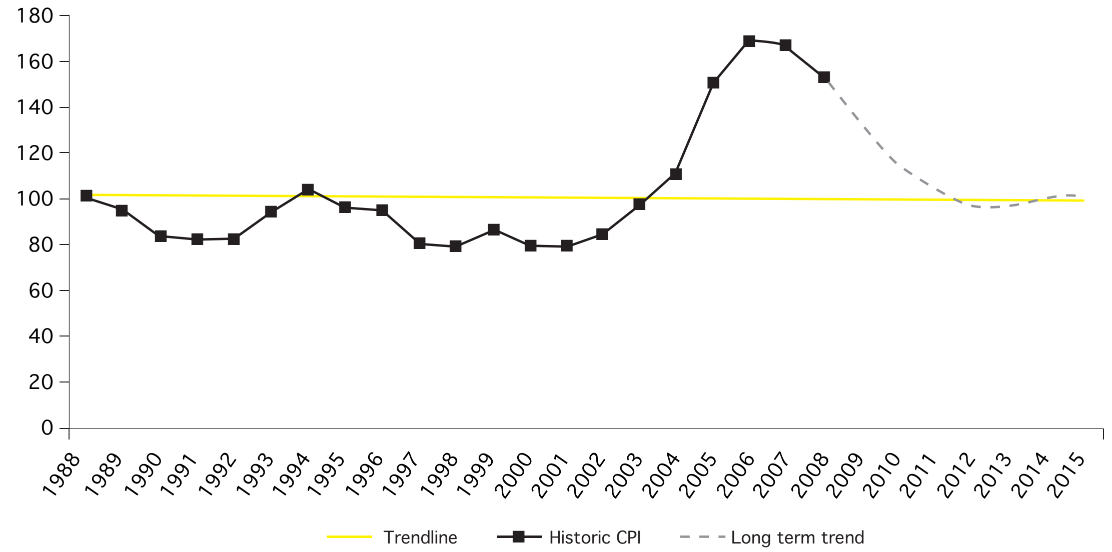
Source: Bloomberg, HSBC Global Carbon Steel Index

Figure 4.18 Foundation cost - indicative trend line 2006-2012 (E&Y, 2009)



Source: Ernst & Young, DECC reference project data

Figure 4.19 Commodity prices – historic index rebased to 1988 (E&Y, 2009)



Source: Bloomberg, IMF Industrial Inputs Price Index

inputs to the rising cost of wind turbines over the period. What is striking is that whilst a little over half the price increase of offshore wind turbines over the four year period is attributable directly to commodity, steel, equipment, and labour price rises, there still remains a significant unexplained portion. This is partly accounted for by the declining value of sterling versus the euro (see following sub-section) but is also likely to be due in part to the lack of competition in the offshore turbine market (see section 4.5.2).

Figure 4.20 Main input price increases 2003 to 2007 (Carbon Trust, 2008)

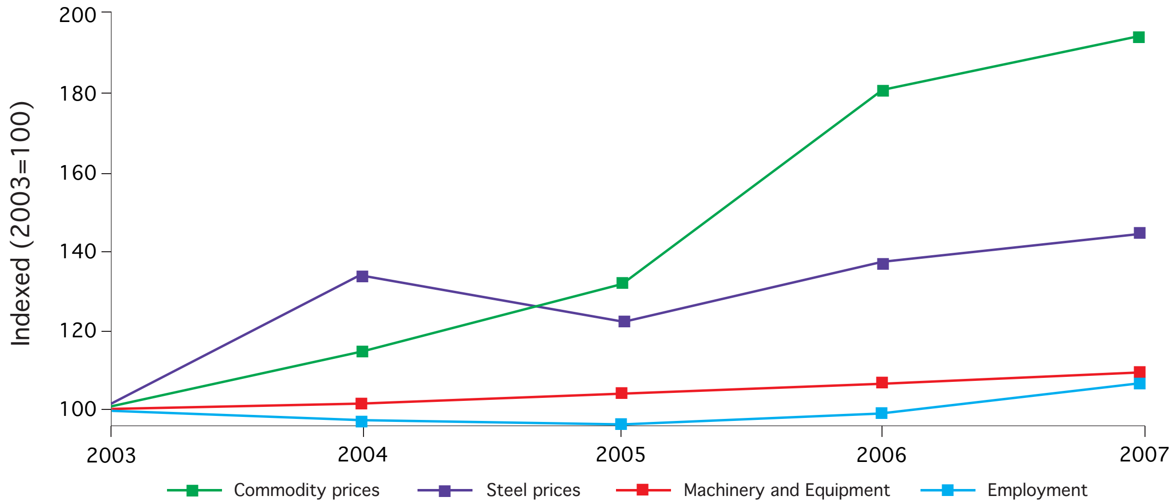
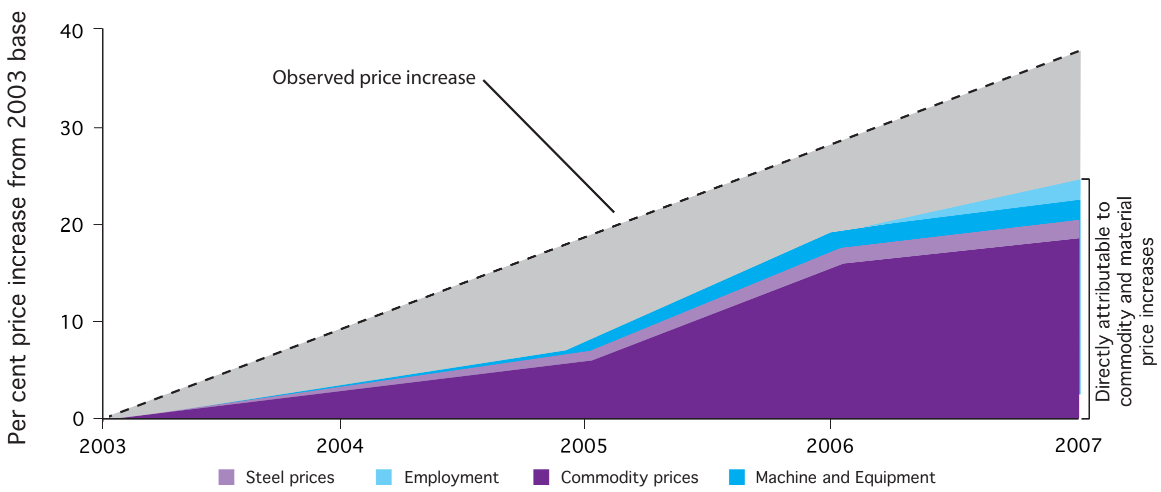


Figure 4.21 Proportion of turbine price increase explained by input prices (Carbon Trust, 2008)



Assumptions relating to Figure 4.20 and Figure 4.21: Contributions to costs of a turbine as follows: 4.2% from steel, 20% from other commodities, 30% from manufacturing components, 17% from wages (based on Vestas reports).

Original data from: Commodity price: IMF Industrial Inputs; WTG Prices; Observed increases from BTM Steel price: Composed steel price in the US published by MYB, converted to real terms by consumer inflation index (CPI); Machinery and equipment: German manufacture of engines and turbines, except aircraft, vehicle and cycle engines from Eurostat; Employment: Wages from German manufacture of engines and turbines, except aircraft, vehicle and cycle engines from Eurostat.

Exchange rates

The euro/sterling exchange rate also contributed to the rise in project costs borne by UK offshore wind developers for much of the decade. The majority of offshore wind components imported into the UK are either priced in euros or priced in a currency tied to the euro hence until 2009 UK developers experienced continued increases in component costs because of the euro's gradual appreciation. Vessels and services are also largely sourced from continental Europe, hence installation costs also rose due to the weakening of sterling against the euro (E&Y, 2009).

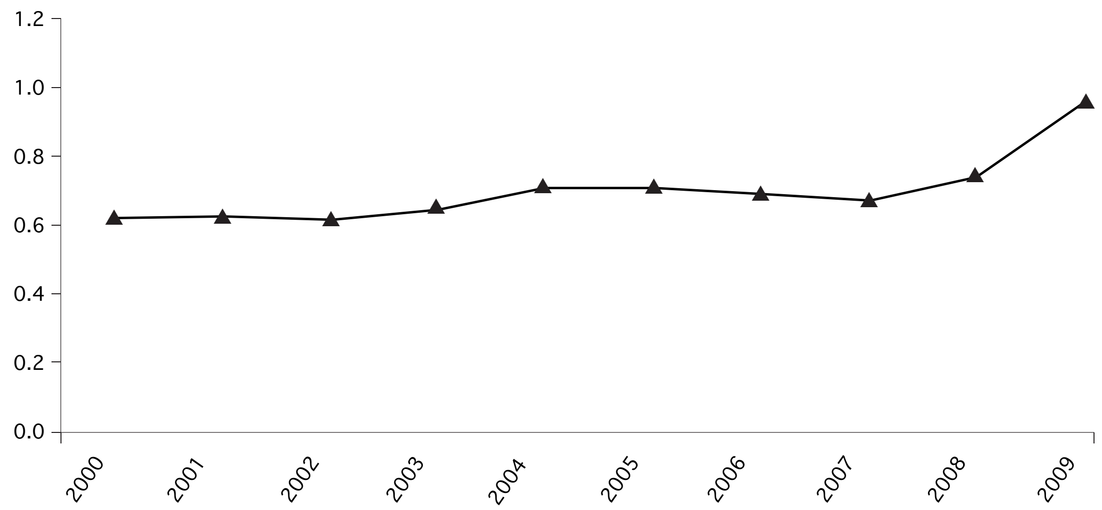
Figure 4.22 illustrates how, since 2000, the euro became stronger against the pound reaching almost one-for-one parity in December 2008. Thus, whilst prices for commodities have fallen since 2008 as a result of the global downturn any positive effect on turbine prices had until recently been more than offset by the appreciation of the euro against sterling (E&Y, 2009). However, in 2009 the euro started to decline and by mid-June 2010 it stood at approximately €1 = £0.83, which would be expected to feed through into lower turbine prices in due course.

Impact of credit crisis and subsequent recession

During the post-boom credit crisis of 2007/2008, offshore wind costs continued to rise. However, in 2009 the Renewables Advisory Board expected the fall in steel and other commodity price to be reflected in future component contracts (RAB, 2009) and there is now some signs that a possible plateau in costs may have been reached. This suggests that the recession of the last couple of years has had a beneficial effect on offshore wind costs. Indeed, this may well have helped the wind industry in general to maintain strong growth in the face of the recession and of the consequent fall in competing fossil fuel prices (Wind Stats, 2009b). By the summer of 2009 there appeared to be little evidence of a slow down in the growth of the wind industry.

Going forward, availability of finance could be a particularly significant issue if the economic climate deters investors. In June 2010, Bloomberg reported that German offshore wind development could slow down for this reason though UK development is still expected to progress steadily (Wind Stats, 2009b). That said, if project finance markets worldwide are constrained then UK development is likely

Figure 4.22 GBP EUR exchange rates – historic trend since 2000 (E&Y, 2009)



Source: Bloomberg, GBP EUR year end closing prices, DECC to face the same funding challenge as other countries.

4.5.4 Quantifying the relative impact of factors

The factors that drove the costs escalations from the mid 2000s are well understood. For example, rises in materials, commodities and labour costs have contributed to between of 50-70% of the increase in turbine costs. At the current time around 80% of the value of a typical offshore wind farm is paid for in Euros, and in the period from 2005 currency movements increased costs to UK developers by up to 30%. The remainder is accounted for by the absence of competition in key components; supply chain constraints; the costs of going further offshore; the full costs of early offshore wind farms being revealed; capital and O&M costs associated with improving reliability; a 'niche premium' for turbine makers; and planning and consenting delays. Accurate quantification of the contribution from these factors is much more challenging and could not, in our view, be substantiated by the available data. Having said that, it is possible to form a view of the *relative* contribution from these past major drivers, and our judgement is that they were (in descending order of impact):

1. Materials, commodities and labour costs
2. Currency movements
3. Increasing prices for turbines over and above the cost of materials, due to supply chain constraints, market conditions and engineering issues
4. The increasing depth and distance of more ambitious projects, affecting installation, foundation and O&M costs
5. Supply chain constraints, notably in vessels and ports
6. Planning and consenting delays.

In 2009, key industry actors considered that the likely medium term trajectory of offshore wind costs would be for a slight rise in the following two years followed by only a modest fall from 2009 levels out to 2015. Recent evidence suggests that costs in 2010 are no higher than 2009, suggesting costs may have 'peaked'. As noted in Section 4.2.3 there is some evidence that a turning point may have been reached with the agreed price of Gwynt Y Mor, recently reported at approximately £2.9m/MW.

4.6 Summary

Progress on Round 1 and 2 has been slower than expected, with the typical timeline for a large UK offshore project now estimated to be between seven and nine years. A major reason for this according to industry commentators has been the complexity of the planning process. By June 2010, Round 1 projects totalling approximately 500MW have still to be completed and another 400MW of capacity has been withdrawn (although this should be mitigated by Round 2.5). Meanwhile, Round 2 capacity delivery is predicted to have a longer 'tail' than previously foreseen with the BWEA projecting around 1.5GW still to be built after 2015.

In addition, and contrary to expectations, the costs of offshore wind development from the mid-2000s onwards have been escalating. In 2008, offshore capital costs were double the 2003 level and by 2009, Ernst & Young reported average capital costs of around £3.2m/MW installed, whilst estimates of levelised energy costs had increased 50% between 2006 and 2009.

By 2009 the consensus of key industry actors regarding the likely medium term trajectory in offshore wind costs was for a slight rise in the next two years followed by only a slight fall from current levels out to 2015. In 2009, the BWEA and Garrad Hassan used a capex figure of £3.1m/MW to hypothesise six scenarios impacting capital costs from 2010 to 2015. A significant level of divergence was revealed between the various scenarios with the difference between the most optimistic and pessimistic being 51% at mid-2014. This 'spread', was a reflection of the uncertainty over macro-economic and industry-specific factors. The results also demonstrated the high importance of supply chain response to shifts in macro-economics and onshore wind growth trends, and also the criticality of supply chain confidence.

Regarding this latter point, assuming a high level of supply chain confidence Ernst & Young (2009) suggested that levelised costs could be reduced by around 10% by 2015 and that capital costs could decrease to between £2.3m and £2.8m/MW. By contrast, if industrial momentum were lost due to the supply chain losing confidence in the viability of the sector, project capex would be likely to rise over the next five years, with projections suggesting a range of £3.0 to £3.9m/MW by 2014.

The UK government's view in 2009 was that the increase in offshore wind costs since the mid-2000s would be short term and that in the longer term costs would continue to fall. A range of commentators forecast significant reductions beyond 2020. At its most optimistic, the Carbon Trust suggested that the investment required to deliver 29GW of offshore wind could be reduced by as much as 40% by 2020 – from £75bn to £45bn. This implies a very best case capital cost in 2020 of approximately £1.55m/MW.

After 2005 forecast costs in the relatively near future were higher, nevertheless many commentators were still expecting large cost reductions in the longer term, with post 2020 scenarios often returning to broadly the same level as earlier forecasts. Modelled scenarios in UKERC's 2009 report 'Energy 2050', for example, use a capital cost range at mid-century of approximately £500,000 to £850,000/MW. This implies a higher rate of cost reduction than originally conceived and raises the question as to what the prospects are in the longer term for such an outcome.

Rises in materials, commodities and labour costs, and adverse exchange rate movements have made the largest contributions to cost escalations from the mid 2000s onwards. The remainder is accounted for by: the absence of competition in key components; supply chain constraints; the costs of going further offshore; the full costs of early offshore wind farms being revealed; capital and O&M costs associated with improving reliability; a 'niche premium' for turbine makers; and planning and consenting delays.

Costs have risen since the development of the early UK sites due to this range of intrinsic and external factors but if we account for both types there must remain a significant degree of learning and underlying cost reduction over time. Indeed, there are now some signs that a plateau in costs may have been reached with the majority of commentators suggesting that current typical capex of around £3.0m/MW and energy costs at a little under £150/MWh are approximately the same as a year ago. We explore the potential for costs to fall in the period to around 2025 in Chapter 5.

5. Future costs, issues for policy and conclusions

5.1 Introduction

Building on the evidence of past cost trajectories and analysis of the main drivers for offshore wind energy, Chapter 5 provides an analysis of the future of capital and levelised costs over a 10-15 year time horizon – to around 2025. This is done by considering the main cost escalation drivers identified in Chapter 4, together with a number of other factors, including those with potential to reduce costs.

This is a more detailed and 'disaggregated' approach than the use of learning curves. The analysis essentially takes the form of an 'expert view' on each of the main factors, informed by the literature and our engagement with key stakeholders. It goes beyond engineering issues to include factors such as finance, market conditions and macro-economic effects. Section 5.2 provides a qualitative assessment of the key factors, and indicates which of these factors have a readily quantifiable and substantive impact upon *costs* (or prices). Where possible, the range and scale of potential cost implications is indicated. Building upon this, Section 5.3 provides a review of the potential scale of impact (both positive and negative) of the principal drivers of cost increase/decrease in offshore wind. Section 5.4 draws out the main findings that emerge from this assessment whilst Section 5.5 presents conclusions regarding future costs. Section 5.6 discusses implications for policy and Section 5.7 concludes.

5.2 Cost drivers

5.2.1 Turbine costs

The wind turbine itself is the most important cost component of an offshore wind project constituting up to 50% of total capex (see Section 5.3). A range of interacting drivers will affect costs into the future; we consider here *increasing competition, competing markets, innovation, scale effects and standardisation* before drawing conclusions about the overall scale and trajectory of change to turbine costs.

Increasing competition in wind turbine supply

As noted in this Chapter 4, the offshore turbine market to date has been dominated by just two companies, Siemens and Vestas and there is some evidence that the lack of competition has been significant. Additional manufacturers such as GE, Multibrid, Mitsubishi, Repower and Clipper are now entering or are expected to enter the market (BWEA and Garrad Hassan, 2009a). GE and Siemens are also planning to build factories in the UK, whilst Clipper and Mitsubishi are developing turbines in Britain (Wind Power Monthly, 2010). UK production has the potential to both reduce transport costs and counteract currency movements (discussed below).

Whilst increased competition is likely to place downward pressure on turbine prices, dramatic reductions over the period to 2015 are not expected by industry commentators. Reductions are certainly not expected to be substantial enough to shift cost levels back onto the learning curve trajectories suggested in the mid-2000s and earlier. Longer term, beyond 2015, more significant reductions in turbine costs may be available stemming from both new technology (see below) and from even greater competition assuming a strongly rooted and maturing supply chain. However, this must be set against a context of high and potentially competing demand for turbines, both from UK Round 3 itself and other offshore projects and from the global onshore market, as we now explain.

European offshore, US onshore and other competing markets

Turbine supply to the UK offshore wind sector must be considered within the context of onshore turbine demand from rapidly growing markets such as China, India, and the US, as well as from Europe (both on and offshore). The UK *cumulative* installed offshore wind capacity is approximately 1GW which represents less than 3% of the wind capacity installed worldwide (on and offshore) *during* 2009. The UK offshore wind market has therefore to date represented a small niche within the global wind turbine industry. Whilst there may be long term benefits for companies (and perhaps countries) who gain 'first mover' advantage in such a niche, in the short run manufacturers would typically expect a premium return (hence price) to operate in such a specialist niche.

Quantifying the impact of competing markets – and of any mitigation thereto – is subject to considerable uncertainty and is not included as a specific cost driver in our sensitivity analysis. Nevertheless, despite the threat to supply availability and cost containment represented by competing markets, two factors appear likely to mitigate this. One is the probable increase in the number of turbine and other component suppliers from 2010 onwards. The other factor, already alluded to, is the sheer size of the market represented by UK Round 3 and the 'attractive force' that Round 3 will become.

Innovation and efficiency

Whilst onshore wind technology is largely mature, the offshore wind sector offers significant scope for technology acceleration. Offshore developments include size increases, advanced materials, control, reliability and installation techniques (Winskel et al., 2009). Commentators suggest that there may be potential for acceleration in the design and manufacture of 'dedicated' offshore turbines rather than simply using marinised versions of onshore turbines. The IEA points to several technical and engineering developments in turbines that might lead to efficiency and cost savings in the future (IEA, 2009):

- Dedicated offshore turbine
  - Two-bladed turbine rotating downwind of the tower
  - Direct-drive generator (no gearbox)
  - Simplified power electronics.
- More research into turbine behaviour including:
  - advanced fluid dynamics models
  - methods to reduce loads or suppress transmission
  - innovative aerofoil design
  - technology to reduce icing and dirt build-up.

- Turbine rotor size
  - The larger the swept area, the more power that can be extracted
  - Capacity could be as much as 10MW, with a rotor 150 m in diameter.
- Advanced rotor materials
  - E.g. carbon fibre and titanium
  - Higher strength to mass ratios to help cope with increased loading.
- Lighter generators and other drive train components
  - To reduce tower head mass.
- Turbine O&M enhancements
  - system redundancy
  - remote, advanced condition monitoring
  - self-diagnostic systems.

In the longer term, offshore-specific turbines may be able to increase performance and reliability thereby reducing the cost of generation. For example, the goal of one UK manufacturer of vertical axis offshore wind turbines is to reduce generating costs by 20-30% (Wind Stats, 2009b). However, the potential for dedicated and advanced turbines to reduce costs significantly in the medium term remains uncertain and difficult to quantify.

Scale effects and standardisation

There are several areas in which cost reductions may be realised from scale effects. Increasing the number of turbines installed in total may realise economies of scale through series production. In addition, economies of scale from the wind turbines themselves may be realised by increasing the capacity beyond the current maximum of 5MW. Whilst this would necessitate increased spacing because of wake effects, this is unlikely to be a limiting factor given the size of future offshore zones (Junginger et al., 2008).

As turbine capacity increases, this should result in a saving in the amount of other components or services required, e.g. the number of foundation structures, turbine towers, and operating hours for installation vessels should all reduce relative to capacity installed. A key factor here will be the interactions between the different supply chain capabilities, e.g. port infrastructure and crane capacity. Until the supply chain is genuinely offshore wind-dedicated and capable of meeting greater logistical demands, the potential benefits of much larger turbines cannot be realised.

Further R&D would be required but with increased production, standardisation and orders the cost of turbines could be reduced by 15% (no timescale given) (ODE Limited, 2007). This could reduce the capital cost of a typical offshore project by over 7%.

Conclusions about the scale and trajectory of cost trends for turbines

A number of different drivers affect the cost of offshore turbines. Increased competition is likely to provide downward cost pressure, as will innovation, efficiency, scale effects and standardisation. There is however a potential upward pressure from competing markets. Taken together, we believe the maximum turbine cost reduction that may be achievable is approximately 40%. However, should these factors fail to come to fruition, should supply chain bottlenecks escalate or the attraction of onshore markets 'outcompete' offshore, a risk of cost escalation remains.

5.2.2 Foundations

One of the most significant challenges facing offshore wind engineers is the effective and cost-efficient fixing of the turbine tower to the seabed. To date, this has typically been achieved via a monopile foundation which constitutes approximately 20% to 25% of total capital expenditure in offshore wind farm construction. As with turbines, a range of factors have the potential to affect future costs. We consider here two principal issues; *innovation* and *improvements to the supply chain*.

Innovation and efficiency

Foundation design represents a major area for potential innovation and possible cost reduction (ODE Limited, 2007). With the move towards greater depth, together with larger turbines, greater wind loads, longer blades and taller structures, so the limits of the monopile design will increasingly be challenged.

Foundation alternatives include:

- Jacket.
- Tripod.
- Gravity-based and suction caisson designs.
- Floating structure (for substantially deeper water).

With regard to the foundation costs for deeper sites, ODE Limited (2007) reports that with more R&D, there may be the potential for up to 20% savings compared to current estimates for deep water foundations (although no timeframe is given). Assuming that the relatively more expensive deep water foundations contribute approximately 25% to overall capex, this represents a 5% total saving.

Supply chain developments

With the exception of BiFab Ltd's manufacture of the jacket structures for the Beatrice project, to date there has been no significant UK content for foundations. According to industry experts, most of the monopile foundations used in UK projects have been sourced from Holland and have therefore been subject to sterling-euro currency impacts. It is possible however that the scale of Round 3 will stimulate greater foundation competition, and new companies are entering the market, many of which are British (Wind Power Monthly Special Report 2010), which has benefits related to currency movements (see below). However, increased demand may create supply chain constraints, hence price rises. In addition, the greater depths likely to be faced in the future will place increasing demand on alternatives to the monopile approach. The manufacturing capacity for alternatives such as steel jackets and tripods is still at a relatively early stage (BWEA and Garrad Hassan, 2009a), and for floating structures even more so. Furthermore, whilst concrete foundations can alleviate the commodity (steel) risk, the BWEA suggests that substantial investment in UK port facilities may be needed to facilitate this (BWEA and Garrad Hassan, 2009a). Overall therefore, a mixed picture emerges with regard to foundation supply, making a clear 'cost trend' impossible to discern.

Conclusions about foundation costs

In the shorter term there is the potential for upward pressures on foundation costs of up to 20%. This is because as depths increase the monopile approach will be increasingly replaced with alternatives which are at an earlier stage of development and have not therefore benefited from learning and standardisation. However, longer term, as experience increases, there is the potential for foundation cost reductions of up to 30% through innovation, improved supply chain and increased competition.

5.2.3 Depth & distance

The development of UK Round 3 involves depths and distances which are in most cases considerably greater than current projects. It is worth noting for comparison how much nearer and shallower the Round 1 wind farms are. Excluding the deep water pilot project at Beatrice (50m depth), Round 1 projects, either completed or under construction, lie within a range of 4 – 21m depth and 2 – 13km distance from shore. The Round 3 averaged range is 35 – 53m depth and 20 – 160km distance.

The potential effect of depth and distance on UK Round 3 projects can be illustrated using the relationships between different depth/distance combinations and costs outlined in the Carbon Trust (2008) report discussed in Chapter 4 (see Figure 4.11 and Figure 4.12). We can calculate the percentage change in cost for each of the Carbon Trust's depth/distance combinations relative to this notional mid-depth, mid-distance project costs. For example, a site categorised by the Carbon Trust as both deep and far offshore bears capital costs that are 22% more, and levelised costs that are 24% more, than a mid-depth, mid-distant site. By contrast, a site categorised by the Carbon Trust as mid-depth and near to shore has capital costs that are 4% less, but levelised costs that are 10% more, than a mid-depth, mid-distance site.

Depth and distance data for Round 3 sites is available from The Crown Estate (2010b). This data can be translated into the depth/distance descriptions used by the Carbon Trust, to provide a ballpark estimate of the impact on costs relative to a notional 'mid depth, mid distance' site, which is more typical of Rounds 1 and 2.

Table 5.1 illustrates the relationship between the distance/depth characteristics of the nine UK Round 3 zones and a nominal mid-depth/mid-distance site, assuming all other things are equal.

Table 5.1 is of course a considerable simplification. Construction of Round 3 is not due to begin until 2014/15 for the earliest sites and multiple variables are likely to affect costs over the next five years and beyond. Costs are not generic to distance/depth, since individual site characteristics (such as sea bed conditions) will affect construction costs and load factors will be a function of local wind conditions. Moreover, the majority of both the depth and distance figures are medians between the minima and maxima applicable to each Round 3 zone.

Table 5.1 Depth and distance characteristics of UK Round 3 zones

Round 3 zone	Median or ave. depth in metres	Median or ave. distance in kilometres and nautical miles	Description	Approx. cost change from mid-depth, mid-distance	
				Capex	LC
Moray Firth	43.5 m	28 km/15 nm	Deep/mid-distant	+8%	+5%
Firth of Forth	50 m	54 km/29 nm	Deep/mid-distant	+ 8%	+ 5%
Dogger Bank	41 m	160 km/86 nm	Deep/far	+22%	+24%
Hornsea	35 m	112 km/60 nm	Mid-depth/medium-far	+ 8%	+10%
East Anglia	37.5 m	56 km/30 nm	Mid-depth/mid-distant	+ 0%	+ 0%
Hastings	40 m	20 km/11 nm	Mid-depth/near	- 4%	+10%
West Isle Wight	42 m	21 km/11 nm	Deep/near	+ 3%	+10%
Bristol Channel	40 m	24 km/13 nm	Deep/mid-distant	+ 8%	+ 5%
Irish Sea	53 m	30 km/16 nm	Deep/mid-distant	+ 8%	+ 5%

Nevertheless, the percentage cost adjustment factors show in very general and crude terms how costs rise with increasing depth and distance. If the relationships charted by the Carbon Trust are broadly correct then for the most part the better wind speeds that may be available further from the shore are not, with current construction costs, sufficient to compensate for the higher costs associated with building in deeper, more distant locations. The analysis above indicates that the capex implications of Round 3, relative to a notional mid depth/distance site lie in a range of -4% to +24%, with six of the nine sites increasing by 8% or more. With the exception of one mid-depth, mid-distance site, levelised costs increase in a range between 5% and 24%. On balance, the likelihood is that increasing depth and distance will put upward pressure on total capital costs, unless compensated for by other cost-mitigating factors[13]. Figure 5.1 illustrates this, showing the sensitivity of levelised cost to a zero to 37% increase in depth and zero to quadrupling increase in distance.

5.2.4 Availability/load factor

As explained in Chapter 4, relatively poor availability at some UK wind farm sites has been the main driver of lower than

13 One industry expert has observed that with increasing distance from shore, the sea becomes significantly less busy thus enabling larger projects which in turn should help economic viability.

expected load factors for some Round 1 sites, with a substantive impact on revenues and levelised costs. Moreover, wind farm availability falls with distance from shore (reflecting the challenges of repairing faulty equipment further offshore) and over the lifetime of a wind farm (reflecting ageing equipment) (Carbon Trust, 2008).

The likely implications of these factors for Round 3 development in the medium term and for further development beyond 2020 will depend upon success in improving reliability relative to the cost of doing so. Experience to date indicates that the higher wind speeds and greater distances compared to Rounds 1 and 2 might not augur well for availability and therefore for load factors and levelised costs. On the other hand, better equipment reliability, an already more proactive O&M philosophy, and more sophisticated (probably remote) condition monitoring should increase availability and lengthen maintenance cycles to avoid winter months (Carbon Trust, 2008); (E&Y, 2009). Such improvements will come at a cost but should also increase annual energy yield (Feng et al., 2010).

The impact of availability on load factor[14] is dramatic. As described in Chapter 4, failure to achieve expected reliability levels correlated very closely with load factors of around 30%, when 35% was expected. If moving further offshore increases wind speeds, the impact of low availability *increases*[15]. It is reasonable to assume that the fundamental importance of availability, together with a variety of learning effects (in turbines and in O&M) makes it more likely that availability will improve than decline. This will of course be traded against the increased costs of maintaining and repairing more distant sites, though load factors ought to outweigh O&M costs, as we explain below. At the same time, the nearer sites of Rounds 1 and 2 should benefit considerably with consequent improvement in cost of generation. The combined effect of improved wind speeds and better availability suggests that the load factors may improve by up to seven percentage points from a baseline of 38%. However, we also explore the effect of lowering the load factor by up to three percentage points to acknowledge the possibility of poorer availability in potentially less accessible sites. As we illustrate in Figure 5.1, even these relatively small changes in load factor have a large impact on levelised costs.

Reliability (O&M)

According to industry experts, O&M costs in UK waters are currently averaging approximately £50,000/MW per annum (and the 2009 Ernst & Young report uses an O&M figure of £54,000/MW per annum in their levelised costs calculations). However, note that the O&M of a specific wind farm will be highly dependent on

14 In this example and elsewhere UKERC uses a simple load factor function as an approximation for turbine outputs We recognise that this is a considerable simplification, and that maximising load factor may not, in isolation, deliver the maximum return on investment because of the non-linear relationship between turbine size, cost and actual output at a given site.

15 Consider for example a site with wind conditions sufficient to deliver a 40% load factor in a fictional 100% available turbine. If availability levels seen onshore are achieved (around 98%), such a site would achieve over 39% load factor. However if availability falls to 80%, as in some Round 1 sites, load factor falls to 32%. This is of course a simplification because it takes no account of the actual wind speeds during the periods of unavailability.

location. As discussed in Chapter 4, O&M costs have risen steadily over recent years as a result of:

- Improved budgeting reflecting track record and experience gained from operating early projects, where costs had perhaps been underestimated.
- Evolution of more proactive O&M strategies to extend asset and project life.
- Increases in labour, steel, and other commodity prices, as well as currency impacts (E&Y, 2009).

Several of these issues are dealt with in other sections. As developers seek to optimize the reliability and life of their assets, and as the distance, depth, and marine/weather conditions become more challenging, so this will add to absolute costs. On the other hand, greater reliability and extended asset life (together with possible higher load factors from more distant site location) should improve levelised energy costs. This may be further enhanced by (i) improved weather forecasting to identify suitable 'windows of opportunity' for O&M activity, and (ii) less need for O&M as turbine technology becomes increasingly offshore-dedicated rather than 'onshore marinised'.

The relationship between improving O&M and optimising availability is important. Whilst a range of learning effects are likely to improve effectiveness and increase costs, absolute increases in O&M costs appear likely, given both more challenging conditions and the importance of improved availability. It is therefore important to note that the absolute impacts of increasing O&M spend are not overwhelming, indeed they are relatively minor in comparison to many of the other key drivers reviewed in this chapter. For example, as shown in Figure 5.1 a 25% increase or decrease in O&M spend will respectively increase or decrease levelised costs by less than 3%.

5.2.5 Vessels and port facilities

Vessels

Foundation, turbine, and cable installation together comprise approximately 15 – 20% of overall capex. The same tension between, on the one hand, potentially increased supplier competition resulting from greater supply chain confidence and on the other hand, competition amongst developers in a supply squeeze also exists in the installation vessel market.

A 2009 offshore wind report forecasts that the recent crunch in vessel supply is actually likely to get worse out towards 2015 unless additional capacity comes through (BWEA and Garrad Hassan, 2009a). Indeed, the supply-demand imbalance will continue to be exacerbated by project-specific requirements (e.g. water depth, turbine technology and foundation design) which have the impact of narrowing the vessel supply field, reducing competition and potentially placing some further upward pressure on pricing.

Nevertheless the BWEA/Garrad Hassan (2009a) report indicates that there are many bespoke vessels targeting the offshore wind sector on the drawing board and nine additional main installation vessels are under construction or on order.

Whilst new vessel build times can be up to 36 months and there is significant potential for cancellation or at least delay, this current trend indicates that confidence within the vessel element of the supply chain has risen.

The report considers the most significant 'competing national market' – at least until 2015 - to be offshore wind development in Germany. However, the majority of German activity will be in areas of the North Sea where the environment is by and large more challenging than projects constructed to date elsewhere in northern Europe and more onerous even than Round 1 and 2 UK projects. The BWEA and Garrad Hassan report suggests that this fact to some extent mitigates the degree of supply chain overlap between the UK and Germany. Whilst this may be true in the shorter term, 2015 will see the start of the more challenging projects of UK Round 3. In addition, the Netherlands is also an offshore wind market likely to compete with the UK for finite supply chain resources. Here, the physical characteristics of the planned projects are more similar to those in the UK, at least until 2015 (BWEA and Garrad Hassan, 2009a).

Overall, the potential for either significant cost reduction or escalation in this area in the period to 2015 appears low. Longer term, increasing confidence in the stability of the offshore market especially from Round 3 would be expected to lead to increasing supply and some modest easing of cost pressure. The impact of vessel availability on cost is particularly difficult to quantify and we do not include installation as a key factor in the sensitivity analysis shown in Figure 5.1.

One uncertainty is the prospect of expansion in the oil and gas industry diverting resources away from offshore wind.

Ports and docks

UK supporting infrastructure will be a major issue for Round 3 developers given the huge size of the undertaking, and both port availability and quality are already existing areas of concern (BVG Associates, 2007); (Douglas-Westwood, 2008). Many northern European ports are accessible for UK installations with Denmark, Germany and the Netherlands all offering a choice of deep water harbours. However, whilst sufficient capacity is currently available in continental ports, increasing future demand from Round 3 combined with a possible further decline in the Sterling-Euro rate has the potential to increase non-UK port facility costs.

However, from a project developer's point of view direct port costs are a minor constituent of overall capex, and therefore this is less a cost issue and more one of facilitation/operation. For this reason we do not include installation as a key factor in the sensitivity analysis shown in Figure 5.1. The Carbon Trust argued that levels of port capacity in the UK were too low to adequately support the growth of the supply chain, particularly in areas likely to be development hubs such as the east coast of England and the North West. Many existing ports offered insufficient access for large vessels, quaysides that could not support the weight of large turbine components, a lack of space for new manufacturing, operations and lay-down facilities, or some combination of all these issues (Carbon Trust, 2008).

Mitigating this requires investment in UK facilities with sustained commitment, and perhaps further public spending, likely to be needed to support an emerging UK supply chain (one example cited by an industry expert being Able UK Ltd's plans for an integrated facility on the Humber). Notwithstanding the £60m of government investment in one or more UK ports announced in the March 2010 budget (Wind Power Monthly, 2010), considerable additional investment is likely to be needed. Whilst in opposition the Liberal Democrats suggested investment of £400m or more was needed (Windpower Monthly June 2010) but at the time of writing it is not clear if this will be a feature of the Coalition Government energy plans. Industry experts agree that investment in docks and ports is likely to be absolutely critical to the success of Britain's offshore wind industry, to attracting inward investment from equipment makers and fostering a domestic component and installation industry. The impact on costs is not possible to estimate, but the importance of this factor in creating a UK offshore industry should not be understated.

5.2.6 Macro economic conditions

Many of the factors discussed above are in some way 'intrinsic' to offshore wind farm development, companies and other actors, and policy. This section considers some of what Chapter 4 refers to as 'external' drivers.

Global macro-economic environment

The wider macro-economy may be very important to the future of offshore wind. For example, analysis of future costs by the BWEA and Garrad Hassan suggests offshore wind capital cost may be inversely proportional to global economic recovery and/or the growth of onshore wind (BWEA and Garrad Hassan, 2009a). The rationale for this is not explained in detail. However, the implication is that a prolonged recession results in depressed commodity prices, lower costs of capital and, perhaps, aggressive competition amongst component and services suppliers for the business offered by offshore wind development. Similar considerations apply to a slowdown in onshore growth. Of course, this is rather speculative and counter arguments are not hard to formulate – if growth is slow governments may curtail support for offshore wind in a bid to protect consumers for example, supply chains may contract as companies fail, and low growth may not be associated with cheap credit indefinitely.

It is outside the remit of this report to speculate on the likely trajectory of the global economy (or regional economies) over the next decade. In any case our view is that it is not wholly clear what affect a trajectory either way would actually have on the prospects for offshore wind costs. We therefore set macro-economic considerations (important though they are) to one side in our examination of likely future costs and do not include in our sensitivity analysis.

Finance availability and cost

Separate from, though related to, the macro-economic outlook is the issue of finance, in particular the availability or not in the UK of balance sheet funding for offshore wind projects, the likely impact of credit markets either easing or not and the risk-reward perception of potential financiers.

Large-scale non-recourse project finance for independent wind developers (whether onshore or off, in the UK or mainland Europe) has been difficult – if not impossible – to obtain (BWEA and Garrad Hassan, 2009a). In fact, of the nine Round 3 projects, all are part-owned by utility companies or an industrial conglomerate rather than being wholly independent. Nevertheless, the financial scale of Round 3 means that developers are very unlikely to be willing or able to fund the projects on balance sheet hence actual availability of capital could become a concern[16]. Indeed, if the credit market mechanism were to freeze up again, financing would likely become an impossibility.

In any case, because of the credit crisis, the cost of capital has gone up. As previously discussed the cost to utilities of issuing corporate bonds rose sharply after the global credit crisis first emerged in summer 2007 though it began to fall again during 2009.

Clearly there is an interest rate level at which utilities would no longer be willing to incur debt in order to raise funds for projects such as offshore wind farms. However, the precise magnitude of this will depend on a number of uncertain variables such as project hurdle rates and the future price of electricity.

With regard to non-recourse project finance, the BWEA/Garrad Hassan report suggests that should there be a continuing thawing of credit markets then the return of easier non-recourse debt funding is likely to put upward pressure on capex. This is because such a financing stimulus will encourage greater activity in the independently developed European wind power sector as well as further afield in, for example, the US and China. The effect will be to exert additional demand pressure on an already overstretched supply chain (BWEA and Garrad Hassan, 2009a).

Finally, access to capital and on what terms depends particularly on the situation and perception of potential project financiers. These will consider their own ability to raise finance, at what cost, their perception of project risk and internal hurdle rates, and their consequent willingness to invest. All these factors may change over time and are subject to considerable uncertainty.

As with the overall macro-economic environment, the view of this report is that any long-term forecasts of bond spreads and corporate debt finance costs, of credit market prospects and project risk perceptions are necessarily speculative. Hence the likely availability and cost of financing is a consideration that is set aside and we do not include financing costs in our sensitivity analysis.

Currency impacts

Overall, approximately 80% by capital value of a typical UK offshore wind project may be imported and has therefore been

16 According to one industry commentator, Round 3 could take two decades to complete if developers were to finance construction on balance sheet.

paid for in steadily devalued sterling. As noted in Chapter 4, sterling has gradually depreciated against the European currency, falling from a high of over £1 - €1.75 in 2000 to near parity in December 2008. This has had a considerable impact on offshore wind costs. For example, a developer devising and budgeting a component sourcing strategy in 2007 for delivery/ installation in 2009 would have seen the euro strengthen from under £0.70 to a spike of over £0.95 two years later – making any component costs denominated in euros more than 35% more expensive at that time. On the basis of the turbine component constituting 47% of project total, a project budgeted in 2007, for example, at £2.0m/MW and realized in 2009 could have faced an increase of £350,000/MW from the turbine element alone.

DECC has made a forecast of the euro-sterling rate out to 2015 (E&Y, 2009), estimating that sterling is likely to strengthen somewhat to approximately £1 = €1.25 by 2012 and remain at about that level for at least the following three years. At the time of writing the euro has already declined in value to close to this level at nearly £1 = €1.20. Whilst it is certainly possible that sterling may appreciate even more, DECC's medium term forecast envisages a pound that is still weaker than it was in the early to mid-2000s with a consequent impact on the cost of components and services imported into the UK relative to UK-based activity.

It is outside the scope of this study to take a view on the likely direction and magnitude of future euro-sterling exchange rates, however it is clear that, either way, currency risk creates a great deal of price uncertainty whilst as much as 80% of the total value of an offshore wind farm is imported from elsewhere in Europe (whilst currency hedging may be employed, this obviously incurs a cost). The UK government is in a position to improve the situation by encouraging and stimulating the growth of UK-based manufacturing and services suppliers such that more of the total value of offshore wind production is located – and priced - domestically. Budgeting and financing uncertainties will be reduced and, in addition, local economies and employment prospects will benefit.

Currency movement is thus a key cost driver and we have explored the effect on levelised costs of sterling appreciating by up to 20% and also depreciating by up to 20% against the euro (see Figure 5.1).

5.2.7 Commodity, materials and labour costs

Oil

The contribution of oil (in, for example, manufacturing processes and vessel fuel) is a relatively minor part of offshore wind capex. However, the price of oil is important because of its indirect impact i.e. its potential for diverting marine resources away from offshore wind development towards the oil and gas industry, thus making these resources less available and more expensive (BWEA and Garrad Hassan, 2009a).

Again, this is an area of substantial uncertainty, first because the oil price over the medium to long term is a matter of speculation, and second because quantifying the potential impact of the fluctuating fortunes of the oil and gas industry on offshore wind costs is highly problematic – not least because of the time lags involved between a price signal and the oil and gas sector's response to it in terms of changed activity levels.

For example, the price of crude spiked dramatically over an eighteen month period from early 2007 to mid-2008. At the same time, the capital and generation costs of offshore wind projects were also rising sharply. However, it is difficult to disaggregate the various drivers in terms of their relative contribution to cost and to identify the part played (if at all) by a rising oil price. Indeed, it is possible that it had little or no effect at all on the offshore wind sector for when the oil price collapsed in the second half of 2008, offshore wind costs continued to rise. This could, of course, mean that the plummeting price of crude did indeed beneficially impact offshore wind but the effect was masked by other more potent cost drivers. Alternatively, it is possible that the oil price had little or no effect on the way up and consequently, little or no effect on the way down.

Either way, the so-called secondary impact of the oil price appears to be relatively minor and is in any case difficult to disaggregate and quantify. For these reasons, it is not factored into our medium to long-term projections of offshore wind costs nor included in our sensitivity analysis.

Steel and other commodities

In terms of overall project cost the value-content of steel in a typical offshore wind project is no more than approximately 12% and therefore care should be taken not to overstate its relative importance as a cost driver. Indeed, it is one of the least significant of the cost drivers in our sensitivity analysis in Figure 5.1.

This point is even more applicable to the price of copper which is not included in our sensitivity analysis. Copper is used in significant quantities in the electrical infrastructure. However, whilst electrical infrastructure typically contributes 10 to 20% of overall capex, the raw material value-content of components such as cabling and transformers is small with most of such costs incurred during the manufacturing process (BWEA and Garrad Hassan, 2009a).

In 2008 and 2009 the steel price index fell sharply, returning to its long-term trend. The commodity price index as a whole has also been trending downwards, albeit less precipitously. Ultimately, the medium and long-term price of steel and other commodities will largely depend on future macro-economic conditions which, as discussed above, are subject to a high degree of uncertainty and outside the scope of this report. Given the price volatility of steel and its contribution to overall costs we have explored the effect on levelised costs of steel prices rising by up to 50% and falling by up to 50% (see Figure 5.1).

Skills and labour

UK national labour costs have shown a steady growth of 3.15% per annum over the 20 years to 2007. Ernst & Young (2009) projected the annual growth figure to be the same for 2008, dropping to just under 2% for 2009, presumably as the effects of recession feed through to labour market statistics.

The future cost of labour is closely tied to global macro-economic developments and the UK's specific fortunes within that – a matter of speculation that is outside the scope of this report. However, given the consistency of the historical trend line, there appears to be little risk of labour costs deviating significantly to the upside. Indeed, the likelihood of continued recession – or at least an absence of significant growth - over the medium term makes it more likely that UK labour costs overall could deviate below the trend line.

One caveat, however, is that the offshore wind sector is still a young one and not properly represented by the labour market as a whole. As noted in Chapter 4, there are already concerns in the industry regarding a shortage of skills, caused in part by competition for installation and service crews from the oil and gas industries and other offshore activities worldwide. Thus, in the medium term, specific skills shortages in specialised areas could put upward pressure on parts of a developer's payroll. Over the longer term, however, as the industry gains maturity and scale, this skills squeeze should recede. Overall therefore, the impact of skills and labour costs on total capex is likely to be broadly neutral and we do not include them as a key factor in the sensitivity analysis shown in Figure 5.1.

5.2.8 Other factors – confidence, planning and information flows

Growing confidence in the supply chain

Whilst not a direct cost driver, and therefore not included in the sensitivity analysis, industry experts also emphasise the importance of building commercial confidence in the supply chain overall as well as addressing the individual components of it. The scale of UK Round 3 will require a dramatic increase in manufacturing capacity for offshore wind, and building confidence is key to persuading companies to invest in increased supply chain capacity dedicated to offshore wind. A major benefit of this would be a reduced reliance on other sectors such as onshore wind and oil and gas (BWEA, 2009). In a sense, this is a 'chicken and egg' issue: on the one hand, Round 3 success requires greater supply chain confidence; on the other hand, the promise of Round 3 engenders greater confidence.

However, it is likely that the combination of (i) the government's commitment to the UK's share of the EU 2020 renewables target, plus (ii) an improved and swifter planning/consent process (see later) plus (iii) the on-going development of Round 2 and, especially, (iv) the prospect of game-changing scale represented by Round 3 is already, and will continue to, increase confidence in all aspects of the industry. This will have the effect of stimulating supplies of goods and services, increasingly dedicated to the offshore wind sector and therefore lessening the sector's reliance on inputs from related sectors such as onshore wind, oil and gas, and coastal engineering. Thus, in the medium to longer term, the cost benefits of increasing supply chain confidence engendered by the prospect of greater demand will help to constrain and balance the potential cost escalations arising from that demand.

Planning/consenting

Around 9-12% of offshore wind capital costs relate to project management including a significant portion (more than half) pertaining to planning and consent, and this has an important, though indirect, impact on supply chain confidence. At a recent UK offshore wind conference, one industry actor described planning as being 'in a state of flux…the bugbear of the UK offshore wind industry….*not* easier than onshore' (Garrity, 2010). The same commentator went on to say that it 'may be possible to reduce capex if the planning regime gives [the industry] more certainty resulting in a confirmed pipeline of projects that would lead to greater standardisation and therefore reduced costs'.

The 2008 Planning Act should significantly improve this situation via the Infrastructure Planning Commission. The IPC provides a single approvals process for all offshore wind farms greater than 100MW based upon national policy statements (NPS), defining national needs and priorities (which include development of offshore wind). In principle, this should dramatically reduce the timeline for approval from as long as ten years today to less than three years in the future (Carbon Trust, 2008). At the time of writing (summer 2010) the Coalition Government intends to replace the IPC with a system that directs requests to the Secretary of State. It retains an ambition to streamline planning, however, and minimise delay. Whilst the likely impact of the faster planning is difficult to quantify in monetary terms, the effect should be to boost supply chain confidence and encourage new suppliers into a more vigorous and faster-acting market. This is an additional factor which in the medium to long-term is likely at the very least to help prevent costs from escalating significantly beyond their current 2010 level. Because of the range of impacts on project finance (for example interest during construction, revenue foregone, etc) we do not include planning/consenting as a specific cost driver in our sensitivity analysis.

Information sharing

As far back as 2006, at least one commentator was suggesting that greater interaction and communication was needed throughout the supply chain and that by actively working with a contractor, a project developer's final costs could be reduced (Westwood, 2006). In a similar vein, Smit et al. (2007) observed that there was a lack of knowledge-sharing in the UK and that institutes such as university research departments did not get access to potentially fruitful project information because offshore wind developers were 'afraid of knowledge leaking away'. And at a January 2010 offshore wind conference, the head of offshore wind at Senergy Alternative Energy advocated greater use of learning including more learning from other offshore industries, more from Rounds 1 and 2, and more sharing of information and experience amongst developers and within the supply chain (Garrity, 2010). The idea here is that knowledge and experience should be viewed as common resources which can benefit the industry as a whole rather than be seen as competitive tools.

The IEA has similarly argued that reliability and other operational improvements would be accelerated through a greater sharing of operating experience among industry actors. The IEA points out that, unlike the early stages of the offshore oil and gas industry, there is little evidence of information sharing in the offshore wind industry (IEA, 2009). A database of operating experiences is currently under development at the German Institute for Wind Energy Research and System Integration (IWES), which could represent a potential nucleus for wider, international research cooperation.

Our view is that whilst information sharing may be a sensible and cost-reducing approach, it is difficult to quantify and to make meaningful future projections about and we do not include it as a specific driver in our sensitivity analysis.

5.3 Cost sensitivities

The analysis in Section 5.2 indicates that there is the potential for developments related to turbines, foundations, O&M/availability and various supply chain factors such as vessel availability and docks/ports to reduce costs. Of these turbines, foundations and availability are most important and most amenable to quantification. Moving to deeper, more distant locations is generally likely to place upward pressure on costs, since it appears that improved wind conditions are unlikely to be sufficient to offset higher cabling, installation, foundation and maintenance costs. Macro-economic factors are also important, particularly currency movements. Finally, steel, oil and other input prices can affect costs, though it is important that their impact is not exaggerated. In the sub-sections that follow we quantify the impact on total costs of the ranges described above for turbines, depth and distance, currency movements, O&M availability/load factor, foundation costs and steel prices.

UKERC has developed a simple model[17] of the relative share of various cost components in the levelised costs of offshore wind farms. The baseline data were drawn from Ernst & Young (2009), and reflect the approximate capital cost breakdown for projects at or near financial close in January 2009:

- Turbine - 47% share at £1.5m/MW
- Foundations - 22% share at £0.7m/MW
- Electrical infrastructure - 19% share at £0.6m/MW
- Planning and development costs - 12% share at £0.4m/MW.

The actual cost breakdown for individual offshore developments will of course vary

17 We are grateful to our colleague Dr. Tim Cockerill of Imperial College who created the initial spreadsheet and assisted with its calibration.

– both as a result of the time of development (as prices change) and location (reflecting depth, distance and other factors). See Box 5.1 for a summary of cost component breakdowns from a range of sources.

Other key assumptions for the baseline calculation were:

- Project life of 20 years
- Load factor of 38%
- Discount rate of 10%.

The model output is a levelised cost in £/MWh, and by adjusting the values for the cost drivers within plausible ranges, the overall impact of each driver can be demonstrated.

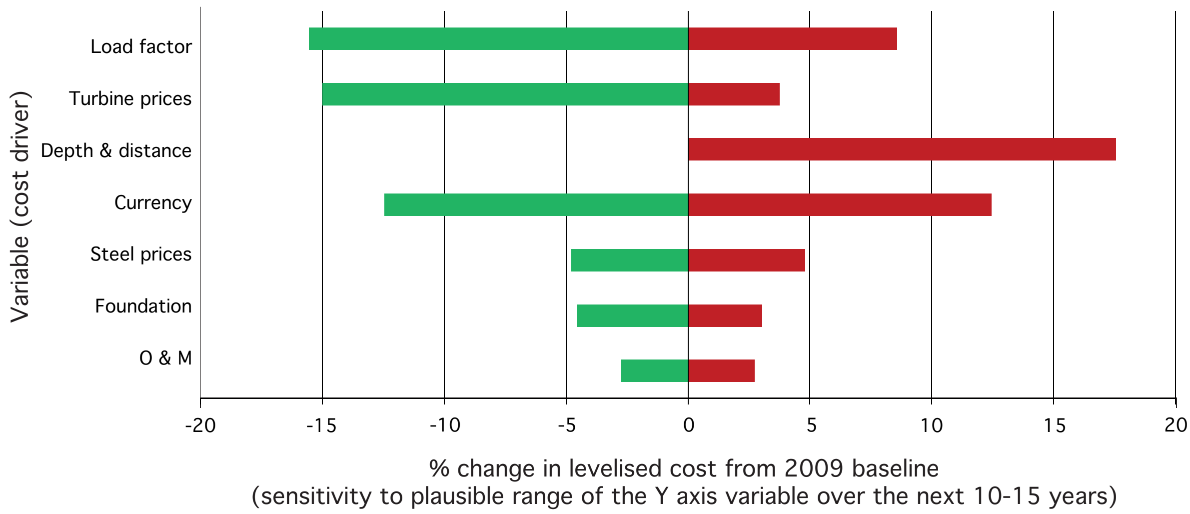
The ranges in cost drivers variables over the next 10-15 years are based on the review of the evidence and analysis of the direction and scale of each driver. The following cost sensitivity ranges were explored:

Turbine prices	(-40%, +10%)
Foundations costs	(-30%, +20%)
Depth and distance	(0%, +22%)[18]
Load factor	(-3%, +7%)[19]
O&M costs	(-25%, +25%)
Currency movements	(-20%, +20%)
Steel costs	(-50%, +50%)

The results are shown in Figure 5.1 below, and demonstrate the critical importance of maximising turbine availability (and therefore load factor), reducing turbine costs, the consequences of going further offshore and in deeper water, and the opportunity that locating more of the supply chain within the UK presents.

There are of course many ways of categorising costs, and in practice there is a considerable degree of overlap and interdependency between any such categories and the cost drivers

Figure 5.1 Levelised cost sensitivities



18 The percentages represent the absolute change in capital costs of going to a deep, far site.

19 The percentages represent absolute changes the in the load factor e.g. changing from the baseline of 38% to a high figure of 45%.

represented in Figure 5.1. For example, different operation and maintenance regimes which are designed to increase reliability and load factor may impose additional costs (albeit with the expectation that such costs will be outweighed by load factor improvements or extension of plant operating life, which in turn would result in a lower levelised cost overall). The categories used in Figure 5.1 are not additive, partly for the reason described above but also because the plausible range of variation for a particular category takes into account the possible impact of variation in other relevant categories (for example, currency movements bear upon the cost of turbines for delivery to UK projects).

In section 5.5 we build upon the analysis above to develop and explain UKERC's view of the likely range of cost outcomes for offshore wind, looking ahead to the mid 2020s.

Box 5.1 Cost component breakdown from four data sources

Table 5.2 below provides a review of cost breakdown data from the literature within the last two to three years. For each of the data sources the table presents the cost component/ element and its percentage of total cost. It is interesting to note the percentage variation for a particular component – for example, across the four sources the turbine plus turbine installation cost lies in a range between 35% and at least 50%. The different data sources do not necessarily categorise the cost components in the same way (some separate towers from nacelles whilst others don't, for example) and the table therefore reflects this fact.

Table 5.2 Cost breakdown of offshore wind project cost elements

	% of total cost according to each data source			
Cost element	**A**	**B**	**C**	**D**
Turbine/tower	33	47	45	49
Turbine installation	2		5	included
Foundation	19	22	17.5	21
Foundation installation	6		7.5	included
Installation		presumed included		
Electrical supply			9	21
Electrical installation			6	included
Cabling	10	19		
Cabling installation	9			
Substation	4			

continued

Project management	5		5	6
Consents	7			
Testing & commissioning	2			
Finance	presumed included	presumed included	presumed included	presumed included
Other	3	12	5	3
O&M	additional 23% of total over lifetime	additional £80,000/ MW/year	additional but not stated	additional £13/MWh/ year
Total	100	100	100	100

Source: A = (ODE Limited, 2007)
B = (E&Y, 2009)
C = (BWEA and Garrad Hassan, 2009a)
D = (EWEA, 2009a)

Notes: 'additional' = additional to capex

5.4 Cost drivers and sensitivities: summary of key findings

Chapter 5 has considered the possible trajectory of future costs out to the 2020s, examining each of the drivers or factors that impact on the cost components of offshore wind power. With around 1GW installed in the UK, and around 1.5GW installed elsewhere, offshore wind remains at a very early stage of development, equivalent in capacity terms to just one conventional power station. In energy output terms, the UK has so far built the equivalent of a single conventional power station of around 350MW. So called 'first of a kind' costs still apply in large part to offshore wind. Supply chains remain under developed, offshore turbines represent a tiny fraction of the global wind market, dedicated facilities and services are only beginning to emerge, considerable scope for innovation, learning and scale remains. As a result very few of the key factors that will affect future costs can be assessed with much certainty. This section provides a brief summary of the main findings on costs, before assessing the sensitivity of total costs to the main drivers, as presented in Figure 5.1.

Turbines represent the largest single cost item in an offshore wind farm, up to half of overall capital expenditure. Turbine prices have gone up in part because of increasing commodity prices, particularly steel. However the total impact of materials, commodity and labour cost increases explains only around half the rise in turbine costs. The remainder may be explained in part by 'learning' – many early sites suffered from poor availability and turbine failures, and making turbines more robust has implications for costs. However many analysts and industry experts believe that low levels of competition in turbine making has had an important impact. Moreover, offshore wind is a small element of wider turbine manufacture. Whilst in the long term the UK offshore wind industry may reap the benefits of 'first movers', in the short run it is to be expected that serving such a 'niche' will require a premium. Technology experts also expect a range of upscaling and other innovations to emerge in the coming decade.

Looking ahead, new market entrants, scale effects, design improvements, innovation and lower commodity prices bode well for the future price of turbines. Given the uncertainties, a downside risk remains and if a range of problems are not addressed the price of turbines could even rise. It does not appear likely that turbine prices will fall rapidly; indeed they are likely to remain at or around their current level until around 2015 or so. However, provided a range of drivers move in the right direction together and assuming no further adverse currency effects (ideally because production moves to the UK) cost reductions could be significant in the period to 2025. We suggest that turbine cost reductions of up to perhaps 40% could be achieved. The implication for levelised cost is a reduction of up to around 15% relative to 2010 levels.

Foundations are subject to a similar set of drivers to turbines. With the exception of the Beatrice development, to date there has been no UK manufacture of foundations. Most of the monopile foundations used in UK projects have been subject to sterling-euro currency fluctuations. Steel prices have also had a significant impact, and moving to deeper waters creates a significant challenge that is likely to increase costs in the short run. Whilst we did not find evidence of insufficient competition in foundation supply, several commentators highlight supply chain constraints. There is considerable potential for innovation, which many believe to offer substantial potential for cost reduction. Overall, we believe that there is a considerable spread of possible outcomes for foundations, the range is from a 20% cost increase to a 30% reduction. The impact on levelised costs is moderated by the fact that foundations account for a relatively small share of total costs, and lies in a range of less than 5% either way.

Depth and distance are of particular relevance to future UK offshore wind development given the more challenging ambitions of UK Round 3. We provide crude estimates of the cost levels for the nine Round 3 zones relative to the capital and levelised costs of a typical mid-depth/mid-distance site more typical of Round 2. Levelised costs increase in all cases but one by between 5% and 24%. Whilst innovation and learning in installation, foundations, maintenance and a range of other factors ought to mitigate the impacts of going to more inherently costly locations, on the whole we believe that depth and distance are likely to place upward pressure on costs. It appears unlikely that better wind speeds will be sufficient to compensate for additional costs associated with going further offshore. Assuming no mitigating factors, a range of up to around 15 to 20% *increase* in levelised cost of energy appears possible.

Load factor is another key intrinsic factor. This has been given particular attention by developers and manufacturers, and improved turbine reliability and better O&M should improve turbine availability. A downside risk remains, since it is possible that the greater distances associated with some Round 3 sites will negatively affect availability, due to greater access restrictions. If Round 3 sites are only able to achieve availability and load factors that are at the lowest end of the plausible range then levelised costs may rise by around 9%. If availability problems are resolved then better wind conditions and optimisation of turbines has the potential to reduce levelised costs. If UK Round 3 developments are able to secure load factors similar to those achieved in several Danish developments, other factors being equal, levelised costs could be reduced by up to around 15%.

O&M costs. The relationship between improving O&M and optimising availability is important. Whilst a range of learning effects are likely to improve effectiveness and decrease relative costs, absolute increases in O&M costs appear likely, given both more challenging conditions and the importance of improved availability. The overall implications of O&M should not be exaggerated. A 25% increase or decrease in O&M spend will respectively increase or decrease levelised costs by less than 3%.

Currency movements are obviously outside the control of project developers (currency hedging aside) or policymakers focused upon offshore wind. Whilst we do not speculate on the future of sterling, it is important to note how large an impact currency movement has had on offshore wind prices. Appreciation/depreciation of 20% has the potential to increase/decrease costs by around 12% in either direction, assuming that around 80% by value of an offshore wind farm is imported. Increasing the UK built, sterling denominated, proportion of offshore wind farm costs therefore has considerable merits in terms of reducing uncertainty as well as bringing wider economic benefits to UK regions. It will also maintain downward pressure on costs if the pound remains relatively cheap by historic norms, in line with recent UK government expectations.

Commodity price movements had a big impact on the price of some of the key components of offshore wind farms, notably turbines and foundations. However, the impact of any single material input on the overall costs of offshore wind should not be overstated. Steel for example accounts for only around 12% of the capital cost of an offshore wind farm. We do not speculate on commodity prices out to 2025, though it is important to note that the prices of steel and copper have returned to their historic mean and there are few reasons to expect dramatic increases in the short term. We illustrate the impact of steel over the longer run by testing sensitivity to a 50% increase/decrease in costs. Fluctuations of this magnitude only change levelised costs by around 5% in either direction.

For the most part the cost impact of the other factors discussed in Chapter 5 is more difficult to assess, but this does not detract from their importance to the growth of offshore wind and cost reduction. The following factors are particularly notable:

Docks and ports are already inadequate to the task and considerable investment is needed. Better facilities exist in mainland Europe, in part because of public investment in docks. Sustained commitment, and perhaps further public spending, is likely to be needed to support an emerging UK supply chain.

Vessels and the wider installation supply chain are also tightly constrained at present and the wind industry must often compete with offshore oil and gas. Longer term, increasing confidence in the stability of the offshore market especially from Round 3 would be expected to lead to increasing supply. Investment in vessels and associated capabilities is expanding.

Economies of scale cut across and apply to several of the above factors including turbines, foundations, docks and ports, and vessels. In the medium to longer term, downward pressure on costs resulting from economies of scale would appear highly likely – provided a range of interacting factors can be addresses (larger turbines can only be effectively deployed given appropriate dock, vessel and other infrastructure).

Planning delays have had a substantive impact on Rounds 1 and 2. We have not attempted to quantify this, but in terms of both absolute costs and revenue foregone it has a substantial and material impact on project finance and economics. It also places further strain on the supply chain, since lengthy delays undermine confidence. The IPC promised to improve matters according to industry observers, and it is essential that the coalition government's revised arrangements do not compromise these improvements.

5.5 Conclusions about future costs

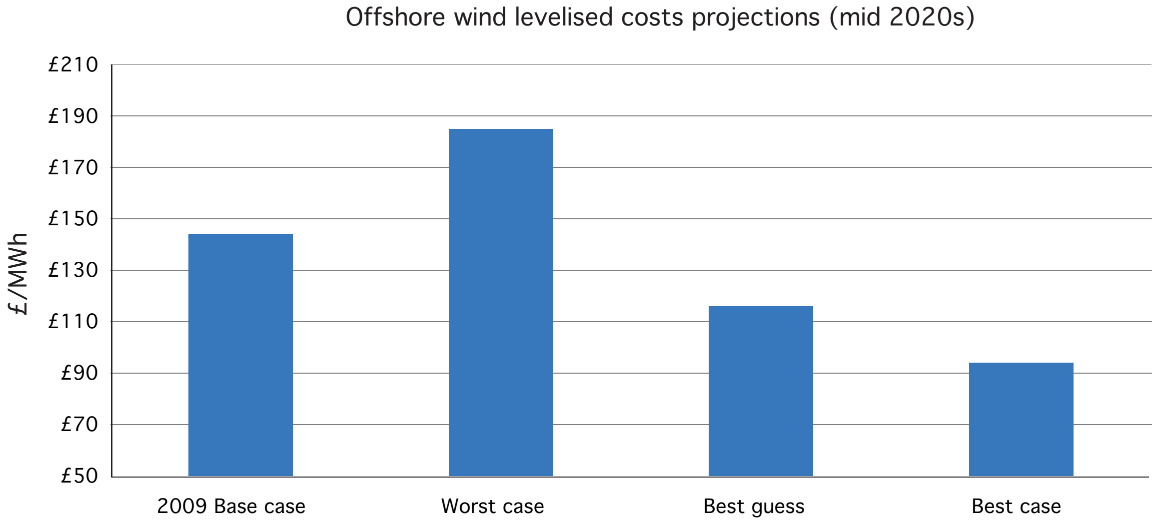
Recent analyses do not envisage a meaningful reduction in costs between now and 2015 and our assessment of the cost drivers tends to support this. Supply chain pressures remain, it will take time for new entrants to penetrate the market and innovation is expected to play a larger role in the medium than short term. Nevertheless many of the factors that drove costs up have either moderated or have the potential to be remedied; in short there are grounds for optimism.

To illustrate the range of possibilities, UKERC used the sensitivity analysis described above to develop a range of plausible developments in key cost factors in the period to 2025. Because of the uncertainties that currently surround offshore wind costs we do not attempt to apply a learning curve based approach, instead we recommend expert market and engineering based assessment.

Figure 5.2 provides an overview of 'best case' 'worse case' and 'best guess,' estimates developed by the TPA team. These estimates are derived from the sensitivities above, modelled using the offshore wind cost calculator developed for this project, and use the following data:

- 2009 base case: baseline data from the analysis described in section 5.3.
- 'Worst case' changes from base case: load factor reduced by 3 percentage points to 35%, turbine costs increased by 10%, foundation costs increased by 20%, O&M costs increased by 25%, plus an additional 10% increase in total

Figure 5.2 Offshore wind costs projections



capital costs to allow for extremes of depth and/or distance.

- 'Best guess' changes from base case: load factor increased by 5 percentage points to 43%, turbine costs reduced by 25%, foundation costs reduced by 5%, O&M costs increased by 10%.
- 'Best case' changes from base case: load factor increased by 7 percentage points to 45%, turbine costs reduced by 40%, foundation costs reduced by 30%, O&M costs reduced by 25%.

In all these cases, exchange rates are kept constant. We illustrate the effects of exchange rate fluctuations in section 5.3.

In our worse case, the costs of offshore wind rise from a current level of around £145/MWh to around £185/MWh. On the other hand, if favourable developments take place in all of the main factors, then costs could fall to just under £95/MWh. The corresponding capex values are £3.8m/MW for the worst case and £2.4m for the best case.

Cost projections have to be tentative at the current stage in the history of the offshore wind industry. Whilst mindful of the remaining uncertainties we believe it is reasonable to expect a gradual fall in the cost of offshore wind over the period between now and the mid 2020s, particularly if policy can place downward pressure on costs and support the emerging UK supply chain. ***Our 'best guess' figure for 2025 is a fall of around 20% from current levels to £116/MWh (£2.8m/MW capex), with continued falls thereafter.***

Greater reductions are possible, but would require most, if not all, of the major cost drivers to move decisively in the right direction at once. A significant downside risk remains and it is possible that the costs of offshore wind could continue to go *up*, particularly if supply chain problems are not addressed.

5.6 Implications for policy

At the time of writing the support regime for offshore wind in the medium term is somewhat uncertain. The coalition government has indicated that it wishes to bring in a Feed-in Tariff (FiT), but details are not yet available. Meanwhile, the current 2 ROC multiple is due to expire in 2014. Our analysis indicates that sustained cost reductions will be required to bring costs down to the 1.5 ROC range (see Box 5.2).

Our analysis suggests that achieving overall costs which are consistent with reducing support from the ROC multiple back down to 1.5 ROCs/MWh will require capital cost reduction of the order of 17-18%, assuming no major change in other factors.

Long term signals and cost monitoring capabilities

Concern has been expressed by some commentators about the relationship between the emergence of the 2 ROC multiple and the market power of some in the offshore wind supply chain, with limited competition in some areas and strong demand from a booming onshore market. A range of factors conspired to drive up costs and the government made the decision to provide 'emergency' 2 ROC support in response. Without additional support it is likely that offshore wind development would have faltered. Industry representatives will obviously wish to alert policymakers to cost escalations when development depends in part on policy subsidies. However, industry 'capture' of regulatory change is clearly a danger if support levels are in some part the product of a *negotiation* between policymakers and industry, particularly where industry structure is relatively concentrated.

Detailed development of a process for setting ROC multiples or FiT rates is beyond the scope of this report. Nevertheless we believe that it is essential for such arrangements to create clear, long term and binding signals that costs need to be reduced. Periodic 'reviews' cannot set long term signals and may be amenable to lobbying by special interests, particularly where key cost data is allowed to reside solely within the private sector. One means by which this might be achieved would be for the government to establish clearly specified regression in support levels over time. This is common in FiT regimes overseas, a feature of the micro-generation FiT, and whilst simplest in FiT systems could apply to either FiT or ROC based support for UK offshore wind in future. In order to better inform this it may also be desirable for the government to support the development of an independent, non-commercial cost monitoring capability, perhaps in collaboration with other countries, international bodies and academia. Such a capability could shape expectations ahead of time.

Planning and transmission

It is essential that government's proposed changes to planning rules do not undermine progress made towards accelerating planning. 'Join-up' is essential, since the benefits of a streamlined system for offshore assets would be undermined

Box 5.2 Cost reduction implications for ROC multiples

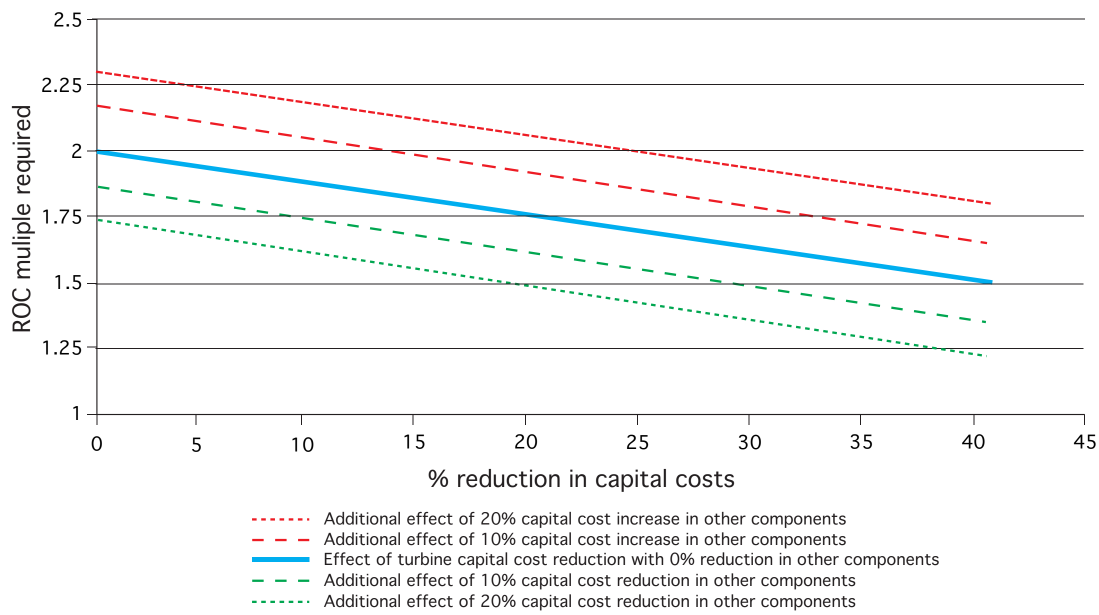
The banding of the Renewables Obligation which came into force in 2009 was designed to align more closely the support offered to the actual costs of technologies at different levels of maturity. The ROC multiple available for offshore wind projects was set at 1.5 when banding first came into force but this was subsequently revised upwards to 2 ROCs as it became apparent that costs had risen steeply. When announced, the increase to 2 ROCs was for a limited period, with the intention that the multiple would reduce back to 1.5 ROCs by 2014.

Since the implication is that policy makers expected costs to decline to a level which was consistent with the support offered by 1.5 ROCs, the TPA team undertook their own analysis to illustrate the degree of cost reductions required to be consistent with this level of support. The baseline data for the analysis were drawn from (E&Y, 2009), with the levelised cost and ROC multiple calculations calibrated to an assumption that 2009 baseline costs were consistent with the support offered by 2 ROCS, on the basis that projects are currently proceeding at this level.

The analysis explores the effects of capital cost reductions in the turbine only, and also the effect of capital cost reductions (and increases) in the other elements that make up the total overall capital cost. The results are shown in Figure 5.3 below, where the central solid line plots the ROC multiple effect of reducing turbine capital costs whilst holding other components of total capital cost constant. The dashed green lines show the *additional* effect of reducing the other components of total capital cost by 10% and 20%, whilst the dashed red lines show the *additional* effect of increasing the other components of total capital cost by 10% and 20%.

What Figure 5.3 suggests is that achieving overall costs which are consistent with the support of 1.5 ROCs will require capital cost reduction of the order of 40% if limited to the turbine alone, or between approximately 18% and 28% for the turbine if combined with capital cost reductions in other elements. Whilst levelised cost calculations are notoriously sensitive to the underlying assumptions (Gross et al., 2007), this does give an indication of the required cost reductions if offshore wind is to be compatible with the support available from 1.5 ROCs.

Figure 5.3 Cost reductions and ROC multiples



by a slower process for substations and other onshore assets. Similar concerns relate to OFTOs and connections to the national grid – though we have excluded these aspects from this review.

Support for innovation

Given the importance of continued innovation to cost reduction we also recommend that support for innovation in offshore wind continues to be given a priority in RD&D programmes. Important research on innovative, cost-reducing solutions is already a focus of the Carbon Trust's offshore wind 'accelerator', the ETI offshore wind work and the European Wind Energy Technology Platform.

Support for the supply chain

Our analysis also suggests that building a UK industry offers benefits related to currency movements. It also brings with it obvious employment and industrial development benefits, at a time when the government is seeking to both rebalance the economy towards manufacturing and create a 'green economy'. Given that UK consumers will foot the bill for offshore wind, a case can also be made that it would be reasonable to expect the benefits to accrue to UK companies. This will require investment, particularly in dock facilities, since there is little point in making turbines and other large components in the UK if we lack the wherewithal to install from UK bases. We believe that direct and targeted support lower in the supply chain, in addition to the overarching incentive provided by the RO (or a FiT), is likely to be a cost effective way to secure UK based offshore wind. Failing to do this effectively risks both a higher cost trajectory for offshore wind and that UK developments are built out of ports in other parts of Europe. It is beyond the scope of this report to speculate further about the role of policy in securing UK manufacture, but doing so is likely to be key, both to cost reduction and perhaps to maintaining support from consumers.

Further work could investigate the potential to explicitly target a fraction of the support coming through the RO to the UK supply chain and perhaps UK RD&D.

5.7 Conclusions

Offshore wind offers lessons for policymakers and technology analysts alike. This report has charted the progress with offshore wind – and the aspirations for it – from its beginnings in Denmark in the 1990s to present developments in Britain, now the world leader in offshore installation. Our review suggests that early, small scale, developments did not give a good guide to future costs and indicates that rapid upscaling of an emerging technology can create supply chain constraints, amplify design flaws and cause costs to rise whilst progress is slower than expected. External economic factors can also – at least for a while – overwhelm intrinsic learning or other effects. There is actually nothing new or unique to offshore wind about this.

Chapters 2 and 3 document a relationship between encouraging cost trends and ambitious policies. Chapter 4 explains how costs rose and expectations changed. The factors that drove the costs escalations from the mid 2000s are well understood.

Recent evidence suggests that costs in 2010 are no higher than 2009, suggesting costs may have 'peaked' and there is some evidence that a turning point may have been reached.

In this chapter we have shown that there are grounds to believe that offshore wind costs *can* be reduced over time. In the medium and longer term, the potential for cost reductions arising from greater competition and from increased supply chain confidence, along with innovation, learning and economies of scale in key areas, may outweigh the cost increases resulting from greater depth and distance of Round 3. However, the trend downwards is not likely to mirror the recent precipitous trend upwards. The period to the mid 2020s is most likely to see *gradual* reductions. And these can only be delivered if a range of key drivers can be aligned.

Perhaps the greatest challenge facing policymakers is reconciling the scale and pace of development desired for offshore wind with the potential growth rate the supply chain can sustain. The scale of Round 3 represents an 'attractive force' that has the potential to bring in new capacity and reduce costs. However, the *pace* of growth implied by meeting EU targets could create upward pressure on costs. It is important for policy to create clear signals that costs must fall, whilst encouraging the supply chain to mature and bringing more of it into Britain.

It is important not to lose sight of the fact that offshore wind *is still in its infancy*, less than 2% of total wind capacity is currently located offshore. In effect we are still building the equivalent of our *first* conventional power station. In energy output terms, the UK has so far built a single power station of around 350MW. So called 'first of a kind' costs still apply in large part. It is also important to avoid 'dogged optimism'; extending the timeframe in order to demonstrate that costs can be attractive, eventually. However, we should not be particularly surprised that we have arrived at a point in the history of a particular emerging technology when costs have increased and problems mounted. Many technologies go through such a period, and still go on to offer cost effective performance in the long run. Overall, there are grounds to be optimistic about offshore wind, tempered with *realism* about the challenges associated with its development and the need for policy to engage effectively with *all* the factors that will affect its success.

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Annex 1: Systematic review

With the exception of consultation with industry actors and with the project's expert group, and in line with defined UKERC TPA practice, this report does not undertake new quantitative or qualitative research. The majority of the data therefore are sourced from a review of the available literature most directly relevant to offshore wind power costs. To this end, a systematic search was carried out for reports and papers related to the subject in academic and other targeted research sources.

The principal academic databases used were Elsevier Science Direct, ISI Web of Science, CSA Illumina (Natural Sciences, Social Sciences, Technology), and Compendex. A set of key words and search terms was determined (Table) which provided the basis for the creation of specific search strings.

Table A1.1 Systematic review search terms

"offshore wind"	cost or "cost reduction" or "cost escalation"	"engineering assessment" or engineering or assessment	"learning effects" or "learning curves" or "experience curves" or experience or learning or curve	"supply chain" or bottleneck

The search strings are described using Boolean terminology and where a search term is contained within quotation marks (e.g. "*supply chain*") the words within the marks will only be found when they occur next to each other as a phrase. The challenge was to keep the number of search strings to a manageable level without losing relevant papers from the review process. The project team selected those combinations of terms deemed to provide the appropriate coverage (Table) but in the event that a search string resulted in an unfeasible number of 'hits' (e.g. "offshore wind" AND engineering), the search results were not saved to the reference management system and instead the string was refined to produce a more focused and manageable number of results.

Table A1.2 Systematic review search strings and results

Database	Search String	Hits	Notes
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY(cost OR "cost reduction" OR "cost escalation")	31	All years
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY("engineering assessment")	0	,,
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY(engineering)	12	,,
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY(assessment)	25	,,
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY("learning effect*" OR "learning curve*" OR "experience curve*")	0	,,

continued overleaf

Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY(experience)	11	,,
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY(learning)	3	,,
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY(curve)	4	,,
Science Direct	TITLE-ABSTR-KEY("offshore wind") AND TITLE-ABSTR-KEY("supply chain" OR bottleneck)	2	,,
Science Direct	Total saved hits from all Boolean combinations tried above	88	
ISI Web of Science	TS=("offshore wind") AND TS=(cost OR "cost reduction" OR "cost escalation")	73	,,
ISI Web of Science	TS=("offshore wind") AND TS=("engineering assessment")	0	,,
ISI Web of Science	TS=("offshore wind") AND TS=(engineering)	37	,,
ISI Web of Science	TS=("offshore wind") AND TS=(assessment)	72	,,
ISI Web of Science	TS=("offshore wind") AND TS=("learning effect*" OR "learning curve*" OR "experience curve*")	0	,,
ISI Web of Science	TS=("offshore wind") AND TS=(experience)	34	,,
ISI Web of Science	TS=("offshore wind") AND TS=(learning)	3	,,
ISI Web of Science	TS=("offshore wind") AND TS=(curve)	5	,,
ISI Web of Science	TS=("offshore wind") AND TS=("supply chain" OR bottleneck)	1	,,
ISI Web of Science	Total saved hits from all Boolean combinations tried above	225	
CSA Illumina	KW=("offshore wind") AND KW=(cost OR "cost reduction" OR "cost escalation")	71	Natural Science
CSA Illumina	KW=("offshore wind") AND KW=("engineering assessment")	0	,,
CSA Illumina	KW=("offshore wind") AND KW=(engineering)	143	,,
CSA Illumina	KW=("offshore wind") AND KW=(assessment)	96	,,
CSA Illumina	KW=("offshore wind") AND KW=("learning effect*" OR "learning curve*" OR "experience curve*")	1	,,
CSA Illumina	KW=("offshore wind") AND KW=(experience)	38	,,
CSA Illumina	KW=("offshore wind") AND KW=(learning)	6	,,
CSA Illumina	KW=("offshore wind") AND KW=(curve)	4	,,

CSA Illumina	KW=("offshore wind") AND KW=("supply chain" OR bottleneck)	2	,,
CSA Illumina	KW=("offshore wind") AND KW=(cost OR "cost reduction" OR "cost escalation")	82	Technology
CSA Illumina	KW=("offshore wind") AND KW=("engineering assessment")	0	,,
CSA Illumina	KW=("offshore wind") AND KW=(engineering)	465	,, Not saved
CSA Illumina	KW=("offshore wind") AND KW=(assessment)	56	,,
CSA Illumina	KW=("offshore wind") AND KW=("learning effect*" OR "learning curve*" OR "experience curve*")	3	,,
CSA Illumina	KW=("offshore wind") AND KW=(experience)	30	,,
CSA Illumina	KW=("offshore wind") AND KW=(learning)	5	,,
CSA Illumina	KW=("offshore wind") AND KW=(curve)	4	,,
CSA Illumina	KW=("offshore wind") AND KW=("supply chain" OR bottleneck)	5	,,
CSA Illumina	Total saved hits from all Boolean combinations tried above	546	
Compendex	("offshore wind") wn KY AND (cost) wn KY	180	From 1987
Compendex	("offshore wind") wn KY AND (engineering assessment) wn KY	17	,,
Compendex	("offshore wind") wn KY AND (engineering) wn KY	198	,, Not saved
Compendex	("offshore wind") wn KY AND (assessment) wn KY	116	,, Not saved
Compendex	("offshore wind") wn KY AND ("learning effect*" OR "learning curve*" OR "experience curve*") wn KY	2	,,
Compendex	("offshore wind") wn KY AND (experience) wn KY	64	,,
Compendex	("offshore wind") wn KY AND (learning) wn KY	9	,,
Compendex	("offshore wind") wn KY AND (curve) wn KY	15	,,
Compendex	("offshore wind") wn KY AND ("supply chain" OR bottleneck) wn KY	6	,,
Compendex	Total saved hits from all Boolean combinations tried above	293	
Above four databases together	Grand total saved hits from all Boolean combinations tried above	1152	

On this basis, the systematic search revealed approximately 1150 evidence hits. However, a great many of these were duplicates across the four databases and removal of these reduced the results total to approximately 450. This number was then approximately halved by removal of any hits that, judging from their title or abstract, were immediately obvious as being of little or no relevance. The total was then increased by the addition of evidence from following 'citation trails' and from specific recommendations, and also from non-academic sources such as industry publications (e.g. Wind Power Monthly) and relevant websites (e.g. BWEA),

This process produced a total of approximately 350 pieces of evidence that were rated for relevance. The relevance ratings are as follows:

- A rating of 1 indicates that the piece of evidence deals very clearly with one or more aspects of the research questions.
- A rating of 2 indicates that although the paper is relevant, its findings are presented in a way that could preclude direct comparison with other results.
- A rating of 3 indicates limited relevance and/or clarity.
- A rating of 4 denotes papers that are duplicative or, on closer inspection, were deemed not relevant.

In the writing of this report, the majority of the evidence used is rated 1 or 2 with only very limited contextual use made of evidence rated 3 and 4.

Annex 2: Actual and forecast capital costs

Figure A2.1 shows all the individual values for reported actual costs for offshore wind farms, drawn from the literature identified by the systematic review described in Annex 1. All values were converted to 2009 GBP in a two step process:

- Values denominated in currencies other than GBP were converted to GBP using the exchange rate prevailing for the year which the reported value relates to.
- Values (now all denominated in GBP) were inflated to 2009 values using the Office of National Statistics RNNK index.

Figure A2.1 represents the full data set used to calculate the in-year average values shown in figures 2.2 and 4.1 in the main report.

Figure A2.2 shows all the individual values for forecast costs for offshore wind. As for Figure A2.1 all values were converted to 2009 GBP using the same process as described above (except that the conversion rate used was that prevailing for the year the forecast was made). There is an additional complexity in Figure A2.2 in that as well as the year the forecast was made, there is also the year the forecast relates to. In the figure, forecasts made in the same year e.g. 1998 are grouped as a data series. Figure A2.2 represents the full data set used to calculate in-year average (pre and post-2005) values shown in figure 4.8 in the main report.

Figure A2.3 combines figures 4.1 and 4.8 from the main report to show actual and forecast values on the same chart.

Figure A2.1 Reported actual costs data

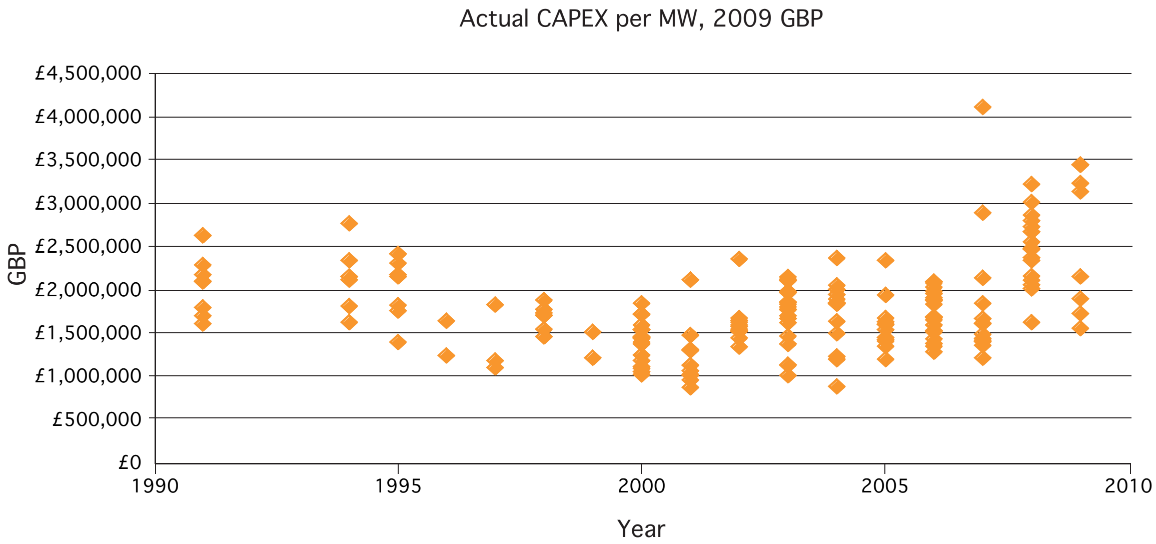


Figure A2.2 Reported forecast costs data

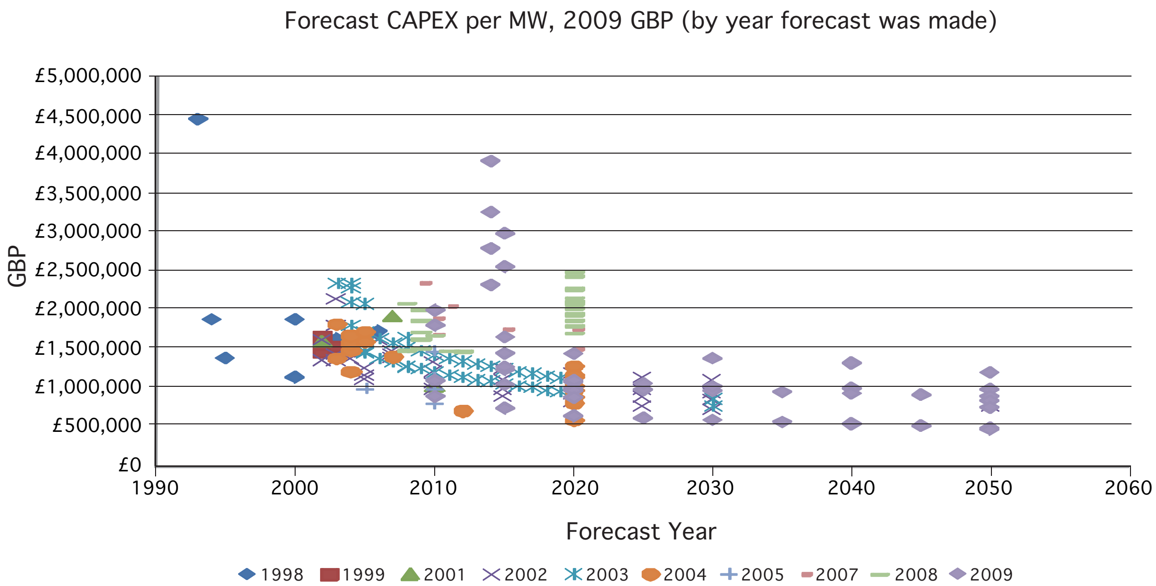
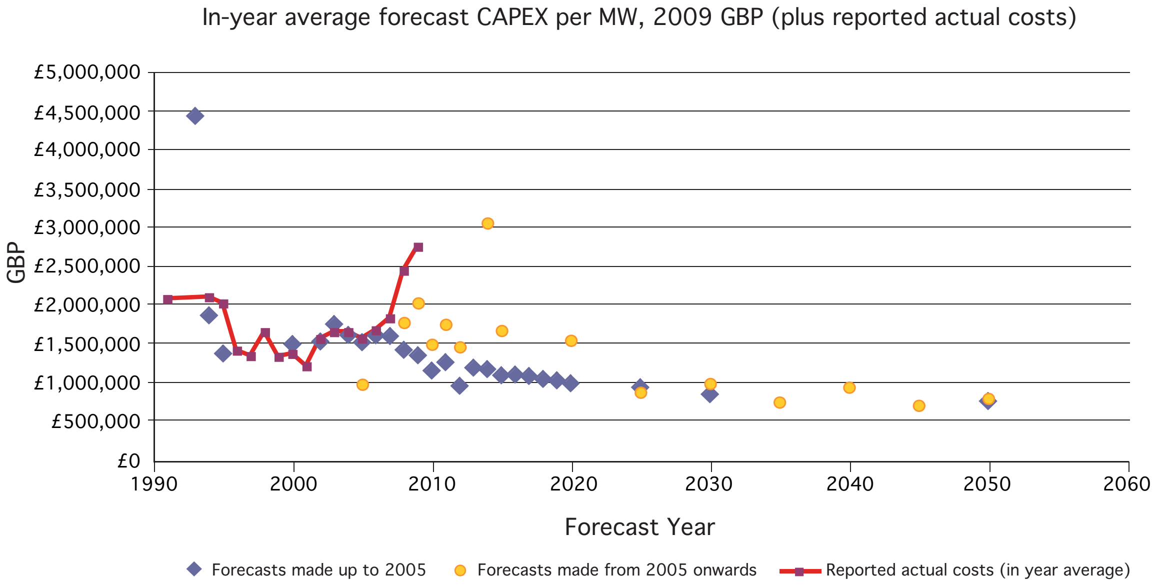


Figure A2.3 In year average forecasts (pre and post 2005) and in-year average actual data



Annex 3: Acknowledgements

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