Cost of and financial support for offshore wind

A report for the Department of Energy and Climate Change

27 April 2009

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Private and confidential

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24 April 2009

Dear Katherine,

Cost of and support for offshore wind

In accordance with our contract dated 14 January 2009, we have prepared our report (the "Report") in relation to the cost of and financial support for offshore wind power in the UK.

This study was commissioned by the Department of Energy and Climate Change (DECC) to provide:

- An assessment of the current capital and operating costs for offshore wind projects in the UK and the historical evolution of the key drivers of these costs
- An initial assessment of the likely evolution of such costs (assuming current project characteristics)
- The level of financial support required to encourage the short-term roll-out of offshore wind projects in the UK
- An outline of alternative support measures to be considered in providing additional support to the offshore wind industry in the UK

In carrying out our work and preparing our report, we have worked solely on the instructions of DECC and for DECC's purposes. Our report may not have considered issues relevant to any third parties, any use such third parties may choose to make of our report is entirely at their own risk and we shall have no responsibility whatsoever in relation to any such use.

Our Report is based on certain publicly available information (as listed in Appendix A), project information obtained by DECC, Ernst & Young proprietary data (where it has been legally possible to share it) and discussions with DECC's Steering Committee. We have not sought to verify the accuracy of the data or the information and explanations provided by any such sources.

If you would like to clarify any aspect of this review or discuss other related matters then please do not hesitate to contact us.

Yours faithfully

Ernst & Young LLP

Executive summary

Background

In the context of the European led renewable energy targets for the UK and the expected contribution of the power generation sector to help meet these targets, offshore wind is forecast to play a major role in contributing to renewable power generation capacity by 2020.

The increase in the cost of building and operating offshore wind projects in recent years has made the economic case for developers seeking to construct and own offshore wind farms increasingly difficult to justify, both by themselves and when compared to other economic investment choices. This is cause for concern given the contribution offshore wind is likely to make to the UK's Renewable Energy Strategy. DECC therefore needed to reassess the economics of offshore wind to ensure that it understands the effectiveness of its support regime.

This study was commissioned by DECC to provide:

- An assessment of the current capital and operating costs for offshore wind projects in the UK and the historical evolution of the key drivers of these costs;
- An initial assessment of the likely evolution of such costs (assuming current project characteristics)
- The level of financial support required to encourage the short-term roll-out of offshore wind projects in the UK; and,
- An outline of alternative measures that could be considered in providing additional support to the offshore wind industry in the UK.

Methodology

This work was based on publicly available information, project information obtained by DECC, Ernst & Young proprietary data (where it has been legally possible to share it) and discussions with DECC's Steering Committee. The study involved the following key tasks:

- Establishing an estimate of the current cost for offshore wind (for both capital and operating expenditure) for projects at or near financial close as of January 2009.
- Examining the material capital and operating costs and relying on publicly available analysis (see Appendix A) to identify their respective cost drivers (i.e. labour, commodities, steel, water depth, distance from shore). This analysis formed the basis for much of the qualitative discussion contained in this report.
- Applying projections for capacity deployment for offshore wind in the UK (see Appendix C), which influences the rate of cost reduction associated with industry learning. Learning rates are applied to current costs to show the possible effects of increased industry experience on project costs.
- Using estimated current and future project costs (calculated in January 2009 real terms), a discounted cash flow model was used to derive levelised costs for projects reaching financial close in 2009 and 2015 respectively.
- On the basis of a range of estimates for forward wholesale power and ROC revenue curves, the model was used to calculate the level of RO banding required to meet specific rates of return (10% post-tax real in the Base Case).

Conclusions

The analysis indicates that offshore wind projects at or near financial close in January 2009 have considerably higher costs than in EY's analysis completed in April 2007. Whilst a range of alternative means of providing support could be considered, if such support were to be provided through the existing mechanism of the RO, the level of financial support required to provide a reasonable economic return would be between 2.0 and 2.5 ROCs per MWh, based on the analysis performed. The current level of support to offshore wind is 1.5 ROCs per MWh.

- Average capital costs have doubled over the last five years to c.£3.2m/MW; the cost increase appears largely driven by supply chain constraints for components (e.g. wind turbine generators) and services (e.g. installation), and also to a lesser extent recent fluctuations in Euro Sterling exchange rates and commodity prices.

- Average expected operating costs have increased c.65% over the same period to c.£79k per MW per annum; the cost increase appears largely driven by greater experience of running such projects and also a change in O&M philosophy by offshore wind operators which now seek to adopt a more proactive maintenance approach with a view to extending the life of their assets.

- Cost reductions, both in terms of capital and operating costs, could be anticipated in future for projects of similar technical characteristics to those being developed today, if:

  - There is sufficient offshore wind deployment to provide opportunity for industry learning

  - Supply chain constraints, such as supplier dominance and capacity shortages, are overcome through new entrants and investment in new production respectively

- On the basis of the above costs and other project parameters set out in Appendix D, and to meet a post-tax nominal hurdle rate of 12%, the analysis indicates that additional financial support is required to ensure an adequate level of revenue to project developers. A range of alternative means of providing support could be considered which have been outlined in Table 1 below; however if such support were to be provided through the existing mechanism an increase of the RO banding for offshore wind from 1.5 to 2 to 2.5 ROCs per MWh would be required.

- This analysis uses a comparable approach to that adopted by the Department for Trade and Industry (DTI) of April 2007 (Source: Impact of banding the renewables obligation – costs of electricity generation, Ernst & Young report for DTI, April 2007), which found, using cost data from the time, that 1.5 ROCs would be sufficient support for offshore wind.

- Sensitivity analysis on some of the assumptions indicates that a re-banding of offshore wind would be highly sensitive to project-specific considerations and that a 2 ROC per MWh banding (rather than 2.5) might satisfy some investors on certain projects where:

  - The net output (load factor) is higher than the Base Case assumption of 38%

  - Assumptions are taken in regards to introducing the OFTO regime which gives a positive effect on project economics (assumed to be value-neutral at this stage in the Base Case analysis)

  - Capital and operating cost assumptions are lower than those assumed in the Base Case

  - More optimistic assumptions are taken for forward power, ROC or LEC prices

  - Lower hurdle rates (e.g. 10% post-tax nominal per the analysis) are assumed

The analysis indicates that the increases in levelised costs for offshore wind were largely driven by increases in capital expenditure. Some of these increases can be justified through higher commodity prices and exchange rate fluctuations, however the majority cannot be justified in this way.

The relative immaturity of the supply chain for offshore wind components and support services appears to be driving market inefficiencies, which have led to significant cost increases particularly relating to the cost of procuring and installing wind turbines and foundations. These constraints may be partially overcome by increased competition in the supply chain and support services industry. In addition, technological development and industry learning are already underway, but the economic effect of these has been and may continue to be muted whilst supply constraints continue. Capacity constraints and perhaps competition issues in the supply chain may be responsible for some of the unexplained part of the cost increases, but this study has not looked in detail at the market conditions of the supply chain industries.

Limitations of the analysis

Readers should be aware of the following:

- The literature review (see Appendix A) revealed that there is limited information available regarding the main Cost Drivers for key offshore wind cost components, in particular regarding the contribution of these Cost Drivers towards overall capital and operating expenditure for a project. This analysis has had to rely on this limited information and has not involved a bottom-up analysis of 'fundamentals'.

- Capital and operating expenditure information provided by DECC or compiled by Ernst & Young have not been audited, therefore its accuracy could not be verified.

- In assessing project economics, investors will use their own proprietary forward wholesale power, ROC and LEC curves, and their own confidential hurdle rates. The analysis uses estimates for these pieces of information, hence the translation of levelised cost to ROCs required may not exactly reflect the true ROC requirement for individual projects.

- Within this analysis, forward ROC price curves are not linked to variations in the future wind capacity deployment assumptions (in reality the ROC Recycle price will change with the level of roll-out of offshore wind, for example one would expect low offshore wind roll-out to result in high ROC prices).

- Although the introduction of the OFTO regime is anticipated to be beneficial to project economics, for the purposes of this study, the new regime was assumed to be value neutral in the Base Case (this approach is based on recent discussions with industry participants). If the OFTO regime were to have a positive impact on project economics, the levelised cost and RO banding analysis carried out in this report would over-estimate the level of support required.

In order to highlight the variation in the level of support required, this study includes sensitivities on key assumptions including investor rate of return, revenue assumptions, net power exported, OFTO rate of return and the effects of industry learning and supply chain easing. Only RO banding has been modelled here.

Recommendations

Given the key findings above, it is recommended that the UK Government considers:

- Providing additional support in the near term to enable projects to proceed to counteract short term price issues (i.e. exchange rate fluctuations)

- How it can support the industry and encourage medium and long term growth of this sector without stimulating further cost inflation to the price of offshore turbines, whilst,

- Ensuring that any change in the RO banding for offshore wind does not create the impression of RO policy instability

Government could consider the relative merits of different measures to support offshore wind over the short to long term. A summary of possible support mechanisms is provided in Table 1 below.

Table 1: Possible support measures to offshore wind

Support measure	Potential impact	Implications
RO banding	Immediate	► Increased investment in projects ► No direct impact on supply chain (provides demand-pull)
Investment / production tax credits and tax depreciation	Immediate	► Effectiveness proven in the US onshore wind market and UK CHP market ► Implementable and extendable quickly using secondary legislation ► Typically requires high level of equity participation for full benefit ► Large projects would require significant UK taxable profits ► Reduces Treasury income
Capital grants	Immediate	► Avoids disrupting the existing RO regime and provides targeted support ► Does not incentivise efficient output-based production ► Can be administratively complex for applicants ► Requires a dedicated cash budget from Treasury and State-aid clearance; hence possible high cost to the Exchequer
Government intervention to reduce project specific risks (e.g. partially underwrite contingencies and provide insurance for projects)	Immediate	► Reduced uncertainty around unknown or unquantifiable risks, hence helps lower cost of capital ► Mitigates revenue flow-through to the supply chain ► Able to be phased out as unknown risks become known through learning ► Avoids disrupting the RO
Soft loans/credit guarantees/ Government participation in projects	Immediate	► Useful for assisting new entrants and smaller developers ► Helps lower the cost of capital required for the project ► Could be useful for new UK-based WTG manufacturers to assist in funding initial pilot projects
Non-financial support to UK-based WTG manufacturing	Medium term	► Fast-track planning or special 'economic zones' and rent-free holidays for new WTG manufacturing capacity could impact UK market three to five years later
R&D funding	Long term	► Advances in new technology likely to see commercial operation 10+ years after funding
Other (e.g. feed-in tariff)	Long term	► Feed-in tariff requires primary legislation to enable

Given the limited supply of offshore turbines, any stimulus will only increase the number of projects to the extent that there is slack in the supply chain and support services. As the production of new offshore turbines increases from existing and new players, installation capacity should become less of a constraint although the ambitious targets for offshore wind being sought by the UK and Germany in particular, as well as competition from onshore wind, means that the market for offshore components and services may remain constrained for some time.

Any increase in the level of support to the offshore wind industry should therefore take into consideration the possible flow-through of this support to the supply chain, as well as the impact of future changes in exchange rates and raw material prices.

Contents

Abbreviations

CT	Carbon Trust
DECC	Department of Energy and Climate Change
EI	Electrical Infrastructure
Ernst & Young	Ernst and Young LLP
GW	Giga Watt
HVDC	High Voltage Direct Current
IRR	Internal Rate of Return
k	Thousand
km	Kilometre
LEC	Levy Exemption Certificate
m	Metre/Millions
MW	Mega Watt
MWh	Mega Watt hour
NPV	Net Present Value
OFTO	Offshore Transmission Operator
Ofgem	Office of Gas and Electricity Markets
O&M	Operation and Maintenance
R&D	Research and Development
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
TNUoS	Transmission Network Use of System
UK	United Kingdom
WTG	Wind Turbine Generator

1. Introduction

In March 2007 the European Commission set a target to increase the contribution of renewable sources of energy to 20% of total energy consumption across all energy sectors in Europe by 2020. In this context, the European Commission set the UK a target of increasing the contribution of renewable energy to 15% of total energy consumption by 2020.

The UK power generation market is expected to contribute a larger proportion of the target than the heat and transport sectors. In practice, the power sector expects to have to increase the proportion of renewable generation to a level of 30-35% by 2020, from around 5% at the end of 2007.

Given this regulatory framework, the UK Government hopes to facilitate the build of up to 40GW of offshore wind power capacity, representing a five fold increase on the 8GW already planned or built under Rounds 1 and 2.

Industry and government have become concerned over the recent increase in the cost of offshore wind and the impact this may have on the UK meeting its long-term renewable energy objectives.

The aim of this study is to provide an assessment of the current costs and economics of a typical offshore wind project in the UK to inform DECC as to whether additional support for offshore wind projects is required to ensure the short-term roll-out of the UK pipeline.

2. Approach and methodology

2.1 Approach

This analysis was based on information collected from the public domain (see Appendix A for a list of sources used in preparing this report) and project data obtained from both DECC and Ernst & Young.

The work involved three key tasks:

- The collection of current cost information;
- The calculation of current and future levelised costs for offshore wind on the basis of current project characteristics and current project economics (in line with Ernst & Young's previous analysis dated April 2007) combined with assumptions on deployment and learning rates; and,
- The calculation of the ROC banding level required to meet specific rates of return for current offshore wind projects and consideration of alternative means of support.

2.2 Methodology

2.2.1 Current costs

The study of current costs involved the following:

- Establishing an estimate of the current cost of offshore wind (for both capital and operating expenditure) for projects at or near financial close as of January 2009.
- Examining the material capital and operating costs and relying on publicly available analysis (see Appendix A) to identify their respective cost drivers (i.e. labour, commodities, steel, water depth, distance from shore). This analysis formed the basis for much of the qualitative discussion contained in this report.
- Applying projections for capacity deployment for offshore wind in the UK (see Appendix C) which influences the rate of cost reduction associated with industry learning. Learning rates are applied to current costs to show the possible effects of increased industry experience on project costs.

2.2.2 Levelised cost

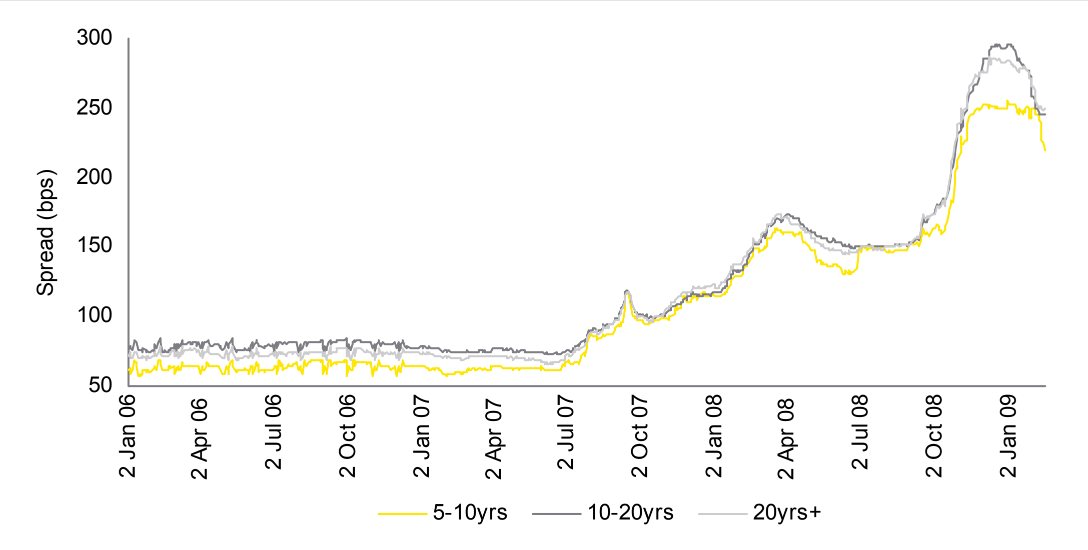
Using estimated current and future project costs (calculated in January 2009 real terms), a discounted cash flow model was used to derive levelised costs for projects reaching financial close in 2009 and 2015 respectively.

The Base Case for all levelised cost calculations used a post-tax real discount rate of 10%. This is in line with the Ernst & Young RO banding analysis of April 2007, which used a 12% pre-tax real discount rate for offshore wind.

Utility developers, which represent the majority of offshore wind capacity installed to date, will typically finance offshore wind projects using balance sheet financing. Figure 1 shows utility bond prices from January 2006 to January 2009 and demonstrates that recent increases in the costs of financing new capital projects are a result of a higher cost of debt for these companies.

Figure 1: Sterling utilities bond indices

Source: Merrill Lynch indices, Bloomberg



With increasing experience in the construction and operation of offshore wind assets, the risk premium for offshore wind should gradually reduce for developers, resulting in decreasing cost of capital. However, the significant rise in spreads for utility bonds since summer 2007 as a result of the global financial crisis has led to a general rise in the cost of capital for these businesses. As a consequence, the cost of capital for offshore wind is assumed to have remained largely the same since 2007 levels.

2.2.3 RO banding

On the basis of a range of estimates for forward wholesale power and ROC revenue curves, the model was used to calculate the level of RO banding required to meet specific rates of return (10% post-tax real in the Base Case.

2.3 Limitations of the analysis

Readers should be aware of the following:

- The literature review (see Appendix A) revealed that there is limited information available regarding the main Cost Drivers for key offshore wind cost components, in particular regarding the contribution of these Cost Drivers towards overall capital and operating expenditure for a project. This analysis has had to rely on this limited information and has not involved a bottom-up analysis of 'fundamentals'.

- Capital and operating expenditure information provided by DECC or compiled by Ernst & Young have not been audited, therefore its accuracy could not be verified.

- Given the limited granularity of cost data made available for this study, installation costs were not analysed separately and were assumed to be included in each Material Cost (turbines, foundations, electrical infrastructure). The contribution of this element of cost to the evolution of Material Costs is therefore relatively uncertain.

- In assessing project economics, investors will use their own proprietary forward wholesale power, ROC and LEC curves, and their own confidential hurdle rates. The analysis estimates for these pieces of information, hence the translation of levelised cost to ROCs required may not exactly reflect the true ROC requirement for individual projects.

- Within this analysis, forward ROC price curves are not linked to variations in the future wind capacity deployment assumptions (in reality the ROC Recycle price will change with the level of roll-out of offshore wind, for example one would expect low offshore wind roll-out to result in high ROC prices).

- Although the introduction of the OFTO regime is anticipated to be beneficial to project economics, for the purposes of this study, the new regime was assumed to be value neutral in the Base Case (this approach is based on recent discussions with industry participants). If the OFTO regime were to have a positive impact on project economics, the levelised cost and RO banding analysis carried out in this report would over-estimate the level of support required.

In order to highlight the variation in the level of support required, this study includes sensitivities on key assumptions including investor rate of return, revenue assumptions, net power exported, OFTO rate of return and the effects of industry learning and supply chain easing. Only RO banding has been modelled here.

3. Current cost of offshore wind

3.1 Capital expenditure

3.1.1 Total capital costs

Figure 2: Total capital costs at COD – indicative trend line 2006-2012

Source: Ernst & Young, DECC reference project data

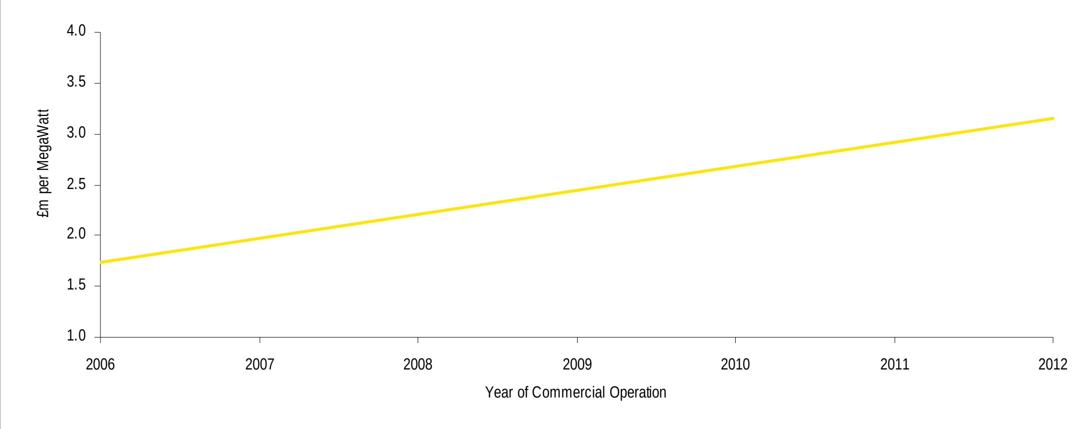


Figure 2 shows the evolution of total capital expenditure over time (against Commercial Operation Date – COD) for a range of Round I and Round II projects. Contracts affecting capital costs are assumed to be finalised approximately two to two and a half years before COD and therefore 2012 costs plotted above would reflect the economics of projects being submitted for investment approval in 2009/10.

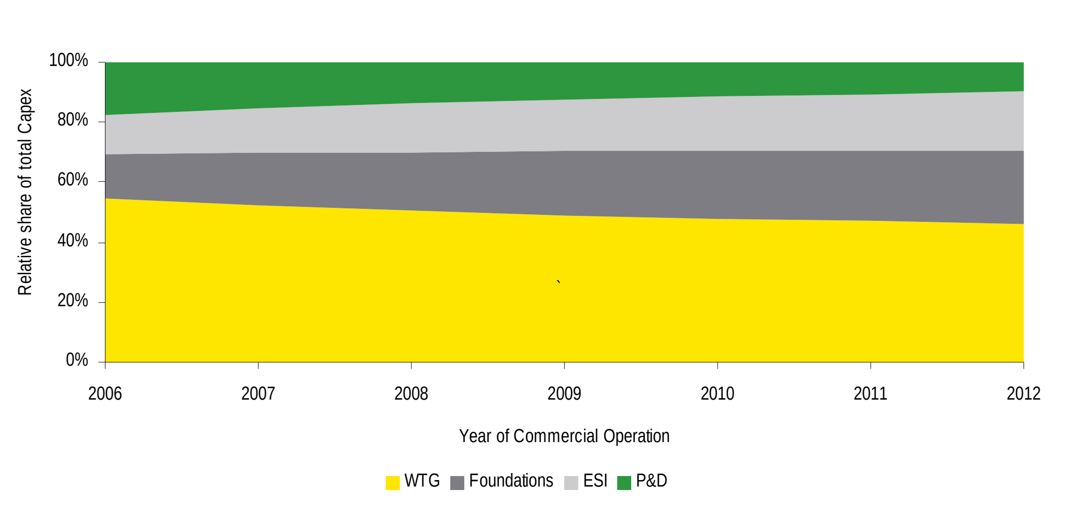
The data indicates that total capital costs have increased by approximately 30% over the period 2006-2008 (contracted costs) and that this trend has continued to 2010-12 (current quoted costs).

Current estimated capital costs have been derived from the megawatt-weighted average of project capital costs for projects at or near financial close in January 2009 of £3.2m per MW. Further analysis shows that the Material Costs to capital costs for projects at or near financial close in January 2009 include (see Figure 3):

- Wind turbine generators (WTG), which make up around 47% at £1.5m per MW.
- Foundations, which make up around 22% at £0.7m per MW.
- Electrical infrastructure, which makes up around 19% at £0.6m per MW.
- Planning and development costs, which make up the remaining 12% at £0.4m per MW.

Figure 3: Material Costs as a proportion of total capital costs over time

Source: Ernst & Young analysis, DECC reference project data



Each of the Material Costs is described in more detail in the following sections.

3.1.2 Wind Turbine Generator (WTG)

Figure 4: WTG cost at COD – indicative trend line 2006-2012

Source: Ernst & Young, DECC reference project data

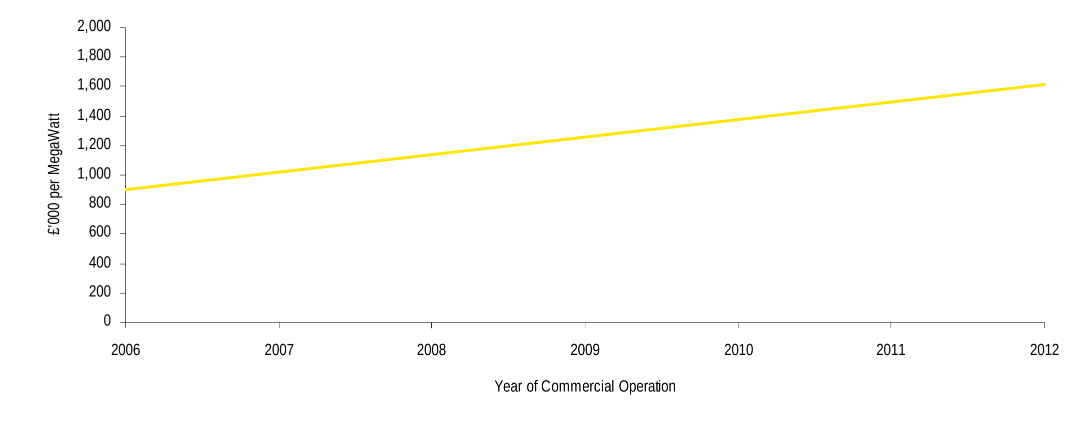


Figure 4, which shows the evolution of WTG costs over time (against Commercial Operation Date – COD) for a range of Round I and Round II projects, indicates that WTG costs have increased from an average £0.9m to around £1.5m per MW (67%) over the five year period to 2011 (where financial close is expected in 2009).

It is believed that this cost increase is predominantly driven by supply chain constraints and other cost drivers.

Supply chain constraints

The UK offshore wind turbine market is dominated by Siemens and Vestas, which together account for 98% of turbines installed to date (48% and 50% respectively). Siemens was the sole supplier to the sector during both 2007 and 2008. More recently, REpower and Multibrid have won large contracts with leading European utilities to supply their offshore wind projects but their products are still being tested. Given the relatively small number of WTG suppliers for offshore wind, it could be that competitive pressures are not yet particularly strong.

However, the increase in WTG prices over the past five years may also be driven by other key component suppliers, whose high prices are passed on to developers by turbine manufacturers. This may in turn in part reflect capacity constraints and/or competition issues in WTG component markets.

In addition, offshore wind turbine supply is in direct competition with onshore wind turbine supply for production capacity and component procurement. As a result, supply constraints may persist in the near-term until offshore wind production capacity catches up with demand. For example, gearboxes and rotor blades have been in relatively short supply for the global wind market in general.

Other factors affecting WTG prices include the level of Research and Development (R&D) investment by the supply chain, the level of profitability required by manufacturers and the investment made in expanding the supply chain production capacity. Current WTG prices may therefore reflect such investments being made within the supply chain, which may become apparent through future cost reductions.

Exchange rates and commodity drivers

The Euro/Sterling exchange rate and commodity and steel prices (see Appendix B) have also contributed to the rise in turbine prices for UK offshore wind developers. Up until 2008, global increases in prices for commodities and steel put upward pressure on the cost of materials and services in the supply chain for offshore wind turbines.

Since then, prices for commodities and steel have fallen as a result of the global economic downturn but the positive effect on WTG prices has been more than offset by the appreciation of the Euro against the Pound Sterling. UK project developers have experienced continued increases in costs since the majority of turbine supply contracts are Euro denominated.

3.1.3 Foundation costs

Figure 5: Foundation cost at COD – indicative trend line 2006-2012

Source: Ernst & Young, DECC reference project data

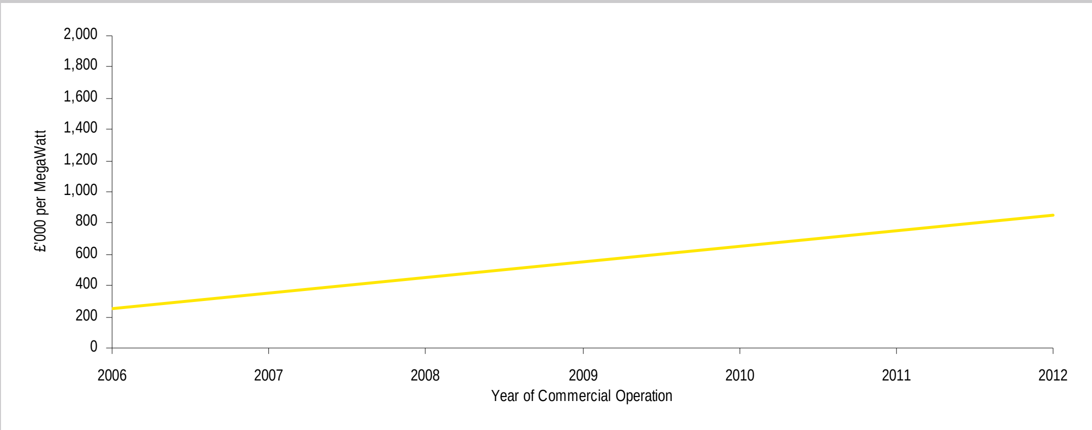


Figure 5, which shows the evolution of foundation costs over time (against Commercial Operation Date – COD) for a range of Round I and Round II projects, indicates that foundation costs have increased from around £250k to £700k per MW (c.180%) over the last five years. Since around three quarters of foundation costs relate to material costs (mainly steel), a major contributing factor to increased foundation costs is the rapid rise in steel prices between 2006 and 2008 (see Appendix B). Foundation components, comprising piles and towers, are manufactured in the UK and therefore the impact of the Euro exchange rate is small on these components.

At the same time, constraints on the availability of installation vessels and services have placed further upward pressure on installation costs and since these services are largely sourced from continental Europe, installation costs have also risen due to the weakening of the Pound Sterling against the Euro (see Appendix B).

3.1.4 Electrical infrastructure (EI)

Figure 6: Electrical infrastructure cost vs. distance from shore

Source: Ernst & Young, DECC reference project data

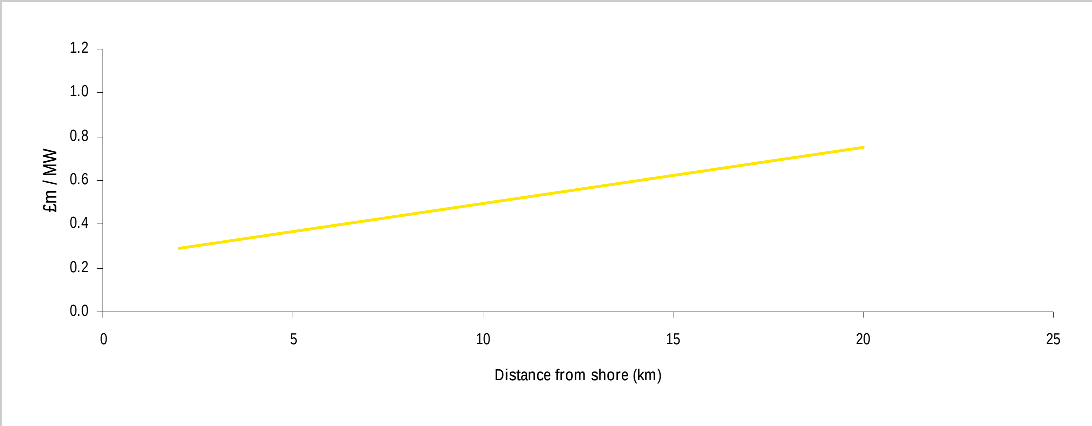


Figure 6, which shows the evolution of electrical infrastructure costs versus distance from shore for a range of Round I and Round II projects, indicates that the cost of electrical infrastructure is closely correlated to a project's distance from shore. The impact of other factors on the cost of electrical infrastructure has been found to be relatively small by comparison (for example, there was little evidence of tight supply for EI components in the UK at the time of this study). Since more recent projects are located further offshore they see higher electrical infrastructure costs than earlier near-shore projects.

3.2 Operating expenditure

3.2.1 Total forecast operating costs (Year 1-5)

Figure 7: Total forecast operating costs at COD – indicative trend line 2006-2012

Source: Ernst & Young, DECC reference project data

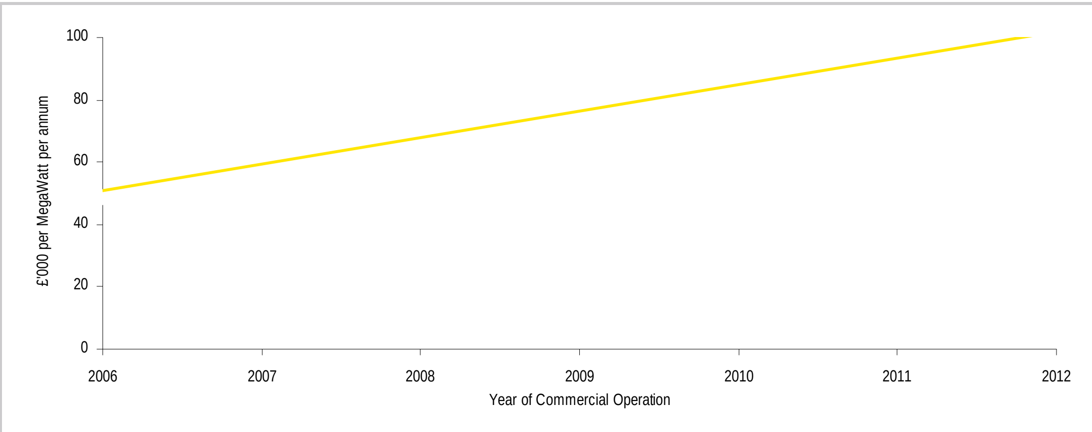


Figure 7, which shows the evolution of forecast operating costs over time (against Commercial Operation Date – COD) for a range of Round I and Round II projects, indicates that total pre-OFTO operating costs have increased from £48k to £79k per MW per annum (c.65%) over the five year period to January 2009 (reflecting projects achieving COD up to and including 2012). This increase is largely a result of increased operating and maintenance (O&M) costs over this period, as described in more detail below.

Other costs contributing to UK offshore wind project operating costs include: the Crown Estate lease; Transmission Network Use of System (TNUoS) charges; grid maintenance costs; insurance premiums; and decommissioning provisions.

3.2.2 Operation and Maintenance (O&M)

The trend in forecast O&M costs since 2006 is shown below.

Figure 8: Forecast O&M costs (years one-five) – indicative trend line 2006-2012

Source: Ernst & Young, DECC reference project data

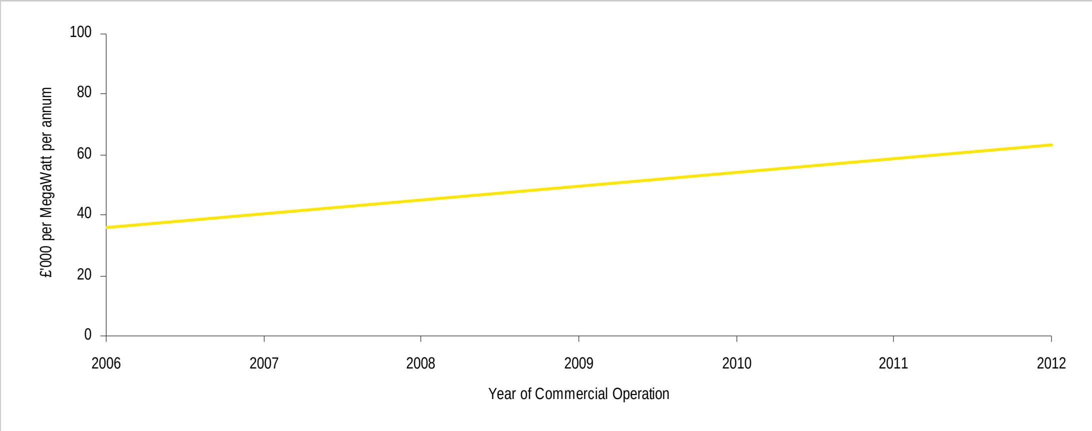


Figure 8, which shows the evolution of forecast O&M costs over time (against Commercial Operation Date – COD) for a range of Round I and Round II projects, indicates that total pre-OFTO O&M has increased from £38k to around £60k per MW per annum (c.58%) over the five year period to January 2009 (reflecting projects achieving COD up to and including 2012). This increase may largely be driven by:

- Improved budgeting – reflecting track record and experience gained from operating early projects (e.g., better handle of post-installation repair work, frequency of parts replacement, performance and availability levels, accessibility) where costs had perhaps been underestimated at first.

- Evolution of the O&M strategies which were historically formulated under the assumption of a 20-year project life with limited preventive maintenance. With Crown Estate lease periods lasting 40 or 50 years, some industry participants are seeking to develop more proactive and preventive O&M strategies to extend project life.

Since materials and services for O&M are largely related to the WTG market, costs have been affected by past rises in commodity, labour and steel prices, as well as the more recent strengthening of the Euro against the Pound Sterling.

3.2.3 Other Operating cost

TNUoS and grid maintenance have increased marginally over the last five years, which is largely due to more recent projects being located further offshore hence increasing maintenance and transmission costs accordingly.

Crown Estate lease costs are a fixed at c.1% of gross wind farm revenues (at current wholesale and ROC prices), thus only vary in accordance with projects' power output.

Insurance premiums have also increased marginally over the last five years. With shorter warranty periods and less comprehensive service contracts, risk is being increasingly transferred from the component and service suppliers to project developers; this is reflected in higher insurance costs.

4. Levelised cost and support requirements

4.1 Levelised cost

The diagram below shows the change in levelised cost, driven by capital costs, operating costs and cost of capital, since Ernst & Young published its RO banding analysis in April 2007 (using 2006 data).

Figure 9: Levelised cost increase since Ernst & Young's April 2007 RO banding study

Source: Ernst & Young analysis

	2006	2009 (pre-OFTO)
Capital expenditure	£1.7m/MW[2]	£3.2m/MW
Operating expenditure	£45k/MW p.a.[3]	£79k/MW p.a.[4]
Cost of Capital[1]	12%	12%
Levelised cost @ 12%[1]	£91/MWh	£144/MWh

1 *April 2006 RO Banding work was based on 12% pre-tax real. This analysis was performed using 10% post-tax real. Both approximate to around 12% post-tax nominal.*

2. *April 2006 RO banding analysis adjusted to reflect pre-OFTO costs.*

3. *Operating costs per RO Banding work adjusted to exclude £18k/MW p.a. decommissioning and normalised TNUoS (pre-OFTO).*

4. *Excluding £18k/MW p.a. decommissioning costs, which are included in the final levelised cost calculation.*

Figure 9, which provides a comparative analysis of capital, O&M and levelised costs for UK offshore wind under Ernst & Young's previous analysis dated April 2007 and that conducted in for this study, shows an increase in levelised cost from £91 to £144 per MWh (58% increase).

This increase is primarily driven by increased capital and operating costs as described earlier.

4.2 Support required (Base Case)

Figure 10: Level of RO banding required to achieve a 12% post-tax nominal rate of return

Source: DECC, Ernst & Young analysis

	2006	2009 (pre-OFTO)
Levelised cost @ 12%[1]	£91/MWh	£144/MWh
Wholesale power price	c.£42/MWh (falling to £40 long-term)	£60/MWh (flat)
ROC banding @ 12%[1]	1.5 ROCs/MWh	2.5 ROCs/MWh

1. *April 2006 RO Banding work was based on 12% pre-tax real. This analysis was performed using 10% post-tax real. Both approximate to around 12% post-tax nominal.*

Figure 10 provides a comparative analysis of the levelised costs and RO banding support for UK offshore wind under both Ernst & Young's analysis dated April 2007 and that conducted in January 2009.

The power curve used by Oxera in their RO banding study of May 2007 applied prices of £42/MWh falling to £40/MWh in the long term. Power prices subsequently increased significantly to mid-2008 and have only recently reduced. Long-term estimates of future wholesale power mean that a flat price of £60/MWh was used for the purposes of this study.

On the basis of these cost and power price assumptions, an increase in support from 1.5 ROCs per MWh to 2.5 ROCs per MWh would be required to achieve a 12% post-tax nominal rate of return in 2009.

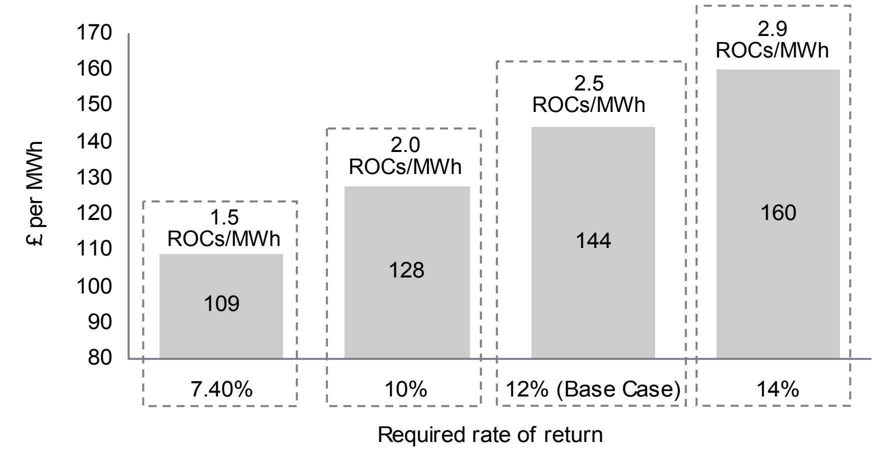
4.3 Sensitivities

4.3.1 Required rate of return

Figure 11 illustrates the sensitivity of levelised cost and RO banding levels to the assumed project discount rate.

Figure 11: Levelised cost and RO banding required to deliver a specified IRR[1]

Source: Ernst & Young analysis



1. *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.*

Under the current RO banding level of 1.5 ROCs per MWh, project developers would need to accept a rate of return of around 7.4%, based on the Base Case assumptions.

This study was conducted using a discount rate 12%, as used in EY's 2007 analysis, and found that support under the RO would need to increase to 2.5 ROCs per MWh to provide sufficient support to offshore wind projects at or near financial close in January 2009.

Other sensitivities with different input assumptions have also been run which give different levels of support.

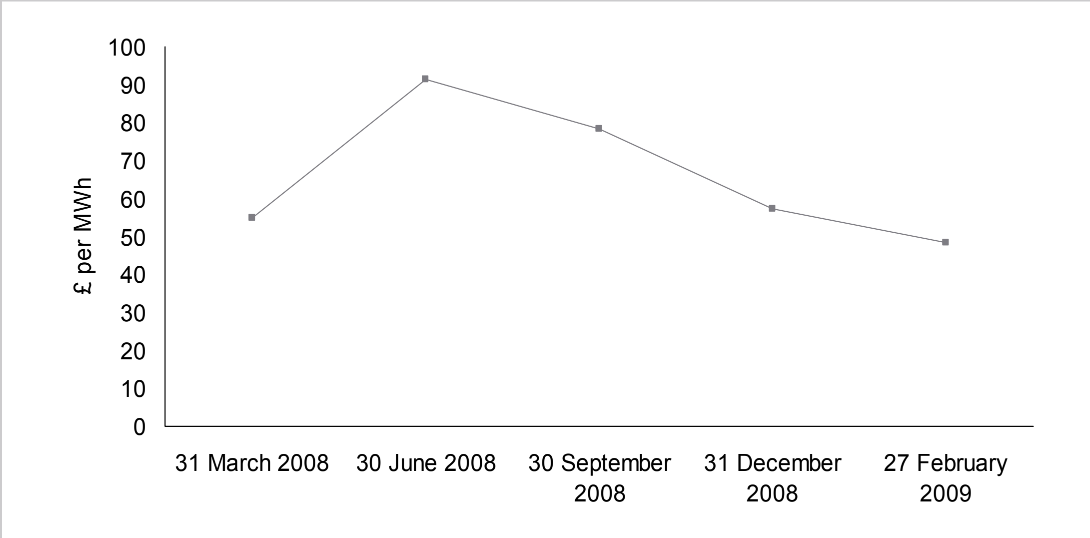
The graph depicts a strong impact of rate of return on the level of support required. Cost of capital may be reduced by risk mitigation, industry learning and a slackening of the cost of debt for developers; this may result in a lower level of ROC support required.

4.3.2 Revenue assumptions

Industry players will continuously revise their forecasts for wholesale power, ROC and LEC prices, which can have a profound effect on the economics of an offshore wind project. Power prices are influenced by a number of factors, including the oil price, demand and in the long-term, the level of generation capacity retired or commissioned. To illustrate the variability in power price forecasts, the change in year-ahead power prices from March 2008 to February 2009 is shown below.

Figure 12: Year-ahead base load power prices in 2008/2009

Source: Heren European Daily Electricity Markets



UK wholesale power prices have fallen from a peak of around £90/MWh in June 2008 to around £50/MWh in February 2009. This change has consequently led industry to lower its long-term forecasts for power prices, having a significant negative impact on project economics. This section seeks to highlight the relative sensitivity of power prices on project economics with the resultant impact on the level of support required.

Three different revenue scenarios have been applied in this study which are summarised in Table 2 below.

Table 2: Base case, high and low revenue scenarios (real at January 2009)

Source: DECC

Scenario	Brown power	ROC buy out	ROC recycle	LEC
High	£80.00 flat over the project life	£35.76 flat over the project life	10% above Base Case to 2037	£4.56 flat over the project life
Base Case	£60.00 flat over the project life	£35.76 flat over the project life	50% of ROC buy out, gradually reducing to 8% to 2037	£4.56 flat over the project life
Low	£40.00 flat over the project life	£35.76 flat over the project life	8% of ROC buy out to 2037	£4.56 flat over the project life
Assumed proportion to generator	90%	92.5%	92.5%	92.5%

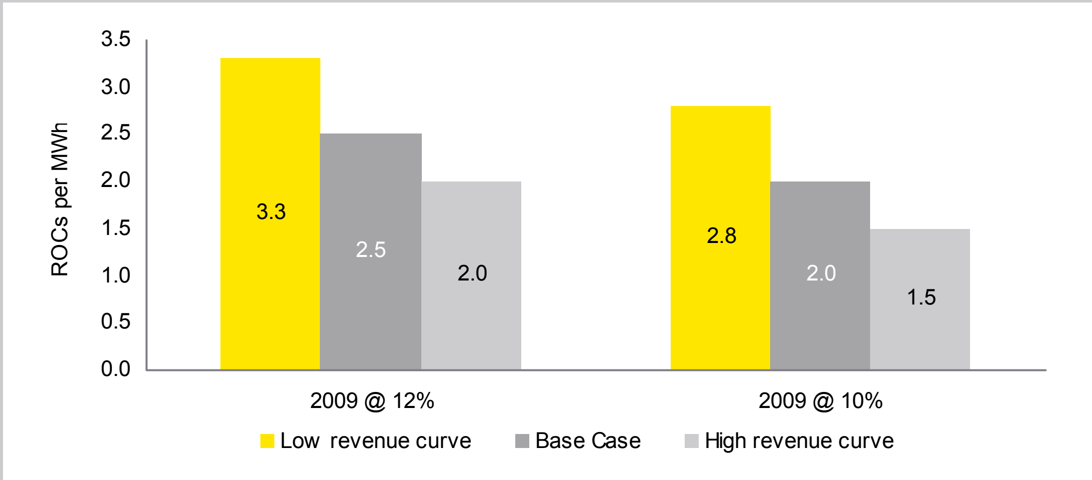
The Base Case in this study applied a long-term forward revenue curve of £60 per MWh over the 20 year life of the project. It should be noted that a 'flat' revenue curve was used in order to isolate and study changes in project costs over time. In addition, DECC provided a forecast for ROC and LEC prices over the 20 year project period.

Sensitivities around project revenues include high and low forecasts for wholesale power, ROC and LEC prices.

Figure 13 shows the impact of different revenue scenarios on the level of RO support required.

Figure 13: RO banding required to deliver a specified IRR with different revenue curves[1]

Source: Ernst & Young analysis



1. *Post-tax nominal. 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.*

The level of support required by offshore wind projects at discount rates of 12% and 10% respectively varies significantly for different power revenue curves. To achieve the same levels of return under the high and low power revenue curves a change in the level of support of 1.3 ROCs per MWh is required.

Some project developers claim to need 2.0 ROCs per MWh for offshore wind. This would appear to be justified if high revenue curve assumptions and a discount rate of 12%.were applied. Alternatively, this level of support would also be required using the Base Case revenue assumptions and a 10% discount rate.

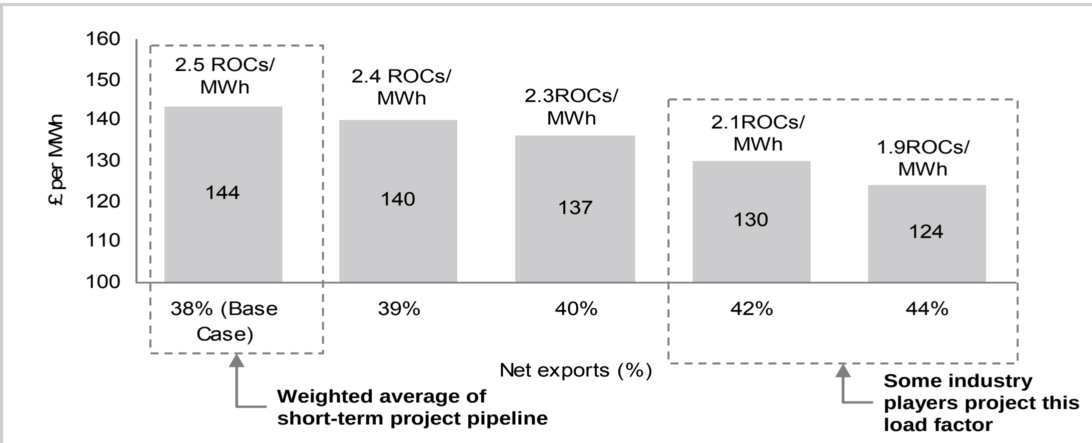
It is not the purpose of this study to prescribe the discount rate for the offshore wind industry: the aim of this analysis is to highlight that project economics are significantly influenced by revenues received for wholesale power and ROCs.

4.3.3 Net power exports

Figure 14 shows the variation in levelised costs and RO banding requirements for different assumptions about the net power exported to the electricity network.

Figure 14: Levelised cost and RO banding required under different net export assumptions[1]

Source: Ernst & Young analysis



1. *At 12% post-tax nominal discount rate. 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.*

The Base Case scenario assumes net exports of 38%, reflecting the weighted average of projects at or near financial close in January 2009.

With every 1% increase in net exports, levelised costs reduce by approximately £3-4/MWh and the required level of support decreases by approximately 0.1 ROC/MWh.

If net exports of 42-44% were achieved by a typical project at or near financial close in January 2009, the level of support required would be around 2.0 ROCs per MWh at a discount rate of 12%.

The predicted level of net power exports remains a relatively uncertain area for the offshore wind sector. Factors influencing net exports include:

- Wind speed and variability over time
- Wind turbine availability and accessibility
- Electrical transmission losses
- Array losses
- Shadow or wake effects

For this reason, the assumed level of net exports in the Base Case may be under- or over-estimated.

4.3.4 OFTO required rate of return

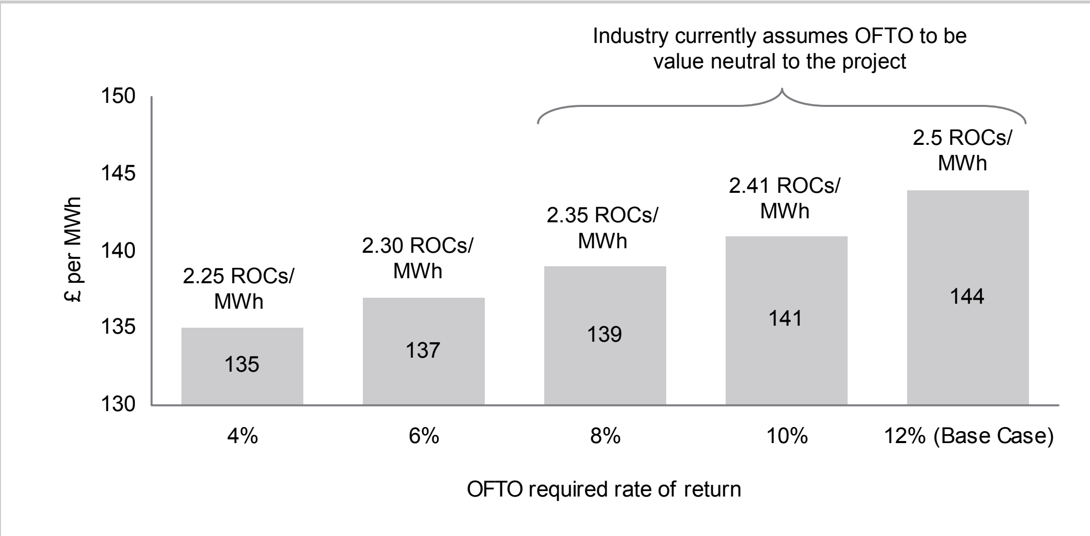
In recognition of the upcoming Offshore Transmission Operator (OFTO) licensing regime, this study has performed a range of sensitivities on the impact of this mechanism on project economics. Since the proposed OFTO regime will operate like a sale and leaseback mechanism for transitional projects, the key benefit to projects would be a saving of lease costs over time compared to the upfront outlay of electrical infrastructure.

Consequently, the focus of this analysis is on the required rate of return for the OFTO. Since the new regime is designed to be beneficial to offshore projects, this study has only considered OFTO required rates of return that would be cost neutral or provide a net upside to the project.

Figure 15 illustrates the variation of levelised cost and RO banding required for different OFTO rates of return.

Figure 15: Levelised cost and RO banding required assuming different OFTO return requirements[1]

Source: Ernst & Young analysis



1. *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.*

Many industry participants assume that the new regime will be value neutral to the project until this is proven otherwise.

If the cost of capital of the OFTO were lower than that of a project developer, say between 4% and 6%, levelised costs would consequently reduce to between £135/MWh and £137/MWh and the number of ROCs required to between 2.25 and 2.30/MWh respectively.

Ultimately, the OFTO's required rate of return will depend on the cost of risk free funds, the risk premium applied for building an offshore transmission network, the security of cash flows from the project and the perceived level of competition under the Ofgem tender process. However, given that the increase in costs for offshore wind power is principally driven by other factors, even with a positive impact of the OFTO licensing regime on project economics, the provision of further financial support to the offshore wind industry is still needed.

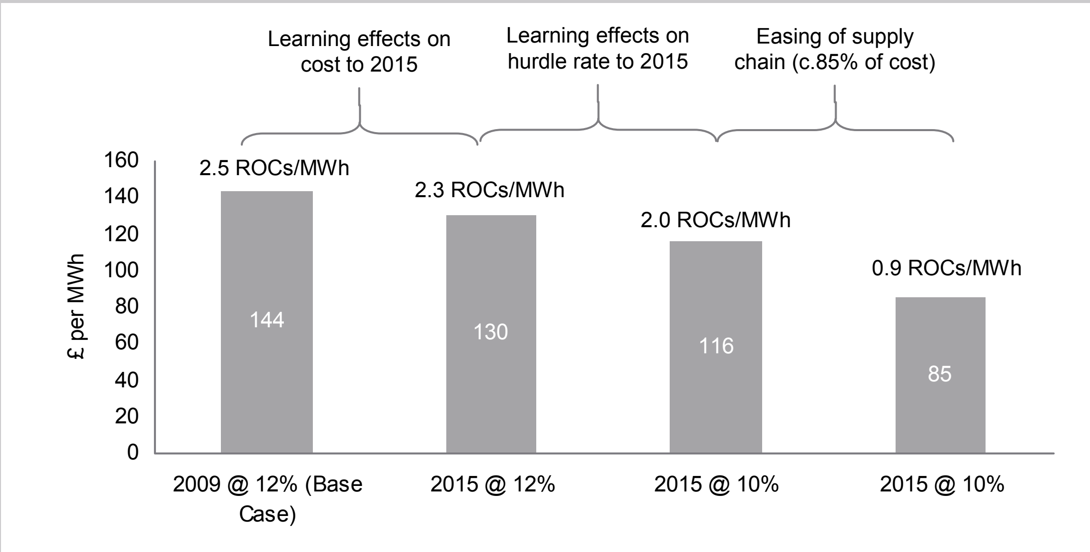
4.4 Industry learning and supply chain

The cost of offshore wind, as with other early-stage technologies, would normally be expected to fall as the sector develops and experience is gained. That costs have risen since the RO banding work of April 2007, illustrates the upward pressures of raw materials prices, exchange rates and supply constraints on the industry as a whole.

Figure 16 shows the possible decrease in levelised costs and RO banding levels on current projects (i.e. those near or at financial close in January 2009) as a result of learning effects and easing of supply constraints in the offshore wind sector.

Figure 16: Cumulative decrease in levelised cost on current Round 1 and 2 projects if learning effects are included (at specified hurdle rates[1])

Source: Ernst & Young analysis



1. *Post-tax nominal. 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.*

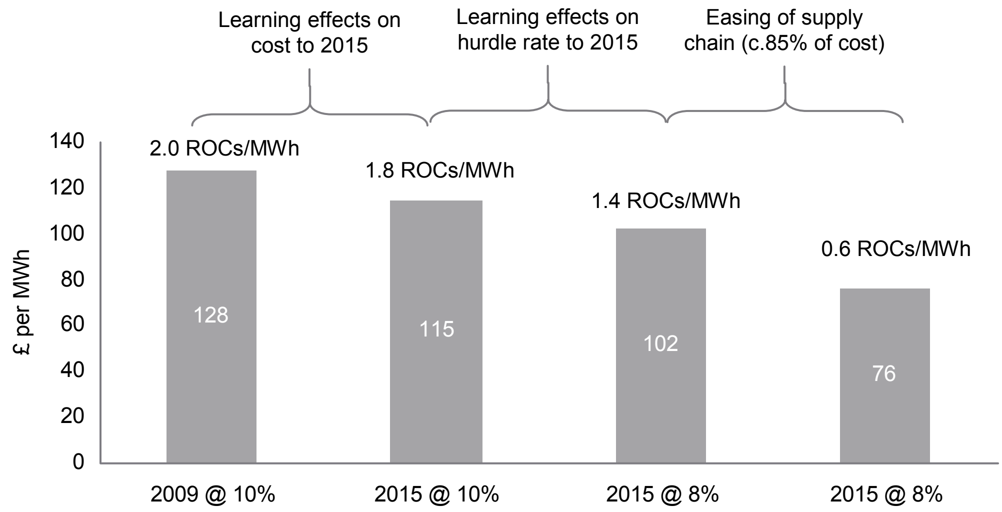
As more offshore wind capacity is built (see Appendix C) and operational experience increases over the next five years one could expect learning effects in the industry, which should lead to a reduction in levelised cost and level of support required for projects with the same technical characteristics, such as water depth and distance from shore, providing supply chain issues do not push prices in the other direction. By applying learning effects to the current cost of offshore wind, levelised cost could reduce by around 10%, based on the analysis and the level of RO banding support required could fall from 2.5 to 2.3 ROCs per MWh by 2015.

Another consequence of an extended industry track record is that offshore wind project risks should be better understood, which may be reflected in a project developers' cost of capital. A reduction in the cost of capital from 12% to 10%, combined with the learning effects discussed above, would lower the levelised cost of offshore wind by 19% and the RO banding required from 2.5 to 2.0 ROCs by 2015 compared to today.

Finally, as competition and manufacturing and services capacity relating to the offshore wind supply chain increase, constraints should eventually ease and procurement costs decrease as a result. The timeframe for this occurring is uncertain, but by way of illustration, the impact of easing supply constraints (mainly affecting WTGs and foundations) could have the effect of bringing costs down to the level they were at in 2006 (at around £85 per MWh and 0.9 ROCs required). This is likely to over-estimate the benefits of supply chain easing, given that project characteristics (in terms of water depth and distance from shore) and O&M philosophy are very different today than they were in 2006.

Figure 17: Cumulative decrease in levelised cost on current Round 1 and 2 projects if learning effects are included (at specified hurdle rates[1])

Source: Ernst & Young analysis



1. *Post-tax nominal. 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.*

A similar analysis, starting at a 10% post-tax nominal discount rate is shown in Figure 17. This shows that the level of RO banding support required would reduce from 2.0 ROCs per MWh for projects at or near financial close in January 2009 to 1.8 ROCs per MWh by 2015 with industry learning on costs and to 1.4 ROCs per MWh if the industry learning were to extend to a lower cost of capital for project developers. An easing of supply chain constraints leading to a reduction in procurement costs could result in a decrease of the required support to 0.6 ROCs per MWh. As above, the analysis of reductions in levelised costs and required support as a result of industry learning was carried out on the basis of projects with the same technical characteristics (size, water depth and distance from shore).

The proposed zones for Round 3 of offshore wind are of course further offshore and/or in deeper water than Round 1 and 2 sites, and this - along with learning rates and other factors - will affect development costs. This analysis does not apply to the proposed Round 3 zones.

5. Conclusions and recommendations

5.1 Conclusions

The analysis indicates that offshore wind projects at or near financial close in January 2009 have considerably higher costs than in EY's analysis completed in April 2007 when the RO banding was introduced. Whilst a range of alternative means of providing support could be considered, if such support were to be provided through the existing mechanism of the RO, the level of financial support required to provide a reasonable economic return would be between 2.0 and 2.5 ROCs per MWh, based on the analysis performed. The current level of support to offshore wind is 1.5 ROCs per MWh.

- Average capital costs have doubled over the last five years to c.£3.2m/MW; the cost increase appears largely driven by supply chain constraints for components (e.g. wind turbine generators) and services (e.g. installation), and also to a lesser extent recent fluctuations in Euro Sterling exchange rates and commodity prices.

- Average expected operating costs have increased c.65% over the same period to c.£79k per MW per annum; the cost increase appears largely driven by greater experience of running such projects and also a change in O&M philosophy by offshore wind operators which now seek to adopt a more proactive maintenance approach with a view to extending the life of their assets.

- Cost reductions, both in terms of capital and operating costs, could be anticipated in future for projects of similar technical characteristics to those being developed today, if:

    - There is sufficient offshore wind deployment to provide opportunity for industry learning

    - Supply chain constraints, such as supplier dominance and capacity shortages, are overcome through new entrants and investment in new production respectively

- On the basis of the above costs and other project parameters set out in Appendix D, and to meet a post-tax nominal hurdle rate of 12%, the analysis indicates that additional financial support is required to ensure an adequate level of revenue to project developers. A range of alternative means of providing support could be considered which have been outlined in Table 1 below; however if such support were to be provided through the existing mechanism an increase of the RO banding for offshore wind from 1.5 to 2 to 2.5 ROCs per MWh would be required.

- This analysis uses a comparable approach to that adopted by the Department for Trade and Industry (DTI) of April 2007 (Source: Impact of banding the renewables obligation – costs of electricity generation, Ernst & Young report for DTI, April 2007), which found, using cost data from the time, that 1.5 ROCs would be sufficient support for offshore wind.

- However, sensitivity analysis on some of the assumptions indicates that a re-banding of offshore wind would be highly sensitive to project-specific considerations and that a 2 ROC per MWh banding (rather than 2.5) might satisfy some investors on certain projects where:

    - The net output (load factor) is higher than the Base Case assumption of 38%

    - Assumptions are taken in regards to introducing the OFTO regime which gives a positive effect on project economics (assumed to be value-neutral at this stage in the Base Case analysis)

- Capital and operating cost assumptions are lower than those assumed in the Base Case
- More optimistic assumptions are taken for forward power, ROC or LEC prices
- Lower hurdle rates (e.g. 10% post-tax nominal per the analysis) are assumed

The analysis indicates that the increases in levelised costs for offshore wind were largely driven by increases in capital expenditure. Some of these increases can be justified through higher commodity prices and exchange rate fluctuations, however the majority cannot be justified in this way.

The relative immaturity of the supply chain for offshore wind components and support services appears to be driving market inefficiencies, which have led to significant cost increases particularly relating to the cost of procuring and installing wind turbines and foundations. These constraints may be partially overcome by increased competition in the supply chain and support services industry. In addition, technological development and industry learning are already underway, but the economic effect of these has been and may continue to be muted whilst supply constraints continue. Capacity constraints and perhaps competition issues in the supply chain may be responsible for some of the unexplained part of the cost increases, but this study has not looked in detail at the market conditions of the supply chain industries.

5.2 Recommendations

Given the key findings above, it is recommended that the UK Government considers:

- Providing additional support in the near term to enable projects to proceed to counteract short term price issues (i.e. exchange rate fluctuations)
- How it can support the industry and encourage medium and long term growth of this sector without stimulating cost inflation to the price of offshore turbines, whilst
- Ensuring that any change in the RO banding for offshore wind does not create the impression of RO policy instability or further regulatory risk associated with UK renewable policy

Government could consider the relative merits of different measures to support offshore wind over the short to long term. A summary of possible support mechanisms is provided in Table 3 below.

Table 3: Possible support measures to offshore wind

Support measure	Potential impact	Implications
RO banding	Immediate	► Increased investment in projects ► No direct impact on supply chain (provides demand-pull)
Investment / production tax credits and tax depreciation	Immediate	► Effectiveness proven in the US onshore wind market and UK CHP market ► Implementable and extendable quickly using secondary legislation ► Typically requires high level of equity participation for full benefit ► Large projects would require significant UK taxable profits ► Reduces Treasury income
Capital grants	Immediate	► Avoids disrupting the existing RO regime and provides targeted support ► Does not incentivise efficient output-based production ► Can be administratively complex for applicants ► Requires a dedicated cash budget from Treasury and State-aid clearance; hence possible high cost to the Exchequer
Government intervention to	Immediate	► Reduced uncertainty around unknown or unquantifiable risks, hence helps lower cost of capital

reduce project specific risks (e.g. partially underwrite contingencies and provide insurance for projects)		► Mitigates revenue flow-through to the supply chain ► Able to be phased out as unknown risks become known through learning ► Avoids disrupting the RO
Soft loans/credit guarantees/Govern ment participation in projects	Immediate	► Useful for assisting new entrants and smaller developers ► Helps lower the cost of capital required for the project ► Could be useful for new UK-based WTG manufacturers to assist in funding initial pilot projects
Non-financial support to UK-based WTG manufacturing	Medium term	► Fast-track planning or special 'economic zones' and rent-free holidays for new WTG manufacturing capacity could impact UK market three to five years later
R&D funding	Long term	► Advances in new technology likely to see commercial operation 10+ years after funding
Other (e.g., feed-in tariff)	Long term	► Feed-in tariff requires primary legislation to enable

Given the limited supply of offshore turbines, any stimulus will only increase the number of projects to the extent that there is slack in the supply chain and support services. As the production of new offshore turbines increases from existing and new players, installation capacity should become less of a constraint although the ambitious targets for offshore wind being sought by the UK and Germany in particular, as well as competition from onshore wind, means that the market for offshore components and services may remain constrained for some time.

Any increase in the level of support to the offshore wind industry should therefore take into consideration the possible flow-through of this support to the supply chain, as well as the impact of future changes in exchange rates and raw material prices.

Appendix A Sources

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Scroby Sands – Supply Chain Analysis, Renewables East, July 2005.

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Supply Chain Constraints on the Deployment of Renewable Electricity Technologies, Douglas Westwood/BERR, June 2008.

The mapping of materials supply chains in the UK's power generation sector, Materials UK Energy Review 2008, Materials UK, April 2008.

UK Offshore Energy SEA Environmental Report, DECC, January 2009.

UK Offshore wind: Moving Up a Gear: An updated assessment of UK offshore wind deliverability to 2015 and beyond, BVG Associates for BWEA, Winter 2007.

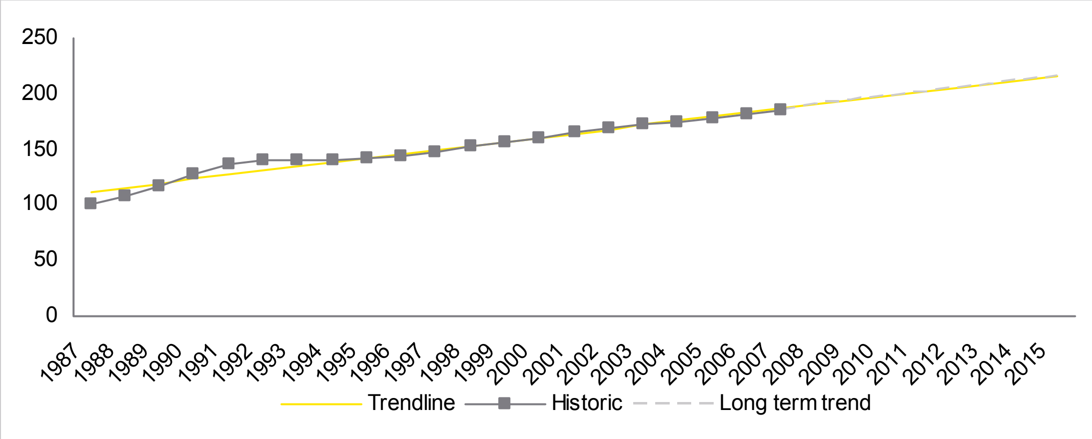
Appendix B Cost drivers

Labour

A historic analysis of labour costs since 1987 is shown below.

Figure 18: Labour costs – historic index rebased to 1987

Source: Office of National Statistics Labour Market Statistics database – Productivity and Unit Wage Costs (seasonally adjusted unit wage cost percentage change for the whole UK economy since 1987).



Historic analysis

The mean annual percentage change in the index over the 20 year period is 3.15%, (five year moving average of 2.62%).

Using a linear trend line on the index would forecast a 1.96% growth between 2008 and 2009. The five year moving average trend line forecasts a growth of 1.9%.

Overall the historic results show that there has been consistent growth throughout the last 20 years with minimal seasonal variation closely tracking the linear trend line

Future trend

Due to the minimal variation from the historic trend, the long term estimate of labour cost growth is based on a linear growth extension to the historic trend.

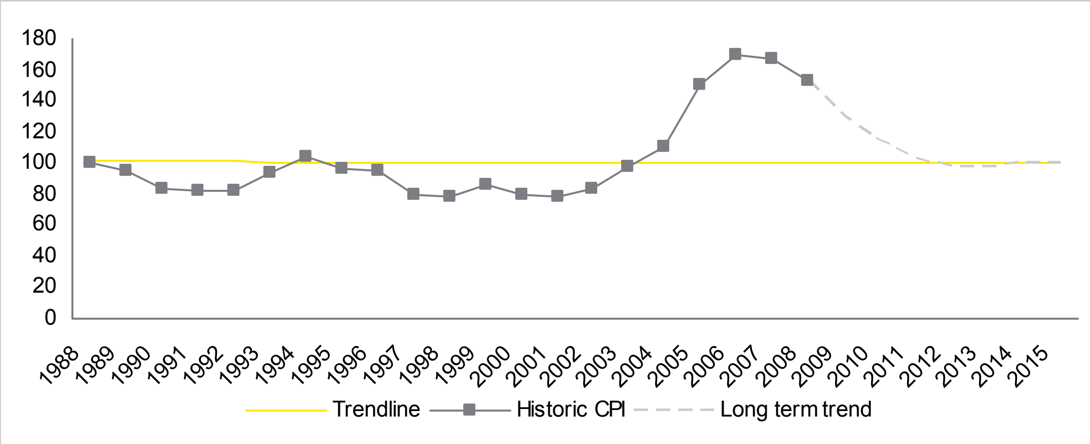
Projecting the trend line from the actual 2007 data point gives growth forecasts of 3.15% and 1.96% for 2008 and 2009 respectively.

Commodity prices

An analysis of historic commodity prices is shown below.

Figure 19: Commodity prices – historic index rebased to 1988

Source: Bloomberg, IMF Industrial Inputs Price Index



Historic analysis

The mean annual percentage change in the index over the 20 year period is 2.82% (five year moving average 3.57%).

Until 2002 the index has fluctuated between a minimum rebased level of 78 and a maximum of 104 and the largest percentage changes were a 14% growth in 1993 and a 17% contraction in 1997.

Between 2002 and 2006 the index grew at 19% CAGR which represents the largest growth the index has seen from the long term norm.

Since 2006 the index has fallen by 5% CAGR but still remains highly above the historical trend line.

Future trend

Until 2004 the volatility of the index seemed to very low and it is only since then the index has moved significantly away from its long term trend.

Due to this, the long term future estimate is that the index will continue to decline until 2012. To achieve this, the forecast is set to decline 15% in 2009 decreasing to a 5% decline in 2012.

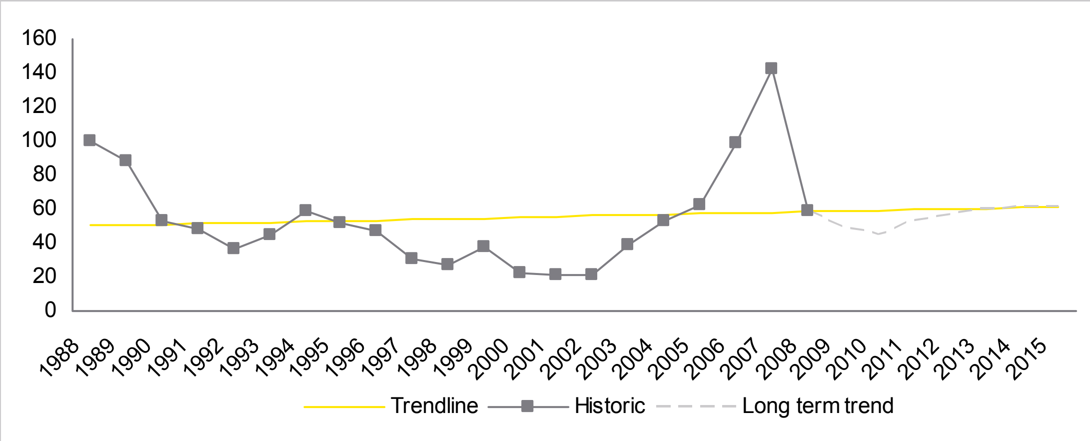
The forecast returns to historic long-term trend in 2012 and from then on it is assumed that growth will continue at this level indefinitely.

Steel prices

A historic analysis of steel prices since 1988 is shown below.

Figure 20: Steel prices – historic index rebased to 1988

Source: Bloomberg, HSBC Global Carbon Steel Index (Code JCGSTCST)



Historic analysis

The mean annual percentage change over the 20 year period is 3.87% (five year moving average 3.00%).

The index rose sharply in the late 1980s before declining throughout the 1990s, despite a slight resurgence in 1993 and 1994, until it reached its lowest levels in 2002.

From 2002 to 2007 the index experienced growth of 47% CAGR. In 2008 however the index fell by 58% returning to the long-term historic trend.

Future trend

Despite the volatility of the index, the long term future estimate for the index is based on a linear historic trend.

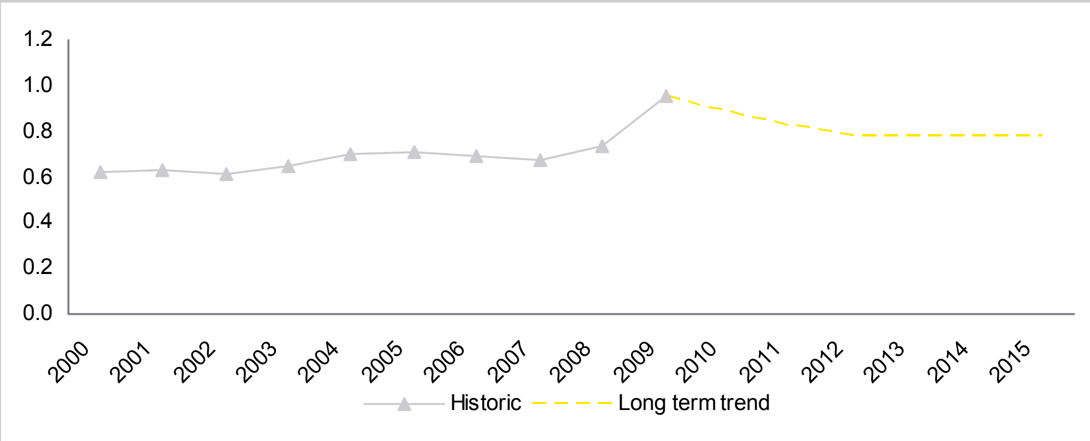
Given the oscillating nature of the long term trend, the period from 2009 to 2013 is assumed to dip below the long-term historic trend before following this line from 2014 onwards.

Exchange rates

Given that the majority of offshore wind components imported into the UK are either priced in Euros or priced in a currency tied to the Euro, the exchange rate impact is assumed to relate only to the Euro/Sterling exchange rate.

Figure 21: GBP EUR exchange rates – historic trend since 2000

Source: Bloomberg, GBP EUR year end closing prices, DECC



Historic analysis

The historic trend of the exchange rate shows that since the Euro's introduction in 1999 it has gradually become stronger against the pound.

More recently the Euro has become particularly strong against the Pound reaching almost one-for-one parity in December 2008. Since then, the Pound has slightly recovered to circa 0.9 Pounds Sterling per Euro.

Future trend

DECC have supplied the forecast exchange rates for 2009 onwards.

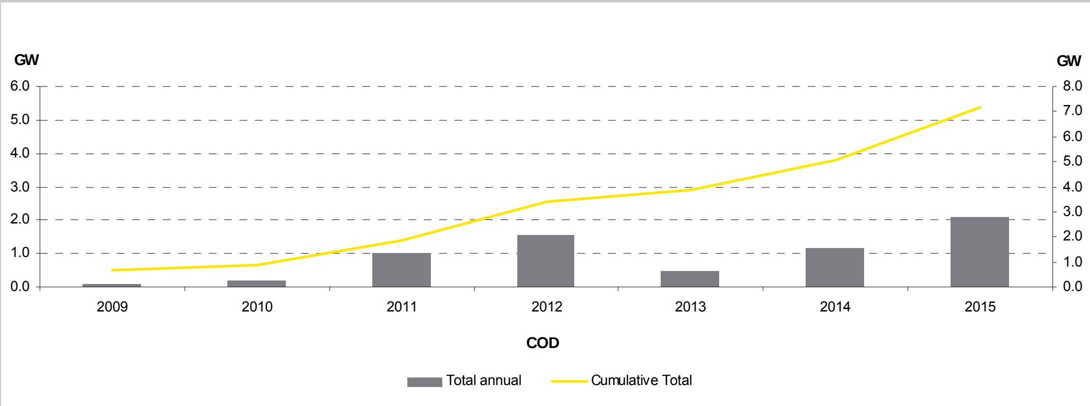
Appendix C Industry learning

Offshore wind capacity forecast

The learning effects associated with industry experience are partly determined by the capacity of offshore wind installed. For the purposes of this analysis, a forecast of installed capacity for offshore wind in the UK has been derived to reflect a roll-out broadly in line with offshore wind developers' expectations of project commissioning (to the extent that it is known) to 2015. This is shown in the graph below.

Figure 22: Forecast MW deployment to 2015

Source: Ernst & Young analysis, DECC



Technology development

Industry learning is also influenced by the level of R&D invested into new component design, manufacturing processes and other technological advances that help bring the cost of offshore wind technologies down over time. The rate of learning, which is expressed as a percentage, is linked to the capacity installed, such that greater learning effects are felt with higher rates of capacity deployment.

Table 4: Learning rates

Source: Ernst & Young analysis, Carbon Trust (See Appendix A)

Material cost	Learning rate	Source
Capital costs		
Turbines	10%	EY/CT
Foundations	5%	EY/CT
Electrical Infrastructure	N/A	EY
Planning and Development	N/A	EY
Operating costs		
Insurance	10%	EY/CT
Lease	N/A	EY
Grid (TNUoS)	N/A	EY
O&M	10%	EY/CT

Table 4 shows the specific learning rates that have been applied to current capital and operating costs, to give an estimate of future costs given the offshore wind capacity forecast outlined above. These learning rates have been applied to the respective costs for every doubling of installed offshore wind power capacity.

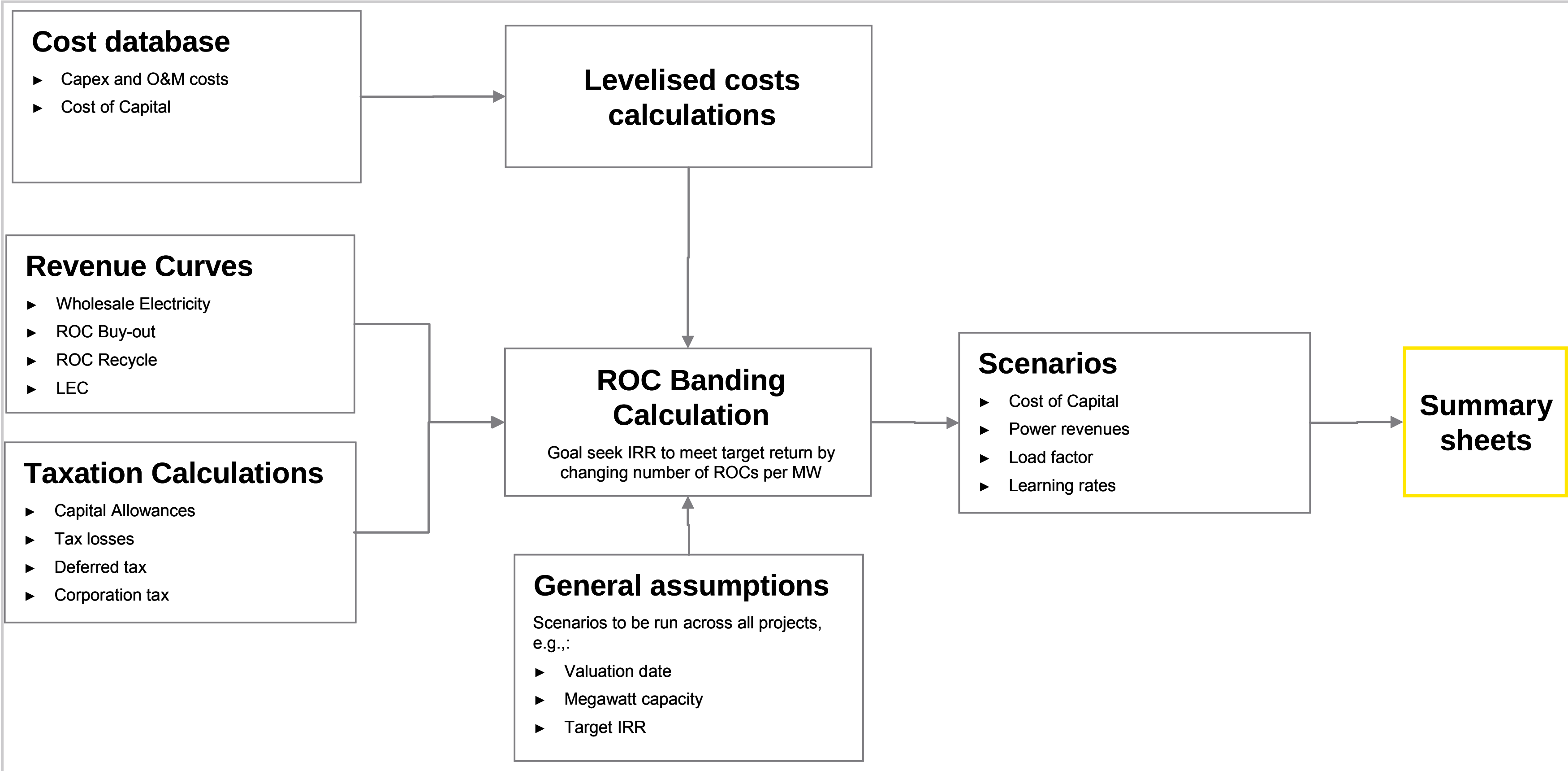
Effects of supply constraints

Whilst conditions in the supply chain have pushed prices for offshore wind components and services higher over the past five years, the expectation is that these costs should ease in future as supply gradually meets demand. This supply demand imbalance may, however, persist beyond 2015 and for this reason the effects of supply chain easing have been modelled last (after industry learning effects) and are shown in Figure 16.

Appendix D Modelling methodology

Figure 23: Levelised cost and RO banding modelling methodology

Source: Ernst & Young



Base case assumptions

The base case levelised costs were calculated using the following assumptions:

Base case assumption	Value
Discount rate (post-tax real)	10% (12% post-tax nominal)
Project life	20 years
Availability	94%
Net load factor	38%
Forward revenue curve	DECC provided Medium curve
Generator share of revenues under PPA: ► Wholesale power ► ROC Buy-out ► ROC Recycle ► LEC	 ► 90% ► 92.5% ► 92.5% ► 92.5%
OFTO required rate of return	10% (same as project)
MW capacity deployment	Base case scenario (see Appendix C)
Corporation tax rate	28%
Capital Allowances	► 70% of fixed assets @ 20% reducing balance ► 28% of fixed assets @ 10% reducing balance ► 2% of fixed assets do not qualify for capital allowances
Capital costs	► WTG: £1.5m/MW ► Foundations: £0.7m/MW ► Electrical infrastructure: £0.6m/MW ► Planning and development: £0.4m/MW
Operating costs (years 1-5) – pre-OFTO	► O&M: £54k/MW p.a. ► Grid: £7.5k/MW p.a. ► Insurance: £12k/MW p.a. ► Lease: 1% of revenues over the project life ► Decommissioning: £18k/MW p.a.
Operating costs (years 6-20) – pre-OFTO	► O&M: £66k/MW p.a. ► Grid: £7.5k/MW p.a. ► Insurance: £12k/MW p.a. ► Lease: 1% of revenues over the project life ► Decommissioning: £18k/MW p.a.