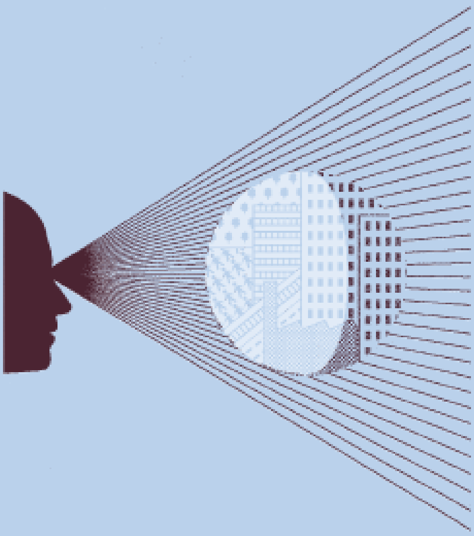
Oxera

Outlook for onshore wind

Analysis to inform DECC's Call for Evidence: Onshore Wind - Costs

Prepared for ScottishPower

December 2012



Executive summary

DECC's Renewables Obligation (RO) Banding Review assessed the possible future costs and revenues of onshore wind projects, and concluded that 'capital and levelised costs are projected to fall over the decade, meaning that support for onshore wind can also come down.'[1] On the basis of this projected decrease in costs, DECC committed to reducing support for onshore wind to 0.9 ROC/MWh for new accreditations and capacity additions in the Banding Review period (April 1st 2013 to March 31st 2017).

DECC's current call for evidence on onshore wind costs reflects an intention to consider the possibility that these costs could fall by more or less than first projected in the Banding Review.[2] DECC's call for evidence focuses on costs,[3] although expected revenues are also a relevant factor—and any subsequent review of onshore support levels would also require an assessment of expected revenues.[4] DECC has committed itself to an approach that 'would be as rigorously evidence-based as it has been in the current banding review',[5] and to considering evidence from all parts of the UK.

ScottishPower has commissioned this report to review the outlook for the key cost and revenue drivers of onshore wind economics, with a view to assessing whether there has been a significant change compared with DECC's assumptions in the Banding Review. The report also updates Oxera's previous work on the deployment impacts (including a regional analysis) associated with different RO banding levels.[6]

Changes in the outlook for onshore wind economics

The updated outlook for onshore wind since the Banding Review highlights a combination of i) changes to DECC's assumptions on the main determinants of electricity prices; ii) changes in the outlook for future operating costs; and iii) changes in the outlook for transmission charges as a result of recent proposals for reform (although there remains some uncertainty as to the precise outcome of this).

With regard to revenues, DECC's revised fossil-fuel and demand projections suggest that annual average electricity prices could be lower than the projections used in the Banding Review by an amount varying over time between £1/MWh and £4/MWh. This could reduce the expected internal rate of return (IRR) of a representative project in South Scotland by around 25–32 basis points, equivalent to an increase of 0.03–0.05 ROC/MWh in the required support.

[1] DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', p. 28.

[2] DECC (2012), 'Onshore Wind – Call for Evidence. Part B - Costs', September 20th.

[3] DECC's accompanying consultation on community support (Part A) recognises that there are a number of new cost pressures on wind economics in this area and DECC wishes to consider these as part of its analysis. It is also interested in gathering additional information on financing costs and how these might have changed in recent years. See DECC (2012), 'Onshore Wind – Call for Evidence. Part B - Costs', September 20th, paras 16 and 25.

[4] See Article 33 of the Renewables Obligation Order 2009, available at http://www.legislation.gov.uk/uksi/2009/785/article/33/made.

[5] DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', p. 30.

[6] Oxera (2011), 'Banding scenarios: impacts on onshore wind deployment', June; Oxera (2011), 'Banding scenarios: impacts on onshore wind—supplementary note', July 28th, and Oxera (2012), 'Assessment of DECC's onshore wind banding proposal', January 12th.

The outlook for capital cost movements appears relatively unchanged. The recent decrease in the price of steel translates into a relatively small impact on total capital expenditure (CAPEX), and has not led to reductions in observed project costs—which may reflect the expectation, observed in forward prices, that the price will increase in future. There also remains a risk that DECC's assumed cost reductions from learning effects will fail to have the projected impact on UK costs. Empirical analysis of reductions in the costs of turbines suggests that country-specific factors (as well as the nature of the evolution of turbine designs) can lead to more limited impacts than that implied by the global analysis relied on by DECC in the Banding Review.

Upward pressure on operating expenditure (OPEX) is also a key cost component of the current outlook—recent increases in developers' expected maintenance and site management costs, of around £5,000/MW per annum, are broadly equal to the reduction applied by DECC to ARUP's central OPEX estimate put forward during the Banding Review. This effect further reduces the expected returns of a South Scotland project by around 36–37 basis points, equivalent to an increase of around 0.05 ROC/MWh in the required support.

In addition, community benefit is an increasingly important fixed cost that affects project economics, as reflected in DECC's call for evidence on this.[7] Typical levels of community benefit have risen to around £5,000/MW. [8] The assumptions used in the Banding Review are not made explicit—however, given the recent increase in these costs, the impact of a conservative estimate that costs have risen by around £1,000/MW per annum has been assessed, which is equivalent to an increase in the required support of around 0.01 ROC/MWh.

These adverse impacts could be partially offset by recent proposals that could lead to lower transmission (Transmission Network Use of System, TNUoS) charges for wind projects. Illustrative projections of future charges under an 'improved ICRP' model (as proposed under Ofgem's Project TransmiT) could lower the charges for intermittent generation compared with the current structure and level of charges—although these effects are likely to vary regionally and by type of project.[9] Thus:

– for embedded generation that is not liable to pay TNUoS charges, there would be no benefit;

– for a typical large Scottish project (ie, greater than 100MW), the effect of lower charges would be equivalent to a benefit of around 0.06–0.07 ROC/MWh;

– for small Scottish transmission-connected plant (ie, less than 100MW), Ofgem has recently extended the small generator discount to 2015/16 (worth around £8/kW per annum). The most favourable case for such plant (which would involve an indefinite extension) would provide a benefit equivalent to around 0.08 ROC/MWh.

However, the final impact of the transmission charging reforms will not become clear until after the recommendations of the Connection and Use of System Code (CUSC) working group have been published, and the options duly assessed by Ofgem.

[7] DECC (2012), 'Onshore Wind – Call for Evidence. Part A – Community Engagement and Benefits', September.

[8] Since 2000, community benefits have increased from around £1,000/MW to around £5,000/MW, index linked for the operational life of the windfarm, although this may be subject to change should project economics alter significantly. For evidence of recent cost changes see ScottishPower (2012), 'Onshore wind call for evidence', November 20th.

[9] Current transmission charges are derived on the basis of investment cost-related pricing (ICRP). The principle of this approach is that charges should reflect the impact that users of the transmission system at different locations would have on the transmission owner's costs if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system, and maintaining a system capable of providing a secure bulk supply of energy.

Taking account of all of the cost categories discussed above, the overall outlook for costs across different project types is broadly unchanged. The impact of the change in outlook across all of these cost factors is less than an equivalent change in support of 0.01 ROC/MWh—based on a conservative assumption that future TNUoS discounts are offered to small Scottish generators beyond 2015/16. If such a discount were not maintained after that date, the average revised cost outlook for projects across Great Britain would be adverse.

This neutral or adverse cost outlook does not provide evidence to substantiate the need for a review of onshore wind support. This conclusion is reinforced by the deterioration in the revenue outlook, and suggests that there has been an adverse change in the overall outlook for onshore wind economics since the Banding Review.

The net effect of the revised outlook for costs and revenues is a reduction in the IRR of a representative TNUoS-paying Scottish onshore project by around 15–22 basis points, or equivalently, an increase in the required support level for a representative project by around 0.02–0.03 ROC/MWh. The effects vary between regions depending on project costs, load factors and the revised outlook for TNUoS charges across charging zones.

Financing costs

The hurdle rate for onshore wind represents the forward-looking return required by project sponsors to invest in a potential project. The rate captures the returns required to compensate for those risks that investors cannot reduce by investing in several different projects (‘systematic’ risks), in addition to project-specific risks, and other factors that affect investor behaviour.

Since the onset of the financial crisis, banks and credit agencies have looked for more robust credit metrics for borrowers, which have constrained the availability of debt finance. Capital spending limitations imposed by companies, together with a potential need to use more equity, have resulted in upwards pressure on required returns and financing costs.

There is considerable uncertainty about future macroeconomic conditions in the UK, reflecting the ongoing volatility in the eurozone and evidenced by continued significant volatility (and hence risk) in equity markets. The volatility in equity values is also likely to reflect increased uncertainty about the value of the underlying assets, raising the risk of default, and hence is also likely to correspond to a higher cost of debt. This uncertainty in macroeconomic conditions compounds the difficulties of estimating future financing costs accurately, and project sponsors are likely to incorporate this elevated risk when determining the appropriate hurdle rate.

These factors suggest that there is no evidence that hurdle rates have declined in recent years, or are expected to decline over the forthcoming Banding Review period.

Deployment impacts and effects of a potential banding revision

The impact of the revised outlook for onshore wind since the Banding Review could make an additional 3.3% of the deployment potential uneconomic to develop by 2016/17, equivalent to around 150MW or 0.35TWh. This impact varies by project type (ie, size and grid connection):

– the deployment impact for small Scottish transmission-connected plant is positive (assuming there is an indefinite extension to the small generator discount, see above), while there is an adverse effect on full-TNUoS-paying generators, and on embedded generation;

– more than half of the deterred projects are expected to be located in England and Wales. This is because a relatively high proportion of potential projects are expected to be embedded or located in transmission zones with relatively low or negative charges (where the possible charging reforms are likely to have a less beneficial impact).

A further reduction in RO banding support for onshore wind from 0.9 ROC/MWh to 0.8 ROC/MWh could make an additional 10% of the deployment potential uneconomic to develop, equivalent to around 430MW or 1.05TWh by 2016/17. Under this finding:

- deployment impacts in 2016/17, as well as in 2014/15 and 2015/16, are considered relevant on the basis that the support under future Contracts for Difference (CfDs) is likely to be set at a risk-adjusted level equivalent to that of the RO (or at least takes account of the level of support under the RO);
- around 75% of the reduction in deployment due to such a further reduction in RO banding would be likely to be in Scotland (driven in large part by the relative resource potential in Scotland).

The overall impact of a further decrease in onshore support from 0.9 ROC/MWh to 0.8 ROC/MWh could lead to an increase in consumer costs of around £20m per annum. This is based on the assumption that a reduction in onshore wind deployment would be replaced by offshore wind in order to maintain the UK's progress towards its 2020 renewables target. It is also consistent with DECC's position that offshore wind represents the marginal cost of meeting the 2020 target.

In summary, the revised cost outlook for onshore wind does not provide evidence to substantiate the need for a review of support levels. Indeed, if the change in revenue outlook is also considered, there is evidence to suggest that there has been an overall adverse change in the outlook for onshore wind since the Banding Review. A reduction in support from 0.9 ROC/MWh to 0.8 ROC/MWh could make an additional 10% of the deployment potential uneconomic to develop (equivalent to around 430 MW, with the majority of deterred projects in Scotland)—and lead to an increase in consumer costs of around £20m per annum.

Contents

List of tables

List of figures

1 Introduction

DECC's Renewables Obligation (RO) Banding Review assessed the possible future costs and revenues of onshore wind projects, and concluded that 'capital and levelised costs are projected to fall over the decade, meaning that support for onshore wind can also come down'.[10] On the basis of this projected decrease in costs, DECC committed to reducing support for onshore wind to 0.9 ROC/MWh for new accreditations and capacity additions in the Banding Review period (April 1st 2013 to March 31st 2017).

DECC's analysis acknowledged that reducing the level of onshore support would have an adverse effect on deployment, given the distribution of costs and operating characteristics across potential projects. DECC concluded that the volume impact of a reduction in support to 0.9 ROC/MWh would deter investment in 350–430MW (equivalent to output of 0.9–1.1TWh) by 2015/16.

Oxera analysis during the Banding Review concluded that a reduction in onshore wind support to 0.9 ROC/MWh could have a larger adverse effect than that suggested by DECC, on the basis that:

– Oxera's estimate of deployment effects suggested that up to 610MW (equivalent to 1.5TWh) could be deterred by 2015/16 (over two-thirds of which was expected to be in Scotland);[11]

– Oxera also considered that DECC's analysis should have included potential deployment effects in 2016/17, on the basis that the support under future Contracts for Difference (CfDs) is likely to be set at a risk-adjusted level equivalent to that of the RO (or at least takes account of the level of support under the RO).[12] This could deter a further 0.49TWh (180MW) compared with the potential effects in 2015/16;

– the impact of these deterred volumes could be to increase net costs by as much as £40m per annum, given that onshore wind is a relatively low-cost renewable technology, and that substitution of the deterred output by relatively more expensive offshore wind in order to maintain progress towards the UK's 2020 renewables target would entail higher support costs and infrastructure investment.

DECC's current call for evidence on onshore wind costs reflects an intention to consider the possibility of these costs falling by more or less than first projected in the Banding Review.[13] DECC's call for evidence focuses on costs,[14] although expected revenues are also a relevant factor—and any subsequent review of onshore support levels would also require an assessment of expected revenues.[15] DECC has committed itself to an approach that 'would

[10] DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013–2017 and the Renewables Obligations Order 2012', July 25th, p. 28, para 3.3.

[11] Oxera (2012), 'Assessment of DECC's onshore wind banding proposal', January 12th, p 5.

[12] This would also be consistent with DECC's offshore assessment, which outlined that support under the proposed CfDs might be lower than that provided under the RO, so that developers might be likely to prefer the RO. See DECC (2011), 'Consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', October, para 4.8.

[13] DECC (2012), 'Onshore Wind – Call for Evidence. Part B - Costs', September 20th.

[14] DECC's accompanying consultation on community support (Part A) recognises that there are a number of new cost pressures on wind economics in this area and DECC wishes to consider these as part of its analysis. It is also interested in gathering additional information on financing costs and how these might have changed in recent years. See DECC (2012), 'Onshore Wind – Call for Evidence. Part B - Costs', September 20th, paras 16 and 25.

[15] See Article 33 of the Renewables Obligation Order 2009, available at http://www.legislation.gov.uk/uksi/2009/785/article/33/made.

be as rigorously evidence-based as it has been in the current banding review',[16] and to considering evidence from all parts of the UK.

ScottishPower has commissioned this report to review the outlook for the key cost and revenue drivers of onshore wind economics, with a view to assessing whether there has been a significant change compared with DECC's assumptions in the Banding Review. The report also updates Oxera's previous work on the deployment impacts (including a regional analysis) associated with different RO banding levels.[17]

The report is structured as follows:

– section 2 outlines the revenue and cost drivers for onshore wind projects, and the pressures likely to affect the outlook for those projects over the Banding Review period;

– section 3 gives an overview of recent factors affecting the drivers of developers' hurdle rates;

– section 4 sets out Oxera's analysis of deployment scenarios, and provides a regional and UK-wide assessment of the impact of a potential further reduction in onshore wind support from 0.9 ROC/MWh to 0.8 ROC/MWh; and

– section 5 concludes.

Appendix 1 gives further detail on factors affecting the outlook for financing costs.

[16] DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', p. 30.
[17] Oxera (2011), 'Banding scenarios: impacts on onshore wind deployment', June; Oxera (2011), 'Banding scenarios: impacts on onshore wind—supplementary note', July 28th, and Oxera (2012), 'Assessment of DECC's onshore wind banding proposal', January 12th.

2 Onshore wind economics

Onshore wind economics—key findings

The revised outlook for onshore wind since the Banding Review reflects a combination of changes to DECC's assumptions on key determinants of electricity prices, changes in the outlook for future operating costs, and changes in the outlook for transmission charges (although there remains some uncertainty as to the precise outcome of this).

– With regard to revenues, DECC's revised fossil-fuel and demand projections suggest that annual average electricity prices could be lower than the projections used in the Banding Review by an amount varying over time between £1/MWh and £4/MWh. This could reduce the expected internal rate of return (IRR) of a representative project in South Scotland by around 25–32 basis points, equivalent to an increase of 0.03–0.05 ROC/MWh in the required support.

– The outlook for capital cost movements appears relatively unchanged. The recent decrease in the price of steel translates into a relatively small impact on total capital expenditure (CAPEX), and has not led to reductions in observed project costs—which may reflect the expectation, observed in forward prices, that the price will increase in future. There also remains a risk that DECC's assumed cost reductions from learning effects may fail to have the projected impact on UK costs.

– The outlook for operating expenditure (OPEX) is also a key cost component—recent increases in developers' expected maintenance and site management costs, of around £5,000/MW per annum, are broadly equal to the reduction applied by DECC to ARUP's central OPEX estimate put forward during the Banding Review. This effect further reduces the expected returns of a representative South Scotland project by around 36–37 basis points, equivalent to an increase of around 0.05 ROC/MWh in the required support.

– Community benefit is an increasingly important fixed cost that affects project economics, as reflected in DECC's call for evidence on this.[18] Typical levels of community benefit have risen to around £5,000/MW. [19] The assumptions used in the Banding Review are not made explicit—however, given the recent increase in these costs, the impact of a conservative estimate that costs have risen by around £1,000/MW per annum has been assessed, which is equivalent to an increase in the required support of around 0.01 ROC/MWh.

– These adverse effects could be partially offset by recent proposals that could lead to lower transmission (Transmission Network Use of System, TNUoS) charges for wind projects. Illustrative projections of future charges under an 'improved ICRP' model (as proposed under Ofgem's Project TransmiT) could lower the charges for intermittent generation compared with the current structure and level of charges,[20] although these effects are likely to vary by region and type of project. Thus:

  – for embedded generation that is not liable to pay TNUoS charges, there would be no benefit;
  – for a typical large Scottish project (ie, greater than 100MW), the effect of lower charges would be equivalent to a benefit of around 0.06–0.07 ROC/MWh;
  – for small Scottish transmission connected plant (ie, less than100MW), Ofgem has recently extended the small generator discount to 2015/16 (worth around £8/kW per annum). The

[18] DECC (2012), 'Onshore Wind – Call for Evidence. Part A – Community Engagement and Benefits', September.

[19] Since 2000, community benefits have increased from around £1,000/MW to around £5,000/MW, index linked for the operational life of the windfarm, although this may be subject to change should project economics alter significantly. For evidence of recent cost changes see ScottishPower (2012), 'Onshore wind call for evidence', November 20th.

[20] Current transmission charges are derived on the basis of investment cost-related pricing (ICRP). The principle of this approach is that charges should reflect the impact that users of the transmission system at different locations would have on the transmission owner's costs if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system, and maintaining a system capable of providing a secure bulk supply of energy.

most favourable case for such plant (which would involve an indefinite extension) would provide a benefit equivalent to around 0.08 ROC/MWh.

– However, the impact of the final transmission charging reforms will not become clear until the recommendations of the CUSC working group are published, which are also subject to approval by Ofgem.

Taking account of all of the cost categories above, the overall outlook for costs across different project types is broadly unchanged (ie, the impact of the change in outlook across all of these cost factors is less than an equivalent change in support of 0.01 ROC/MWh). This is based on a conservative assumption that future TNUoS discounts are offered to small Scottish generators beyond 2015/16. If such a discount were not maintained after that date, the average revised cost outlook for projects across Great Britain would be adverse.

Taking account of revenues as well as costs, the net effect of this revised outlook is a reduction in the IRR of a representative TNUoS-paying Scottish onshore project by around 15–22 basis points, or, equivalently, an increase in the required support for a representative project by around 0.02–0.03 ROC/MWh. The effects vary between regions depending on project costs, load factors and the revised outlook for TNUoS charges across charging zones.

This section provides an assessment of recent changes in the outlook for onshore wind economics, and reviews the assumptions used by DECC during the Banding Review consultation and in its final Impact Assessment.

The analysis focuses on the outlook for revenues as well as costs, as any subsequent review of onshore support levels would also require an assessment of expected revenues.[21]

The implications of recent revisions to DECC's assumptions on electricity price drivers are set out below, followed by analysis of the outlook for capital and operating costs (including transmission charges and community benefit). Discounted-cash-flow models of representative project types across charging regions within GB are used to assess the overall impact of these factors.

2.1 Revenue outlook

Based on Oxera's analysis of future ROC and electricity prices, ROC revenues provide around 35% of expected total onshore wind revenues.[22] This makes the outlook for electricity prices a critical component of project returns, and, in turn, the appropriate level of support under the RO. This was recognised in DECC's Banding Review final Impact Assessment:

> Assumptions on investor expectations of wholesale electricity prices can influence the ROC banding needed significantly, i.e. if lower wholesale electricity prices are assumed, a higher ROC band is needed for the investment to break even.[23]

Commodity prices (in particular, gas), carbon prices, and electricity demand are key inputs into the outlook for electricity prices. For its Banding Review consultation and in its final Impact Assessment, DECC relied on different projections for these key inputs. As set out below, its recent revision to its projections of global commodity prices and GB electricity demand—which are more in line with market expectations—implies a significant deterioration in the outlook for electricity prices, and in turn onshore wind revenues, when compared with the Banding Review assumptions.

[21] See Article 33 of the Renewables Obligation Order 2009, available at http://www.legislation.gov.uk/uksi/2009/785/article/33/made.
[22] Based on current RO banding and Oxera modelling of future electricity prices using DECC's commodity price assumptions and demand outlook.
[23] DECC (2012), 'Impact Assessment. Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', p. 9, footnote 10.

2.1.1 Electricity price outlook

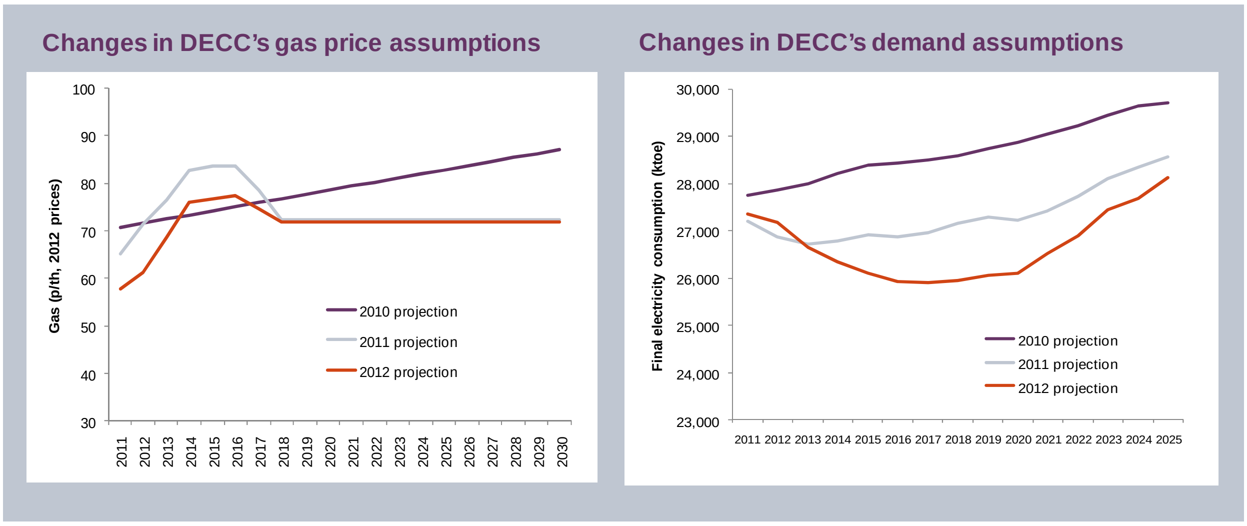
Figure 2.1 highlights DECC's revisions to the assumptions made on the power price drivers used in the Banding Review consultation, DECC's final Impact Assessment, as well as its most recent projections. The figure highlights that:

– the **2010** fossil-fuel price and demand growth assumptions (used in the Banding Review consultation) exhibit high price and demand levels relative to recent revisions;[24]

– the **2011** fossil-fuel and demand projections (used in DECC's final Impact Assessment) exhibit a significant near-term increase in gas prices, followed by lower levels in later years relative to the **2010** assumptions, alongside lower levels of demand;[25]

– the recent **2012** fossil-fuel and demand projections from DECC exhibit a reduction in the near-term outlook for gas prices, and further medium-term reductions in demand.[26]

Figure 2.1 Recent revisions to DECC's gas and electricity demand assumptions



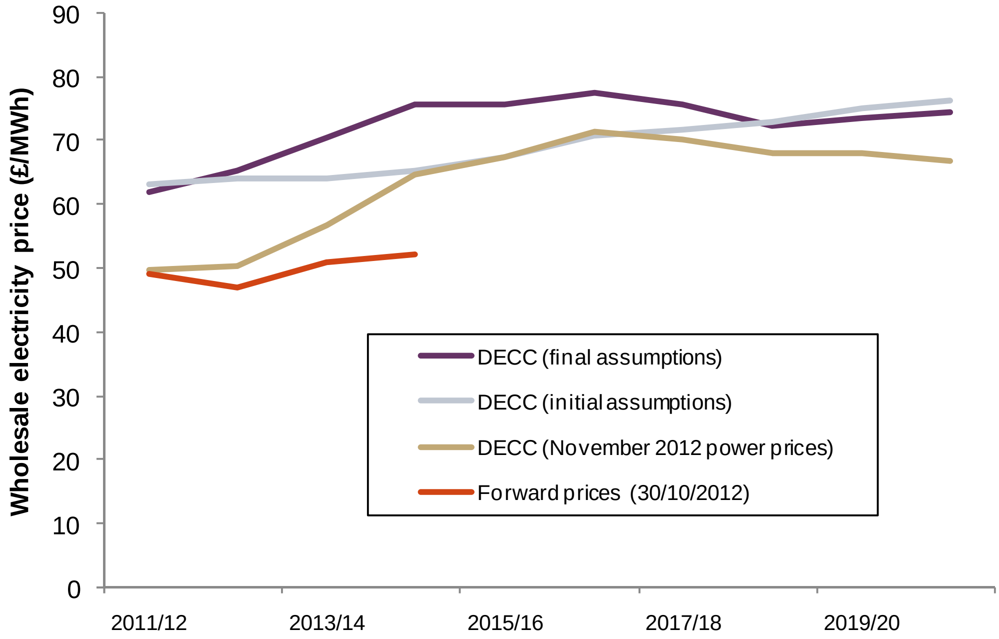
Source: DECC.

Figure 2.2 highlights the impact of these different input assumptions on the outlook for electricity prices. Comparisons between the different projections are not straightforward because of the different models used: the electricity prices used in the Banding Review consultation and final Impact Assessment were based on Poyry modelling using DECC inputs, whereas the most recent projection using 2012 assumptions is based on DECC modelling.

The figure shows that the most recent revisions to DECC's underlying assumptions imply a significant reduction in expected prices. The figure also highlights that previous assumptions led to electricity price projections that were significantly (£14–£20/MWh) above outturn spot and forward prices.

[24] DECC (2010), 'Updated energy and emissions projections', June.
[25] DECC (2011), 'Updated energy and emissions projections', October.
[26] DECC (2012), 'Updated energy and emissions projections', October.

Figure 2.2 DECC power price assumptions relative to market expectations

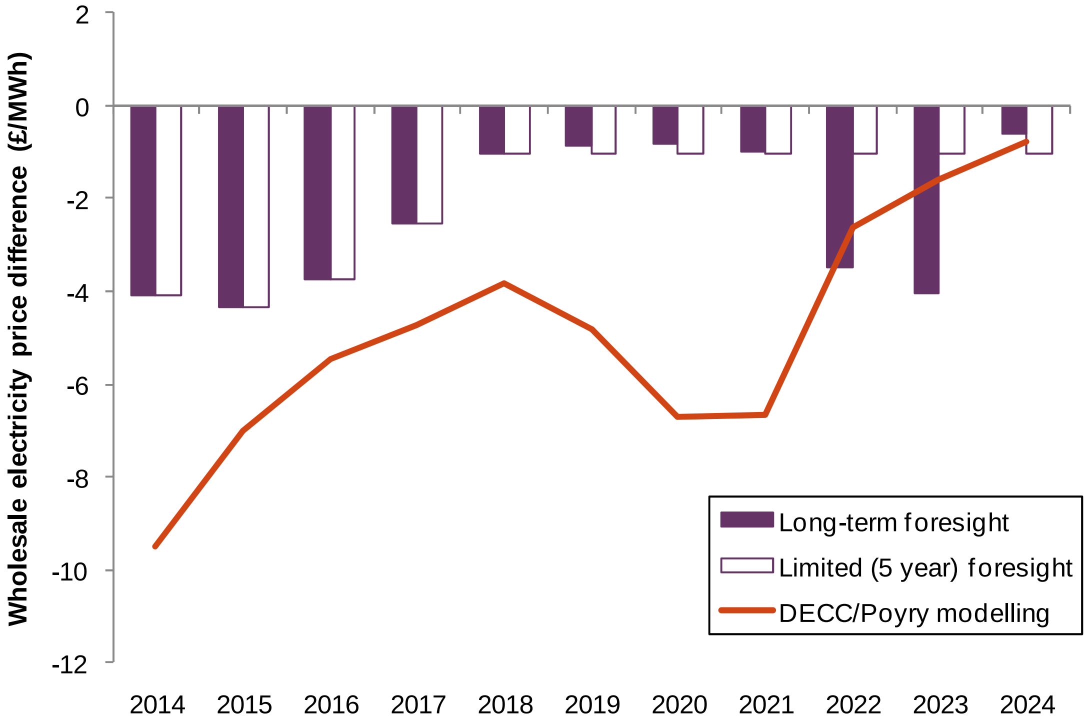


Note: Electricity prices shown using 2010 and 2011 assumptions are based on modelling from Poyry using DECC's commodity price and demand assumptions. Electricity prices using 2012 assumptions are based on DECC's recent updated energy projections.
Source: DECC (2012), 'Updated energy and emissions projections 2012', October, Annex F, and Platts UK price assessment, October 30th 2012.

The revision to DECC's assumptions for the key drivers of electricity prices implies a significant reduction in expected power prices compared with the Banding Review assumptions, and a consequent increase in the RO support required by onshore wind.

Given the difficulties in comparing the electricity price projections derived using different models, Figure 2.3 shows the annual difference in power price expectations due to the change in DECC's assumptions since the Banding Review final Impact Assessment, using Oxera's GB power model.

Figure 2.3 Changes in power price outlook based on 2011 and 2012 assumptions



Note: The relative decrease in the outlook for 2022/23 prices is a consequence of lower expected demand, which gives rise to a higher capacity margin and hence lower peak prices.
Source: Oxera.

The figure highlights that:

– using DECC's revised assumptions as inputs to Oxera's GB power model leads to a reduction in power prices varying between £1 and £4/MWh over the life of a 2014/15 onshore wind project, relative to the final Banding Review assumptions;

  – this difference—and the resulting impact on project viability—is sustained regardless of the view taken as to whether investment decisions are based on long-term projections of the electricity price or on a limited five-year horizon;[27]

– making a direct comparison of DECC's latest power price projections on the one hand, and those used in the Banding Review final Impact Assessment on the other, the revised assumptions lead to a reduction in power prices varying between £1 and £10/MWh, although, as noted above, these two projections have been derived from different models.

As a conservative approach, the analysis in this report is based on the power price difference determined using DECC's fossil-fuel price and electricity demand projections as inputs into Oxera's GB model. The impact of this for onshore wind economics and deployment has been assessed within discounted-cash-flow models of representative onshore wind projects across different regions within GB.

Other downside risks to power prices that a developer may take into account when evaluating the economics of onshore wind projects are excluded, such as doubt about the enduring nature of the unilateral UK carbon price floor, which may be discounted in developers' decisions due to its lack of long-term 'bankability'.

[27] Changes in the near-term outlook are especially important to project appraisal in present-value terms, as future costs and revenues are discounted. Thus, using DECC's hurdle rate assumption, costs and revenues in year 6 of the project life are multiplied by a discount factor of 0.58, and by a factor of 0.4 in year 10.

For a representative project in South Scotland (the most abundant region in terms of resource potential), the impact of the reduced power price outlook implied by DECC's revisions to its commodity and demand projections since the Banding Review final Impact Assessment on the project IRR ranges between 25–32 basis points (for a 2014/15 project and 2016/17 project respectively).

An increase in support, of around 0.03–0.05 ROC/MWh, would be required to offset this deterioration in project economics.

2.2 Outlook for key cost drivers

On the cost side, the key drivers of onshore wind economics are the outlook for capital costs (CAPEX)—including whether DECC's conclusion that 'capital and levelised costs are projected to fall over the decade' is likely to materialise[28]—the outlook for operating costs (OPEX), the significance of recent trends for increasing community benefit payments, and the proposed revisions to the transmission charging regime.

Each of these factors is discussed in turn.

2.2.1 Capital costs

Capital costs are driven by the price of key factor inputs—in the case of onshore wind, mainly steel and exchange rates, and the scope for technological improvements, as captured in assumed learning rates. DECC's forward-looking cost assumptions used in the Banding Review were based on work commissioned from ARUP, in which the main cost components were used to build a composite cost index.[29]

The following assumptions underpin the outlook for onshore capital costs in DECC's Banding Review analysis:

– no anticipated change in exchange rates due to the uncertainty of such movements;[30]
– steel prices (described by ARUP as 'the primary positive price inflator over the next 20 years') to remain constant in real terms;[31]
– learning effects were therefore the main driver of (downward) future cost trends.

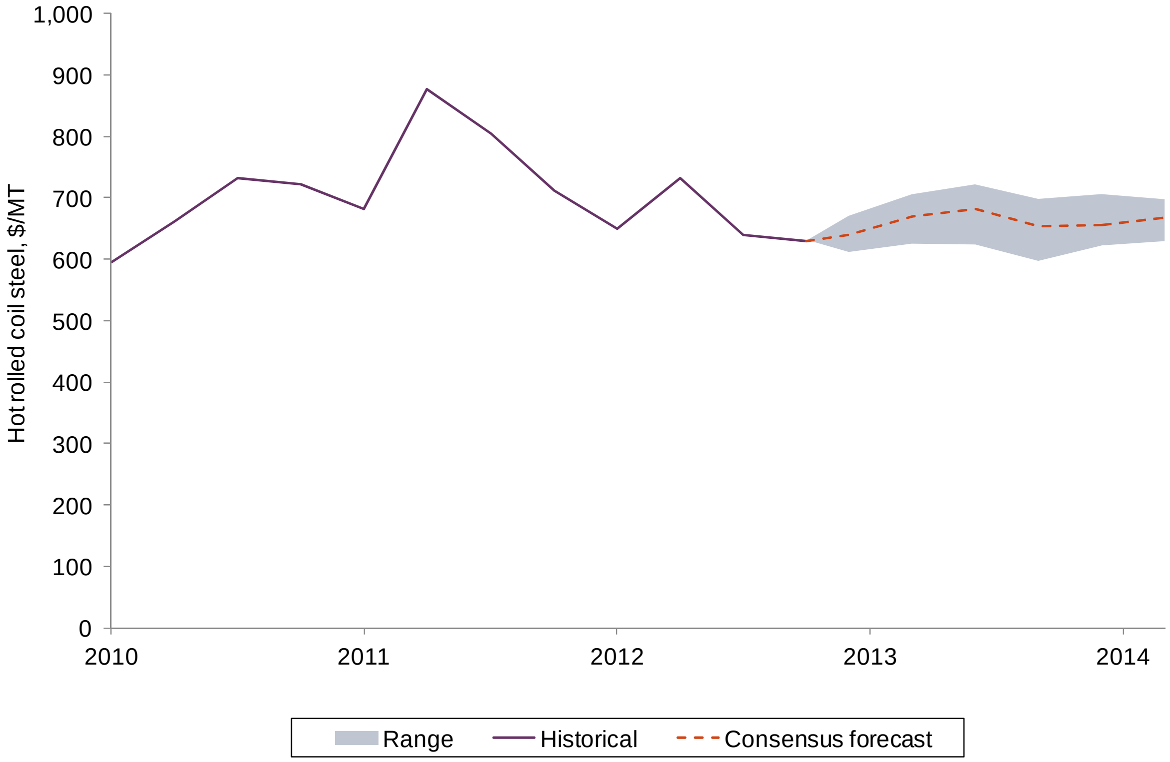
These assumptions are examined in turn. However, given the continued macroeconomic uncertainty that surrounds the eurozone and wider global economy, and the volatility that this creates for foreign exchange and commodity prices (as described in section 3 and Appendix 1), the main focus of the analysis below is on the materiality of the potential risk that DECC's assumed learning effects might not be realised.

Steel prices and exchange rates

Since the Banding Review, prices for the benchmark flat steel product, hot rolled coil (HRC), have fallen by around 10%, from $700/MT in late 2011 to $630/MT in late 2012, with current market expectations suggesting that there is likely to be a moderate price rise in the medium term.[32] Historical prices and consensus forecasts for HRC steel are shown in Figure 2.4.

[28] DECC (2012), DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013–2017 and the Renewables Obligations Order 2012', July 25th, p. 28.
[29] See ARUP (2011), 'Review of the generation costs and deployment potential of renewable electricity technologies in the UK', October, p. 20.
[30] Ibid., p. 8.
[31] Ibid., p. 20.
[32] Steel prices are typically reported in US dollars. The euro has weakened slightly (by around 5%) relative to the dollar since the start of the Banding Review, which has the effect of increasing the cost of steel to European manufacturers. However, as a

Figure 2.4 European hot rolled coil steel prices



Source: Consensus Economics (2012) 'Energy & Metals consensus forecasts', October. Historical data originally produced by MEPS Ltd.

Steel is the main material input to wind turbine production, but translates into a relatively limited contribution to total turbine costs. The cost of the tower typically represents around 25% of turbine costs, and is usually made from tubular steel (manufactured from flat steel, for which HRC is the benchmark product). Other turbine components, such as the gearbox, rotor hub and generator, also have steel components,[33] but do not make up such a large portion of the total turbine cost, and contribute around 13%, 1% and 3% of that cost respectively.[34] As with other more complex products, the costs of these other components are also likely to be more heavily weighted towards labour and capital costs of production rather than direct steel costs.[35]

Overall, the prospect for significant reductions in onshore wind CAPEX as a result of recent reductions in the steel price appears limited. For a typical onshore wind project, the turbine represents around 65% of total CAPEX—the remainder of the cost relates to foundations (15%), grid connection (11%), and planning (9%).[36] On the basis that around 25% of the turbine cost relates to steel,[37] a 10% fall in the steel price—as observed since the start of the Banding Review—could lead to a reduction in onshore CAPEX of around 1–2%.[38] In practice, this effect could be less since turbine manufacturers have longer-term contracts in

conservative approach, the analysis in this report does not adjust observed steel price movements to reflect changes in the $/€ exchange rate.

[33] See, for example, PERI (2001), 'Wind Turbine – Materials and Manufacturing Fact Sheet', Table 3.

[34] IRENA (2012), 'Wind Power', Renewable energy technologies: cost analysis series, Volume 1: Power Sector, Issue 5, and EWEA (2009), 'The Economics of Wind Energy'

[35] See PERI (2001) 'Wind Turbine – Materials and Manufacturing Fact Sheet', Tables 1 and 3. The difference between weight-of-turbine share and cost-of-turbine share for these components compared with the same for the tower indicates the scale of the difference in steel's share of the component cost.

[36] IRENA (2012) op. cit., and ScottishPower development portfolio.

[37] For the purposes of this calculation, the tower cost has been assumed to represent entirely the cost of the steel (ie, no labour or machining cost), and the remainder of the turbine cost is assumed to be weakly correlated with the steel price.

[38] Calculated as: steel price fall (10%) * steel share of turbine (25%) * turbine share of CAPEX (65%) = 2%.

place for purchasing steel to hedge against variation in prices, and forward prices reflect expectations of moderate price growth. This is consistent with the observation that developers have not experienced recent reductions in outturn turbine prices.[39]

The decrease in steel prices since the start of the Banding Review has largely been driven by changes in the economic growth of China, which slowed slightly during 2012, to 7.4% in Q3 (year-on-year) from 9.1% a year earlier.[40] China is the world's largest producer (46%) and consumer (45%) of steel, and as such the balance of its internal market can have significant implications for the market in the rest of the world.[41] Recent announcements by the Chinese government to introduce an infrastructure-based stimulus package to boost economic growth is likely to place upward pressure on the steel price, as highlighted in Figure 2.4.

The combined effect of recent steel price movements and expected future trends is equivalent to a marginal reduction in expected CAPEX of a 2014/15 project of around 1%—although, as outlined below, this could be largely offset by slower learning effects than those assumed by DECC.

With respect to exchange rates, the uncertainty surrounding the growth prospects of the UK and the eurozone has shown little sign of abating since the Banding Review; and, in turn, suggests that conditions remain the same as those used by DECC to support the conclusion that it is unclear whether to expect material appreciation or depreciation of sterling relative to the euro.

Recent statements from the Bank of England highlight the uncertainty surrounding its GDP growth forecast. This uncertainty has increased significantly since the start of the financial crisis, and especially since the onset of the eurozone debt crisis. The Bank's recent assessment highlights the interdependencies between the two currency areas, and the consequent difficulty in projecting exchange rates between them:

> The outlook for UK growth remains unusually uncertain. The greatest threat to the recovery stems from the risk that an effective policy response is not implemented sufficiently promptly in the euro area to ensure that the adjustments in the level of debt and competitiveness required by some member countries occur in an orderly manner.[42]

Figure 2.5 highlights that exchange rate volatility remains above pre-crisis levels, and does not provide further evidence on which to revise DECC's Banding Review assumptions.

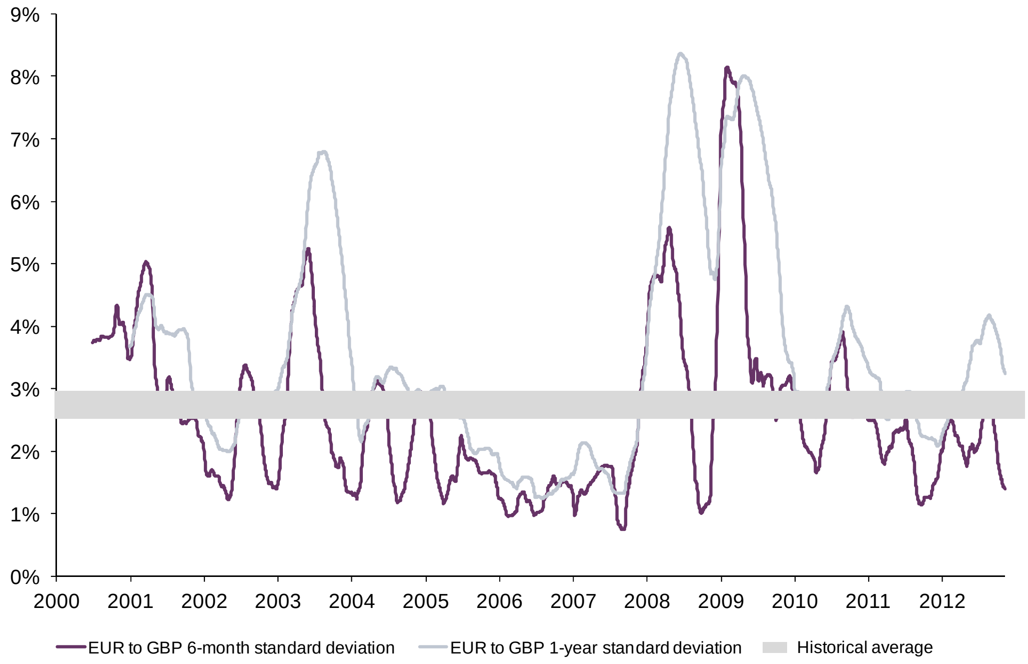
[39] As outlined in ScottishPower's response to DECC's call for evidence. See ScottishPower (2012), 'Onshore wind call for evidence', November 20th.

[40] Based on real Chinese GDP figures reported by Bloomberg.

[41] Consensus Economics (2012), 'Energy and metals consensus forecasts', October 22nd.

[42] Bank of England (2012), 'Inflation Report', August, p. 6.

Figure 2.5 Exchange rate volatility (€/£)



Note: Rolling standard deviations are presented. The historical average is defined as the average over the period prior to the onset of the financial crisis—ie, up to 2007.
Source: Oxera analysis, based on Datastream.

Learning effects

The conclusions of DECC's Banding Review suggested that a reduction in onshore wind support was justified on the basis of expected reductions in future capital costs, driven by learning effects. DECC's learning rate assumption for onshore wind is 7%, and is applied on a global basis—ie, each doubling of global onshore wind leads to a 7% reduction in costs.

The robustness of the cost reductions modelled in such an analysis depends on the assumptions used for:

– the rate of global deployment;

– the learning rate, and, given the nature of the technology involved, whether such a rate should be applied to global or national deployment levels.

The **global deployment** trajectory used in DECC's analysis was the IEA's BLUE map scenario, which works backwards from an assumption of global climate stabilisation in 2050 to generate a set of optimal investment trajectories in the intervening years.

Recent reports from bodies such as the IEA itself highlight that progress in addressing climate change is not following such trajectories. The IEA's 2012 World Energy Outlook suggests that 'the world is still failing to put the global energy system onto a more sustainable path'.[43] Indeed, under the New Policies scenario of the Outlook, the IEA predicts a 6% probability of limiting temperature change to 2°C by 2050. The same scenario projects deployment of 586GW of wind power (on- and offshore) by 2020. In contrast, the BLUE map scenario from the IEA's Energy Technology Perspectives 2010 sets 671GW of wind power as its roadmap target for 2020. The actual level of deployment in 2011 was 238GW.[44]

[43] IEA (2012), 'World Energy Outlook 2012 – Executive Summary', p. 1.
[44] IEA (2012), 'World Energy Outlook'.

However, these differences may have only a moderate impact on the outlook for future costs. Using DECC's learning-rate assumption of 7%, this difference in potential deployment by 2020 reduces the scope for cost reduction from learning from 9.6% by 2020 under the BLUE map scenario, to 8.4% by 2020 under the New Policies scenario. More important, therefore, is the extent to which national rather than global deployment rates are appropriate, as discussed below.

Learning rates are an important driver of long-run capital costs, especially for new technologies, and describe the rate at which costs fall as a result of increased use of a particular technology. Intuitively, learning occurs as a result of experience and knowledge transfer—by applying a technology, industries learn what works and what does not, and find opportunities for further development and efficiency.

Critical in the assessment of learning rates is the relevant domain for learning to take place, either within organisations, or across national or even global industries, as well as the nature of the technology and its evolution. On this second point, the extent to which learning from one turbine design can be readily transferred to another turbine design can also limit learning effects. These two factors are discussed below.

The significance of the assumed domain for learning was highlighted in a recent meta-study which examined the learning rate for onshore wind in 35 other studies and concluded:

> Most notably, wind power studies that assume the presence of global learning generate significantly higher learning rates than those studies that instead assume a more limited geographical domain for the learning processes.[45]

Such analysis also highlights the caution that should be applied in reviewing recent trends in global cost indices (examples include the Bloomberg Wind Turbine Price Index), which by their nature capture cost reductions across potentially rapidly expanding overseas markets that may not apply in other jurisdictions.[46]

With regard to specific technology features and their impact on learning rates, price falls have not been seen to the same extent in the larger, more modern, turbine designs that are characteristic of UK onshore wind sites. Thus, costs observed in the UK may be relatively higher due to the use of new turbine models with higher tower structures and larger rotor diameters.[47]

Wider learning effects are also discussed in empirical analysis,[48] which suggests that limits to turbine learning rates could be because:

– many components were not designed specifically for turbines, and so may not have the same potential for cost reduction as components that were specifically designed for use in wind turbines;[49]
– relatively rapid progression to newer turbine designs to exploit scale effects in the turbines themselves place limits on the learning effects that can occur, given that learning from one design may not be directly transferable to another.

[45] Lindman, A. and Soderholm, P. (2012), 'Wind power learning rates: a conceptual review and meta-analysis', *Energy Economics*, **34**:3, May, pp. 754–61.
[46] Bloomberg notes that its Wind Turbine Price Index represents data collected across the world's largest buyers of wind turbines, with a main focus on the Americas and Europe. See Bloomberg (2012), 'Overcapacity and new players keep wind turbine prices in the doldrums', press release, March.
[47] For example, the Bloomberg Wind Turbine Price Index analysis notes that reductions in its index have been driven by falls in the price of older, smaller, turbine designs that have seen large-scale deployment in the USA. See Bloomberg (2012), 'Overcapacity and new players keep wind turbine prices in the doldrums', press release, March.
[48] See, for example, Neij, L (1999), op. cit.
[49] For example, gearbox designs have been employed in many industrial applications, and the scope for additional cost reductions in the context of wind power may be limited.

Table 2.1 highlights the very different learning rates observed when different turbine designs are considered separately. Neij (1999) suggests that these could be due to 'costs added through design changes and performance improvements'.[50]

Table 2.1 Learning rates for Danish-produced wind turbines

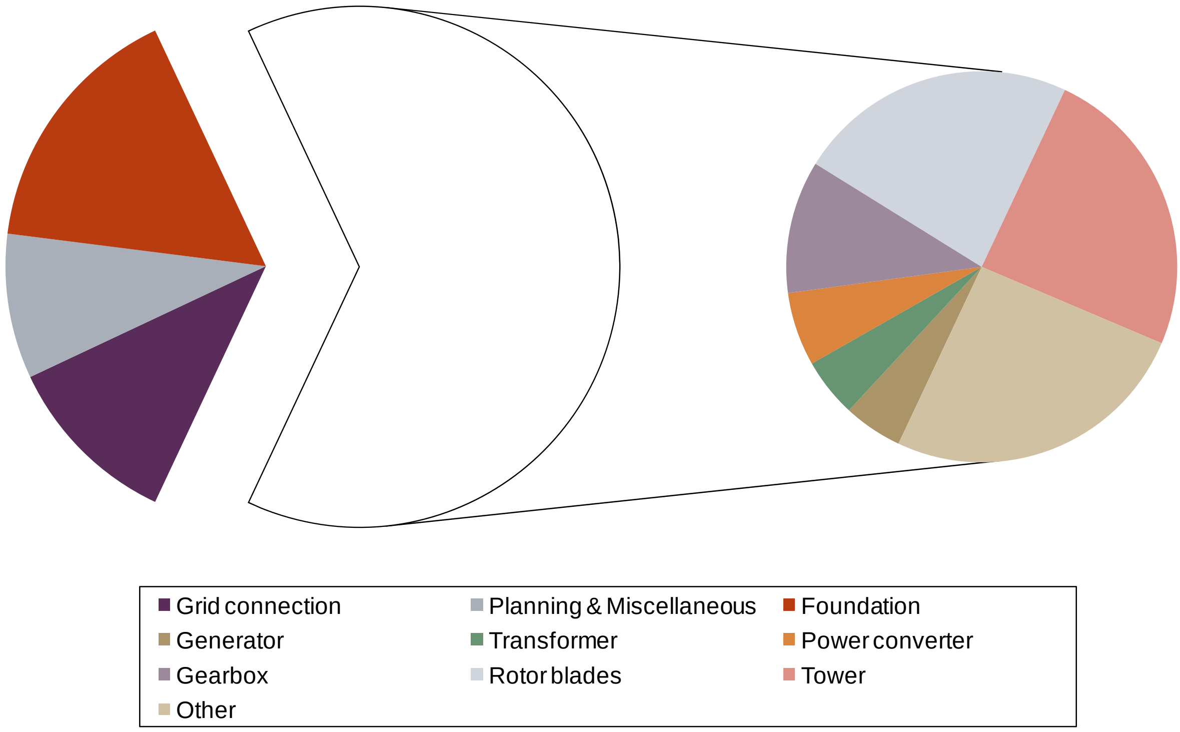
	Time period	Learning rate (%)
Selected wind turbines		
All Danish-produced wind turbines	1982–97	8
Wind turbines produced by:	1982–97	6
major manufacturers	1982–97	6
major manufacturers >55kW	1982–97	4
major manufacturers >150kW	1982–97	2
major manufacturers >55kW	1990–97	5
major manufacturers >150kW	1990–97	5

Note: 'Major manufacturers' includes Bonus, Micon, Nordtank and Vestas. Neij (1999) presents progress ratios in the original table. The learning rate is calculated as LR=1 – PR, where LR is the learning rate (the proportional cost savings made for a doubling of cumulative capacity), and PR is the progress ratio (the ratio of costs in time t and initial costs).
Source: Neij (1999), op. cit., Table 1.

Figure 2.6 highlights that an onshore turbine is comprised of a number of components that are not new in their design or application (such as the gearbox). One study suggests that only 30% of the cost of a turbine is made up of components manufactured exclusively for turbines.[51] The figure also highlights that around one-third of onshore capital costs do not relate to turbines, but to other cost categories, such as grid connection, planning and foundations, where there is likely to be relatively little scope for learning effects to be realised.[52]

[50] Neij (1999), op. cit.
[51] As cited in Neij (1999), op. cit.
[52] Ibid.

Figure 2.6 CAPEX breakdown for onshore wind



Source: IRENA (2012), 'Wind Power', Renewable energy technologies: cost analysis series, Volume 1: Power Sector, Issue 5. Data taken from Blanco (2009).

The considerations above suggest that factors specific to the UK, such as the use of larger rotor diameters, as well as the fact that a number of components of onshore CAPEX have limited scope for cost reduction, are consistent with the lower learning rates adopted in other recognised studies—such as Mott MacDonald's study for the independent Committee on Climate Change, which used UK-specific learning rates for large onshore wind, in an estimated range of 2.5–7.5%. The analysis below highlights the impact of using the midpoint of this range.

Table 2.2 provides a revised outlook for capital costs based on a UK-specific 5% learning rate, and applied to the anticipated central range for UK deployment in DECC's UK Renewables Roadmap.[53] The table highlights that this revision implies a 3.6% reduction in capital costs for a 2015 project relative to 2010 levels, compared with the 4.4% reduction assumed by DECC in the Banding Review.

Table 2.2 ARUP central and alternative cost scenarios

Capital costs (£'000/MW, 2011 prices)	2010	2015	2020
ARUP central case	1,524	1,503	1,500
Banding Review assumption	1,524	1,457	1,407
Oxera 5% learning case	**1,524**	**1,468**	**1,420**

Note: Figures shown are for onshore wind greater than 5MW. Banding Review costs taken from the government's response to the Banding Review consultation are assumed to be in 2012 prices.
Source: ARUP, DECC and Oxera analysis.

[53] DECC (2011), 'UK Renewable Energy Roadmap', July. This deployment rate itself is dependent on the perceived risk in the sector and strength of regulatory support.

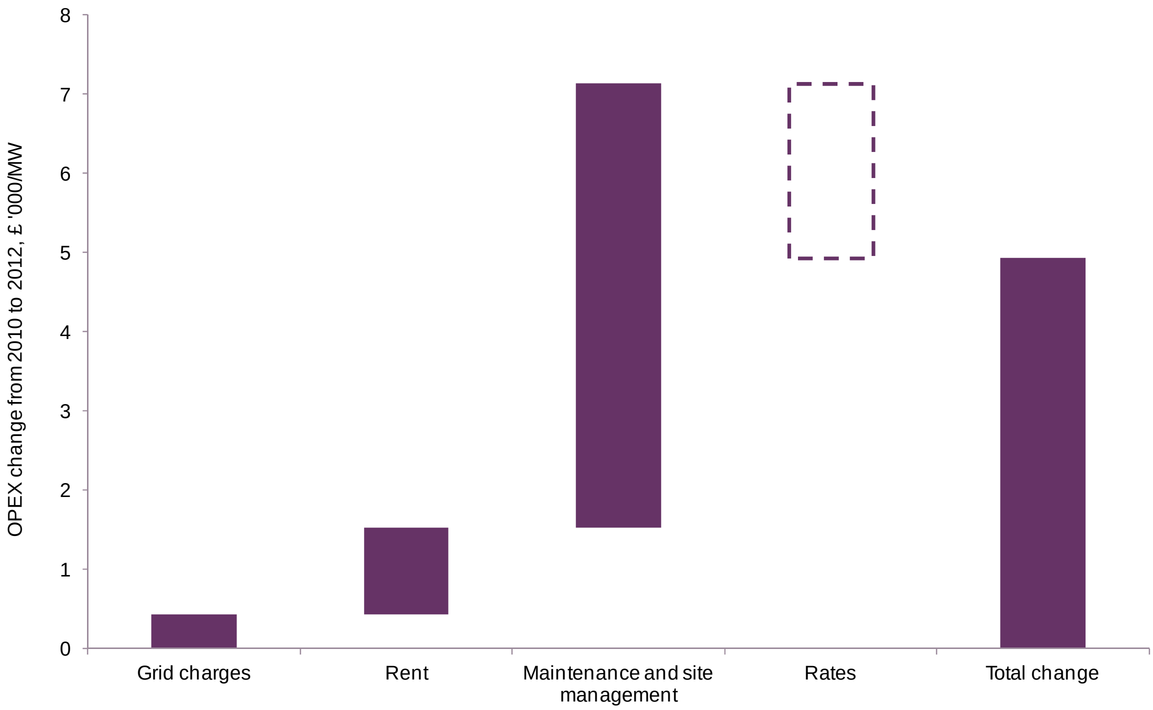
2.2.2 Operating costs

The relatively unchanged outlook for capital costs outlined above suggests that any significant change in the outlook for onshore wind costs is likely to be driven by developments in operating and other fixed costs. Recent revisions to the outlook for OPEX and transmission charges are examined below.

DECC's Banding Review analysis assumed a lower level of OPEX than that put forward in ARUP's central case, although the reasons for this adjustment are not described. DECC's revision to ARUP's assessment is equivalent to £4,200/MW per annum or 6% of fixed costs.

Figure 2.7 shows the average adjustment to expected future operating costs of the 19 potential projects in ScottishPower's development portfolio used in Oxera's analysis prepared for the Banding Review. The figure highlights that across potential projects in GB, there has been an upward revision in anticipated grid charges, rent and maintenance, and site management costs, alongside a reduction in expected rates. The net effect of these factors is to increase expected OPEX by around £5,000/MW per annum, driven in large part by the expected increase in maintenance and site management costs—which is broadly equivalent to the reduction applied by DECC to ARUP's cost assessment during the Banding Review.

Figure 2.7 Recent increase in OPEX outlook from 2010 to 2012



Note: The ScottishPower data represents developments over the 2011 to 2019 period (in 2012 prices).
Source: ScottishPower data, Oxera analysis.

This evidence suggests that it may be more appropriate to use ARUP's central case OPEX assumptions, as highlighted below in Table 2.3, rather than to rely on the Alternative case that includes DECC's unexplained OPEX reduction.

Table 2.3 ARUP central and alternative scenario cost projections

Operating costs (£'000/MW, 2011 prices)	2010	2015	2020
Central case	57	58	59
Alternative case	53	53	53

Note: Figures shown are for onshore wind greater than 5MW.
Source: ARUP.

In addition, community benefit is an increasingly important fixed cost that affects project economics, as reflected in DECC's call for evidence on this.[54] Typical levels of community benefit have risen to around £5,000/MW.[55] The assumptions used in the Banding Review are not made explicit—however, given the recent increase in these costs, the impact of a conservative estimate that costs have risen by around £1,000/MW per annum has been assessed, which is equivalent to an increase in the required support of around 0.01 ROC/MWh.

TNUoS

The transmission costs of a typical Scottish wind plant account for around 18–28% of annual fixed costs. Under the current arrangements, wind power generators also pay the same level of transmission charges as conventional generators.

Ofgem's Project TransmiT, a Significant Code Review (SCR) of the electricity transmission charging arrangements, set out to assess whether reform of the current arrangements is required. One of the recommendations in Ofgem's May 2012 conclusions was that the TNUoS charging methodology be amended so as to:

- better reflect the costs imposed on the electricity transmission network by different types of generators (in particular, renewable generators);
- take into account in an appropriate manner the potential Scottish island links that are currently being considered;
- take account of the development of HVDC links that will run parallel to the onshore network.

While these arrangements set the direction of travel for reform, there remains significant uncertainty about the exact implications of the possible changes in the level of transmission charges, as outlined in Ofgem's conclusions:

> This decision will not result in any changes to transmission charges at this stage but will start an industry led process to further develop an improved form of ICRP. Once this industry process is complete we will then be presented with the industry's amendment proposal, which we will decide whether to approve for implementation.[56]

Preliminary analysis was undertaken as part of Ofgem's SCR, which, as acknowledged by Ofgem, 'modelled one form of Improved ICRP and we expect the approach can be improved further'.[57] There have also been further developments since the undertaking of that analysis that have implications for any projection of future transmission charges, including changes to the generation background and the proposals for the forthcoming transmission price control period (RIIO-T1).

[54] DECC (2012), 'Onshore Wind – Call for Evidence. Part A – Community Engagement and Benefits', September.
[55] Since 2000, community benefits have increased from around £1,000/MW to around £5,000/MW, index linked for the operational life of the windfarm, although this may be subject to change should project economics alter significantly. For evidence of recent cost changes see ScottishPower (2012), 'Onshore wind call for evidence', November 20th.
[56] Ofgem (2012), 'Electricity transmission charging arrangements: Significant Code Review conclusions', May, p. 5.
[57] Ofgem (2012), op. cit., p. 5.

To assess the order of magnitude of these developments, Oxera has developed illustrative charging scenarios drawing on previous analysis commissioned by Ofgem, and recent announcements by National Grid on the impact of changes to the generation background and RIIO on charges for 2013/14. The impact of these illustrative charges and their projected profile over time on project economics is compared with the existing level of charges.

The analysis below first identifies different project types (by size and location) and highlights the reforms that will affect the TNUoS charges they face. This is followed by a more detailed description of the level of future charges.

Charging reform impacts by project type
The TNUoS liabilities of onshore wind projects vary depending on their size (ie, whether they are greater or less than 100MW), whether they are transmission-connected or embedded, and their location, as highlighted in Table 2.4. The table highlights that:

– for England and Wales transmission-connected projects, Scottish transmission-connected plant larger than 100MW, and all embedded generation plant larger than 100MW, the change in the outlook for transmission charges depends on the implementation of improved ICRP charges;

– for Scottish transmission-connected projects smaller than 100MW, Ofgem has recently extended the small generator discount to 2015/16 (worth around £8/kW per annum). The most favourable case for such plant would involve an indefinite extension of this discount, in addition to the improved ICRP charges;[58]

– embedded generation projects smaller than 100MW do not pay TNUoS charges, and are expected to remain unaffected by the currently proposed changes to the charging regime.

Table 2.4 TNUoS payments by project type

Project type	Initial outlook	Revised outlook
E&W transmission-connected Scottish transmission-connected >100MW GB embedded generation >100MW	National Grid's 2012/13 TNUoS charges (assumed flat real)	Improved ICRP and other revisions (see below)
Scottish transmission-connected <100MW	National Grid's 2012/13 TNUoS charges (assumed flat real)	Small generator discount applied to improved ICRP charges
Embedded generation <100MW	No TNUoS—embedded benefit	No TNUoS—embedded benefit

Source: Oxera.

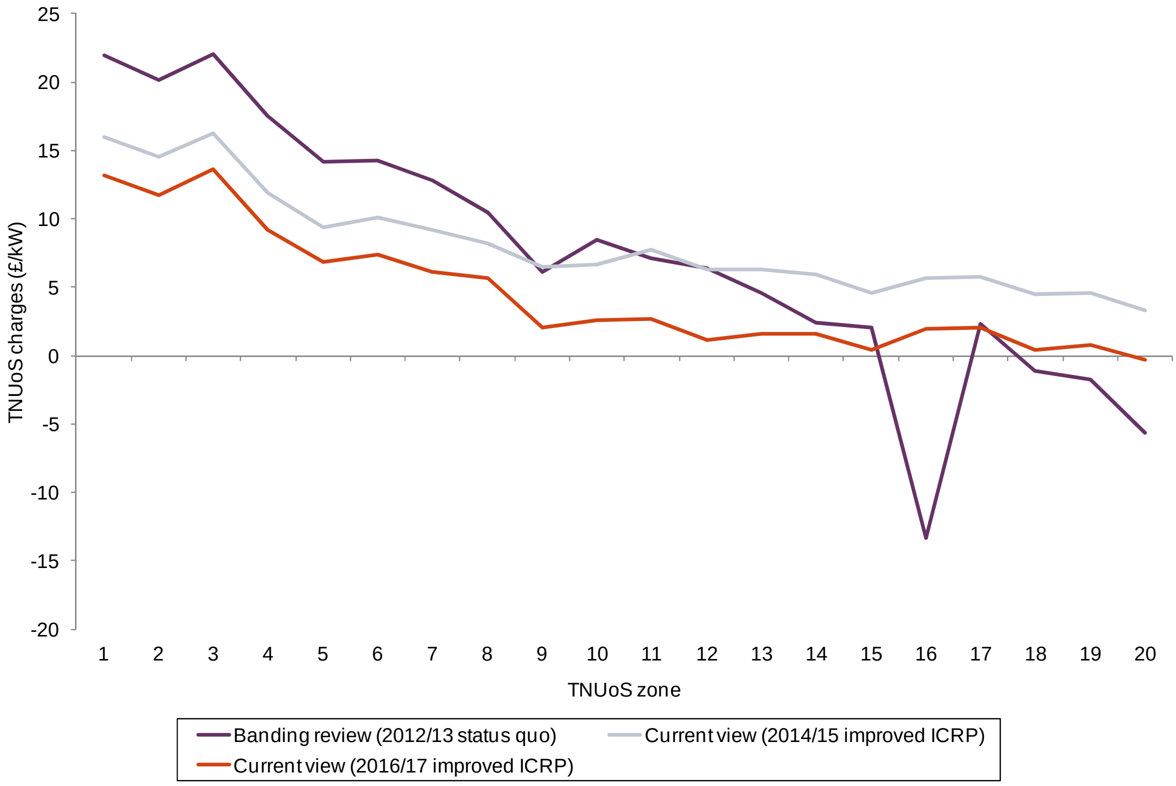
Under the improved ICRP model, transmission charges are to be separated into peak and annual charges. Intermittent generation will be required to pay annual charges only, and not peak charges. In addition, these annual charges will be scaled in proportion to the load factor of a given technology. This is likely to imply that TNUoS charges paid by intermittent generators will be substantially lower than those paid by conventional generators, although the impact relative to the status quo will be greatest where current TNUoS charges are positive and significant.

[58] Ofgem has decided to extend the small generator discount from March 2013 to March 2016. See Ofgem (2012), 'Decision and statutory consultation on extending the discount for small transmission connected generators set out in Standard Licence Condition C13 until 31 March 2016', October. The Oxera analysis applies this discount for the lifetime of relevant onshore wind projects.

Level of charges

Estimates of the change in the outlook for TNUoS charges are highlighted in Figure 2.8. This shows a general reduction in charges over time, particularly in northern zones.

Figure 2.8 Geographic rebalancing of generator TNUoS charges



Note: The improved ICRP charges refer to charges payable by onshore wind plant. All charges are in real 2012/13 prices.
Source: National Grid, Redpoint and Oxera analysis.

The illustrative charges shown in Figure 2.8 are reflective of the following effects.

– **Changes to the generation background and demand forecasts**—the Large Combustion Plant Directive is expected to result in coal plant closures (largely in England and Wales) in 2013/14. At the same time, peak demand is forecast to increase, with the majority of the increase taking place in England and Wales. These two factors are expected to lead to an increase in north to south electricity flows. As a result National Grid forecasts a relatively large increase in TNUoS charges in Scotland, a more moderate increase in northern and central England and Wales, with a decrease in southern England relative to 2012/13 levels.[59]

– **Impact of the Beauly to Denny transmission line** between northern and southern Scotland—this would enable more renewable energy to flow to southern Scotland and to do so through a shorter route. The commissioning of this line is expected to lead to a reduction in TNUoS charges in northern Scottish zones.

– **Impact of RIIO revenue increase—**transmission owners recover their allowed regulatory revenues through TNUoS charges. National Grid forecast the allowed revenue for transmission networks to increase by 25% over the RIIO price control period

[59] National Grid (2012), ‘A Discussion of Possible TNUoS Tariff Scenarios Under Project TransmiT’, April.

(2013–20) to meet required investment in networks. It estimated that this would result in increases in average TNUoS charges of 14% across GB.[60]

- **Impact of changes to expansion constants and factors**—TNUoS charges are a function of the cost of investing in the expansion of the transmission network.[61] The RIIO proposals indicate that the capital costs of some network components (eg, 400kV overhead lines) are likely to increase, although those for others (eg, cables) may decrease.
  - This is expected to result in an increase in TNUoS charges (of up to £2/kW) in Scottish zones, with a smaller decrease in charges in a number of England and Wales zones.
- **Impact of the Western HVDC link** between Scotland and Wales—this undersea link is more expensive than the existing overhead lines. It tends to increase year-round TNUoS charges in Scotland, and in northern England to a smaller extent, decreasing charges in the remainder of England and Wales.

The analysis above indicates the following broad conclusions.

- The outlook for onshore wind is in general improved across the majority of zones with the introduction of improved ICRP charges, although there are differences based on project location and type.
  - **Projects liable to pay TNUoS** are expected to benefit as a result of the introduction of improved ICRP charges.
  - **Scottish 'small generators'** could benefit even more if the recent extension of the small generator discount to 2015/16 were extended indefinitely.
  - **Small embedded generators** face no change as they are not required to pay TNUoS charges.

2.3 Cumulative impact of changes in revenue and cost drivers

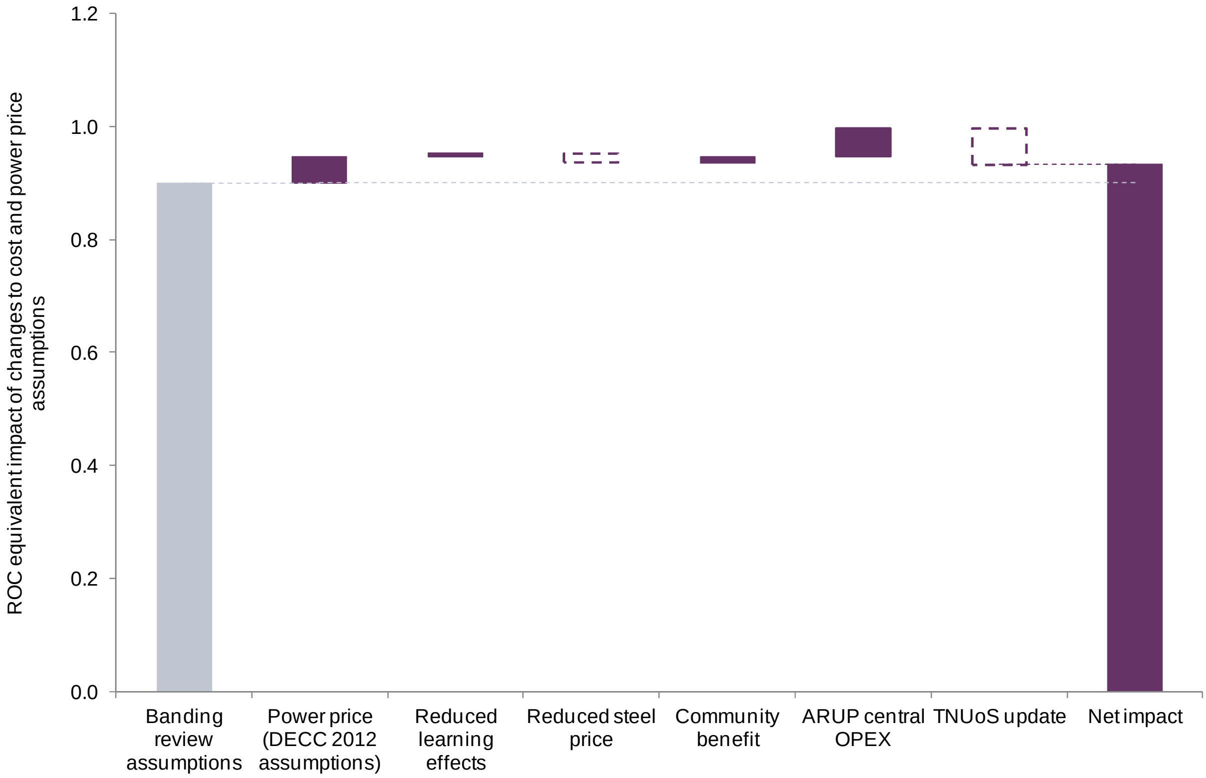
The analysis in this section suggests that, on balance, there has been a moderate decline in the outlook for onshore wind projects relative to the assumptions used in the Banding Review.

Figure 2.9 shows the cumulative effect of the key changes, and highlights that the changes are equivalent to a 0.03 ROC/MWh increase in required support for a representative 2014/15 project in South Scotland.

[60] National Grid (2012), 'Initial view of TNUoS tariffs for 2013/14', April.

[61] Drivers of TNUoS charges include the expansion constant and the expansion factor. The expansion constant is the cost of constructing 1km of 400kV overhead lines. The costs of other types of circuit which are stated relative to this are called expansion factors. The RIIO proposals indicate that the capital costs of 400kV overhead lines are rising, resulting in an increase in National Grid's estimates of the expansion constant from £11.7/MWkm to around £13/MWkm. In addition, the expansion factors for other overhead lines are also expected to increase, whereas that for cables is expected to decrease. Such factors could in turn lead to an increase in TNUoS charges of up to £2/kW in some Scottish zones (eg, North Scotland), with a smaller reduction in a number of England and Wales zones. See National Grid (2012), 'Changes to charging parameters at the start of price controls – Update', September.

Figure 2.9 ROC-equivalent impact of revised outlook, South Scotland, 2014/15 project (full TNUoS-paying plant)



Source: Oxera.

The two most significant adverse factors driving this change are the outlook for electricity prices and the upward revision in OPEX for potential projects. The outlook for other cost movements, such as the combined effects of movements in steel prices and learning effects, which drive the potential for capital cost reductions, appear relatively unchanged.

The impact of the adverse movement in the factors above is partially offset by the change in the expectation of lower transmission charges for wind that might be expected following Ofgem's review of charging arrangements under Project TransmiT—although the final impact of the transmission charging reforms will not become clear until after the recommendations of the Connection and Use of System Code (CUSC) working group have been published, and the options duly assessed by Ofgem.

Tables 2.5 and 2.6 highlight these individual effects and their overall impact on project IRRs and the impact on required support for a representative project in South Scotland. The tables highlight an overall net increase in required support of around 0.02–0.03 ROC/MWh.

Table 2.5 Summary of IRR and ROC-equivalent impact of revised outlook, South Scotland, 2014/15 project (full TNUoS-paying project)

	IRR impact (basis points)	ROC-equivalent required
Power price outlook	– 32	+ 0.05
Steel price outlook	+ 11	– 0.02
Reduced learning effects	– 4	+ 0.01
Community benefit	– 8	+ 0.01
ARUP central OPEX	– 36	+ 0.05
TNUoS discount	+ 47	– 0.06
Net impact	**– 22**	**+ 0.03**

Note: Totals may not equal the sum of individual effects shown owing to rounding. The net cost impact is equal to - 0.01 ROC.
Source: Oxera.

Table 2.6 Summary of IRR and ROC-equivalent impact of revised outlook, South Scotland, 2016/17 project (full TNUoS-paying project)

	IRR impact (basis points)	ROC-equivalent required
Power price outlook	– 25	+ 0.03
Steel price outlook	+ 12	– 0.02
Reduced learning effects	– 8	+ 0.01
Community benefit	– 8	+ 0.01
ARUP central OPEX	– 37	+ 0.05
TNUoS discount	+ 51	– 0.07
Net impact	**– 15**	**+ 0.02**

Note: Totals may not equal the sum of individual effects shown owing to rounding. The net cost impact is equal to + 0.01 ROC.
Source: Oxera.

The effects of transmission charging reform on project economics are not straightforward, and, because of the current and proposed structure of charges, are likely to vary by both region and project type.

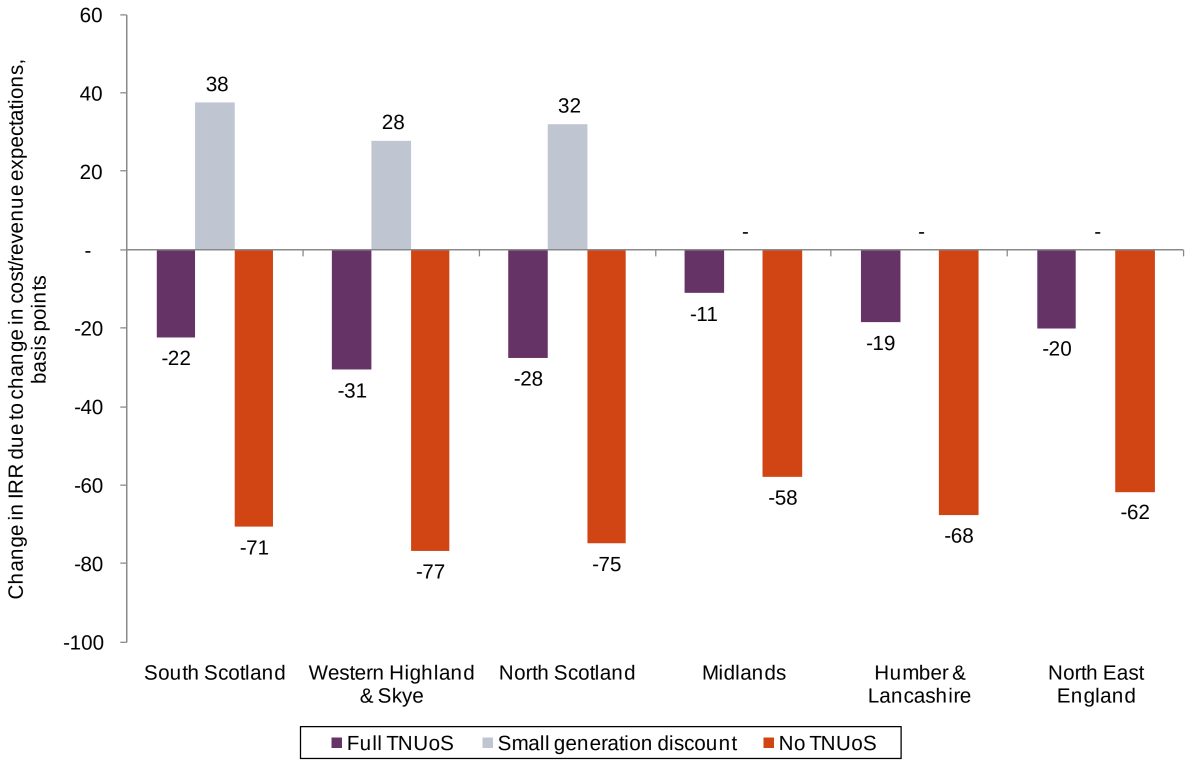
Figure 2.10 summarises the net impact of the change in outlook for onshore wind across the three representative project types that face different TNUoS treatment, and within the six most resource-abundant charging zones. It highlights that:

– the outlook for prospective TNUoS-paying projects has deteriorated across all regions, as the impact of lower TNUoS charges is outweighed by the adverse outlook for power prices, OPEX, and other costs;

– the outlook for projects entitled to the small generator discount in Scotland has improved. The most favourable case for such plant (which would involve an indefinite extension) would provide a benefit equivalent to around 0.08 ROC/MWh. This could subsequently outweigh the decrease in expected power price revenues and the adverse outlook for other costs;

– the outlook for small embedded generators that do not pay TNUoS charges has seen the largest deterioration across all regions, as there is no TNUoS benefit to offset the other adverse impacts.

Figure 2.10 Total IRR impact by project type in 2014/15 (selected zones)



Source: Oxera.

Overall outlook

Taking account of all of the cost categories discussed above, the overall outlook for costs across different project types is broadly unchanged (ie, the impact of the change in outlook across all of these cost factors is less than an equivalent change in support of 0.01 ROC/MWh)—based on a conservative assumption that future TNUoS discounts are offered to small Scottish generators beyond 2015/16. If such a discount were not maintained after that date, the average revised cost outlook for projects across Great Britain would be adverse.

This neutral or adverse cost outlook does not provide evidence to substantiate the need for a review of onshore wind support. This conclusion is reinforced by the deterioration in the revenue outlook, and suggests that there has been an adverse change in the overall outlook since the Banding Review.

3 Financing costs and hurdle rate impacts

Financing costs and hurdle rate impacts—key findings

The hurdle rate for onshore wind represents the forward-looking return required by project sponsors to invest in a potential project. The rate captures the returns required to compensate for 'systematic' risks, which investors cannot reduce by investing in several different projects, as well as project-specific risks, and other factors that affect investor behaviour.

A number of factors (outlined below) indicate that the current economic climate continues to place significant upward pressure on financing costs.

– Since the onset of the financial crisis, banks and credit agencies have looked for more robust credit metrics for borrowers, which have constrained the availability of debt finance. Capital spending limitations imposed by companies, together with a potential need to use more equity, have resulted in upward pressure on required returns and financing costs.

– There is considerable uncertainty about future macroeconomic conditions in the UK, reflecting the ongoing volatility in the eurozone, and there continues to be significant volatility in equity markets. This implies that investors are exposed to greater market risk and hence are likely to require a higher premium as compensation for exposure to additional risk.

– The volatility that is observed in equity markets would also be expected to translate into a higher cost of debt. This is because greater volatility in share prices is likely to reflect additional volatility in the underlying value of the assets, and implies that there is a greater likelihood of default.

– This uncertainty in macroeconomic conditions compounds the difficulties of accurately estimating future financing costs. Project sponsors will incorporate this elevated risk when determining the appropriate hurdle rate, which is likely to increase required returns.

These factors suggest that there is no evidence that hurdle rates have declined in recent years, or are expected to decline over the forthcoming Banding Review period.

3.1 Framework to assess the drivers of hurdle rates

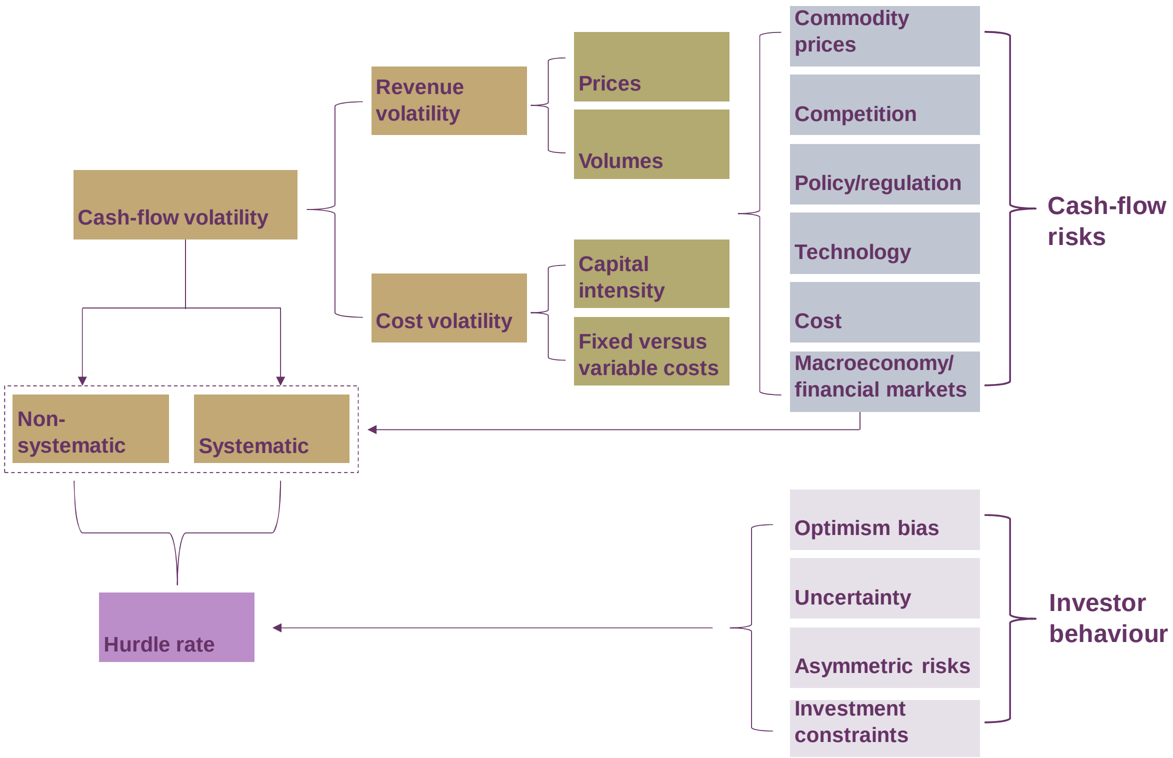
The hurdle rate for onshore wind represents the forward-looking return required by investors to invest in a potential project. The rate captures the returns required to compensate for 'systematic' risks, which investors cannot reduce by investing in several different projects, as well as 'idiosyncratic' risks associated with investment in onshore wind farms, in addition to factors that reflect investors' behaviour (such as the tendency to overestimate cash-flow projections).[62]

As shown in Figure 3.1, idiosyncratic and systematic risk factors will influence the volatility of cash flows associated with investments in onshore wind farms ('cash-flow risks'), which, together with characteristics of investors' behaviour, influence the hurdle rate.[63]

[62] The hurdle rate may therefore differ from the estimate of the cost of capital for onshore wind farms. The cost of capital is typically estimated with reference to the capital asset pricing model (CAPM). Under the CAPM, the cost of capital reflects systematic risks only, rather than idiosyncratic risks—ie, the model assumes that the market rewards only those risks that cannot be diversified (ie, systematic risks).

[63] Cash-flow risks are likely to translate into an increase in the volatility of either revenues or costs, implying an increase in cash-flow volatility. Under standard finance theory, there is a clear link between risk, which is measured by volatility, and returns required by investors. All else being equal, investors require compensation for greater variability in returns.

Figure 3.1 Overview of the determinants of the hurdle rate



Source: Oxera.

3.2 Implications of macroeconomic developments for required returns

Based on the framework above, this section provides an assessment of recent developments related to the macroeconomy and financial markets, and their implications for the returns required by investors.[64] Further evidence in support of these findings is presented in Appendix 1.

3.2.1 Conditions in debt markets remain tight

Since the onset of the financial crisis, banks and credit agencies have looked for more robust credit metrics for borrowers, which have constrained the availability of debt finance. Capital spending limitations imposed by companies, together with a potential need to use more equity, have resulted in upward pressure on required returns and financing costs. Evidence of tightening credit requirements is highlighted in recent research from the credit rating agencies:

> We have, in many cases, revised our financial credit metric targets in recent years. For example, E.ON AG (A/Negative/A-1), SSE PLC (A-/Stable/A-2), Gas Natural SDG S.A. (BBB/Stable/A-2), and Fortum Oyj (A/Negative/A-1) have received stricter guidance to maintain their current financial risk profiles, while we retain the same financial rating targets for Vattenfall AB (A-/Stable/A-2) and Iberdrola S.A. (A-/Stable/A-2), even though their financial risk profiles have recently been lowered by one category (from "intermediate" to "significant"). We believe that credit metric requirements are likely to continue to tighten, in particular for competitively exposed integrated power and gas companies.[65]

Evidence from the Bank of England also indicates that banks' longer-term financing costs have steadily increased since 2007, implying that they face elevated financing costs; this has

[64] An assessment of the other factors presented in Figure 3.1 is outside the scope of this assessment.

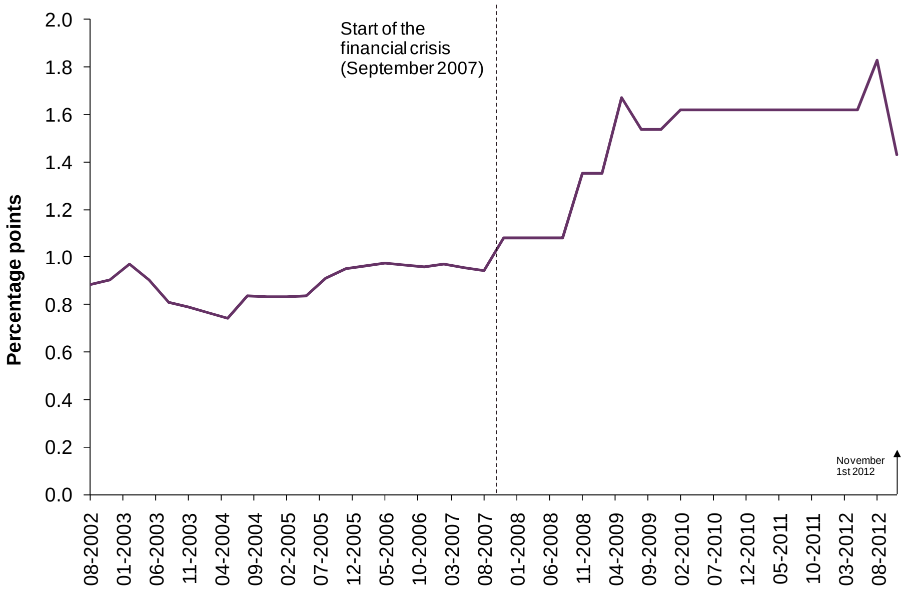
[65] Standard & Poor's (2012), 'Tough Market Conditions Keep 25 Top European Utilities Under Pressure', March 28th, p. 4.

contributed towards a tightening of credit conditions, with the availability of bank loans falling since the onset of the financial crisis.[66] According to the Bank of England, lenders recently reported that, with limited options for restructuring and alternative sources of financing, default rates are expected to rise.[67]

3.2.2 Significant uncertainty about future macroeconomic conditions

As acknowledged by the Bank of England, there continues to be significant uncertainty over future macroeconomic conditions in the UK.[68] As shown in Figure 3.2, the Bank of England's estimates of the degree of uncertainty around its own forecasts of GDP growth has increased sharply, and, despite the slight dip recently, remain significantly higher than before the onset of the financial crisis. This uncertainty in macroeconomic conditions compounds the difficulties of accurately estimating future financing costs, and project sponsors will incorporate this elevated risk when determining the appropriate hurdle rate.

Figure 3.2 Bank of England's estimates of the uncertainty associated with its own GDP growth forecasts



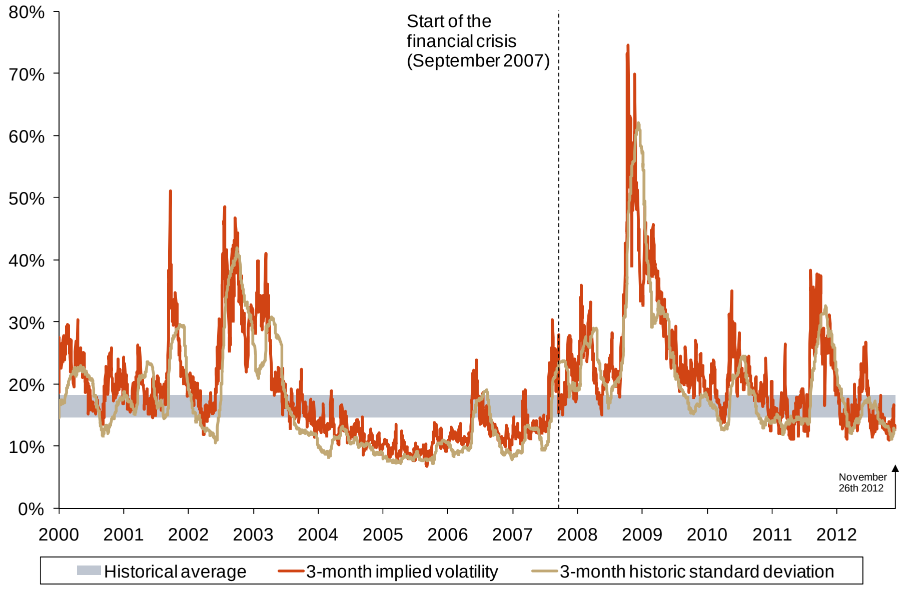
Note: This figure presents a measure of the dispersion of the Bank of England's quarterly GDP projections. The scale should be interpreted as a relative measure. The start of the financial crisis is represented by Northern Rock's request for liquidity support from the Bank of England.
Source: Oxera analysis, based on data from the Bank of England.

3.2.3 Equity markets remain volatile

Although both historical and forward-looking measures of equity market volatility have fallen since their peak in early 2009, there have been periods when volatility has been higher than the historical levels observed before the start of the financial crisis. As the eurozone crisis shows little signs of abating, there is no robust evidence to suggest that market volatility would be expected to diminish, or that it would not increase again, in the near term. This implies that investors will be exposed to higher market risk, and therefore would require a higher premium as compensation for greater exposure to this additional risk.

[66] Bank of England (2012), 'Inflation Report', August, pp. 13 and 15; and Bank of England (2012), 'Inflation Report', November, p. 17.
[67] Bank of England (2012), 'Credit Conditions Survey 2012 Q3', September.
[68] Bank of England (2012), 'Inflation Report', August, p. 6.

Figure 3.3 Implied and historical volatility of the FTSE 100 index



Note: The historical average is defined over the period prior to the financial crisis—ie, between 2000 and 2007. The start of the financial crisis is represented by Northern Rock's request for liquidity support from the Bank of England.
Source: Oxera analysis, based on Datastream.

The volatility observed in equity markets would also be expected to lead to a higher cost of debt because greater volatility in share prices is likely to reflect additional volatility in the underlying value of the assets.[69] This implies that there is a greater probability that the asset value will fall below the face value of debt (ie, that there is a greater likelihood of default).

3.3 Implications for the hurdle rate for investments in onshore wind

The ongoing financial turmoil and the associated volatility in financial markets imply that investors are likely to require a higher premium as compensation for exposure to additional risk.

From a market-wide perspective, the difficulty of estimating the hurdle rate and constraints on the availability of finance suggest that there is no evidence that the hurdle rate has declined, or is expected to decline over the forthcoming Banding Review period. In light of current conditions, there is no new evidence to support an improvement in financing costs, or a revision to the assumption adopted in the Banding Review for the hurdle rate for onshore wind.

DECC also suggests that the hurdle rate for onshore wind will decline in 2016/17 as a result of the perceived reduction in project risks associated with the parallel introduction of the new CfDs. However, as the introduction of CfDs will not affect the risks of projects within the current RO scheme,[70] there is no basis for altering support levels under the RO. Estimating the appropriate hurdle rate for projects receiving the proposed CfDs would require a more detailed review, including a consideration of:

– the construction risks of the technology involved;
– the timing and variability of CfD payments;
– contracting arrangements for the sale of electricity;

[69] Campbell, J. and Taksler, G. (2003), 'Equity Volatility and Corporate Bond Yields', *Journal of Finance*, **58**.
[70] DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013–2017 and the Renewables Obligations Order 2012', July 25th, p. 39.

- exposure to imbalance risks;
- provisions around change of law; and
- financing structures and returns required by investors in projects of similar risk.

4 Deployment impacts and effects of a potential banding revision

Banding and deployment scenarios—key findings

The impact of the revised outlook for onshore wind since the Banding Review could make an additional 3.3% of the deployment potential uneconomic to develop by 2016/17, equivalent to around 150MW or 0.35TWh.

This impact varies by project type (ie, size and grid connection):

– the deployment impact for small Scottish transmission-connected projects is positive (assuming there is an indefinite extension to the small generator discount), whereas there is an adverse effect on full-TNUoS-paying generators, and on embedded generation;

– more than half of the deterred projects are expected to be located in England and Wales. This is because a relatively high proportion of potential projects are expected to be embedded or located in transmission zones with relatively low or negative charges (where the possible charging reforms are likely to have a less beneficial impact).

A further reduction in RO banding from 0.9 ROC/MWh to 0.8 ROC/MWh in 2014/15 could make an additional 10% of the deployment potential uneconomic to develop, equivalent to around 430MW or 1.05TWh by 2016/17:

– deployment impacts in 2016/17, as well as in 2014/15 and 2015/16, are considered relevant on the basis that the support under future CfDs is likely to be set at a risk-adjusted level equivalent to that of the RO (or at least takes account of the level of support under the RO);

– around 75% of the reduction in deployment due to a reduction in RO banding to 0.8 ROC/MWh is likely to be in Scotland.

The overall impact of decreasing onshore banding from 0.9 ROC/MWh to 0.8 ROC/MWh could lead to an increase in annual net support costs of around £20m. This is based on the assumption that a reduction in onshore wind deployment would be replaced by relatively more expensive offshore wind in order for the UK to maintain progress towards its 2020 renewables target. This is consistent with DECC's position that offshore wind represents the marginal cost of meeting the 2020 target.

This section sets out Oxera's analysis of the deployment impact of the revised outlook for revenues and key cost drivers for onshore wind discussed in section 2. The impact of a further reduction in onshore wind support from 0.9 ROC/MWh to 0.8 ROC/MWh is assessed from a regional and UK-wide perspective, and in terms of its impact on overall support costs for renewables.

4.1 Impact on deployment

The results described below are based on discounted-cash-flow models of representative potential onshore wind projects. The analysis updates that previously undertaken by Oxera to input into the Banding Review,[71] which used an assessment of the resource potential combined with the variation in costs and capacity factors of potential projects across GB transmission charging zones.

[71] Oxera (2011), 'Banding scenarios: impacts on onshore wind deployment', June; Oxera (2011), 'Banding scenarios: impacts on onshore wind—supplementary note', July 28th; and Oxera (2012), 'Assessment of DECC's onshore wind banding proposal', January 12th.

4.1.1 Impact of revised cost and revenue outlook

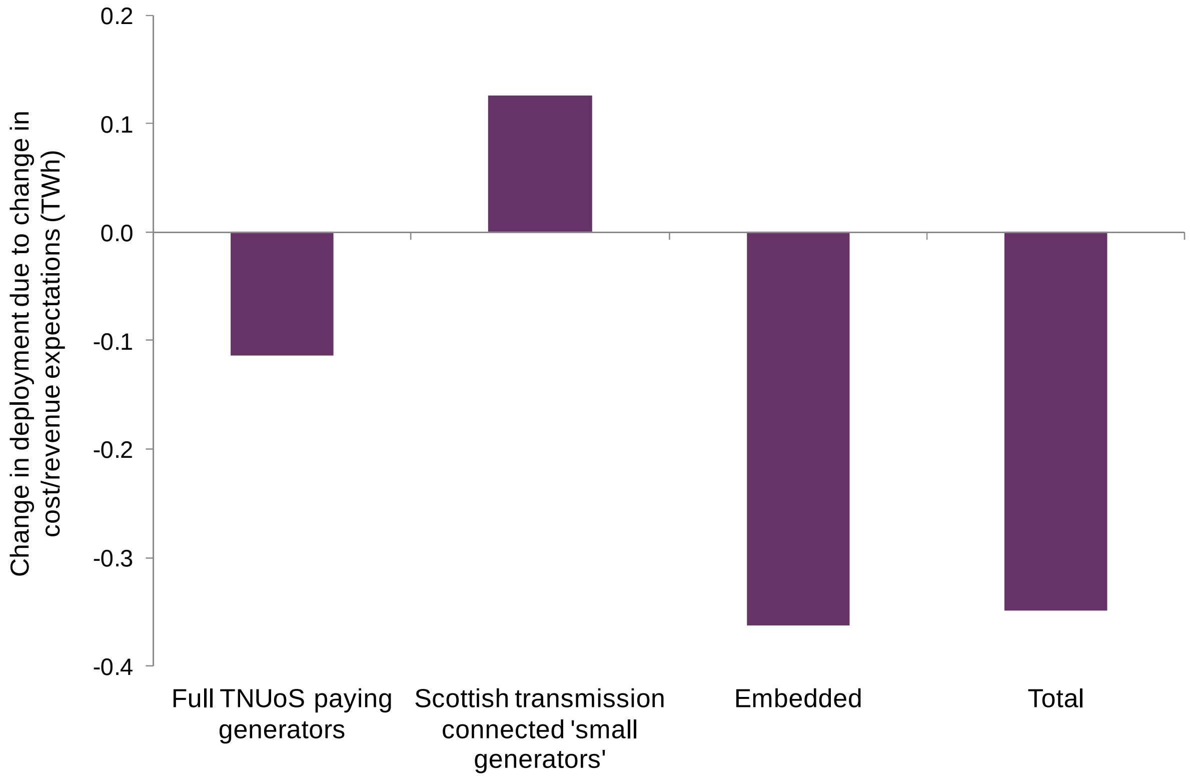
As highlighted in section 2, the outlook for both revenues and costs for onshore wind developers has changed since the evidence for the recent Banding Review was collated. In particular:

– projected revenues are lower due to the revised outlook for electricity prices;
– the outlook for CAPEX remains relatively unchanged, although there is a risk that the cost reductions from learning effects previously assumed might not materialise;
– OPEX projections are higher due to increases in expected maintenance and site management costs;
– community benefit is an increasingly important fixed cost that affects project economics, as reflected in DECC's call for evidence;
– recent proposals on transmission charging could imply that TNUoS charges might be reduced for intermittent generation technologies, albeit this effect is expected to vary regionally and by project type.

The net effect of this revised outlook is a reduction in the IRR of a representative TNUoS-paying onshore project in South Scotland, by around 15–22 basis points, or, equivalently, an increase in the required support for a representative project in South Scotland by around 0.02 to 0.03 ROC/MWh.

The aggregated impact of this revised outlook for different onshore wind project types and across transmission charging zones in Great Britain is shown in Figure 4.1.

Figure 4.1 Impact of change in revenue and cost expectations on deployment by 2016/17



Source: Oxera analysis.

The figure highlights that the revised revenue and cost outlook is expected to deter around 0.35TWh of onshore wind output in the period 2014/15 to 2016/17. Around 30% (or 0.1TWh) of this reduction is projected to be in Scotland.

4.1.2 Impact of further banding revisions

Beyond the impact of the revised outlook for onshore revenues and costs, this section assesses the impact of further reducing the level of support to onshore wind from 0.9 ROC/MWh to 0.8 ROC/MWh on the regional deployment of onshore wind. There is a significant regional variation in deployment as a result of the wide variation in resource potential, costs and load factors across and within TNUoS zones.

The analysis presented below is based on the same methodology as used in Oxera's June 2011 report.[72] Tables 4.1 and 4.2 show the impacts of the revised revenue and cost outlook, as well as a potential reduction in onshore wind support by a further 0.1 ROC/MWh, to 0.8 ROC/MWh in 2014/15.

Table 4.1 Reduction in renewable deployment (%)

TNUoS zone	Share of resource potential (%)	Zone name	Impact of cost and revenue changes (0.9 ROC/MWh) (%)	Additional impact of reduction from 0.9 to 0.8 ROC/MWh (%)
1	13.9	North Scotland	–1.4	–11.3
2	8.0	Peterhead	–0.1	–11.0
3	15.8	Western Highland & Skye	–0.3	–10.1
4	3.6	Central Highlands	–2.6	–11.3
5	8.1	Argyll	–2.6	–12.0
6	3.1	Stirlingshire	–2.6	–12.0
7	14.3	South Scotland	–2.3	–11.1
8	1.3	Auchencrosh	–2.0	–11.9
9	3.1	Humber & Lancashire	–9.8	–10.8
10	2.1	North East England	–10.5	–12.2
11	0.0	Anglesey	0.0	0.0
12	0.1	Dinorwig	–9.5	–11.3
13	7.1	South Yorks & North Wales	–9.1	–10.8
14	9.0	Midlands	–8.9	–10.6
15	8.0	South Wales & Gloucester	–1.6	0.0
16	0.4	Central London	–1.6	0.0
17	0.2	South East	–1.6	0.0
18	0.3	Oxon & South Coast	–1.6	0.0
19	0.9	Wessex	–13.6	–0.5
20	0.8	Peninsula	–12.9	–16.4

Source: Oxera analysis.

[72] Oxera (2011), 'Banding scenarios: impacts on onshore wind deployment', June.

Table 4.2 Reduction in renewable deployment (MW and TWh)

TNUoS zone	Zone name	Impact of cost and revenue changes (0.9 ROC/MWh)		Additional impact of reduction from 0.9 to 0.8 ROC/MWh	
		MW	TWh	MW	TWh
1	North Scotland	–8	–0.02	–64	–0.16
2	Peterhead	0	0.00	–34	–0.09
3	Western Highland & Skye	–2	–0.01	–62	–0.17
4	Central Highlands	–4	–0.01	–18	–0.04
5	Argyll	–9	–0.02	–40	–0.10
6	Stirlingshire	–3	–0.01	–15	–0.04
7	South Scotland	–15	–0.03	–72	–0.17
8	Auchencrosh	–1	0.00	–6	–0.02
9	Humber & Lancashire	–14	–0.03	–15	–0.03
10	North East England	–9	–0.02	–11	–0.03
11	Anglesey	0	0.00	0	0.00
12	Dinorwig	–1	0.00	–1	0.00
13	South Yorks & North Wales	–30	–0.07	–36	–0.08
14	Midlands	–38	–0.08	–45	–0.10
15	South Wales & Gloucester	–6	–0.01	0	0.00
16	Central London	0	0.00	0	0.00
17	South East	0	0.00	0	0.00
18	Oxon & South Coast	0	0.00	0	0.00
19	Wessex	–6	–0.01	0	0.00
20	Peninsula	–5	–0.01	–6	–0.01
Scotland		–42	–0.10	–312	–0.79
England & Wales		–109	–0.25	–114	–0.26
Total		**–152**	**–0.35**	**–426**	**–1.04**

Source: Oxera analysis.

The tables above indicate that the impact of changes to revenue and cost expectations would reduce onshore wind deployment by around 0.35TWh over the period 2014/15 to 2016/17 in Great Britain (of which 0.1TWh could be deterred in Scotland).

Moreover, the tables show that the impact of reducing onshore wind support from 0.9 ROC/MWh to 0.8 ROC/MWh, would deter a further 1.05TWh (430MW) of onshore wind deployment over the same period in Great Britain. Of this deterred volume, around 0.8TWh (310MW) is estimated to be deterred in Scotland. The changes in RO banding affect Scottish projects more than the recent revisions to the changes in revenue and cost outlook for two reasons:

– the impact of the recent deterioration in some of the cost and revenue drivers for small Scottish transmission-connected plant was offset to a greater degree by changes in the outlook for transmission charges compared with projects in England and Wales;
– the impact of changes in RO support adversely affects the revenues of projects across all regions, and leads to greater deployment effects in Scotland where there is greater resource potential.

It is important to note that this volume of deterred deployment would not be expected to be recovered after 2016/17 following the introduction of CfDs, if for example, the terms of these contracts are set to provide support at levels equivalent (on a risk-adjusted basis) to the support available under the RO (or at least take account of the level of support under the RO).[73]

4.2 Impact on overall renewable generation support costs

This section presents Oxera's analysis of the overall impact on the net support costs associated with the deployment impacts discussed in section 4.1. The analysis is based on the assumption that a reduction in onshore wind deployment is replaced by relatively more expensive offshore wind in order that the UK maintains progress towards its 2020 renewables target. This is consistent with DECC's position in the Banding Review:

> To support the renewable generation that we need to meet the 2020 target, the most expensive technology we need to deploy is offshore wind. This technology needs 2 ROC/MWh to deploy, and therefore this level of support is the marginal cost of meeting the target.[74]

Figure 4.2 below shows that decreasing onshore banding from 0.9 ROC/MWh, to 0.8 ROC/MWh could lead to an increase in net support costs of around £21m per annum. This reflects:

– a decrease in onshore support costs on the basis of lower levels of support provided to the onshore wind projects that do get built, and a reduction in the total number of onshore projects that receive support;

– an increase in the number of offshore projects that receive support (based on a conservative estimate that all additional projects receive support at 1.8 ROC/MWh);

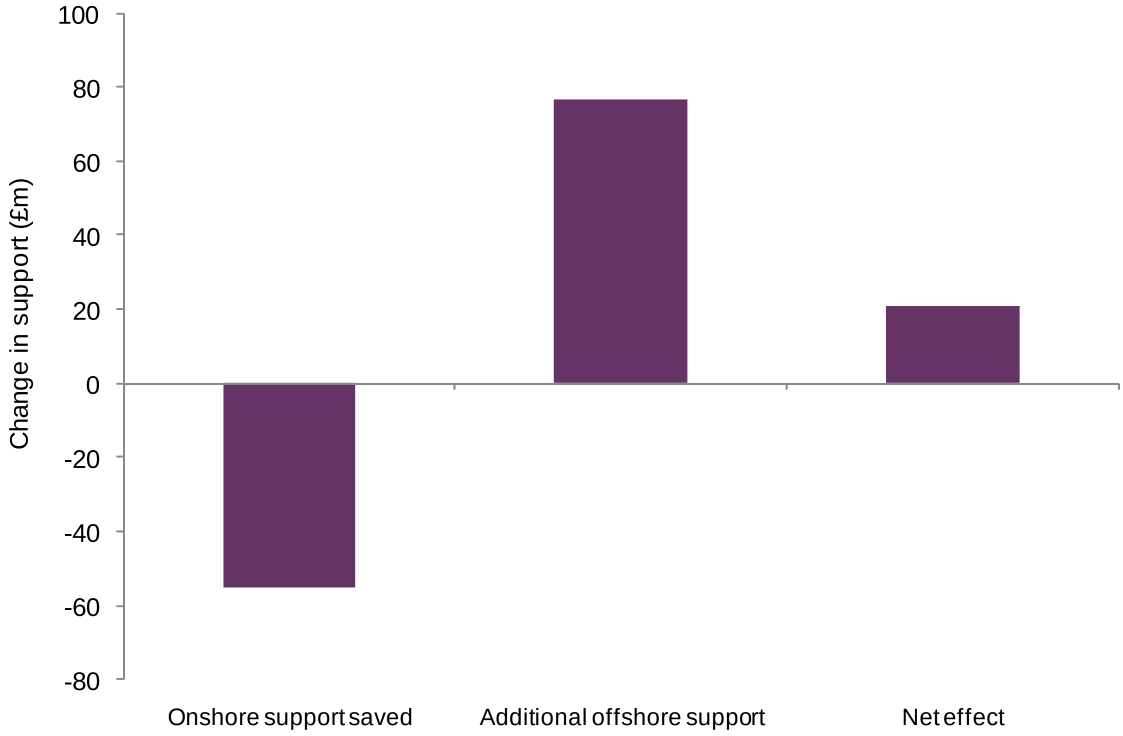
This cost is offset by a small decrease (around £1m per annum) in net transmission costs owing to the reduction in onshore transmission reinforcement required following the replacement of onshore with offshore wind—although there may be a limited incremental impact of small regional changes in onshore deployment on transmission costs.[75] The overall impact would be to increase consumer costs by around £20m per annum.

[73] A key motivation of the introduction of CfDs is to reduce project sponsors' exposure to power prices, and thereby lessen cash-flow volatility, and hence the required rate of return. DECC has suggested that such reductions in risk will translate into the need for lower support payments.

[74] DECC (2011), 'Consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', October, p. 11.

[75] Unlike the associated onshore transmission costs, offshore transmission costs are charged directly to individual projects and reflected in offshore wind support costs, rather than being captured as part of the costs of the transmission network, and hence socialised across all network users in TNUoS charges.

Figure 4.2 Net support costs resulting from a reduction from 0.9/MWh to 0.8 ROC/MWh (excluding transmission cost impacts)



Source: Oxera.

5 Conclusions

Building on Oxera's June 2011 report,[76] this report has set out an assessment of the change in outlook for prospective onshore wind projects relative to the analysis undertaken by DECC that was used to inform the conclusions of the Banding Review.

The report has focused on the change in outlook for both the revenues and costs of prospective projects (as any review of onshore support levels would require an assessment of expected revenues, consistent with the statutory provisions in the Renewables Obligation Order). The report has also provided an assessment of the potential impact of a possible further revision to the level of RO support on total deployment and the associated cost to consumers.

Revised cost and revenue outlook

The analysis suggests that there is an overall adverse change in the outlook for potential onshore wind projects that could be deployed during the Banding Review period.

The overall outlook for costs across different project types is broadly unchanged (ie, the impact of the change in outlook across all of the cost factors is less than an equivalent change in support of 0.01 ROC/MWh)—based on a conservative assumption that future TNUoS discounts are offered to small Scottish generators beyond 2015/16. If such a discount were not maintained after that date, the average revised cost outlook for projects across Great Britain would be adverse.

This neutral or adverse cost outlook does not provide evidence to substantiate the need for a review of onshore wind support. This conclusion is reinforced by the deterioration in the revenue outlook, and suggests that there has been an adverse change in the overall outlook since the Banding Review.

This revised outlook for onshore wind since the Banding Review reflects a combination of changes to DECC's assumptions around key determinants of electricity prices, changes in the outlook for future operating costs, and changes in the outlook for transmission charges (although there remains some uncertainty as to the precise outcome of this). In particular:

– projected revenues are lower due to the revised outlook for electricity prices;

– the outlook for CAPEX remains relatively unchanged, although there is a risk that the cost reductions from learning effects previously assumed might not materialise;

– OPEX projections are higher due to increases in expected maintenance and site management costs;

– community benefit is an increasingly important fixed cost that affects project economics, as reflected in DECC's call for evidence;

– recent proposals on transmission charging reform could lead to lower TNUoS charges for wind projects.

[76] Oxera (2011), 'Banding scenarios: impacts on onshore wind deployment', June.

The regional effects of transmission charging reform on project economics is not straightforward, and, owing to the current and proposed structure of charges, is likely to vary both by region and project type.

Deployment impacts and effects of a potential banding revision

The net overall impact of these changes could be to deter around 0.35TWh (150MW) of potential projects by 2016/17. The change in outlook for small Scottish transmission-connected plant is positive (assuming an indefinite extension of the small generator discount), whereas there is an adverse effect on the deployment of full TNUoS-paying generators, and the most adverse change in outlook is for embedded generation.

A reduction in RO banding from 0.8 ROC/MWh to 0.9 ROC/MWh in 2014/15 could make an additional 10% of the deployment potential uneconomic to develop, equivalent to around 430MW or 1.05TWh by 2016/17. The analysis shows that:

– deployment impacts in 2016/17, as well as in 2014/15 and 2015/16, are considered relevant on the basis that the support under future CfDs will be set at a risk-adjusted level equivalent to that of the RO (or at least takes account of the level of support under the RO);

– around 75% of the reduction in deployment due to such a further reduction in RO banding would be likely to be in Scotland.

The overall impact of decreasing onshore banding by a further 0.1 ROC/MWh could lead to an increase in consumer costs of around £20m per annum. This is based on the assumption that a reduction in onshore wind deployment would be replaced by relatively more expensive offshore wind in order for the UK to maintain progress towards its 2020 renewables target. This is consistent with DECC's position that offshore wind represents the marginal cost of meeting the 2020 target.

In summary, the revised cost outlook for onshore wind does not provide evidence to substantiate the need for a review of support levels. Indeed, if the change in revenue outlook is also considered, there is evidence to suggest that there has been an overall adverse change in the outlook for onshore wind since the Banding Review. A reduction in support from 0.9 ROC/MWh to 0.8 ROC/MWh could make an additional 10% of the deployment potential uneconomic to develop (equivalent to around 430 MW, with the majority of deterred projects in Scotland)—and lead to an increase in consumer costs of around £20m per annum.

A1 Financing costs and hurdle rate impacts

Supplementary to the evidence presented in section 3 about the hurdle rate for investments in onshore wind farms, this appendix presents further evidence to illustrate that, in light of current market conditions, it would not be appropriate to revise downwards the adopted estimate of the hurdle rate.

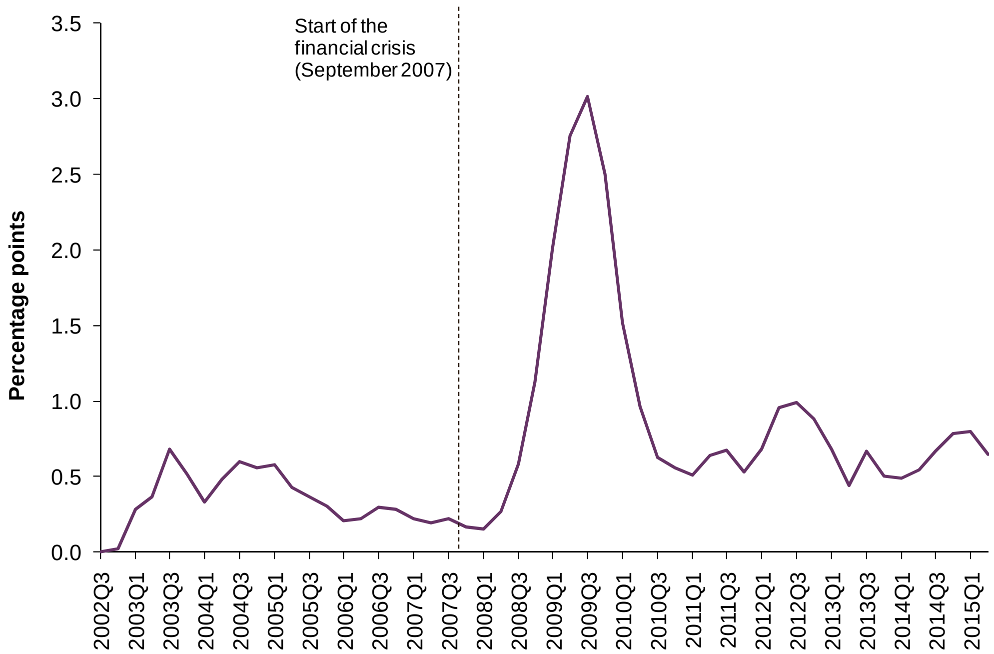
A1.1 Significant uncertainty about future macroeconomic conditions

Building on the evidence presented in section 3.2.2, Figures A1.1 to A1.2 provide further evidence to show that uncertainty around the Bank of England's GDP growth forecasts has increased significantly since the start of the financial crisis in late 2007, and, in particular, since the onset of the eurozone debt crisis. Indeed, the Bank of England has acknowledged that:

> The outlook for UK growth remains unusually uncertain. The greatest threat to the recovery stems from the risk that an effective policy response is not implemented sufficiently promptly in the euro area to ensure that the adjustments in the level of debt and competitiveness required by some member countries occur in an orderly manner.[77]

This uncertainty will compound the difficulties of accurately estimating the hurdle rate, implying that investors are likely to allow a 'margin for error' when estimating the hurdle rate.

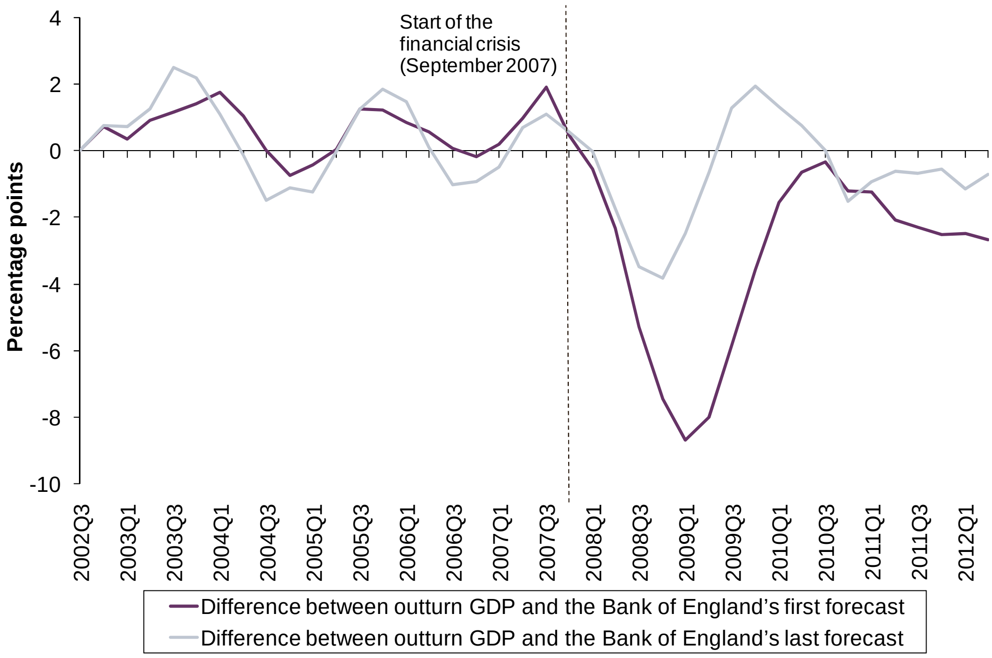
Figure A1.1 Variability of the Bank of England's GDP growth forecasts, as measured by the standard deviation of their forecasts



Note: The figure reports the standard deviation of the Bank of England's GDP forecasts for each quarter. The start of the financial crisis is represented by Northern Rock's request for liquidity support from the Bank of England.
Source: Oxera analysis, based on data from the Bank of England.

[77] Bank of England (2012), 'Inflation Report', August, p. 6.

Figure A1.2 Variability of the Bank of England's GDP growth forecasts, as measured by the difference between their forecasts and outturn GDP growth

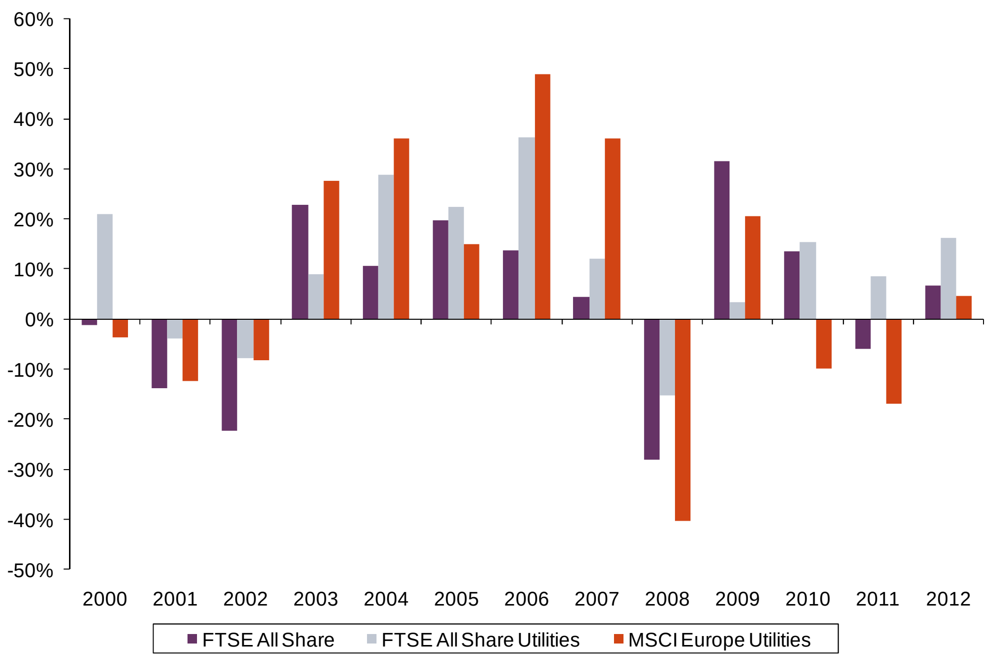


Note: The figure shows the difference between outturn GDP growth and the Bank of England's first and last forecasts for each quarter. The start of the financial crisis is represented by Northern Rock's request for liquidity support from the Bank of England.
Source: Oxera analysis, based on data from the Bank of England.

A1.2 Equity markets remain volatile

As highlighted in section 3.2.3, equity markets remain volatile, with returns on UK and European indices fluctuating from positive to negative, particularly since the intensification of the eurozone debt crisis (see Figure A1.3). Higher volatility implies that investors could be exposed to greater risk, and therefore would require higher returns.

Figure A1.3 Volatility of returns on equity indices in the UK and Europe



Note: The percentage change in total returns is calculated as average returns for December over average returns for January in each year, except for 2012, where the percentage change in total returns is calculated as average

returns for November over average returns for January in that year. The total returns index reflects changes in both the capital gains and any cash distributions, such as dividends, which are assumed to be reinvested back into the index. The estimates presented for 2012 reflect data over the year to date.
Source: Oxera analysis, based on Datastream.

Park Central
40/41 Park End Street
Oxford OX1 1JD
United Kingdom

Tel: +44 (0) 1865 253 000
Fax: +44 (0) 1865 251 172

Stephanie Square Centre
Avenue Louise 65, Box 11
1050 Brussels
Belgium

Tel: +32 (0) 2 535 7878
Fax: +32 (0) 2 535 7770

200 Aldersgate
14th Floor
London EC1A 4HD
United Kingdom

Tel: +44 (0) 20 7776 6600
Fax: +44 (0) 20 7776 6601

www.oxera.com