



Implementation of the EU 2020 Renewables Target in the UK Electricity Sector: RO Reform

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Executive Summary

Context

Under the EU Climate-Energy Package, adopted on 6 April 2009, the UK is committed to sourcing 15% of energy from renewable sources by 2020. This represents a major challenge across the economy, and in the electricity sector a massive increase in large scale renewable generation capacity will be required. This will cost some £20 billion in investment between now and 2020, and add perhaps £37 to an average domestic customer's annual electricity bill by 2020.

On 26 June 2008, the Department of Business, Enterprise & Regulatory Reform (BERR) published its Renewable Energy Strategy Consultation, which laid out potential options for meeting the UK's target. For centralised electricity, the Consultation considered a range of different financial support schemes, and concluded that the Renewables Obligation (RO) should be retained as the prime mechanism for incentivising large scale renewables. It recognised that a minimum level of modifications to the RO would be needed in light of the target, and also identified a number of possible additional changes that could lead to further improvements.

Scope

The scope of this study for the Department of Energy and Climate Change (DECC) was to assess options for both the minimum and potential additional changes to the RO, with a goal of achieving around 28%-29% of electricity from renewable sources by 2020. These options include the removal of the current 20% limit, extending the duration of the scheme, extension of the annual fixed targets, adjusting the "Headroom" value and, more radically, linking rewards from the RO to wholesale electricity prices in order to stabilise overall revenues for generators and to limit the costs to consumers where electricity prices rise. We have assessed the range of potential reforms, short-listed the most promising of these for quantitative analysis, and considered potential investor and implementation issues.

There is a plethora of other considerations that will have a large bearing for the UK in meeting its target, including planning issues, grid expansion and connection, and supply chain growth. Our base modelling assumes that sufficient progress is made in these areas to enable a much higher deployment rate than is currently the case. Were this not to materialise, it is unlikely that renewable generation would exceed around 17% by 2020.

This work did not consider the development or impact of more general decarbonisation policies. For example, subsequent to our analysis, the Government has proposed incentives for large scale carbon capture and storage (CCS) demonstration plant, together with potential future carbon emissions restrictions on new coal generation. Policy developments such as these may have bearing on the future form of the RO.

Minimum Change reference case

We developed a 'Minimum Change' policy Option that, given a Base Case set of assumptions, delivered 28% renewable generation by 2020. This extends the duration of the RO to 2037, removes the 20% cap, and increases the size of the Obligation each year (after the current period of annual targets ends in 2015/16) to be 8-10% higher than the forecast of eligible generation (the 'Headroom' mechanism). This formed our reference case against which to evaluate other possible RO reforms (Options). Subsequent to

the completion of the main part of the analysis, DECC identified a 29% target as a lead scenario for its Renewable Energy Strategy, and a sensitivity analysis was performed against this¹.

Current Headroom sets the Obligation size at 8% above forecast eligible renewables output (where this exceeds annual fixed targets). The intention is to ensure that, even in a year where wind levels were higher than average, the number of ROCs issued does not exceed the Obligation size (with a corresponding fall in the price to below Buy-out). Our analysis indicates that, as the renewables mix changes and with banding up of some technologies, this would need to be increased gradually to 10% to accommodate a greater expected volatility in output.

Our modelling suggests that extending annual Fixed Targets beyond 2015/16 would not be beneficial. In our Base Case, deployment levels mean that the targets are generally exceeded, leaving Headroom to set Obligation size. In our Low Case, the reduction in deployment creates a shortage of ROCs compared to the target, and an increase in ROC price – but this does little to simulate new build, leading merely to higher rents for those projects that are built.

Technology banding levels are a key lever within the RO framework. To achieve 28% in the Minimum Change Base Case we assumed an increase for marine technologies in 2013, to 2 ROCs for offshore wind and 3 ROCs for wave and tidal. (Our analysis pre-dated the announcement in the 2009 Budget of 2 ROCs for offshore wind projects committed in 2009/2010, and 1.75 ROCs the following year.) We then held these constant when modelling other Options and Cases (other than sensitivities). This makes for a clearer comparison of the robustness of policies in delivering efficiently to a target, as we do not attempt to ‘correct’ outcomes retrospectively that deliver more or less renewables by adjusting banding levels.

Our Price Shocks Case, with three very high, but short-lived, price ‘spikes’, was designed to test the efficiency of different Options. Under the Minimum Change Option, economic rents increase by £7bn on a net present value basis relative to the Base Case. (There is no corresponding benefit in deployment since the price spikes are too short to influence investment decisions.) Our Low Case tested effectiveness of Options when commodity prices fall (by more than plant capital costs) and stay low. Under these assumptions, renewables generation reaches only 22% by 2020 under the Minimum Change Option (compared to 28% in the Base Case). The ability to band up under the Minimum Change Option to compensate for lower electricity prices could reduce this risk to effectiveness, although it is a relatively blunt tool. Furthermore, it risks reducing the efficiency of the mechanism if electricity prices were subsequently to rise, by which point the higher bands would be ‘locked in’ for those plant that were already operational with no mechanism to claw back the economic rents that would accrue.

Revenue stabilisation options within the RO

A further objective of our work was to assess possibilities for adapting the support mechanism to stabilise overall revenues for renewable generators, thus potentially improving the efficiency of the RO by reducing the risk to customers of excessive economic rents, whilst increasing its effectiveness by reducing downside risk for investors. The RO is a ‘premium’ subsidy for generators, who still sell their power output on the wholesale market. Whilst there is variation in the ROC price, this is relatively small compared to historic volatility in electricity prices. Where prices rise, then the subsidy paid may be higher than needed, with generators benefiting from rents at the expense of consumers. Likewise, if prices fall, then the subsidy may be insufficient to attract sufficient new development. As a further potential benefit, the reduced revenue risk for generators could make financing easier and lower cost.

¹ The results of this sensitivity analysis are described in Section 4.12.3.

There are two main ways in which the RO may be amended to achieve stabilisation: the setting of the Buy-out price, and the way in which bands are set. In each case the intent would be to change the price or band level inversely to the electricity price – decreasing subsidy to generators where wholesale revenues are rising and vice versa. Both are possible (albeit complex) changes, but the former affects all plant, whilst the latter would only apply to new plant. Since adjustments to the Buy-out price would breach the ‘grandfathering’ principle for existing plant (and have wider ramifications for investor confidence) we did not consider these Options in detail. The ‘Band Indexation’ Options would change the number of Renewable Obligation Certificates (ROCs) issued to technologies within each band on an annual basis, increasing the amount in low electricity price years and decreasing the amount in high electricity price years. The Obligation size is then adjusted up or down respectively to maintain a target ‘Headroom’ level, and leave the value of ROCs largely unchanged. Given that primary legislation would be required to introduce such a change, we assume it would not come into effect until 2013.

We compared the Band Indexation Option to the Minimum Change Option. In the Base Case, with easier financing reflecting the reduced risk, Band Indexation is more effective, achieving nearly 30% renewables generation in 2020 (2% up from Minimum Change). The benefit to effectiveness is even more apparent under the Low Case with deployment only falling back to 27%, compared to 22% under Minimum Change, though relatively more subsidy is paid for the additional build, reducing the efficiency. The stabilisation mechanism restrains rents in the Price Shocks Case (by £6bn compared to Minimum Change) by reducing subsidy in the ‘spike’ years.

The modelling results therefore support the proposition that stabilisation of total revenues may be beneficial in improving the effectiveness and efficiency of the mechanism under certain circumstances. However, the complexity of the formulae required to achieve the stabilisation, and the counter-intuitive nature of an Obligation size changing year to year in a manner unrelated to any target level, is a serious implementation concern. It could undermine credibility, and may appear to investors to represent an imperfect solution heralding more radical changes at a later date, creating uncertainty and possibly leading to more conservative investment decisions.

Electricity price Contract for Difference

As an alternative means of achieving similar effects in terms of revenue stabilisation, we considered an Option whereby renewables generators are offered a Contract for Difference (CfD) struck against an electricity price index. This would be a standard financial swap, familiar from the old England & Wales Pool, which would provide the generator with a hedge to fluctuating wholesale prices. This would be a separate mechanism to the RO, which would continue to operate in parallel, and call for a central entity to manage the associated cashflows, which would be levied on, or rebated to, suppliers.

Modelled results for the CfD Option are very similar to Band Indexation, but the much simpler nature of the approach could significantly reduce implementation concerns. The CfD Option may be attractive to independent developers looking to raise project finance, but less attractive to portfolio players who may view renewables investments as a hedge to other exposures in their business. A potential benefit of the CfD option is that it could be made optional, although the lower the uptake the less the potential benefits to efficiency.

On balance we believe that if stabilisation is seen as desirable, a CfD is the most practical way to achieve this within the current framework of the RO and electricity market arrangements. However, we have identified a range of implementation issues that would need to be considered in more detail to determine whether they pose significant challenges.

Sensitivities

The specific modelling results are very sensitive to the input assumptions, and should be considered in that context. Particularly important are assumptions on annual maximum build rates, commodity and carbon price assumptions, and capital costs. The period of time ahead of implementation that investors make decisions based on forward knowledge of a future policy change is also critical, as is the possibility of a hiatus in project development as the implications of any large changes are absorbed. We tested some of these through a range of sensitivities, to help support the general conclusions that can be drawn.

I Introduction

I.1 Study objectives

This study was commissioned by the Department of Energy and Climate Change (DECC) to assess possible reforms to the Renewables Obligation (RO) in light of the required major expansion of renewable electricity generation in the UK consistent with the overall European Union (EU) renewable energy targets for 2020. In particular, the objective was to identify the minimum changes that might be required and a shortlist of possible further reforms, and to undertake a detailed comparative cost benefit analysis using dynamic modelling of the UK electricity market under the different options. The analysis utilises input assumptions derived from DECC's own forecasts and from other studies commissioned by DECC in support of the 2007 Energy White Paper and UK Renewable Energy Strategy (RES) Consultation. It builds on previous work commissioned by DECC, then the Department for Business, Enterprise and Regulatory Reform (BERR), from Redpoint as part of the RES Consultation, assessing a wide range of financial support schemes for renewables².

I.2 Contributing organisations

The study has been led by Redpoint Energy, working with Trilemma UK.

Redpoint Energy (www.redpointenergy.com) is a specialist energy consultancy, advising clients on investments, risk, strategy, policy and regulation across Europe's liberalised power, gas and carbon markets.

Trilemma UK (www.trilemma-uk.co.uk) provides clients with advice on regulatory, policy and strategic issues affecting UK and European energy markets.

I.3 Conventions

All modelled results are shown in real 2008 terms.

Plant efficiencies are shown in HHV terms.

I.4 Report structure

This report is structured as follows:

In **Section 2** we outline the background to renewable electricity policy in the UK. We summarise the requirements of the EU 2020 targets, provide the historic UK policy context, and examine the requirements for meeting the UK obligation under the targets.

In **Section 3** we describe possible reforms to the RO, evaluate these choices against a set of qualitative criteria and describe how we selected a shortlist of Options for quantitative analysis.

² Redpoint et al. *Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes*, June 2008. http://www.decc.gov.uk/Media/viewfile.ashx?FilePath=Consultations\Renewable%20Energy%20Strategy%20Consultation\Related%20documents\I_20090501131408_e_@_EU2020TargetRenewableSupportSchemesv1.0.pdf&filetype=4

In **Section 4** we present and discuss the quantitative results from our modelling of the shortlisted Options. We describe the detailed policy features, and present our ‘Minimum Change’ Option (considered the minimum reform to make the RO consistent with the high renewables target) as the reference against which other Options are compared. We show the results of this Option in three different Cases of commodity prices and renewables capital costs. We then show the comparative results between the Options under these Cases. Finally we show the impact of a number of different sensitivities.

In **Section 5** we consider the implementation issues for the shortlisted Options, and their effect on investors.

In **Section 6** we present the conclusions of the study.

The **Appendices** contain further details of the approach, assumptions and results:

- Appendix A describes the stabilisation schemes in more detail
- Appendix B describes the modelling framework
- Appendix C documents our modelling input assumptions
- Appendix D describes our hurdle rate calculations
- Appendix E describes our assumptions for modelling output from renewables
- Appendix F presents the results of sensitivity analysis
- Appendix G describes the results of a Status Quo Option, assuming no further policy changes are made (the results of which are not included in the main report)
- Appendix H presents the results of supplementary analysis on specific changes to Headroom and the duration of the RO
- Appendix I contains the detailed cost benefit results for all the Cases and Options modelled
- Appendix J is a summary of the key results

2 Policy Background

2.1 Introduction

The UK has had policies providing explicit financial support for large scale renewable electricity generation since 1989. Without such support, the development of most renewable capacity would not have been commercially viable. The broad objectives of such policies have been to increase directly the level of renewable generation for its environmental benefits, whilst also accelerating progress along the ‘learning curve’ with the long term aim of making renewables competitive with other forms of generation. Alongside the policies, the Government has set targets for renewables deployment. The 2002 Energy Review set a target share for renewables generation of 10% by 2010, and the 2006 Review added an aspirational target of 20% by 2020. As discussed below, the ‘EU 2020’ target proposed by the Commission’s 2008 draft renewables Directive and adopted by the Council in April 2009 represents a step change compared to previous target levels.

Following the introduction of the Climate Change Act 2008, these targets now sit within a legally binding framework for the UK to reduce greenhouse gas emissions to 80% of the 1990 level by 2050. The Act requires the UK government to issue carbon budgets. In April 2009 the UK government issued proposals for the first three carbon budgets, covering 5 year periods from 2009 to 2023. This committed the UK to a reduction of 34% in the third carbon budget period (2018 to 2022).

At a high level, the objective of policies providing financial support for renewables is to establish a mechanism that leads to the deployment of sufficient renewable capacity to meet target generation levels whilst minimising the additional costs to consumers. In practice, assessing the impact of a given potential policy, and determining its likely efficiency and effectiveness, is challenging and complex. In this section, we review the EU 2020 targets and provide background on UK renewable electricity financial support mechanisms to date.

2.2 EU 2020 targets

At the 2007 Spring Council, the EU Heads of State agreed on a target of meeting 20% of total energy consumption from renewable sources by the year 2020. This is one key component in meeting overall EU energy policy objectives of combating climate change, enhancing security of supply and increasing economic competitiveness.

On January 23, 2008, the European Commission proposed a draft Directive³ to implement this target. The *Directive on the promotion of the use of energy from renewable sources* (referred to subsequently as the EU RES 2020 Directive) was adopted with some relatively minor changes in April 2009⁴.

To deliver an arrangement that allows for a fair allocation of the 20% renewable target, shares have been apportioned to Member States taking into account current renewable energy production, resource potential, and relative gross domestic products (GDPs). Under these proposals, the UK target is 15% in 2020, compared to 1.3% level achieved in 2005. (The Directive also presents interim trajectories although these are non-binding.)

³ Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources, Brussels, 23.1.2008 COM(2008) 19 final 2008/0016(COD), at ec.europa.eu/energy/climate_actions/doc/2008_res_directive_en.pdf

⁴ Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources, published in the Official Journal of the EU, June 2009, <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:EN:PDF>

Within the Directive there is a 10% target for the use of biofuels within the transport sector, subject to sustainability. (Electric vehicles can make a contribution to this 10% target based on the average proportion of renewables in the electricity used.) Other than that it is up to Member States how to allocate their individual targets between their electricity, heat and transport sectors.

The Directive contains procedures allowing Member States to enter into bilateral agreements to make statistical transfers of renewable energy or cooperate on joint projects. There is no centralised mechanism for trading of target levels. Guarantees of Origin may be issued, separate from any inter-country transfers, as a means of certifying the source of renewable electricity sold to final customers.

2.3 UK renewable electricity policy development to date

2.3.1 Non-Fossil Fuel Obligation

The 1989 UK Electricity Act introduced the restructuring and privatisation of the electricity sector, and the introduction of the England & Wales Pool. (Separate arrangements applied to Scotland and Northern Ireland.) At the same time, the Non-Fossil Fuel Obligation (NFFO) was introduced, and this remained the prime renewable support scheme until 2002. The NFFO was administered as a series of competitive tenders, for which renewable energy developers submitted bids specifying the price at which they would be prepared to develop a project. The Government determined the level of capacity for different technology bands, and offered contracts to the winning bids. The Public Electricity Supply companies were obliged to purchase all NFFO generation offered to them and to pay the contracted price for this generation. The difference between the contracted price and the wholesale price, which represented the subsidy to renewable generation, was reimbursed using funds from a Fossil Fuel Levy raised on customer bills.

2.3.2 Renewables Obligation

In April 2002, the NFFO was replaced by the Renewables Obligation (RO). Eligible renewable generation facilities receive Renewable Obligation Certificates (ROCs), corresponding to energy produced (1 ROC issued for each 1 MWh of generation). The definition of eligibility is different from that used in calculating the EU targets: in particular pre-existing hydro greater than 20 MW and the biodegradable fraction of solid waste combustion are excluded from the RO. Electricity suppliers are obliged to buy ROCs corresponding to their share of total electricity sales. This obligation was set at 3% of sales in 2002/3, increasing to 15.4% by 2015/16. A supplier that does not obtain sufficient ROCs has to make 'Buy-out' payments (£30/MWh in 2002/3, rising annually in line with inflation). These Buy-out payments are recycled back to suppliers that have presented ROCs, hence increasing the value of producing renewable electricity in years where the obligation size is not achieved.

The UK is in fact covered by three RO schemes. The Renewables Obligation Order, covering England and Wales, and the Renewables Obligation Order (Scotland) were introduced simultaneously. The Renewables Obligation (Northern Ireland) Order came into effect later, in April 2005. The Orders mirror each other in implementation, such that certificates are mutually tradable between the different regions. England and Wales and Scotland have the same obligation levels (in percentage terms), whereas Northern Ireland has smaller relative obligation sizes. Ofgem administers the England and Wales and Scotland schemes, and provides the same service for Northern Ireland on behalf of the Northern Ireland Authority for Utility Regulation (NIAUR).

The original RO provided the same support level irrespective of technology, leading to strong investment in the lower cost technologies such as landfill gas, onshore wind and co-firing. In May 2007, the Government published a consultation document⁵ on the introduction of 'banding', which would lead to the issue of different numbers of ROCs per MWh for different types of renewable generation. The Energy Act 2008, which received Royal Assent in November, provides the necessary powers to introduce banding and the changes to the RO have been implemented from April 2009. Currently there are five bands, ranging from 0.25 to 2 ROCs/MWh, with technologies categorised by market maturity. It is envisaged that technologies will be re-banded from time to time (following a formal banding review) should there be significant changes to costs. It is also possible to undertake 'emergency' re-banding in the event of significant rapid changes to plant capital costs. The Scottish Government amended the Renewables Obligation (Scotland) in 2007 to include a Marine Supply Obligation. This required Scottish suppliers to source a certain proportion of electricity from tidal and wave powered generation. However the Obligation level was set at zero and was removed in 2009, with the intention that it will be replaced with higher RO bands for generation from tidal and wave (3 ROCs/MWh and 5 ROCs/MWh respectively)^{6,7}. This will apply only to wave and tidal projects in Scotland and is subject to approval under EU State Aid rules.

The Energy Act also included two new mechanisms designed to reduce the risk to investors of a ROC price crash in the event that the obligation is exceeded. Under the original RO, if more ROCs were to be issued for a given year than required for suppliers to meet their obligations, the price of certificates could theoretically fall close to zero as generators competed to sell in an oversupplied market. (This situation would be analogous to the collapse of the price of EU Allowances (EUAs) in Phase I of the EU Emissions Trading Scheme for carbon.) The two mechanisms are the Headroom mechanism and the ski-slope mechanism. The Headroom mechanism will adjust the size of the obligation upwards if actual generation is forecast to exceed the target, up to maximum level of 20% of total supply. The Government also has the power to implement the ski-slope mechanism if required. This would ensure that prices tapered down smoothly in the event of oversupply (should the 20% maximum target be reached) rather than collapse. However the details of the mechanism have not been defined and there is currently no ski-slope in place.

In the Pre Budget Report of November 2008⁸, the Government stated an intention to extend the RO to at least 2037. In the Government Response published with the draft Renewables Obligation Order 2009⁹, this statement was clarified to mean that new plant will receive at least 17 years of support, but there is no intention to provide an additional ten years of support to all existing projects. Existing plant will receive support until at least 2027. The Government has also considered in previous consultations whether to provide continuing support for projects that have reached the end of the participation period, and has previously suggested that these plant 'roll off' onto the lowest band (currently 0.25 ROCs/MWh).

In its Budget 2009¹⁰, the Government made use of its 'emergency rebanding' powers to increase the ROC band for offshore wind for the next two years. The 2009/10 band will be 2 ROCs/MWh, and the 2010/11 band will be 1.75 ROCs/MWh. This will only apply to projects fulfilling a specific set of criteria, including ordering their turbines in this period.

⁵ Reform of the Renewables Obligation, BERR, May 2007, <http://www.berr.gov.uk/files/file39497.pdf>

⁶ Renewables Obligation (Scotland) Introduction of Banding Statutory Consultation, Scottish Executive, September 2008, <http://www.scotland.gov.uk/Resource/Doc/917/0065773.pdf>

⁷ Draft: The Renewables Obligation (Scotland) Order 2009, Scottish Executive, https://www.hmso.gov.uk/legislation/scotland/ssi2009/draft/en/sdsien_9780111003268_en.pdf

⁸ Pre-Budget Report 2008, HM Treasury, http://www.hm-treasury.gov.uk/prebud_pbr08_index.htm

⁹ Government Response to the Statutory Consultation on the Renewables Obligation Order 2009, DECC, http://www.hm-treasury.gov.uk/prebud_pbr08_index.htm

¹⁰ Budget 2009, HM Treasury, http://www.hm-treasury.gov.uk/bud_bud09_repindex.htm

2.3.3 Renewable Energy Strategy Consultation

In June 2008, DECC launched the Renewable Energy Strategy (RES) Consultation, giving consideration to required measures in the electricity, heat and transport sectors to meet the EU RES 2020 target.

For the heat sector, the Consultation discussed potential mechanisms for providing financial support for renewables, and the Energy Act gives the Secretary of State the powers to introduce this (the Renewable Heat Incentive). This could be applied from large industrial sites down to the household level, and is likely to have implications for the funding of renewable Combined Heat and Power (CHP) projects, and in particular may change the treatment of these facilities in the RO. The details of this scheme were still under consideration by the Government during this study.

The Government has proposed separating out smaller scale (less than 5MW) generating facilities and introducing a Feed-in Tariff (FIT) to cover future projects of this size. Again, the details of the policy were under consideration by the Government concurrent with this study.

For the large scale renewable electricity sector, the Consultation presented a wide range of possible financial support mechanisms for renewables that, in addition to an extended RO, included alternative FIT and tender mechanisms. The Government has since made clear its intention to retain the RO for large scale generation, as favoured by the majority of the relevant consultation responses.

The Government stated an intention to examine a number of reforms to the RO to ensure that it is compatible with increased targets and to improve the efficiency of the scheme, including:

- an increase or removal of the 20% cap on Obligation size, to allow the RO to grow sufficiently to maintain the level of subsidy with a much greater volume of renewables;
- a continuation of the RO for a sufficiently long period after 2020 to ensure that renewables plant built up until 2020 receive financial support to cover their normal economic lifetimes, and hence maintain incentives to build;
- the use of fixed annual targets compared to a Headroom approach;
- changes to the number of bands, such as moving from one band for a group of technologies to one band for each technology, or multiple bands for a technology, reflecting (for example) different yields for specific sites;
- potential ways to increase the stability of the ROC price; *and*
- a consideration of ways to inversely link the rewards under the RO to the wholesale electricity price, to ensure more stable returns for investors and limit the impact on consumers in times of high wholesale price.

2.4 Meeting the 2020 target

2.4.1 Meeting the UK obligation

The EU RES 2020 Directive allocates the UK a renewable energy target of 15%, and the UK Government will be required to present to the European Commission by March 2010 a 'National Action Plan' which explains how this target will be met.

In preparing the National Action Plan, the Government will need to take a view on two key issues:

- to what extent it intends to meet the target through the domestic production of renewable energy and what assumptions it should make about the ability to enter into agreements to obtain renewable energy from other countries; *and*
- how to split the national target between the electricity, heat and transport sectors.

The Directive allows for four mechanisms by which Member States can count renewable energy generated in another country towards their target. Member States can:

- arrange a statistical transfer of renewable energy from another Member State; *and/or*
- enter into a joint project with another Member State in which the project is commissioned in one Member State but the renewable energy credited to another Member State; *and/or*
- enter into a joint project with a third country which is interconnected with the EU and the energy is physically transferred to the EU; *and/or*
- join or partially combine support schemes with another Member State.

It is unclear to what extent sources of non-domestic renewable energy will be available to the UK. Statistical transfers may only be made from Member States where the share of energy from renewables sources equals or exceeds the indicative trajectory set out in the Directive. Joint projects or the combination of support schemes could both be feasible options but currently there is little indication that these options are under serious discussion with other countries. Consequently, they have not been explored within the scope of this study.

For the purposes of this study we have assumed that the UK can only rely on meeting its target through UK sources of renewable energy. This does not imply that the Government cannot ultimately cooperate with other Member States and agree on the transfer of renewable energy in exchange for financial and technical support for their renewable deployment. Such agreements need not alter renewables support schemes in the UK, only the target level of renewable energy to be delivered in the UK.

The allocation of the national target between the various energy sectors will be critical and Government will therefore need to take a view on the least cost route to deliver the overall target and derive sector targets accordingly. Consideration will need to be given to interactions between sector policies, particularly for common resources such as biomass.

This study is focused solely on policies for large-scale electricity generation. In undertaking the modelling work, it was necessary to assume the proportion of the overall target to be delivered by this part of the electricity sector. The target was taken as an exogenous input, supplied by DECC. The main scenario that we examined was a target level for large scale (greater than 5 MW) renewable electricity of 28% of total generation by 2020. As sensitivities on the main modelling results, we also considered scenarios with higher and lower levels of renewable electricity generation in 2020.

2.4.2 Measures required to meet electricity target

The assumed target level represents a step change compared with expected renewable penetration arising from existing policy measures. Achieving this will involve a combination of policy initiatives including financial support, streamlined planning and connection policy.

For the financial support mechanisms, the potential changes considered in the RES Consultation were discussed in Section 2.3.3.

Relieving the bottlenecks that impose hard physical constraints on renewables deployment is likely to be particularly important. It is expected that, as long as the financial incentives provided by any support

scheme are both attractive and credible, the supply chain will respond to the expected market need and gear up production capacity of the necessary plant and equipment. However, there will be some aspects of the supply chain that will be difficult to expand over even a ten year time horizon, such as the number of installation barges needed to deliver a dramatic expansion of offshore wind capacity.

Other possible bottlenecks, in particular the planning system and grid connection, have been the subject of ongoing policy reviews and legislation. It is however too early to assess the effects of these changes on removing barriers.

The Planning Act 2008 introduced changes to the planning system for nationally significant infrastructure projects across the water, waste, energy and transport sectors along with the establishment of an Infrastructure Planning Commission (IPC). The Act enshrines National Policy Statements (NPS) to set out Government policy for infrastructure development and DECC expects to produce a suite of NPSs for energy infrastructure. The IPC is expected to begin processing applications in 2010.

In the 2007 Energy White Paper, the Government announced a review, the Transmission Access Review, led by Ofgem and BERR (now DECC) of the framework for connecting renewable generation to the grid. The review examined the technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the grid to ensure that they remain fit for purpose as the proportion of renewable generation on the system grows. The final report, published in June 2008, contains actions designed to allow faster connection of some renewable generation in the short-term and steps to introduce new access arrangements to improve the speed of connections and expansion of grid capacity in the long-term. A selection of models for access reform are now under review and proposals have been developed by industry to enable more efficient use of transmission infrastructure, including arrangements for sharing transmission capacity. A key element of the proposals is that transmission companies are likely to be subject to stronger incentives to deliver firm connections on time to financially committed developers.

In 2005, the DTI and Ofgem launched a process to develop a regime for offshore transmission¹¹. The process has gone through a number of consultation stages, and finally concluded in March 2009. Operating offshore transmission networks will become a licensable activity. The ownership and operation of existing offshore assets, and the construction and operation for all future offshore transmission assets, will be awarded through a competitive tender process. As offshore renewables developers indicate that they will require connection to the GB electricity grid, Ofgem will open the tender for new transmission assets in an annual tender window. Potential Offshore Transmission Owners (OFTOs) will bid into the tender process to design, build and maintain the Offshore Transmission assets for a period of twenty years. The process of reforms to the codes and regulations that govern transmission and distribution is currently underway, with the latest proposals published in March 2009¹².

All of these physical build constraints were the subject of a previous study¹³ by consultants Sinclair Knight Merz (SKM) commissioned for the RES Consultation and their results have been used as an input to this work. This work uses the results of SKM's least constrained scenario, in which the key constraints in the planning system and grid connection are assumed to be successfully removed. This is clearly a critical input assumption, and our results should be considered in this context. The SKM study was commissioned before the Planning Act 2008 had been passed and before the Transmission Access Review had concluded.

¹¹ <http://www.berr.gov.uk/energy/sources/renewables/policy/offshore-transmission/consultations/page42095.html>

¹² DECC, *Government Response to 'Offshore Electricity Transmission – A further Joint Ofgem/DECC Regulatory Policy Update'*, March 2009 <http://www.berr.gov.uk/files/file50603.pdf>

¹³ SKM, *Quantification of Constraints on the Growth of UK Renewable Generation Capacity*, June 2008

Finally, some argue that fundamental reform of the overall wholesale market arrangements will be necessary to ensure efficient plant dispatch and utilisation of the transmission network with such a large proportion of non-controllable renewables output, regardless of the support scheme. This is an important issue which requires further consideration, but is outside the scope of this study.

2.4.3 Contribution of large and small scale generation to the target

Renewable generation spans large scale plant directly connected to the transmission system, smaller scale installations, embedded within the distribution system, and microgeneration within a domestic household, perhaps exporting small amounts onto the local grid network. The scenario targets for share of generation from renewable sources modelled in this study include output from central and embedded generation but exclude the additional potential contribution from microgeneration.

As discussed in Section 2.3.3 above, the Government has taken the powers to introduce a FIT for sub 5 MW generation. The policy design process was ongoing during this study. The FIT could cover the range from microgeneration up to individual full scale wind turbines. We have considered but not attempted to quantify the impact this would have on the RO and on overall renewables deployment.

2.4.4 Severn Barrage

During the time of the CEGB, a series of studies was undertaken examining the possibility of harnessing the huge tidal range found in the Severn Estuary (~14m) to generate electricity. These studies concluded in 1989 in Energy Paper 57 and found that an ebb generation scheme between Lavernock Point and Brean Down (the scheme now known as Cardiff-Weston) was (having been identified as the preferred scheme by earlier studies) technically feasible and would have an annual output of approximately 17 TWh. However, Government decided that a Severn Barrage was not a cost-effective option for generating electricity at that time.

With renewed focus on renewable generation there have been various calls to look again at the desirability of a Severn tidal power scheme and the Government initiated a feasibility study¹⁴ in 2008 which is expected to last up to two years. It has looked at a number of potential locations and technologies, and has identified a shortlist of five schemes to take forward to detailed Impact Assessments.

While this feasibility study is still ongoing, it is difficult to make modelling assumptions as to whether a tidal power project in the Severn Estuary will be delivered or the location and timing of any electricity output generated by a potential project. In this work we have assumed that any Severn Tidal Power project is less than 1 GW and covered by the RO. (Sensitivities that considered the Cardiff-Weston 8 GW scheme, which would need to be developed outside of the RO were conducted in our previous study.)

2.4.5 Northern Ireland

On 1 November 2007, the Single Electricity Market (SEM) went live, under which a single set of wholesale trading arrangements is in effect for both the Republic of Ireland and Northern Ireland. The SEM consists of a mandatory Pool, with centralised dispatch based on day-ahead commercial and technical offers from generators, combined with a Capacity Payment Mechanism, whereby an annually set 'pot' is paid to

¹⁴ <http://www.berr.gov.uk/energy/sources/renewables/explained/severntidalpower/page41473.html>

generators based on availability. As a result, the investment framework for new generation is very different to Great Britain.

The renewable support mechanisms in the Republic and the North are still, however, those set by the respective Governments, with the Northern Ireland RO in the North and a FIT scheme in the Republic.

The main focus of this study has been the Great Britain (GB) electricity market. However, careful consideration is required as to whether the changes to the RO in GB can be successfully applied in Northern Ireland given the different underlying market arrangements. It will also be necessary to determine the contribution of renewables plant in Northern Ireland to the UK target. For the purposes of this study we have implicitly assumed that Northern Ireland will contribute the same proportion of renewables generation as a percentage of consumption as the rest of the UK. However, modelling of the Northern Ireland market was not included in the quantitative assessment in this study.

3 Options for reform of the RO

3.1 Introduction

The RES Consultation (see Section 2.3.3) identified a number of areas of further consideration for the RO. For the purposes of this study, these issues have been summarised into two key questions¹⁵:

1. What changes to the RO are required to ensure that it is consistent with achieving the 2020 renewables targets?
2. Is there any advantage to consumers and/or renewables generators in introducing mechanisms that will tend to stabilise future revenues for renewable generation?

The first question relates to adapting the RO to the new 2020 target. In particular the overall size of the subsidy potentially available to renewables needs to increase.

The second question concerns a means to increase efficiency and effectiveness of the mechanism. Both the RES Consultation and our previous study identified that there are theoretical benefits to revenue stabilisation for renewables.

We treated these two questions separately in considering design choices. Phase 1 tackled the first question and Phase 2 the second. In both cases, the following overall approach has been followed:

1. Identify a set of 'design choices'
2. Undertake an evaluation of this list of design choices against a set of criteria
3. Produce a 'short list' of options which can be analysed quantitatively

This section describes these steps for each of the two Phases, explaining how the short list of options was identified.

3.2 Phase I: Updating the RO for consistency with the 2020 RES targets

3.2.1 Design choices

Under the current RO mechanism, the Obligation size is capped at 20% of electricity supplied. If the number of ROCs were to approach this level, there would be a significant risk that the ROC price could decrease towards zero, reducing the incentive for new investment. It is clear, therefore, that the cap will need to be removed such that renewable build is incentivised to achieve volumes in line with the 2020 renewables targets.

In extending the RO size, there are a number of 'dimensions' to changes that could be considered, each with a set of more detailed design choices. The dimensions are:

¹⁵ Consideration of the possibility of changing the banding structure, identified as a potential area of change in the RES Consultation, was not within scope for this study.

- **Trajectory.** Under the current RO, the Obligation size is set by a series of fixed annual targets that increase linearly to 15.4% in 2015/16. These targets could be extended along a trajectory which would correspond to meeting a large scale renewable electricity target of, say, 28% in 2020. A spectrum of trajectories can then be defined which take us from the current level to the target: linear, concave, or convex. Alternatively, no fixed targets could be set beyond 2015/16, and the size of the Obligation could be driven up using the Headroom mechanism alone (with the Obligation size each year being set at a given percentage above expected output levels).
- **Handling banding in targets.** Due to banding in the RO, the total MWh of generation from RO-qualifying plant going forward will not be equal to the total number of ROCs issued. When setting a trajectory up to the target level, annual targets could be adjusted to take this into account, scaling for 'net banding' in that year (the total ROCs issued divided by the total TWh generated). The RO size could be adjusted either ex-ante or ex-post.
- **Pricing mechanism.** This dimension captures a range of choices which would affect pricing in the RO. Headroom is both a volume and pricing mechanism, in that it controls the ROC price by setting the Obligation size at a fixed level above the expected number of ROCs. A 'ski-slope' is designed to set the ROC price when the number of ROCs exceeds the Obligation size. The use of at least one of these mechanisms is required to prevent a ROC price crash in this situation. More explicit pricing mechanisms could include the imposition of a cap and collar to set a range in which the ROC price would be allowed to move. By bounding the upper range of the ROC price, the scarcity signal associated with a shortfall in renewables generation is dampened, whilst the potential economic rents for operational plant are decreased. At the limit, this would set a fixed price for ROCs. Note that the pricing options are not all mutually exclusive.
- **Volume basis.** Currently the RO is set as a proportion of electricity supplied. Setting an absolute volume-based target (in TWh) would take away this risk for generators but potentially increase the risk for suppliers.
- **Other parameters.** There are also a number of other parameters to consider which are more or less independent of the other design choices. These include the size of Headroom, the duration that the RO lasts for and which projects participate in the RO, and the frequency of banding reviews.

The key dimensions for further consideration in determining design options were identified as the **trajectory** and the **pricing mechanism**.

We considered that the appropriate size of Headroom and duration of participation period could be assessed independently of the other design choices. This analysis is described in Appendix H, with key conclusions highlighted in Section 6.

Two other dimensions have not been explored as part of this study. The volume basis of the RO has been assumed to continue as a proportion of electricity supplied. Where we have implemented future banding changes in our modelling, we have assumed that this is limited to two RO reviews in 2013 and 2018. (In practice the Government could re-band more frequently should circumstances demand.)

The design choices identified for the trajectory were:

- Linear from 2010 until 2020
- Concave (based on Directive trajectories)
- Following existing targets until 2012/13 (or another date) and then linear interpolation to 2020
- None post 2015/16

The design choices for the pricing mechanism were:

- Headroom
- Ski-slope
- Cap/collar (on the ROC price)
- Fixed price
- None

These design choices were combined to create a ‘long list’ of Phase I Policy Options. In essence, these Options are exploring various ways to set the obligation size and the strength of the scarcity signal in the ROC price.

In the following section we assess the key design choices for the Trajectory and Pricing mechanism dimensions against a range of evaluation criteria.

3.2.2 Evaluation of Phase I design choices

A number of evaluation criteria were identified against which the Phase I design choices were assessed. The results of this exercise are summarised in Table I.

Table I Assessment of design choices against evaluation criteria

Evaluation criterion	Evaluation
Strength of investment signal	<p>A stronger scarcity signal will tend to increase the strength of the investment signal. Therefore, other things being equal, the choice of a fixed trajectory scores highest, with a linear interpolation being stronger than a concave trajectory. In the case of no trajectory post 2015/16 the expectation of ROC price beyond 2015/16 is likely to be close to a Buy-out + Headroom level, so the strength of the investment signal is relatively weak under this option.</p> <p>Headroom as a pricing mechanism was considered to create slightly stronger investment signals than ski-slope since it creates a floor expectation somewhat higher than the Buy-out price, whereas under ski-slope pricing the price could fall below the Buy-out price. The strength of the investment signal under cap/collar pricing will depend on where the cap and collar are set. Fixed price will be weaker than all but ski-slope, assuming it is set close to the Buy-out price.</p>
Policy certainty	<p>The mechanisms designed with a visible 2020 target have greater policy certainty than the minimum change approaches where future decisions on Headroom are unknown. Fixed price has greatest certainty.</p>
Reducing the cost of capital/resource costs	<p>None of the approaches would have a material impact on the cost of capital, since the primary source of risk under RO-type models is commodity price volatility. Those with greatest scarcity signal scored slightly worse due to increased price uncertainty.</p>
Attractiveness to independents/new entrants	<p>Apart from a mechanism with a fixed price, all the approaches were seen to have broadly similar levels of complexity and predictability and hence none was considered likely to increase attractiveness to this class of investors relative to others.</p>
Attractiveness to portfolio generators	<p>Portfolio generators, such as utilities, may have a preference for approaches which leave price exposure, since they have relative competitive advantage in managing the associated risks. Also, their</p>

Evaluation criterion	Evaluation
	boards/investment committees are familiar with the RO structure. Fixed price therefore might be seen to be diminishing their competitive advantage.
Minimising rents for existing plant	The greater the scarcity signal, the greater the potential for economic rents. This is the inverse of the strength of investment signal criterion. An option with a fixed price could reduce rents accruing to existing plant in the circumstances where the ROC price would otherwise rise.
Minimising rents for new plant	As above except the relative advantage of fixed price over Headroom pricing is reduced, since excessive rents for new plant are less likely with a managed Headroom approach.
Robustness to build constraints	Build constraints give the potential for rents in those approaches with the greatest scarcity signal. Cap/collar and fixed price (or Headroom once existing fixed targets expire) would be more robust here.
Robustness to changing costs	A scarcity signal will tend to help offset the impact of adverse capital cost/commodity price scenarios by providing higher ROC prices in these scenarios where investment would otherwise slow.
Minimising complexity	The approaches have broadly similar levels of complexity with cap/collar mechanisms seen as slightly more complex and fixed price as somewhat simpler.
Policy flexibility	This is broadly the inverse of policy certainty with approaches that have no trajectory post 2015/16 seen to have the greatest potential for future adjustment. As a pricing mechanism, Headroom provides somewhat more flexibility than ski-slope pricing or cap/collar which are pre-set.
Ease of transition	The greater the level of change, the greater the resources needed to be deployed by market participants and administrators to implement the new system, and the greater the potential uncertainty surrounding the new arrangements for market participants.
Minimising market distortions	There is no basis to differentiate the approaches under this criterion.

3.2.3 Selection of Phase I Options

The evaluation exercise illustrates that each of the designs has advantages and disadvantages and any attempt to select preferred options on this qualitative basis would be highly subjective. A key requirement was to test a **Minimum Change** Option which would limit the changes to the RO to only those considered absolutely necessary to make it consistent with the 2020 target. These included the following:

- a lifting of the 20% cap, considered essential to make the RO consistent with the 2020 target;
- an increase in Headroom percentage, considered necessary to accommodate future increased variability in ROC output, in particular caused by the increased band for offshore wind (based on the separate analysis of this issue in Appendix H.2); *and*
- the extension of the RO to 2037/38, required to meet stated government policy of a minimum participation period of 17 years, and to ensure that investment in renewables does not slow prior to 2020.

We have also assumed a minimum participation period of 20 years, which is not strictly a 'minimum change', but is consistent with investor expectations of receiving ROCs for the entirety of the typical economic lifetime of an investment. This change has limited impact, as shown in the analysis in Appendix H.1.

The evaluation suggested that a key differentiator between the design choices is the potential strength of the scarcity signal. Using **Minimum Change** as the reference case, then the **Fixed Targets** case, with a

defined trajectory to 2020, provides the greatest scarcity signal, whilst the **Fixed Price** approach represents the opposite extreme in which no scarcity signal exists. However, it was decided not to take the **Fixed Price** approach forward on the basis that it was too far removed from the existing mechanism to be consistent with the policy decision to retain the RO.

The Minimum Change and Fixed Targets Options were therefore selected for quantitative analysis. The complete specification for these options was defined as follows:

1. Minimum Change

- Extension of RO to 2037/38
- Extension of participation period to 20 years for new projects
- Fixed annual targets to 2015/16 and then Headroom only
- 20% cap on Obligation size lifted
- Obligation size increased as necessary to maintain Headroom
- Increase in Headroom percentage, rising by 0.5 percentage points per annum from 8% in 2010 to 10% in 2014

2. Fixed Targets

- Extension of RO to 2037/38
- Extension of participation period to 20 years for new projects
- Existing targets until 2012/13 and then linear interpolation to 2020 target (adjusted for net banding)¹⁶
- Obligation size further increased, if required, to maintain Headroom
- Increase in Headroom percentage, rising by 0.5 percentage points per annum from 8% in 2010 to 10% in 2014

3.3 Phase 2: Stabilisation of future earnings

3.3.1 Design choices

Renewables generators are exposed to uncertainty in future earnings due to volatility in wholesale electricity prices, and variability in the value of ROCs. Revenue stabilisation schemes would reduce this exposure, with the risk of falling electricity being transferred from the renewables generator to consumers. Conversely, the risk of rising electricity prices would be transferred from the consumer to the generator (whilst still ensuring a reasonable return could be earned). These reductions in risk should theoretically make it easier to secure financing at a lower cost, with potential benefits for scheme effectiveness, whilst improving the efficiency of the scheme with benefits to consumers should electricity prices increase in the future.

Revenue stabilisation can also improve robustness of scheme effectiveness to falling commodity prices, without resorting to re-banding (which can lock in economic rents should electricity prices subsequently

¹⁶ The logic for this target profile is that it provides an increased incentive ahead of 2015, but not before there is some prospect the current bottlenecks in grid connection and planning have begun to reduce.

rise). Because investors will automatically be shielded from falling commodity prices, there is less likely to be a reduction in investment if commodity prices go down. Furthermore, re-banding is a one off adjustment and does not remove the enduring exposure to electricity price volatility.

Independent renewables generators can seek to remove their price exposure through signing PPAs with other players. However, the contracting market lacks transparency or long term price signals, and this may enable larger counterparties to extract rents, reducing the overall efficiency of the mechanism. Further, at times when commodity forwards prices are low, it is likely that long term contract prices will also fall, so effectiveness is still likely to be a concern in these circumstances.

It has been suggested that this risk for generators would in any case be lower if there were a positive correlation between wholesale prices and capital costs. If commodity (and hence electricity) prices were to fall, capital costs could also fall, and vice versa. It is not yet clear from limited historic evidence that a strong correlation exists, but more importantly, because capital costs are sunk at the start of the project, whereas wholesale price variability endures through the project, this does not remove the revenue exposure.

Some more fundamental change to the existing RO, or an additional mechanism, would therefore be required to increase revenue stabilisation.

Design choices within the RO

The following methods of stabilising revenues for renewables plant within the RO were considered:

- **Buy-out price indexation.** This mechanism involves inversely relating the Buy-out price to an index based on wholesale electricity price, in order to stabilise overall revenues. The index could be defined on a wholesale price index, a generation weighted price index, or a basket of commodity prices. The adjustment could be used to stabilise revenues fully or to place a cap and collar on total revenue. The adjustment could be based on a scalar or an absolute £/MWh adjustment. A Buy-out price mechanism would impact all (new and existing) plant.
- **Band level indexation.** Currently bands are adjusted based on views of different technology costs, and grandfathered for new plant. This mechanism would change the methodology for banding such that they would not be fixed for each plant, but rather adjusted annually based either on some form of capital cost index, or a wholesale price index. Again, this could be structured to place a cap and collar on total revenue. The band concept could also be changed from acting as a ROC “multiplier” (for example, receiving 2 ROCs for each MWh produced) to “absolute” bands, where a fixed additional premium (or rebate) (in £/MWh) for a given technology would be paid in addition to the issuing of each ROC. This new mechanism could be applied just to new plant (with bands for existing plant grandfathered).
- **Buy-out fund recycling.** It would be possible to make changes to the Buy-out fund recycling, by either removing the recycling completely or indexing to one of the indices discussed above.

These design options all imply a much greater level of change than for the Phase I options. The key dimensions identified for further investigation through quantitative analysis were **Buy-out price indexation** and **band level indexation**.

The **Buy-out fund recycling** was not considered in detail on the basis that it would have a relatively limited impact compared to the other options. A possible approach would be to link the repayment of Buy-out fund revenues to a wholesale price index, such that if the index exceeded a certain level, payments from the fund would be reduced. This would be a method of (marginally) reducing revenues for renewable generators when wholesale prices are high. Potentially, these funds could then be distributed back to consumers in some other way. However the impact of this measure is highly dependant on the level of revenue recycling in a particular year.

The design choices considered for Buy-out price indexation were:

- Time-weighted wholesale electricity price
- Generation-weighted (average per renewable technology class) wholesale electricity price
- Commodity price basket
- Combination of the above
- Cap/collar on total revenue
- RPI indexation (as current)
- Indexation structured as a scalar or as an adder

The design choices for banding were:

- Technology cost dependent (as current)
- Annual re-banding relative to published capital cost indices
- Wholesale electricity price adjustments
- Move to absolute bands
- Cap/collar or full band adjustment

The design choice to adjust the banding based on capital cost indices was not considered any further as these indices would be very difficult to define in a transparent manner, and hence may not lead in practice to a material difference compared to the current re-banding methodology, which aims to adjust for capital cost movements in any case.

Design choices outside of the RO

All the above discussion considers designs which fall within the RO. We have not considered options which would remove the RO completely and move to a different scheme entirely such as a FIT, as the previous study¹⁷ examined these options in detail and the Government has since signalled its intention to retain the RO. However, we have considered revenue stabilisation options which would operate outside of the RO but in tandem with it.

The greatest revenue risk for renewable generators, and the greatest potential contributor to rents, is the future movement of wholesale price. This could be tackled outside of the RO through the imposition of a long term contract on renewable generators. This could be a physical or a financial contract:

- **Power Purchase Agreement (PPA).** This is an agreement between a generator and an off-taker to purchase physical power from the generator at a fixed price.
- **Contract for Difference (CfD).** A CfD, or swap, is an agreement made between a party and a generator to make payments based on the difference between a (wholesale price) index and a strike price. Settlement is made through cash payment and there is no physical transfer of power.

Imposing PPAs on generators would require an agency to manage the physical power and sell it into the market. Also, this may unnecessarily undermine the existing commercial market in PPAs whereby most output and ROCs from independent producers is currently sold under long term contracts to larger suppliers. In contrast, a scheme which imposes CfDs on generators does not directly alter the physical

¹⁷ Redpoint et al. *Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes*, June 2008.
http://www.decc.gov.uk/Media/viewfile.ashx?FilePath=Consultations\Renewable%20Energy%20Strategy%20Consultation\Related%20documents\1_20090501131408_e_@_EU2020TargetRenewableSupportSchemesv110.pdf&filetype=4

trading of power, and independent generators can still elect to sell their physical output (and ROCs) under long term PPAs, albeit with different pricing terms, or alternatively engage in wholesale trading themselves. Generators will still be exposed to any differences between the index used for settlement of the CfD and the price they achieve from selling their power in the physical market. An agency would be required to manage the new cashflows associated with the CfDs. For these reasons, we have considered the CfD Option rather than the PPA Option in the Phase 2 evaluation.

3.3.2 Evaluation of Phase 2 options

A different approach was taken from Phase 1. Given that the main aim was to explore revenue stabilisation, a set of options was constructed which attempted to do this in a number of ways. The full list is described in Appendix A.

Initial analysis of these options revealed that the presence of relative bands and a scarcity signal within the underlying RO mechanism mean that simple indices do not stabilise earnings across all wholesale price ranges and bands. In this section we illustrate some of the issues, using the concept of a pay-off diagram. (Relevant formulae are shown for the options selected for quantitative analysis in Section 3.3.3.)

A pay-off diagram for the current RO is shown in Figure 1. The diagram shows the total (wholesale electricity and ROC) revenue (y-axis) for a range of bands (with the green, blue and red lines showing 0.25, 1 and 1.5 ROC bands respectively) as the electricity price changes (x-axis). It is clear that as the electricity price increases for an unchanged ROC price (the purple line), the revenue of all plant increases linearly.

Figure 1 Pay-off diagram for current RO

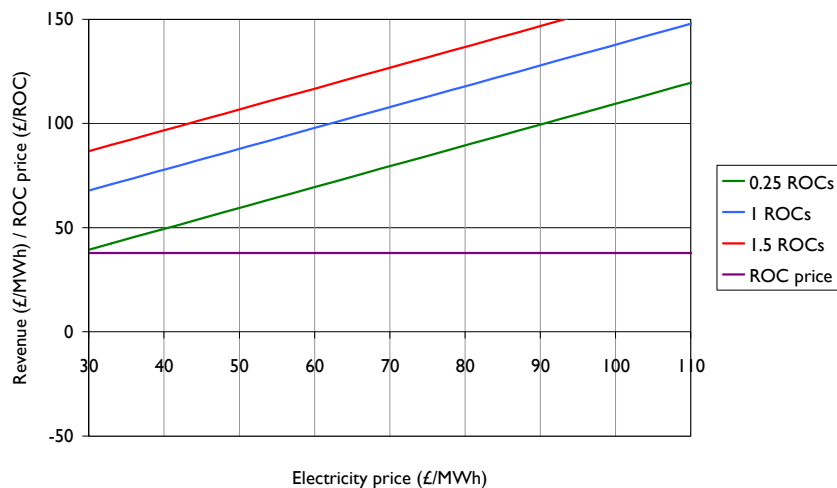
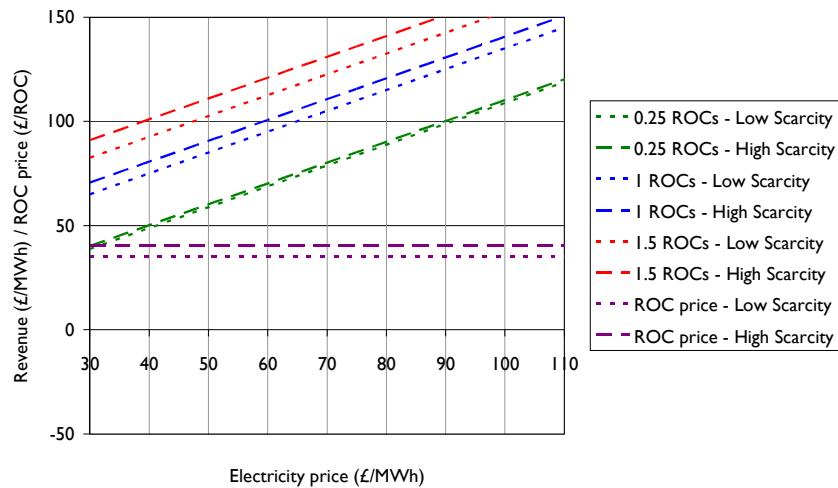


Figure 2 shows the same diagram, but now for a range of ROC prices, from 35 - 40 £/ROC. The variation in ROC price is based on the scarcity of ROCs relative to the Obligation size. It is clear that the revenues increase in the high scarcity scenario (long dashes) and decrease in the low scarcity scenario (short dashes). For each band the difference is constant across the range of electricity prices. The range between the revenues in the high and low scarcity scenarios is greatest for the highest band. This illustrates a current feature of the RO that high band technologies are most exposed to ROC price risk.

Figure 2 Pay off diagram for current RO (range of ROC prices)



A policy which provides full revenue stabilisation will show a flat line on a pay-off diagram for all technologies. There are three key issues with attempting to achieve full revenue stabilisation through the RO:

- **Banding limits usefulness of a simple scalar on the Buy-out price.** The presence of a number of relative bands in the RO leads to difficulties in stabilising the revenue of all plant based on a simple adjustment to the Buy-out price.
- **Avoiding ‘negative’ subsidies.** The level of subsidy received under the RO currently ranges from about 10 £/MWh to about 80 £/MWh. At the lower end of this scale, there is very little scope to stabilise the revenue without creating a situation where the RO could take money away from generators under certain circumstances. Trying to recover revenues from generators would be very difficult to implement.
- **Impact of scarcity signal.** The ROC price varies form year to year based on the size of the recycle fund. Any indexation can amplify or reduce the effect of this variation, depending on the level of the wholesale price.

Figure 3 shows the pay-off diagram for a simple scaling of the Buy-out price. The Buy-out price is scaled inversely based on the wholesale price. It is clear that the revenues have not been stabilised and are non-linear. Relativities between bands change depending on the electricity price.

Figure 3 Scaled Buy-out price

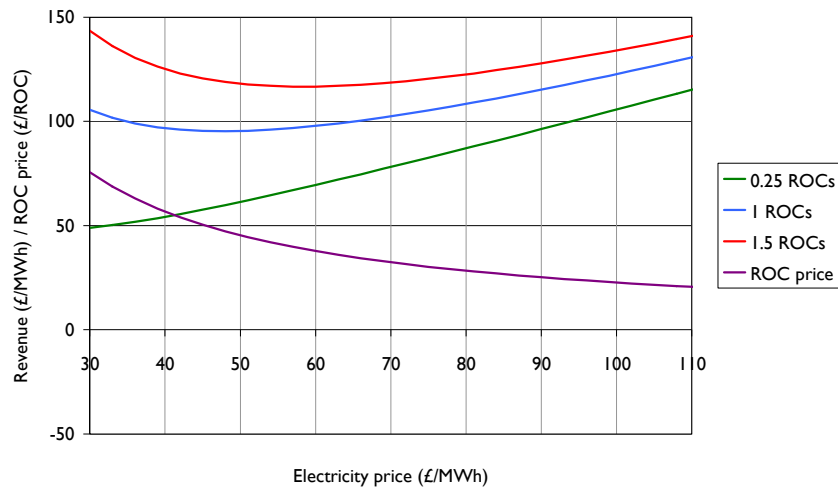


Figure 4 shows an adjusted Buy-out price scheme, where the Buy-out price is adjusted up or down by the same amount in absolute £/MWh terms (rather than scaled as was the case shown in Figure 3) as the wholesale price moves down or up from a base price. This method achieves stabilisation for the 1 ROC band, but not for other bands. Indeed for the 1.5 ROC band, the pay-off is counter-intuitive with all in revenues *decreasing* as electricity prices increase.

Another feature of this option is that past a certain point, the ROC price would have to become negative in order to maintain the stabilisation. In this situation, the RO would become a mechanism for recovering money from renewable generators which in practice would be hard to implement. This could be avoided by placing a floor on the ROC price at zero.

Figure 4 Adjusted Buy-out price

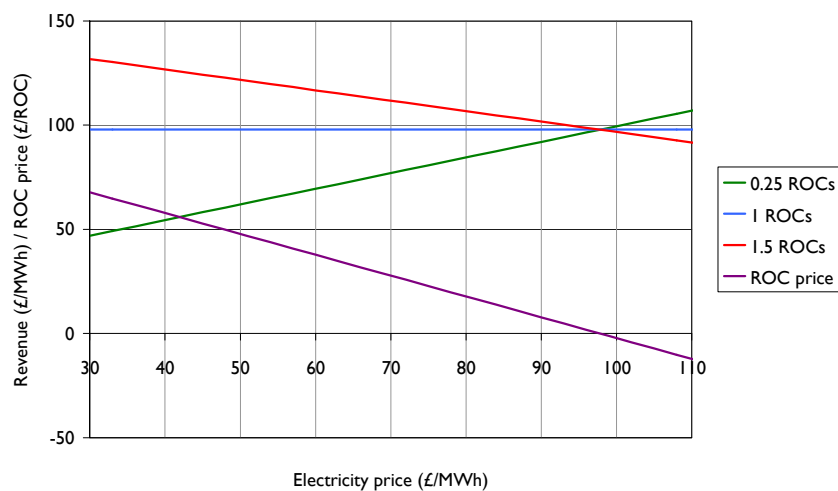
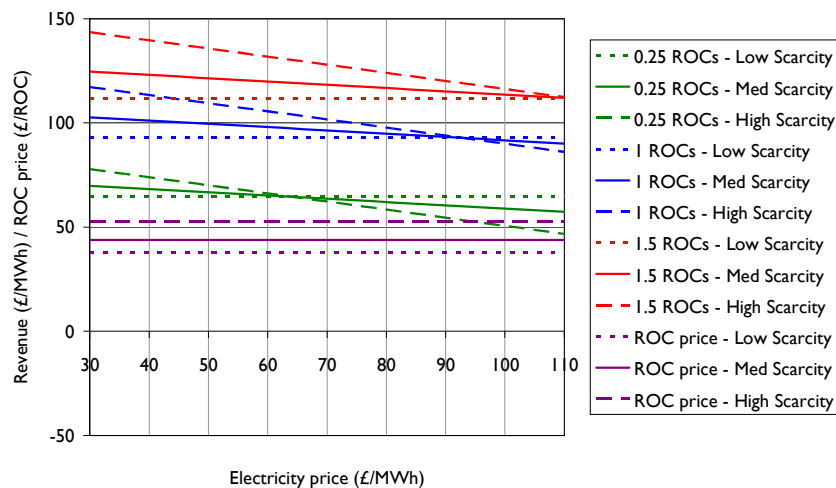


Figure 5 shows the impact of a varying ROC price (scarcity signal) on stabilisation. In this example we show a band level indexation approach, in which the bands, rather than the Buy-out price, are adjusted to keep revenues stable. As scarcity increases, the stabilisation becomes poorer – as can be seen as the slope

of the line increases from low scarcity (short dashes) through medium scarcity (solid) to high scarcity (long dashes). In fact revenues go down as wholesale prices go up. This is because the effect of the scarcity signal is multiplied when the wholesale price is low (and hence the band adjustment is higher, increasing the scaling effect as the ROC price varies), but reduced when the wholesale price is high (and the band adjustment is low, dampening the effect of changes in the Buy-out price).

Figure 5 Adjusted bands + fixed annual target



The previous discussion highlights the difficulties of completely stabilising the revenues of renewable generators using the RO. Simple adjustments to bands or the Buy-out price do not work for all cases. However it is possible to design more complex adjustments which do achieve this aim. Having illustrated some of the difficulties in finding approach ways to introduce stabilisation, we explain in the following section how we have sought to address these and made the selection for the shortlisted Options for quantitative analysis.

3.3.3 Selection of Phase 2 Options for Quantitative Analysis

A key challenge for an approach which adjusts the Buy-out price is that it affects future revenues of all plant, rather than just new plant, and therefore undermines the grandfathering principle (see Section 5). It was therefore decided to include only a single option of this sort in the shortlist. To reduce the impact on existing plant, the option selected employs a cap and collar approach which, depending on how the caps and collars are set, will leave plant unaffected within a given range of wholesale prices.

Two options were selected that use the banding mechanism to achieve stabilisation, leaving existing plant unaffected. One cap and collar and one full stabilisation option were included to enable a direct comparison.

The analysis shows that revenue stabilisation options involving adjustments to the Buy-out price or banding become less effective (and may even create perverse signals) when fixed annual targets can cause a significant scarcity signal. To avoid this problem, if a fixed target approach is adopted, alternative mechanisms outside the RO may be considered. We have investigated how this could work by modelling a CfD struck against the electricity wholesale price operating in addition to RO mechanism.

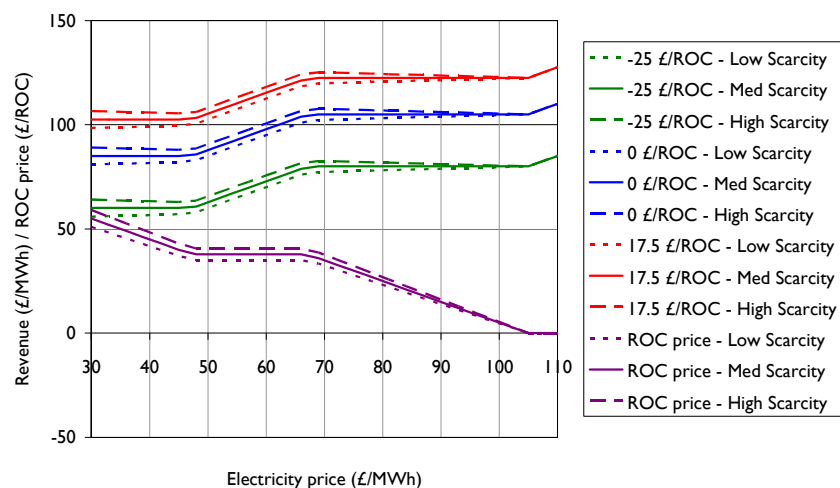
These four shortlisted options are described below in more detail:

Cap and collar on Buy-out + absolute bands

As described above, it would not be possible to create full revenue stabilisation for all types of renewable plant by indexing the Buy-out price with the current banding approach in place. Hence, in this option we have imposed ‘absolute’ bands (i.e. a fixed premium or discount in £/MWh). This would simplify the ROC market since 1 ROC would equal 1 MWh again, but would require a separate cashflow to collect and distribute premia and discounts. It is likely that there would be a shortfall in this fund (since net banding is expected to be greater than one) which would need to be levied on consumers via suppliers.

The pay-off diagram for different banded renewables when cap and collar revenue stabilisation is applied to the Buy-out price is shown in Figure 6. We have applied a floor of zero to the ROC price. Further, an adjustment is applied such that full stabilisation is achieved should the Obligation size in a given year be exactly the Headroom percentage above outturn (shown as the “medium scarcity” solid lines in the figure). Where the Obligation size varies from this (as it will due to annual variability in intermittent renewables), revenues will move somewhat away from full stabilisation.

Figure 6 Buy-out Cap-Collar pay-off diagram¹⁸



In this option, the Buy-out price is indexed as follows:

$$\text{If } ROC_t + E_t > Cap_t \text{ then } BO_t = m \times (Cap_t - E_t), \text{ else}$$

$$\text{If } ROC_t + E_t < Collar_t \text{ then } BO_t = m \times (Collar_t - E_t), \text{ else}$$

$$BO_t = BO_0 \times (1 + RPI)^t$$

$$\text{Subject to } BO_t \geq 0$$

Where:

BO_t is the Buy-out price in year t

BO_0 is the starting Buy-out price

¹⁸ In this case the number in the legend represents the absolute premium or discount in terms of £/ROC

E_t is the wholesale electricity price index in year t

E_0 is a defined base electricity price level

ROC_t is the ROC price in year t

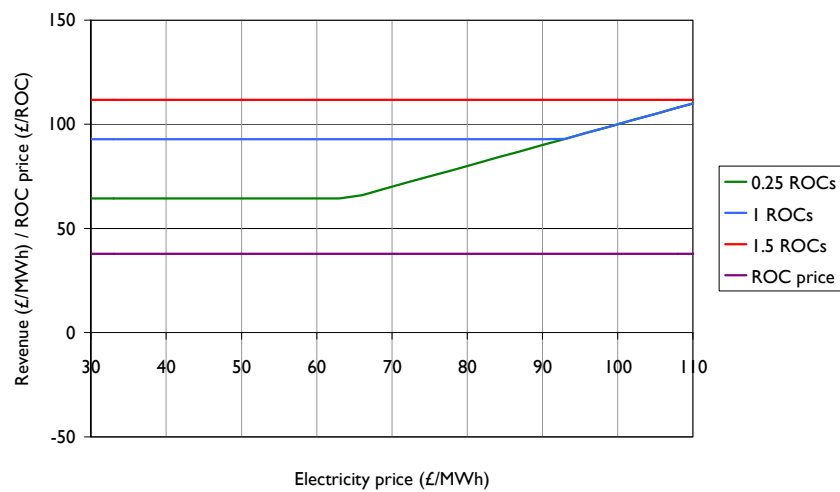
m is a scalar which is set equal to $\frac{1}{1 + Headroom}$

Cap_t and $Collar_t$ are indexed with RPI

Adjusted bands with full revenue stabilisation

Revenue stabilisation based on banding only affects the revenues of new plant. The pay-offs for different banded renewables (new plant) and the ROC price when revenue stabilisation is applied via bands are shown in Figure 7.

Figure 7 Band Indexation pay-off diagram¹⁹



Each ROC band is adjusted according to the following formula:

$$Band_t = Band_0 - \frac{E_t - (E_0 \times (1 + RPI)^t)}{BO_0 \times (1 + RPI)^t \times (1 + Headroom)}$$

Subject to $Band_t \geq 0$

Where:

$Band_t$ is the band in year t

$Band_0$ is the band in the starting year

¹⁹ In this case the number in the legend represents the multiplier for the band

Since the supply of ROCs will be a function of wholesale electricity prices under this approach, the size of the Obligation must be adjusted accordingly each year. For example, if the electricity price is very high, the bands will be reduced and the number of ROCs will be very low. However, if the Obligation size is not adjusted down to compensate, the outturn ROC price could be very high. To achieve full stabilisation, the Obligation size would need to be set equal to the total number of ROCs, once this is known. This would remove the effect of scarcity completely.

By requiring that no band can be negative, the ability of the Option to fix total wholesale revenues expires when the subsidy is fully removed (the band is zero) – after this point, the total revenues begin to increase with the wholesale price. In other words, money is not recovered from generators once the subsidy reaches zero. This is particularly visible in Figure 7 for the 0.25 ROC band.

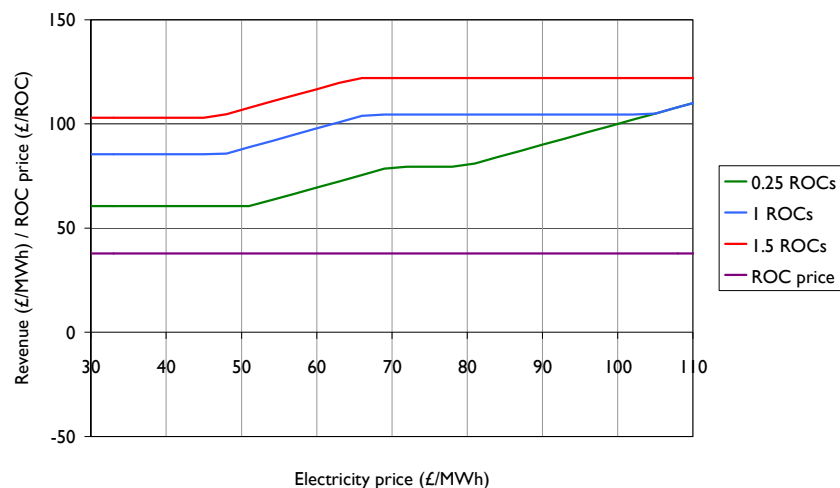
Biomass generators (including co-firing) have significant variable costs and stabilising revenues for biomass will therefore not necessarily reduce gross margin risk, and could potentially increase it (for example if biomass costs were correlated with electricity prices). Therefore we have excluded biomass from the revenue stabilisation in this option, and the bands for these generators are not adjusted by the formula above.

Adjusted bands with Cap and collar

A cap/collar on the bands would remove extreme revenue outcomes for new plant, reducing investment risk and risk of economic rents, but to a lesser degree than full revenue stabilisation.

The pay-offs for different banded renewables (new plant) and the ROC price when a cap and collar are applied via adjusting the bands are shown in Figure 8.

Figure 8 Band Cap-Collar pay-off diagram²⁰



Each ROC band is adjusted according to the following formula:

$$\text{If } ROC_t \times Band_0 + E_t > Cap_t, \text{ then } Band_t = \frac{Cap_t - E_t}{BO_0 \times (1 + RPI)^t \times (1 + Headroom)}$$

²⁰ In this case the number in the legend represents the multiplier for the band

$$\text{If } ROC_t \times Band_0 + E_t < Collar_t, \text{ then } Band_t = \frac{Collar_t - E_t}{BO_0 \times (1 + RPI)^t \times (1 + Headroom)}$$

$$\text{Else } Band_t = Band_0$$

$$\text{Subject to } Band_t \geq 0$$

As is the case with the full stabilisation option, the supply of ROCs would need to be adjusted if the caps or collars are breached and bands are re-adjusted. We also impose the same restriction that bands cannot be negative, and exclude biomass and co-firing from the stabilisation.

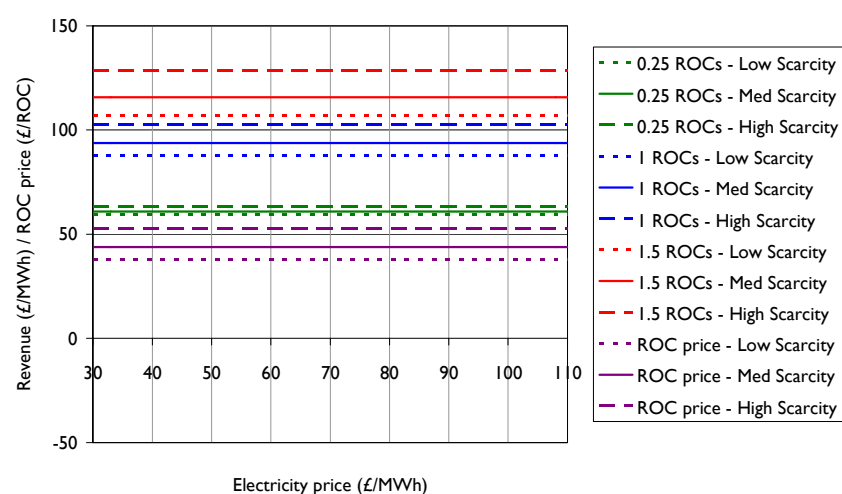
CfD outside RO mechanism

Given that the major portion of the revenue risk is wholesale price risk, there is value in considering an option which manages this directly without changing the RO. A mandatory CfD option was therefore evaluated within the quantitative analysis in which new renewables generators are obliged to enter into a two-way Contract for Difference (CfD) against a wholesale electricity price index.

The RO-based options outlined above are more compatible with the Headroom approach from Phase 1 than an approach with fixed targets, since the introduction of a scarcity signal ‘pollutes’ the revenue stabilisation and revenues decline with higher electricity prices. Achieving stabilisation outside of the RO avoids this problem. For this reason, the RO mechanism we have modelled for this Option includes fixed targets, although it is equally compatible with a Headroom only mechanism.

Figure 9 shows the pay-offs for different ‘ROC bands’ under this approach. It demonstrates that for a given level of scarcity the revenues are insensitive to wholesale electricity price. Revenues can only increase if scarcity increases and vice versa.

Figure 9 Contract for Difference pay-off diagram



The pay off for the CfD is simply:

$$\text{Payment to generator} = E_0 - E_t$$

where the payment may be either positive or negative.

The tenure of the CfD would be an important design choice. Here we assume a 20-year contract (consistent with our assumed participation period within the RO).

4 Quantitative assessment

4.1 Introduction

The objective of the quantitative assessment phase was to analyse in further detail the potential impact of the selected Policy Options on renewables investment and the costs of achieving the renewables target in the GB electricity sector. In particular, we assessed the effectiveness of each scheme chosen in achieving the target level of renewables generation, and their impacts in terms of resource costs, costs to consumers and overall net welfare (relative to a Minimum Change reference option).

The quantitative assessment required sophisticated simulation of investments, retirements and market operation in the GB power sector between 2009 and 2030.

This section of the report is structured as follows:

1. A description of the RO policy assumptions in the modelling (Section 4.2)
2. A summary of our commodity price and capital cost assumptions (Section 4.3)
3. Discussion and explanation of the key metrics and outputs used to characterise the results (Section 4.4)
4. Detailed analysis of the Minimum Change Option (Section 4.5)
5. Detailed discussion of the results of the other Options modelled, compared to Minimum Change (Sections 4.6 to 4.10), focussing on key differences
6. Summary of all results and key conclusions (Section 4.11)
7. Sensitivity analysis around specific assumptions (Section 4.12)

A description of our modelling approach can be found in Appendix B, and additional assumptions are presented in Appendix C.

The Policy Option sections are structured in the following manner:

1. An overview of the Option outlining key features and the headline results from the modelling across all Cases in 2020. We provide:
 - a. total renewable capacity (GW)
 - b. total renewable electricity generation (TWh), including co-firing and non-RO qualifying generation
 - c. renewable generation as a percentage (effectiveness)
 - d. relative cost levels (efficiency)
2. Analysis of the results of the Option under different assumptions, and between Options. This is split into three main areas:
 - a. capacity mix for both thermal and renewable generation

- b. prices, including ROCs, wholesale prices and domestic consumer prices
 - c. rents for renewable generators, focussing on differing rent levels within technologies and total renewables rent.
3. Summary of efficiency and effectiveness.

4.2 RO policy assumptions

4.2.1 Assumptions common to all Options

Across all Policy Options (including the revenue stabilisation Options) we have made some common assumptions around changes to the Renewables Obligation and how these are implemented. These are:

- Extension of the RO to 2037/38
- Participation period extended to 20 years for new projects
- Headroom at 8% in 2010, rising by 0.5 percentage points per annum to 10% in 2014
- Once renewable plant reach the end of the participation period, plant are rolled-off to a support level of 0.25 ROCs per MWh²¹.

Headroom

The Headroom level is assumed to increase by 0.5 percentage points per annum from 8% in 2010 to 10% in 2014. This is based on analysis we performed on the impact of the variability of annual renewable output taking into account likely banding (see Appendix H.2). We assume that in any one year in the modelling period, the Government has reasonable forward visibility of the new RO-qualifying build being commissioned in the following few years and thus sets the Obligation size accordingly to support a ROC price of at least the Buy-out price plus the Headroom percentage. In reality, this is a complex and difficult task due to delays and other issues with renewables projects under development, renewable output volatility (compounded by different band levels for different technologies), and demand variation.

Modelling transitions to new schemes

An assumption has been made in all Policy Options that investors' decisions are not affected by any additional uncertainty associated with a transition to an amended policy framework. In reality there is a risk that investors become more cautious around the time of any policy change as it will take time for policy details to become clear, and as they assess what the change entails for them. This could in turn lead to a slowing in project commitment and development for a period of time. This risk is explored in a sensitivity described in Section 4.12.

Banding

Banding assumptions are shown in Table 2.

²¹ This has minimal impact on the results as there is no roll-off prior to 2027.

Table 2 Banding assumptions

Technology	2009	2013	2018
Onshore Wind	1	1	1
Offshore Wind	1.5	2	2
Biomass (regular)	1.5	1.5	1.5
Biomass (energy crop)	2	2	2
Biomass CHP	2	2	2
Wave	2	3	3
Tidal Stream	2	3	3
Tidal Range	2	3	3
Biowaste	1	1	1
Biogas	2	2	2
Co-firing (regular)	0.5	0.5	0.5
Co-firing (energy crops)	1	1	1

Banding levels in 2009 are as announced in the draft Renewables Obligation Order²². We assume that banding changes are implemented in 2013 and 2018, and we make exogenous assumptions as to the changes in these years.

In 2013, we make changes to the level needed in the model to meet the 28% target in the Minimum Change Base Case. We assume that offshore wind is banded up from 1.5 to 2 ROCs²³ and the marine technologies are banded up from 2 to 3 ROCs. Other alternative sets of banding assumptions could also have been used to deliver the same target, which would have resulted in a slightly different technology mix. The permutations of banding changes are limited given other constraints such as resource and build rates. In 2018, no changes are made to any of the bands.

From an investor perspective, these banding changes are visible two years prior and developers receive the greater ROC level visible at time of commissioning.

These bands are held constant for the modelling of all other Options and Cases (other than sensitivities). This makes for a clearer comparison of the robustness of policies in delivering efficiently to a target, as we do not attempt to ‘correct’ outcomes retrospectively that deliver more or less renewables by adjusting banding levels.

We have also conducted a number of sensitivities in which bands are adjusted such that specific 2020 renewable generation targets are met under different assumptions. These are described in Section 4.12.3.

4.2.2 Revenue stabilisation assumptions

When considering revenue stabilisation (Sections 4.7 to 4.10), we have kept the key parameters constant across the Policy Options, in order to allow robust comparisons to be made between them.

²² <http://www.berr.gov.uk/energy/sources/renewables/policy/renewables-obligation/key-stages/ro-consultation-2009/page46709.html>

²³ The analysis was performed prior to the 2009 Budget’s announcement in relation to banding changes of offshore wind (described in Section 2.3.2).

- All Options are mandatory and plant build decisions under the Option take full account of the impact (with a corresponding reduction in hurdle rates where revenues are stabilised).
- The Phase 2 Options are implemented in 2013. Investors are aware of the change two years earlier, in 2011.
- The base wholesale electricity price around which stabilisation is set (E_0) is 60 £/MWh. The same E_0 is also used as the strike price for the CfD Option.
- Caps and collars, for the Options that include them, are set to create a range of ± 10 £/MWh around the total target revenue (for a given band) achieved with the wholesale price at E_0 . This equates to approximately ± 0.25 ROCs in the Band Cap/Collar Option.

E_0 has been set at a level close to that of prevailing wholesale prices in the Minimum Change Base Case, since that led to renewables deployment in the model close to the desired 2020 target (combined with appropriate re-banding). The level of the cap and collar was chosen such that it is effective in limiting the consequences of extreme events, such as price shocks or large drops in electricity price, but is still broad enough to have a material affect on investors' earnings and perceived risk.

4.3 Commodity and capital cost assumptions ('Cases')

Fuel and carbon price assumptions are based on the January 2009 Updated Fossil Fuel Price Assumptions (UFPF) published by DECC. Carbon price assumptions were provided by DECC for the study.

Renewable plant capital costs are based in part on the (unpublished) outputs of a Generation Cost Workshop hosted by DECC on 28th November 2008, and in part on our internal analysis. We also include a 'learning curve' effect which reduces these capital costs over time in anticipation of technology developments and increasing competitiveness of the supply chain.

Three permutations of commodity and capital costs have been considered. We refer to each of these permutations as a Case. The sources of the key assumptions are outlined in Table 3, and discussed further below.

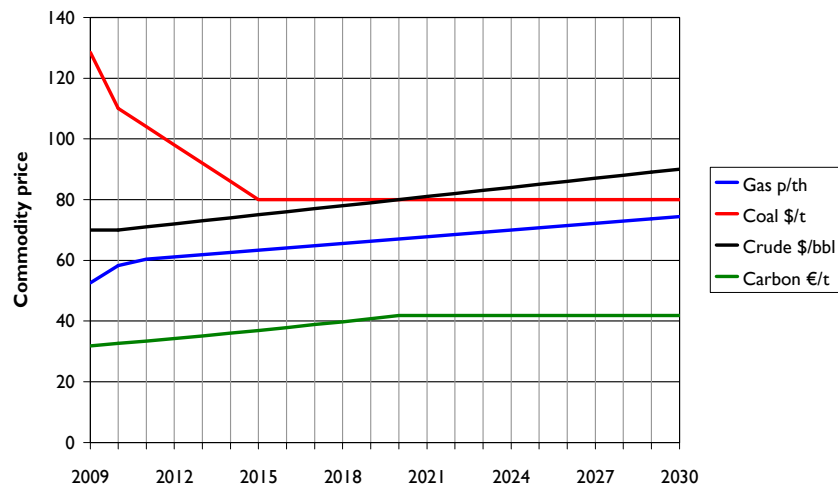
Table 3 Case assumptions

Case	Commodity prices	Capital costs
Base	DECC Updated Fossil Fuel Prices and EUA assumptions (DECC Central Scenario)	Based on DECC assumptions from generation cost workshop
Price Shocks	Same as Base, but for three years prices taken from the DECC High High Scenario	Same as Base
Low	DECC Updated Fossil Fuel Prices and EUA assumptions (DECC Low Scenario)	Same as Base, but with renewables capital costs decreasing to lower levels

Base Case

The Base Case uses the UFFP January 2009 central view of long term commodity prices. Renewable capital costs decline gradually through time, and commodity prices slowly increase. These are shown in Figure 10.

Figure 10 Base Case commodity assumptions



Price Shocks Case

This Case has been developed to assess the impact of continuing volatility in the commodity markets, as has been observed in the last two years. Capital cost assumptions are the same as the Base Case, and Commodity prices are the same except in three years, 2015, 2022 and 2029, when commodity prices spike to the DECC 'High High'²⁴ view. The spikes are illustrative and no significance should be attached to their particular timing. The Price Shocks Case is designed in particular to differentiate Policy Options based on their ability to limit excessive rents for renewables in the event of short-lived periods of high electricity prices.

Low Case

This Case tests the impact of changing the relativity between capital costs and commodity costs. Whilst both are lower compared to the Base Case, the reduction in the commodity price assumptions is much larger than the reduction in capital costs. Qualitatively, this reduces expected revenues in the Low Case more than the reduction in costs, creating a more challenging environment for investment.

4.4 Results Metrics

In this section we introduce the metrics that are used to present the results of the quantitative analysis.

²⁴ DECC produce four commodity cost scenarios which are labelled in ascending order Low, Central, High and 'High High'

4.4.1 Key metrics

Comparing the performance of different Policy Options is a complicated process given the complexity of the interactions between costs, revenues and subsidies for different technologies of different vintages, and how these change over time. We use Effectiveness and Efficiency metrics to assist in this comparison, which we have defined as follows.

- **Effectiveness** is the percentage level of renewable electricity generated (compared to total) in 2020. This should be compared to the target level for the electricity sector within the overall renewables 15% target. For this study, we have assumed that the electricity sector target is 28%.
- **Efficiency** is a ‘value for money measure’, comparing the additional amount paid by consumers for renewables to the underlying generation cost. A value of 100% would indicate that the level of subsidy provided is approximately the same as the average cost of renewable generation compared to a conventional non-renewable generation benchmark (for which we use the cost of generation from a new CCGT). Efficiency can be calculated by the Generation Cost Index divided by Consumer Cost Index, where these are defined as:
 - **Generation Cost Index = Renewable Generation Cost / New CCGT Cost**
A measure of the additional cost of renewables to producers, relative to a conventional generation benchmark (CCGT). A value of one would indicate renewables cost equal to the cost of generation from conventional non-renewable plant.
 - **Consumer Cost Index = (Renewable Subsidy + New CCGT Cost) / New CCGT Cost**
This is a measure of the additional cost of renewables to consumers, relative to a conventional generation benchmark.

The terms in these metrics are described further below.

Renewable Generation Cost

This is the total cost of renewable generation, accounting for capital, fixed and variable costs. It takes no account of renewable revenue streams. This includes both new plant built by the model, and plant already on the system. For existing plant, we have made estimates of the associated costs but the uncertainty here should be taken into account, particularly in the earlier years, when existing plant are proportionately more of the overall renewable portfolio.

Subsidy

This is the sum of the cost of the Renewables Obligation and subsidy provided through Levy Exemption Certificates (LECs). The RO subsidy is the RO size multiplied by Buy-out price. LEC subsidy is LEC value multiplied by renewable energy delivered.

New CCGT Cost

The New CCGT Cost is intended as a measure of ‘fair value’ of power for the likely marginal new build conventional thermal plant. CCGTs are typically the best new entrant (excluding nuclear) under our Cases. Using such a benchmark is important because it removes the impact of wholesale price movements in the comparisons of Policy Options and Cases. In any year it is simply the cost of the volume of renewables generation if it was instead generated by CCGTs, based on that year’s long run marginal cost.

Changes in the Efficiency metric are driven by a complex combination of underlying variables and effects. Understanding the reasons for differences between Cases and Options can therefore be difficult. However, we believe it provides useful relative summary information to assist in comparisons. In the main body of this report we provide qualitative discussion of changes in efficiency (although we do not explore

the drivers numerically). Quantification of the Generation Cost Index and Consumer Cost Index are provided in Appendix J.

4.4.2 Specific outputs

Alongside the key metrics described in 4.4.1 we present a number of other measures for each set of model results.

ROC Price

The ROC price is the all-in price of a Renewable Obligation Certificate. We model it in two parts²⁵:

- Buy-out, which is 35.76 £/MWh in real 2008 terms and is held constant in real terms throughout. This is referred to as **Buy-out price**, or just Buy-out.
- Recycle revenue, which is the money collected through the Buy-out mechanism from suppliers who have failed to meet their obligation and returned to ROC holders, thus pushing up the value of ROCs above the Buy-out price.

When the Obligation size is set at the correct level to maintain Headroom, the ROC price is increased above Buy-out by the Headroom percentage (10% from 2014, giving 39.34 £/MWh). We refer to this price level as **Buy-out + Headroom**).

Wholesale Price

The annual wholesale electricity prices shown in this report are time-weighted baseload prices. These are clearly a key component of the consumer cost, and earnings for renewables generators. Whilst the level of wholesale price is dominated by the commodity price levels for each Case, there are differences between Options under the same Case. This is a result of the different resulting capacity build profiles, which in turn change the year-to-year system capacity margin, with a resulting impact on electricity prices.

Economic Rent

Economic rent is the additional earnings achieved by a generator above the level required to cover operating costs, debt costs, and to earn a reasonable return on investment. Under the RO as it stands, rents for renewables generators are strongly influenced by the level of wholesale prices. However, even under the revenue stabilisation schemes we have modelled, there will always be a spread of rents both because of the variation of costs of technologies within each of the RO bands, and because of the different treatment of plant of different vintages as a result of grandfathering.

Rent is presented in two ways through this report:

- Renewables rent. This is measured in £mn, and is the total rent achieved by all renewables in a given year
- Technology rent. This is measured in £/MWh for a given technology (and broken out by yield category for wind plant).

It should be noted that for future plant that are developed endogenously within the model, the reported rent is internally consistent, as there is a precise (modelled) definition of each of the components. This differs from existing plant, for which the actual costs are not precisely known to us. As such, the absolute

²⁵ In practice there may be cashflow affects associated with lags between ROC issuance and payments between participants (which will vary based on contractual terms). For simplicity we ignore the impact this may have on the ROC price.

level of reported rent in the early part of the modelling horizon (where existing plant dominate the mix) should be treated with caution. This does not detract from the messages to be drawn from the relative differences in rent between Cases and Options.

Domestic Consumer Price

This is a measure of the final price of electricity for a typical domestic consumer, normally quoted in £/MWh. It is the sum of wholesale electricity costs, RO costs, transmission and distribution charges, supplier margin and VAT. For simplicity, we assume transmission and distribution charges are invariant and tax and supplier margins are fixed percentages, although these components are all likely to change over time.

Capacity Margins

The key indicator we use to assess security of supply between Cases and Options is the de-rated peak capacity margin. This is a measure of expected peak availability compared to peak demand. This takes into account the capacity credit, which measures the percentage of maximum potential output that statistically can be shown to contribute to security of supply. For conventional plant this will cover forced outages, and for intermittent (wind and wave) and variable-output (tidal) renewables it will in addition account for expected output based on probabilistic analysis of resource levels. The methodology for modelling capacity credit of intermittent and variable-output renewables is described in Appendix E.

The energy margin is a measure of the total available generation in TWh compared to annual demand in TWh.

Supply curve effect

For any one renewable technology, the costs can vary significantly between projects for a variety of reasons, such as ease of grid connection, location and supply chain constraints. Therefore, if two sites of the same technology and yield are developed, but have different cost bases, the rent made by these projects will differ. This is frequently described in this report as the 'supply curve effect'. This is not a specific measure that is quantified in the report, but it helps provide qualitative information in relation to plant development and rents.

4.5 Minimum Change

4.5.1 Overview

Minimum Change retains many of the current features of the Renewable Obligation, including the existing annual targets through to a 15.4% level in 2015/16, but removes the absolute limit on the Obligation size so that the Obligation can be increased to the level required (beyond 20%) to maintain Headroom and support the ROC price at or above the Buy-out price. Once the penetration of RO-qualifying renewables plant is above the trajectory, ROC prices are expected to move in a very limited range close to but above the Buy-out price on average.

The premise of the banding changes assumed in 2013 is to deliver 28% generation from renewable sources in 2020. Table 4 shows that in the Base and Price Shocks Case the 28% level is met. In the Low Case the 28% level is missed by 5.6 percentage points, delivering 22.4% of electricity generation. In the Price Shocks Case, efficiency is reduced due to higher levels of rents in the 'price spike' years.

Table 4 Minimum Change summary results ²⁶

2020	Minimum Change		
	Low	Base	Price Shocks
Renewable Capacity (GW)	25.9	32.7	32.7
Renewable Generation (TWh)	86.5	107.4	107.4
Effectiveness %	22.4%	28.1%	28.1%
Efficiency %	85%	75%	72%

These results are explored in more detail in the following sections.

4.5.2 Base Case

Below, we describe the Base Case results for the Minimum Change Option in detail, to provide a basis for comparison for the results of the other Policy Options modelled.

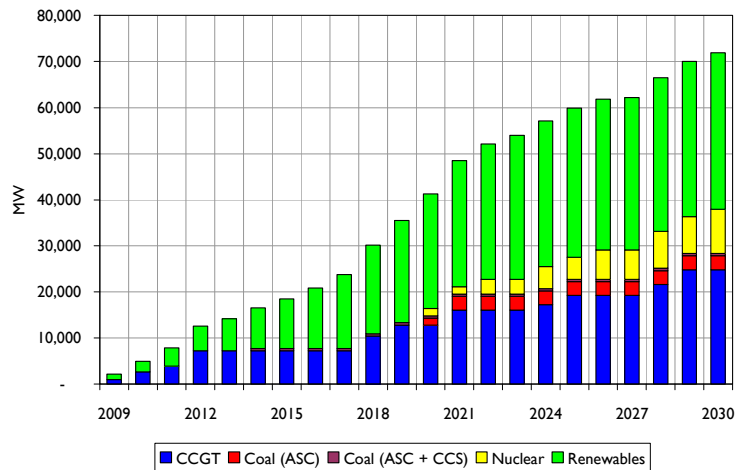
Capacity and Generation Mix

Figure 11 shows the new build of thermal and renewable plant through to 2030. In terms of capacity constructed, renewables have the largest share for the majority of the time period. By 2020 there is 12.8 GW of CCGT, the first 1.6 GW of new nuclear plant are online and 24.7 GW of renewable plant are connected. There is also 1.5 GW of unabated Advanced Super Critical (ASC) coal and a 500 MW CCS demonstration project. (Note that the analysis pre-dated the recent Government announcement to provide support for up to four CCS demonstration projects by 2020, and requiring all new coal plant to be able to retrofit CCS once the technology is technically and economically proven.)

Without financial support, no further CCS is delivered throughout the Case as it is not economic given the assumed capital and operating costs, while a small amount of additional unabated ASC coal is developed. An additional 1.6 GW of nuclear capacity comes online every other year, with a total capacity of 9.6 GW by 2030. There is a further doubling of new CCGT plant in the period 2020-2030.

²⁶ Please note 4.0 TWh of renewable generation does not qualify for the Renewables Obligation. This is static across Cases and all Policy Options. This generation is delivered from 1.25 GW of capacity. .

Figure 11 New plant build, Minimum Change, Base Case



More detail on the renewable deployment is shown in Figure 12. In 2020, of the 24.8 GW of total new renewable deployment from 2009, 90% is wind – 49% offshore and 41% onshore. Biomass build is constrained by the availability of fuel supply. After 2025, no further investment in wind plant is taking place, and tidal stream is contributing most to new build at a rate of 200 MW per annum, reaching a total installed capacity of 3.1 GW by 2030.

Figure 12 Renewables plant build, Minimum Change, Base Case

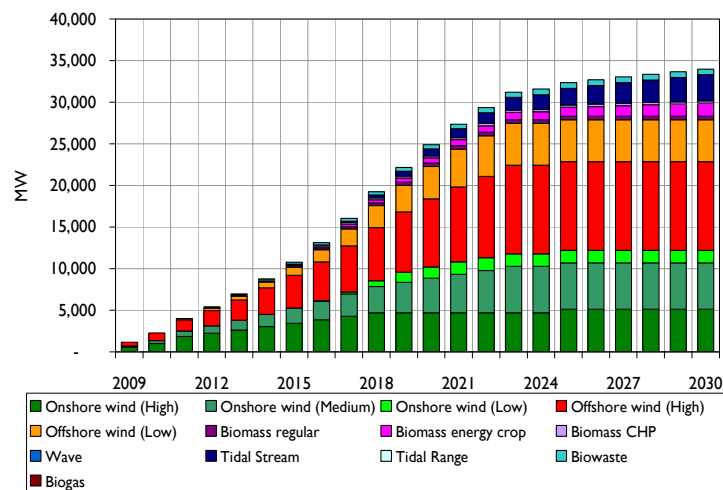
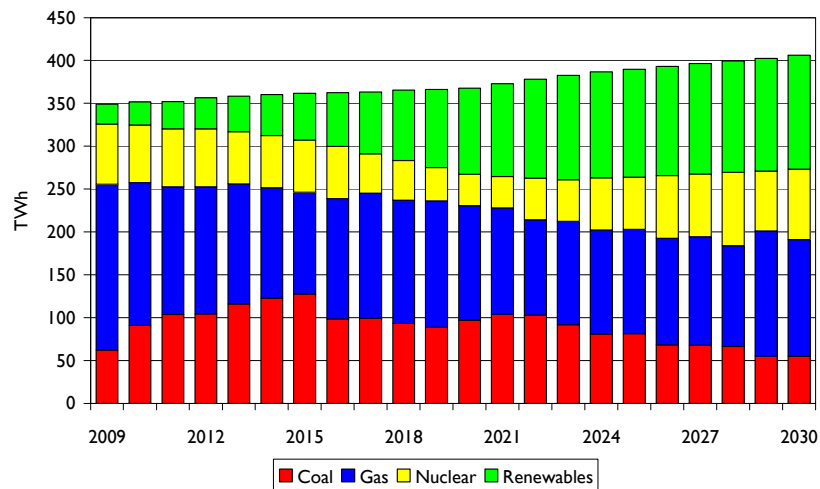


Figure 13 shows output by fuel type. By 2020, 28% of generation is coming from renewable sources. The rate of growth of renewable output is at its greatest between 2015 and 2020, partially due to the increase in bands in 2013, as well as the increasing maximum build rates for renewables. This period coincides with closures under the Large Combustion Plant Directive (LCPD), Industrial Emissions Directive (IED) restrictions on coal and some gas plant and nuclear retirements.

In 2009, fuel and carbon price levels favour generation from gas over generation from coal. This relativity reverses by 2015. Coal generation reduces over time post-LCPD as older capacity is retired and new plant is not built to replace it. However, due to the economics of the Base Case, the more efficient existing coal plant is still profitable by 2030, and having made the necessary investment in retrofitting NOx reducing

equipment and necessary maintenance, some remain open despite their age. Nuclear generation shrinks through to 2019 with the enforced closures of AGR plant, before a new generation of nuclear plant becomes operational during the 2020s. By 2030 nuclear generation has returned to around current levels. Gas generation reduces over time, despite increased build, as the short run economics are not favourable relative to coal, and renewables increase the competition for baseload generation.

Figure 13 Plant output by type, Minimum Change, Base Case



In Figure 14, cumulative plant retirements are shown. The most prominent feature is the closure of the majority of the existing coal fleet, driven by LCPD legislation and the anticipated restrictions of the IED, which may precipitate further closures. Of the existing nuclear fleet, only Sizewell B will still be operating in 2030.

Figure 14 Plant retirements, Minimum Change, Base Case

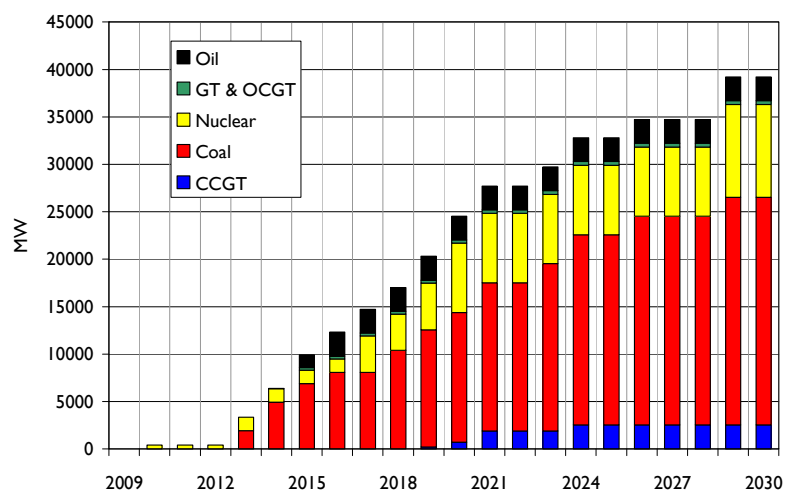


Figure 15 shows three measures of supply margin for the Minimum Change Base Case. The de-rated peak capacity margin rises as new CCGTs come online whilst demand growth remains flat, before reducing to 2017, after which it stabilises in a range of 5% to 10%. This is well below present levels of around 15%. The non-de-rated peak capacity margin continues to increase post 2017 as the total capacity on the system increases relative to the de-rated capacity, due to the increasing penetration of intermittent renewables.

The energy margin drops markedly with LCPD enforced closures and restrictions caused by the IED, before returning to around 40%, a level which is comparable to today.

Figure 15 Supply Margins, Minimum Change, Base Case

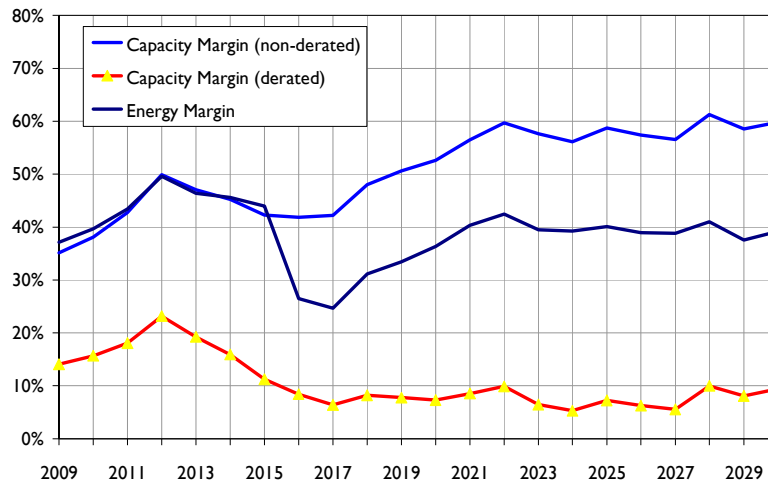
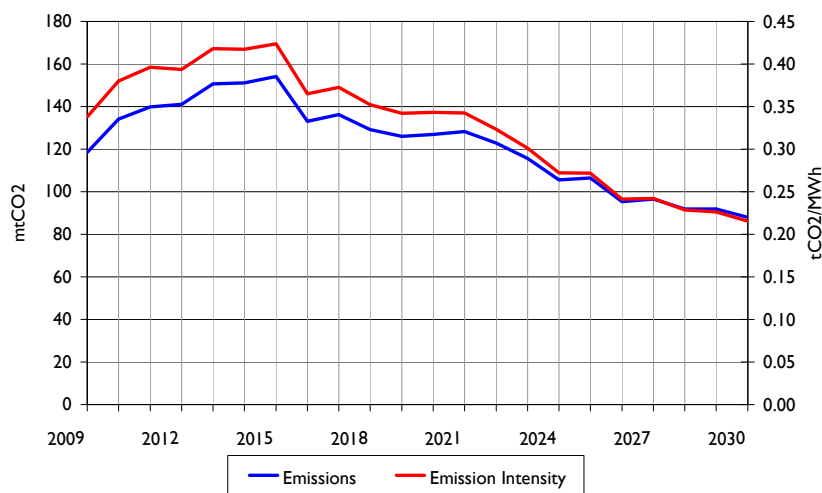


Figure 16 shows the annual carbon dioxide emissions from the power sector. In 2009, emissions are relatively low due to the high proportion of output from CCGTs. From 2010 to 2015, emissions rise as generation from coal displaces generation from gas. However, with the deployment of renewables and later new nuclear, and coal closures, emissions start to reduce from 2016, and continue to do so through to 2030. By 2030 there is a reduction of 26% over 2009 levels. This is still significantly less than the target outlined by the Committee on Climate Change (which requires an emission intensity of 0.12 tCO₂/MWh in 2030, compared to 0.22 tCO₂/MWh in this Case): we have not included any post-2020 decarbonisation policies in our analysis but clearly significant further measures will be required.

Figure 16 Annual carbon dioxide emissions, Minimum Change, Base Case

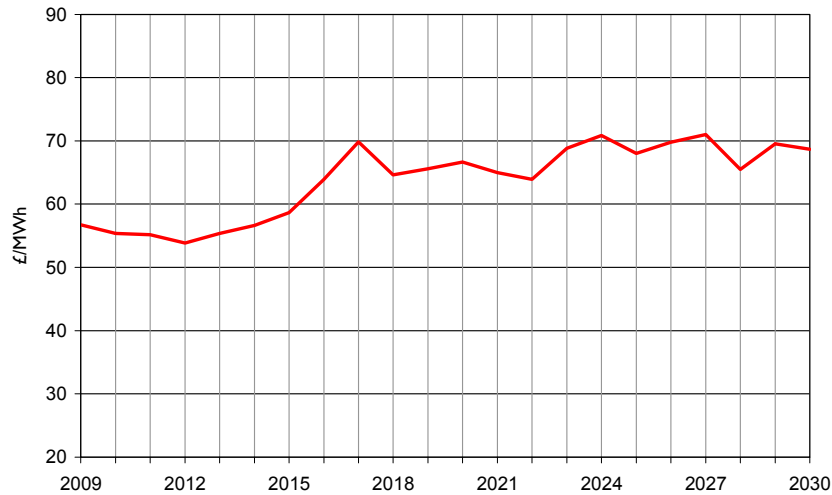


Prices

Figure 17 shows the annual baseload price over the modelled period. In the near term, with increasing capacity margins and steady demand levels, prices decrease. Rising demand, along with plant closures, sees

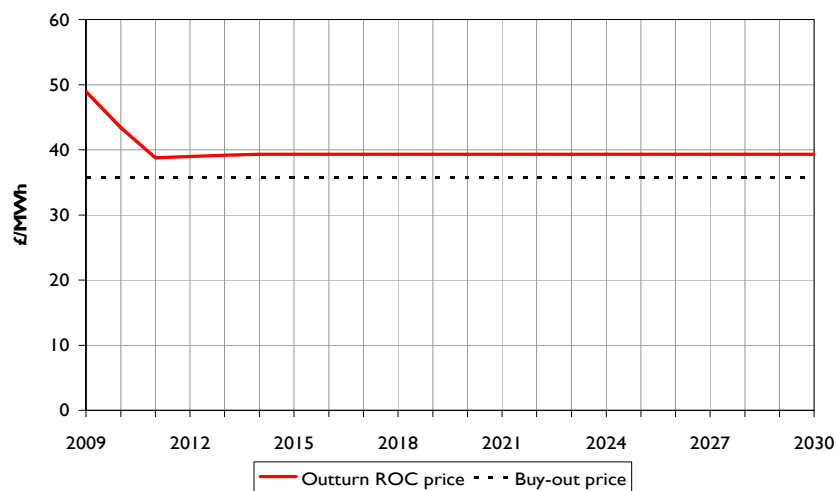
a tightening in margin through to 2017 and a corresponding rise in prices. Prices then slowly trend upwards on the back of increasing commodity price assumptions. The variations in this trend follow fluctuations in capacity margin.

Figure 17 Wholesale baseload electricity prices, Minimum Change, Base Case



The ROC price is sustained at Buy-out plus the Headroom percentage from 2011, as shown in Figure 18. Note the slight increase over time due to the assumed increase in the Headroom percentage between 2010 and 2014. Prior to that, there is a shortage of ROCs relative to Obligation size and therefore significant revenue recycling occurs. It is worth noting that in reality the ROC price will be more variable than that shown here, due to the impact of natural variation in renewables output and the fact that the Government will not have perfect foresight of the volume of renewables being connected in each year when setting the Obligation size.

Figure 18 ROC prices, Minimum Change, Base Case



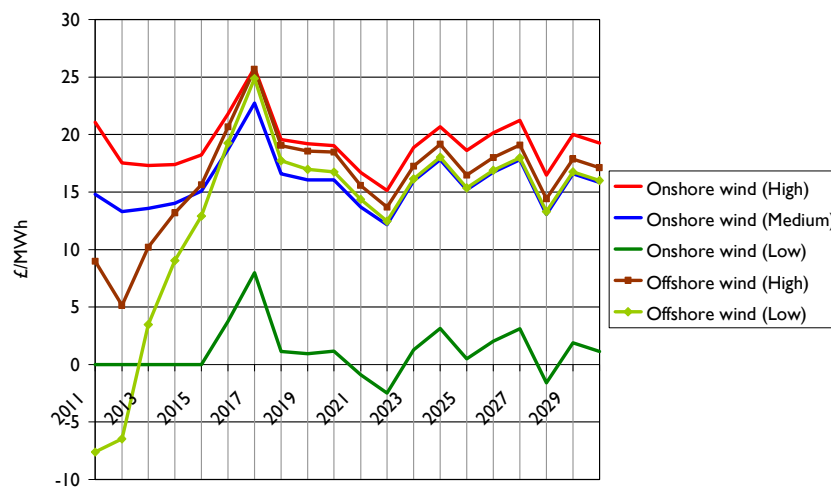
Rents

Figure 19 shows the level of rent received by wind plant, as split by yield category. Rent levels at somewhere below 20 £/MWh are comparable with the value of half a ROC, and hence within the

granularity of banding. In this Case, Onshore wind (Low) is barely economic, which corresponds to the low level of deployment observed in Figure 12.

An interesting feature of the offshore wind is the near convergence of rent levels for differing yields. This is due to the shape of the supply curves and the higher deployment of offshore wind (high). It shows that from an investor perspective, low yield (implying low revenue) sites coupled with low costs (further down the supply curve) offshore wind sites can be preferable to high yield (implying high revenue) sites which have high development costs (further up the supply curve).

Figure 19 Renewable rents, Minimum Change, Base Case



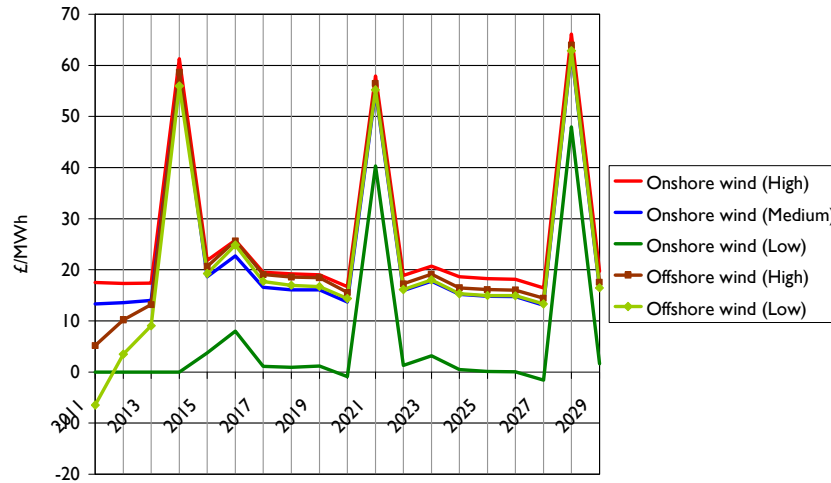
4.5.3 Price Shocks Case

The commodity price shocks occur in 2015, 2022 and 2029. Under Minimum Change assumptions, these shocks make very little difference to the capacity build profile relative to the Base Case, since investors are unable to anticipate them in the model. Renewable build is identical to the Base Case, and hence ROC prices are also the same.

The main difference to the Base Case is that rent levels in price shock years are significantly higher due to the higher wholesale price²⁷. This demonstrates the risk within Minimum Change of high levels of rent for existing plant that do not translate into a signal for further renewable deployment. In the non-price shock years, rent levels are very similar to the Base Case.

²⁷ Where generators have sold their output forward they may not benefit from these price spikes, but the counterpart to the offtake agreement would, notwithstanding other possible exposures within their portfolio caused by the price spikes.

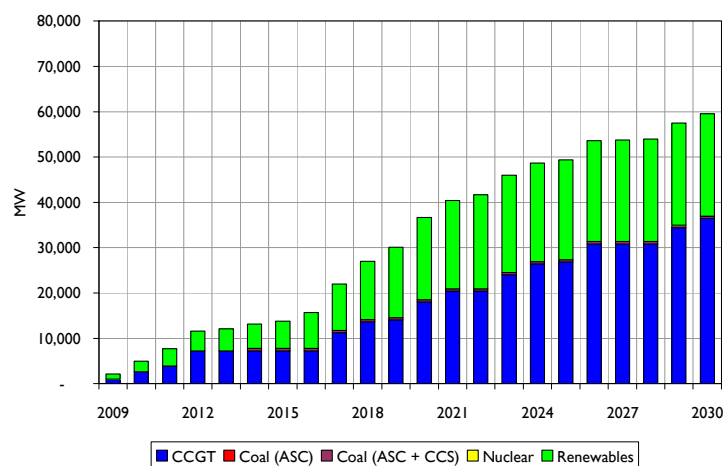
Figure 20 Renewable rents, Minimum Change, Price Shocks Case



4.5.4 Low Case

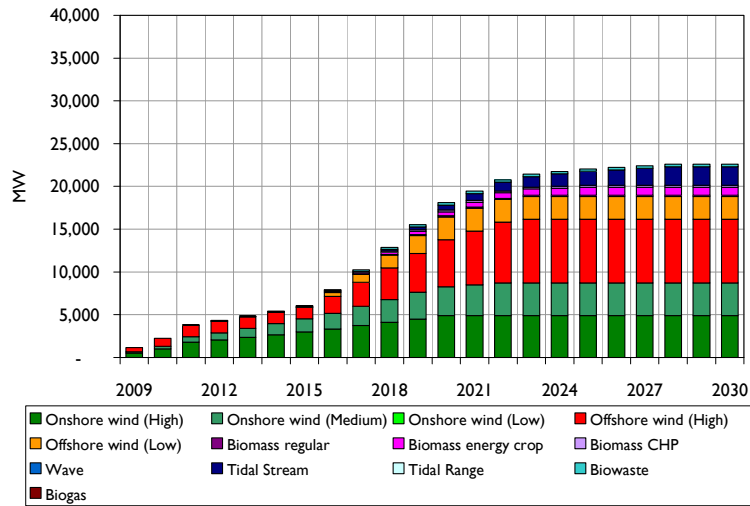
With lower gas prices in the Low Case and lower capital costs, nuclear is no longer economic and new CCGT is the only non-renewables plant built (except for the CCS demonstration plant), with over 35 GW installed by 2030. There is also a lower level of renewable development, with only 22.4% of electricity being delivered by 2020 (approximately 18 GW of capacity).

Figure 21 New plant build, Minimum Change, Low Case



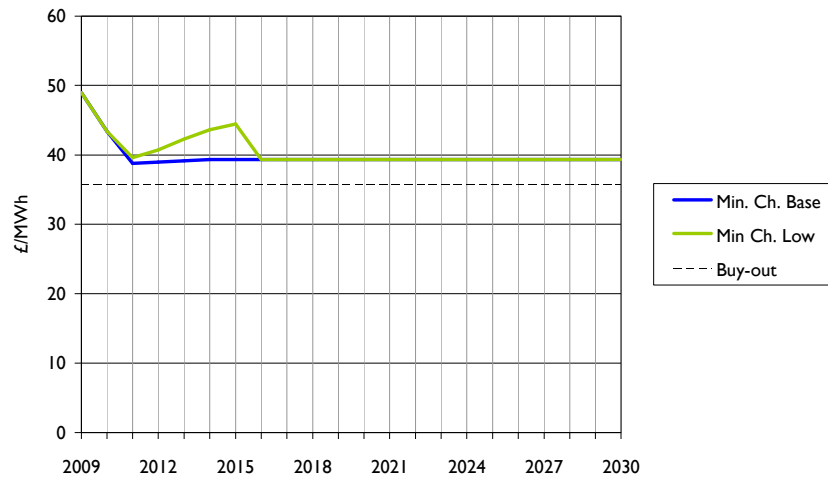
In Figure 22, we see the significant reduction in renewable build. In the Low Case, Onshore wind (Low) is never economic, and deployment of all other technologies is lower relative to the Base Case.

Figure 22 Renewable plant build, Minimum Change, Low Case



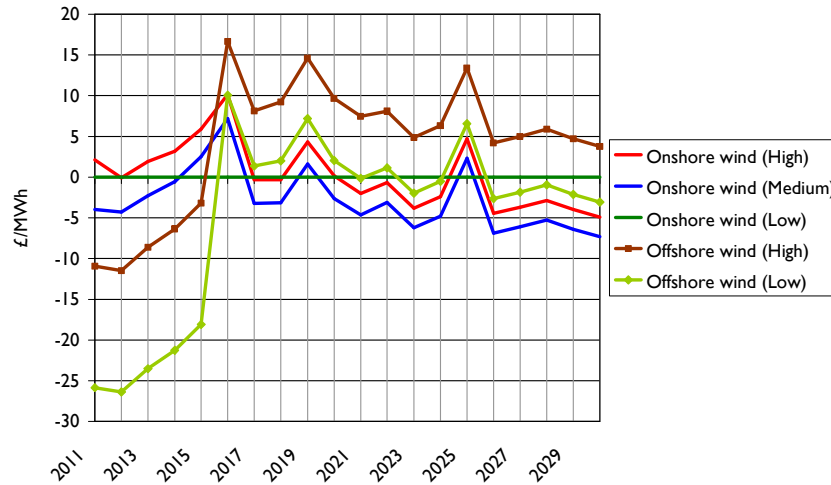
As shown in Figure 23, the outturn ROC price is the same as in the Base Case up to 2011. However, the low commodity prices reduce build such that by 2015, the output of renewable generators and the number of ROCs they receive is less than the 15.4% Obligation size. There is an increase in revenue recycling and therefore the ROC price is higher. Beyond 2015, the output of ROCs exceeds the 15.4% level and so the Obligation size is increased to maintain Headroom, and the ROC price stabilises at the Buy-out price plus Headroom percentage.

Figure 23 ROC price, Minimum Change, Low Case



Rent levels in the Low Case are lower than in the Base Case, due to lower wholesale prices. It can be seen in later years that only high yield offshore wind sites are economic.

Figure 24 Renewable rents, Minimum Change, Low Case

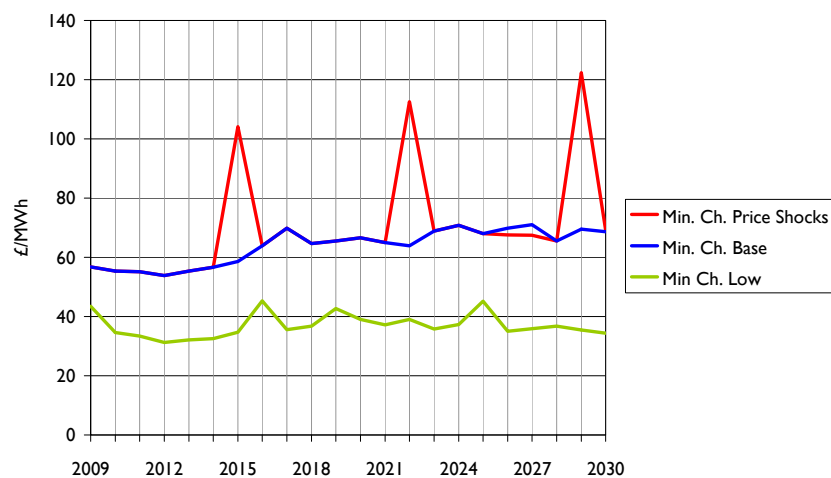


4.5.5 Comparison between Cases

The major differences in electricity prices across the three Cases are driven by commodity price levels. In the Price Shocks Case, they are virtually identical to the Base Case except in 2015, 2022 and 2029 (the ‘price shock’ years). In the Low Case the commodity prices are much lower, and as such the short run operating costs of thermal plant is much lower, reducing wholesale prices.

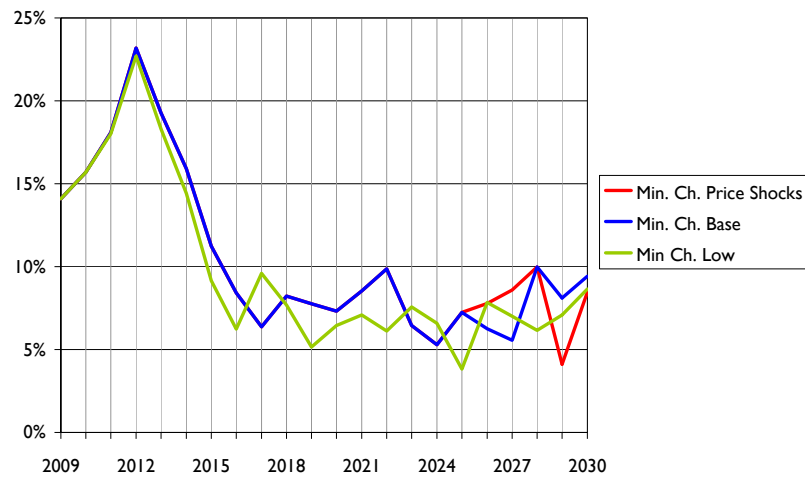
There is an inverse relationship between the de-rated capacity margin and wholesale price, all other things being equal. This can be seen after 2025 by comparing Figure 25 and Figure 26. The lower wholesale prices in the Price Shocks Case relative to the Base Case are driven by higher capacity margins (associated with slightly lower CCGT build).

Figure 25 Wholesale prices, Minimum Change



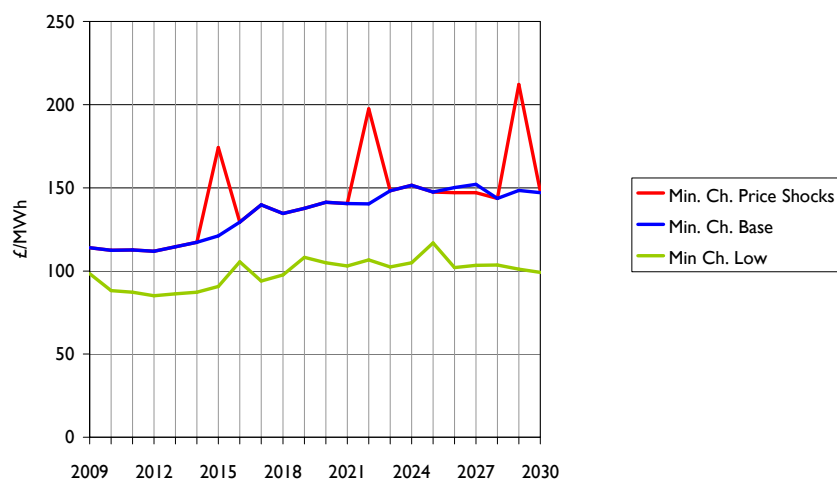
The de-rated capacity margin in the Low Case further reflects the lower rate of investment through to 2015. The closures of LCPD opt-out plant are the same in all three Cases, but in the Low Case there is less new investment to compensate.

Figure 26 De-rated capacity margin, Minimum Change



The wholesale price (as shown in Figure 25) is the main driver of the differences between the final consumer prices in each Case (as shown in Figure 27, noting the different y-axis scale to Figure 25). We recognise the simplicity of this representation since it is highly unlikely that suppliers would pass on the wholesale price spikes immediately given their forward hedging strategies. However, consumers may feel the effects of price spikes in increased tariffs in subsequent years. The impact of the RO is an increasing factor as time progresses as the total amount of subsidy paid to renewable generators increases. This is most apparent in the Low Case where, despite falling wholesale costs, the consumer prices increase.

Figure 27 Consumer Prices, Minimum Change



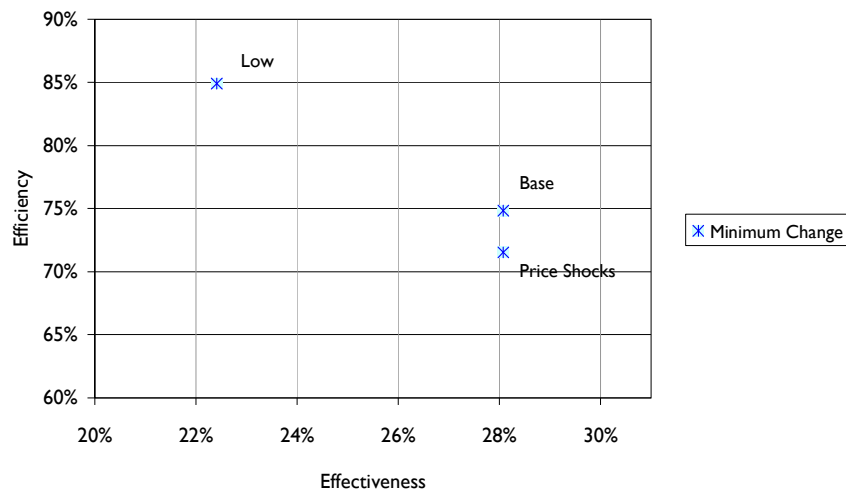
4.5.6 Summary

The banding changes have been set such that, together with the other model assumptions, the Minimum Change Base Case delivers 28% renewable electricity in 2020. The Price Shocks Case results in the same build profile and generation levels (as shocks are too short to affect investor decisions). In the Low Case, however, the effectiveness is reduced as investment in renewables is less attractive given the lower wholesale prices.

Using the key metrics, we can begin to develop the picture of Efficiency and Effectiveness that will aid a comparison of the Policy Options. The Price Shocks and Base Cases are equally effective, but the excess rents in times of price shock reduce the efficiency of the Price Shocks Case relative to the Base Case. In the Low Case, there is a clear reduction in effectiveness, but the efficiency is higher. There are two main drivers for this higher efficiency. First, existing renewable generators receive lower revenues and therefore rents are suppressed. This is amplified by the fact that existing plant form a larger proportion of the total renewables mix in the Low Case. Second, within any one technology, the Low Case favours development of lower cost and/or higher yield sites only. In the Base Case, this same set of generators will be making significant rents due to the higher wholesale price, leading to reduced efficiency.

The Efficiency and Effectiveness metrics for each Case are plotted in Figure 28. Results from the other Options modelled will be added to this plot as they are described.

Figure 28 Efficiency v Effectiveness, Minimum Change

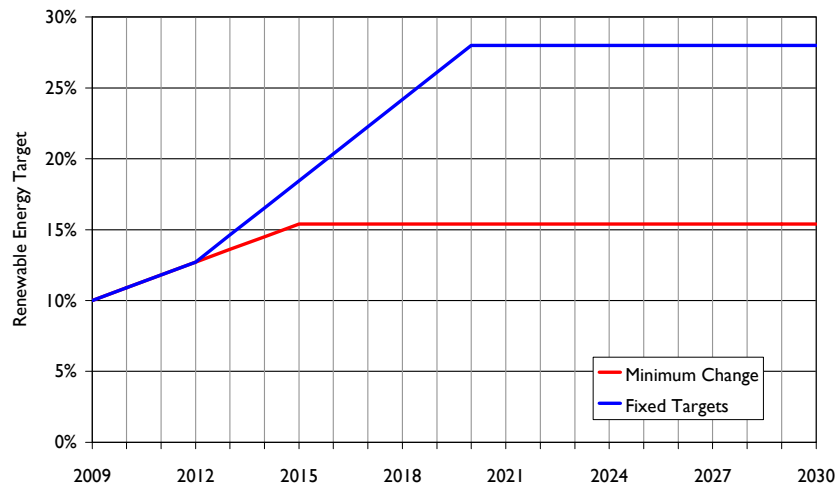


4.6 Fixed Targets

4.6.1 Overview

The key difference between the Fixed Targets Option and the Minimum Change is after 2012, when the annual targets diverge. The Fixed Targets Option has explicit annual targets through to 2020, linearly interpolated from 2012/13 to a level consistent with 28% renewables generation in 2020, as shown in Figure 29. The result of this is to maintain the potential for a scarcity signal (through recycle revenue), compared to the Minimum Change Option.

Figure 29 Fixed Target Trajectories²⁸



In the Base and Price Shocks Cases, the level of renewables build under Fixed Targets in fact exceeds the higher target levels, and as a result the Headroom mechanism comes into play to set the Obligation size. Hence the two Options become equivalent. However, in the Low Case the supply of ROCs does fall below the annual target in some years leading to some revenue recycling. The effect of the resulting scarcity signal is a small increase in renewable build. Renewables generation by 2020 is 22.9%, 0.5 percentage points higher than the Minimum Change Low Case.

The summary results for Fixed Targets are shown in Table 5.

Table 5 Fixed Targets summary results

2020	Fixed Targets			Difference to Minimum Change		
	Low	Base	Price Shocks	Low	Base	Price Shocks
Renewable Capacity (GW)	26.2	32.7	32.7	+0.3	0.0	0.0
Renewable Generation (TWh)	88.4	107.4	107.4	+1.8	0.0	0.0
Effectiveness %	22.9%	28.1%	28.1%	+0.5%	0.0%	0.0%
Efficiency %	83%	75%	72%	-1.7%	0.0%	0.0%

4.6.2 Comparative analysis

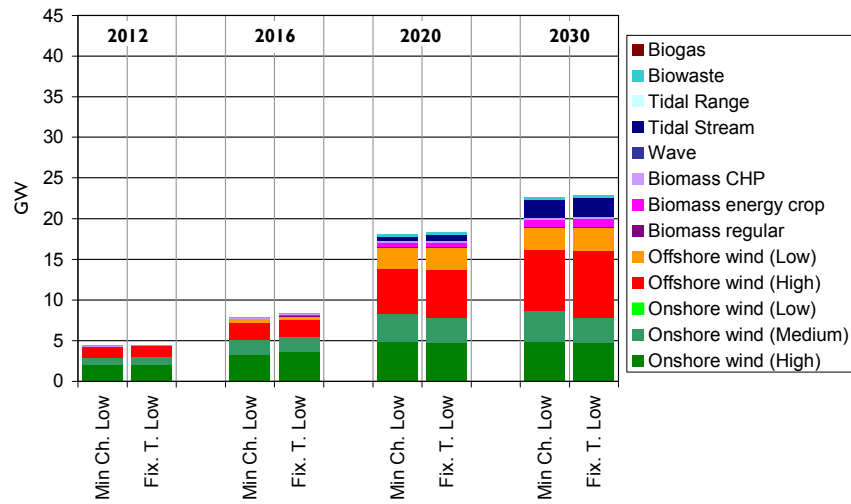
As described above, under the Base and Price Shocks Cases there is no significant difference between the Fixed Targets and Minimum Change Options, so here we focus only on the differences in the Low Case.

Capacity Mix

There is a slight increase in renewable deployment with Fixed Targets, as shown in Figure 30, due to the slighter higher ROC prices in some years. Although there are small differences in the wind deployment, the additional 300 MW is primarily biomass.

²⁸ The outturn Obligation size will differ from this due to the effects of net banding and adjustments to maintain Headroom.

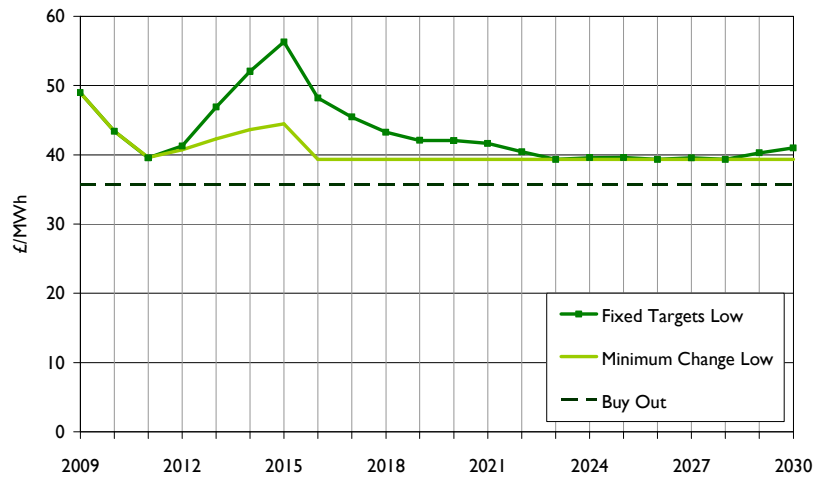
Figure 30 Renewable Build, Low Case, Minimum Change and Fixed Targets



Prices

The increasing targets after 2012 (Figure 29) are not matched by the rate of renewables deployment and so the ROC price rises above Headroom level until after 2020, as shown in Figure 31. The Headroom mechanism only comes into effect after 2023.

Figure 31 ROC Price, Minimum Change and Fixed Targets, Low Case



There is very little difference in wholesale prices between the two Options in the Low Case, as seen in Figure 32, and small differences are driven mainly by changes in capacity margin (Figure 33).

Figure 32 Wholesale price, Minimum Change and Fixed Targets, Low Case

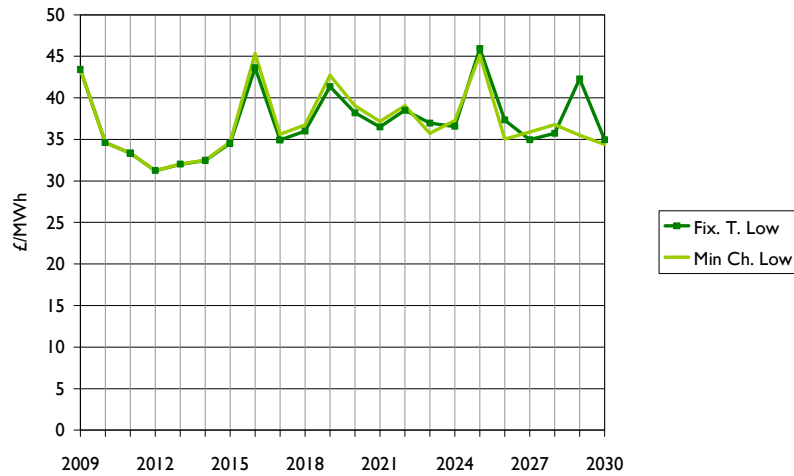
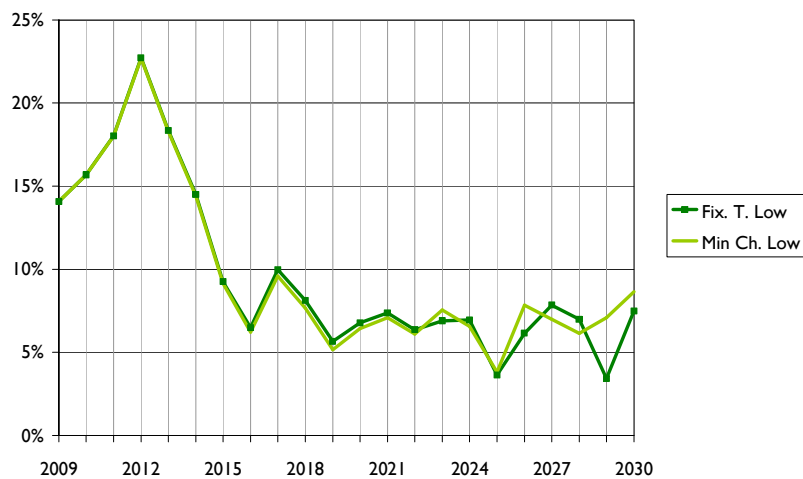
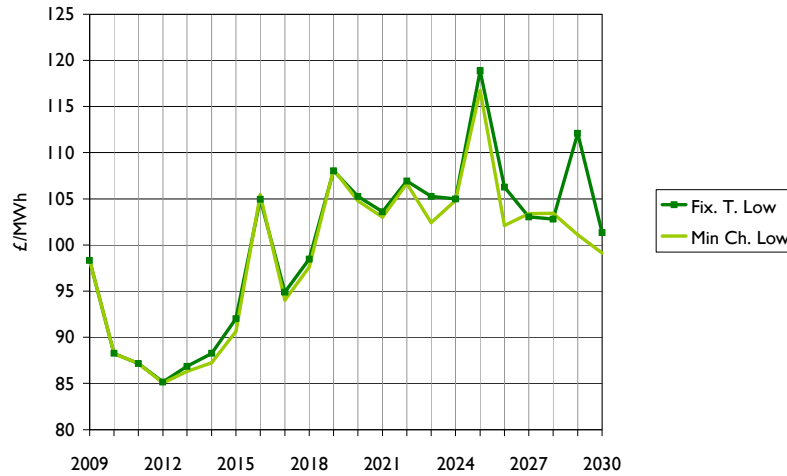


Figure 33 De-rated capacity margin, Minimum Change and Fixed Targets, Low Case



With the similar deployment in renewables and therefore the similar subsidy costs, we see that consumers are paying similar amounts under both Options, as shown in Figure 34. Up to 2015 the change in wholesale prices is reflected in change in consumer prices. After that point, with increasing subsidy due to increasing renewable penetration, consumer bills increase at a faster rate than the wholesale prices. However, the volatility in the wholesale price is passed through.

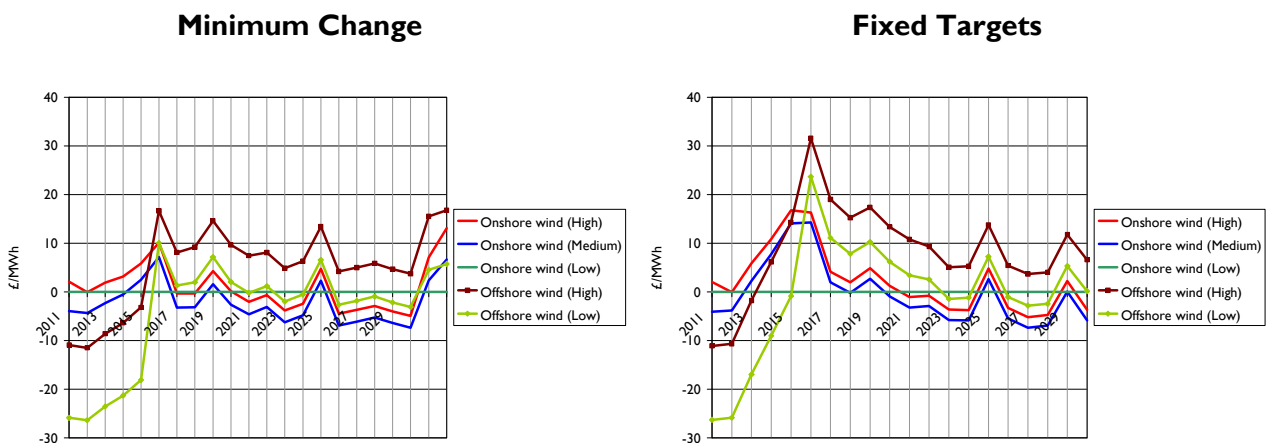
Figure 34 Consumer price, Minimum Change and Fixed Targets, Low Case



Rents

In Figure 35, we show a comparison of rent levels in Minimum Change and Fixed Targets under the Low Case. The level up to 2020 is higher under Fixed Targets, driven by the increased revenue recycling in the ROC price. Whilst this does provide some increase in investment, it also results in a material rent increase for existing plant (though this has a relatively limited impact on consumer prices).

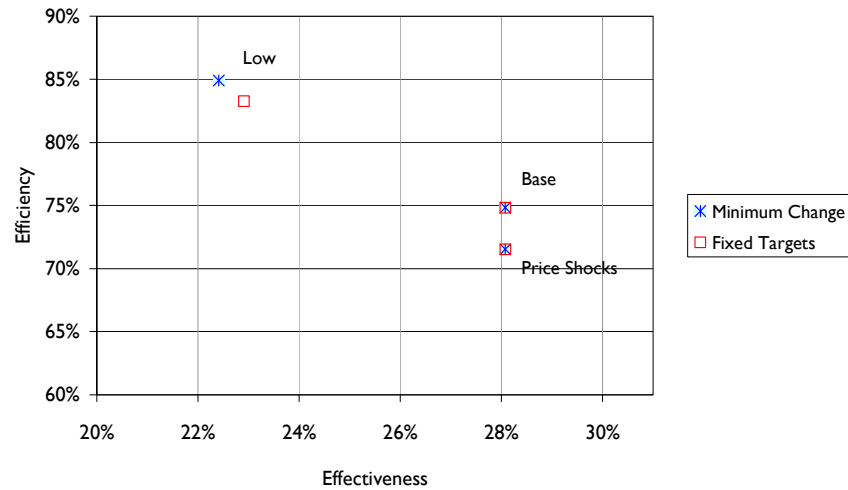
Figure 35 Renewables rent, Minimum Change and Fixed Targets, Low Case



4.6.3 Summary

In Figure 36, we add the key metrics from the Fixed Targets Option into our Efficiency/Effectiveness plot. As discussed above, the results for the Fixed Targets Option are the same as for Minimum Change under the Base and Price Shocks Cases. The differences come in the Low Case, where the greater revenue recycling increases rents (decreasing efficiency), but also slightly increases effectiveness.

Figure 36 Efficiency v Effectiveness, Fixed Targets



In conclusion, the introduction of Fixed Targets does not appear beneficial. The increased ROC prices in the Low Case have a relatively limited impact on increasing deployment levels relative to Minimum Change whilst providing further rent to plant that are already on the system.

4.7 Buy-out Cap/Collar

4.7.1 Overview

This Option introduces indexation on the Buy-out price with the aim of stabilising overall revenues, limiting costs to consumers and downside risk for generators. Given the concern with the inability to ‘grandfather’ the subsidies for existing plant, we have included a Cap and Collar to create a range within which subsidies are unaffected. Where the wholesale price moves by more than ± 10 £/MWh relative to a benchmark level, the Buy-out price is inversely adjusted to keep total revenues for the generator from increasing or decreasing further. Absolute banding is used, as described in Section 3.

By placing a floor on the revenues that renewables generators can earn, the investment risk may be lower under this Option, as described in Section 3.1. We have attempted to derive analytically cost of capital (hurdle rate) assumptions for different support schemes by analysing the gross margin risk for renewables projects over their economic life under the different Options (see Appendix D). By simulating the earnings risk under the Buy-out Cap/Collar Option relative to the Minimum Change, we have estimated the potential reductions in hurdle rates, shown in Table 6. The calculation for biomass plant is more difficult due to the impact of fuel cost on margin. Specific fuel types will vary in the way in which the price correlates with the electricity price, changing the impact of stabilisation on the resulting gross margin risk. In this calculation we have assumed no correlation (which will tend to increase the hurdle rate differential).

We recognise that this exercise is somewhat theoretical since many companies will not be raising capital for individual investments, but rather funding from balance sheets at the weighted average cost of capital (WACC) of the company as a whole²⁹. However, investing in more risky assets will tend to increase the WACC of the company and hence it is valid to consider an incremental cost of capital. The relationship

²⁹ Also the impact of new investments on overall risk will depend on other exposures within the portfolio.

between Policy Option and hurdle rate is more apparent for independent players looking for project finance, since the cost of this finance will directly relate to the perceived riskiness of the investment.

Table 6 Changes in hurdle rates under Buy-out Cap/Collar relative to Minimum Change

Technology	VIUs ³⁰		IPPs ³¹	
	Min	Max	Min	Max
Onshore wind (High)	-0.8%	-1.0%	-1.2%	-1.5%
Onshore wind (Medium)	-1.0%	-1.3%	-1.5%	-1.8%
Onshore wind (Low)	-0.9%	-1.2%	-1.4%	-1.7%
Offshore wind (High)	-0.8%	-1.0%	-1.2%	-1.4%
Offshore wind (Low)	-0.7%	-0.9%	-1.0%	-1.2%
Biomass regular	-1.3%	-1.7%	-2.0%	-2.4%
Biomass energy crop	-0.9%	-1.2%	-1.4%	-1.7%
Biomass CHP	-0.8%	-1.1%	-1.3%	-1.6%
Wave	-0.5%	-0.6%	-0.7%	-0.8%
Tidal Stream	-0.4%	-0.5%	-0.6%	-0.7%
Tidal Range	-0.5%	-0.6%	-0.7%	-0.9%
Biowaste	-0.6%	-0.8%	-0.9%	-1.1%
Biogas	-0.3%	-0.4%	-0.5%	-0.6%

With the lower hurdle rates, renewables investment appears more attractive. As Table 7 shows, this leads to an increase in effectiveness under this Option even under the Base Case (where prices do not move outside the range). In the Low Case, the floor comes into effect, increasing effectiveness further. The increase in efficiency in the Price Shocks Case is mainly due to the reduction of rents in the ‘price spike’ years.

Table 7 Buy-out Cap/Collar high level results

2020	Buy-Out Cap/Collar			Difference to Minimum Change		
	Low	Base	Price Shocks	Low	Base	Price Shocks
Renewable Capacity (GW)	28.9	35.6	35.6	+3.0	+2.9	+2.9
Renewable Generation (TWh)	97.0	114.5	114.5	+10.4	+7.1	+7.1
Effectiveness %	25.2%	30.0%	30.0%	+2.8%	+1.9%	+1.9%
Efficiency %	79%	75%	75%	-6.2%	+0.2%	+3.1%

³⁰ Vertically Integrated Utility

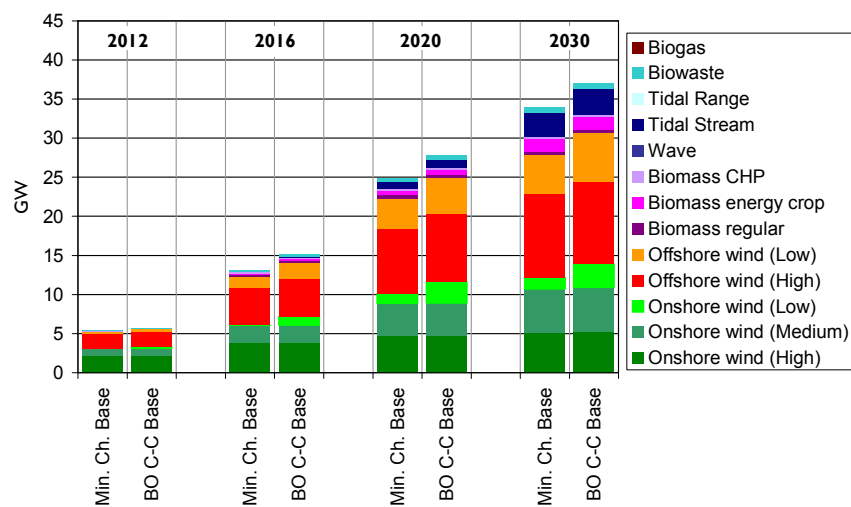
³¹ Independent Power Producer

4.7.2 Comparative analysis

Capacity Mix

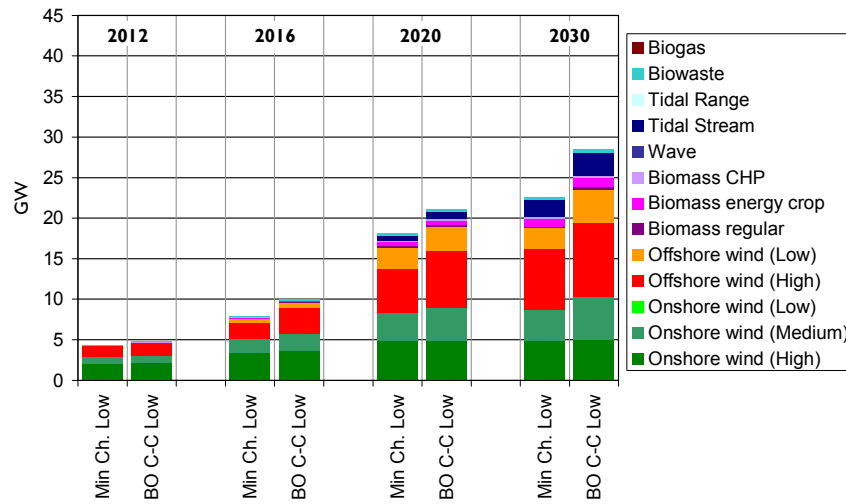
The impact of lower hurdle rates is to bring forward more renewables investment, even in the Base Case and Price Shocks Case where the collar never comes into effect. Figure 37 shows that the main effect is increased build of low yield onshore wind, along with small amounts of additional marine technology (the more marginal technologies under Minimum Change). By 2020, output from renewables is 30% under the Buy-out Cap/Collar compared to 28% under Minimum Change.

Figure 37 Renewables build, Base Case, Minimum Change and Buy-Out Cap/Collar



The impact of the revenue collar is greater still in the Low Case, since the floor comes into effect with the lower wholesale electricity prices. Projects that would otherwise have been uneconomic without the floor now get built. Figure 38 shows that the biggest impact is on volumes of Offshore wind (Low) and Onshore wind (Medium). There are also small increases in the deployment of the marine technologies. Overall renewables output is 2.8% higher under the Buy-out Cap/Collar option by 2020 under the Low Case.

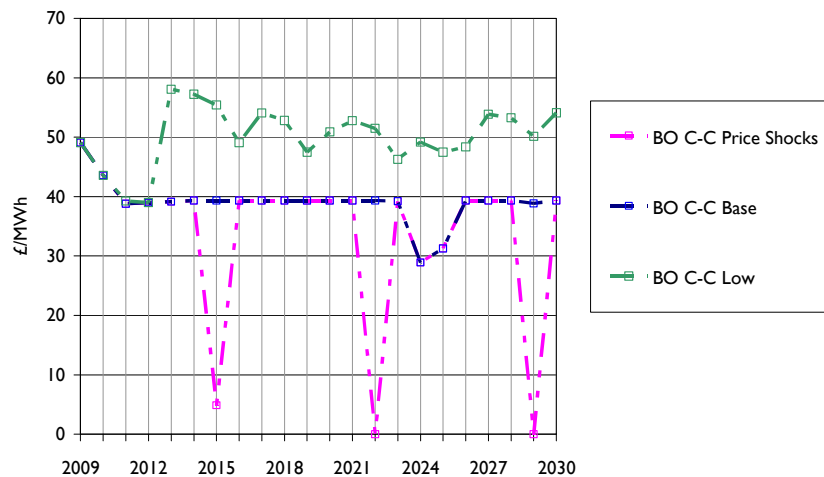
Figure 38 Renewables build, Low Case, Minimum Change and Buy-out Cap/Collar



Prices

In the Buy-out Cap/Collar Option, the Buy-out price is varied to compensate for changes in the wholesale electricity price. Figure 39 shows the resulting variations in ROC price. In the Price Shocks Case, the ROC price falls to zero (the floor level) in the last two shocks. Conversely, in the Low Case, the ROC price is higher, providing the collar on revenues that helps to provide the incentives to develop new projects despite the lower wholesale electricity prices.

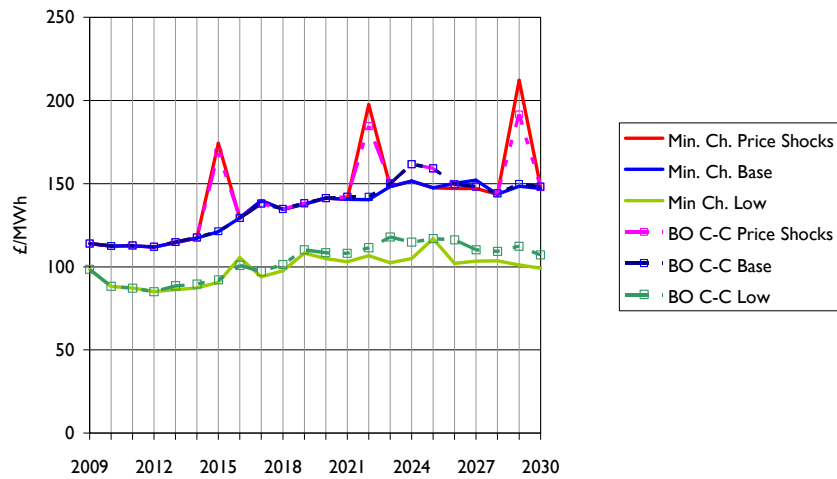
Figure 39 ROC Price, Buy-out Cap/Collar



The effect of the revenue cap can be seen on consumer prices, shown in Figure 40, in the 'spike' years of the Price Shocks case, especially at the end of the modelling period with more renewables on the system.

The revenue collar provides increased renewables build in the Low Case and this increased cost is passed through to the consumer.

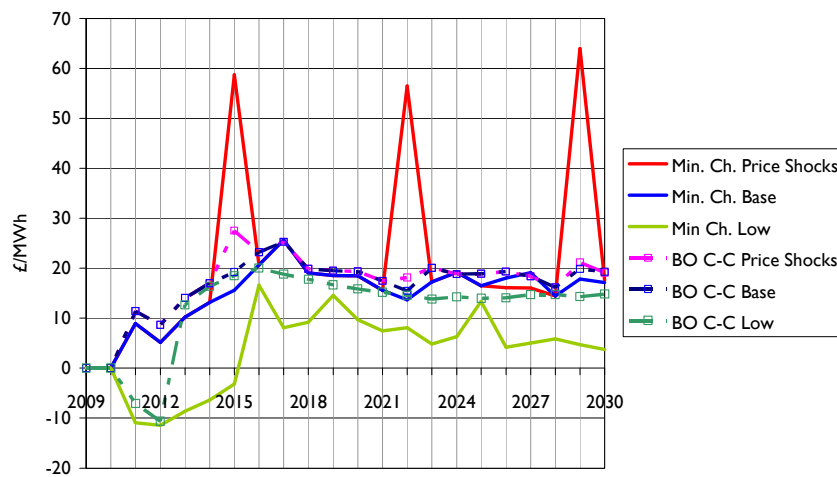
Figure 40 Consumer price, Buy-out Cap/Collar



Rents

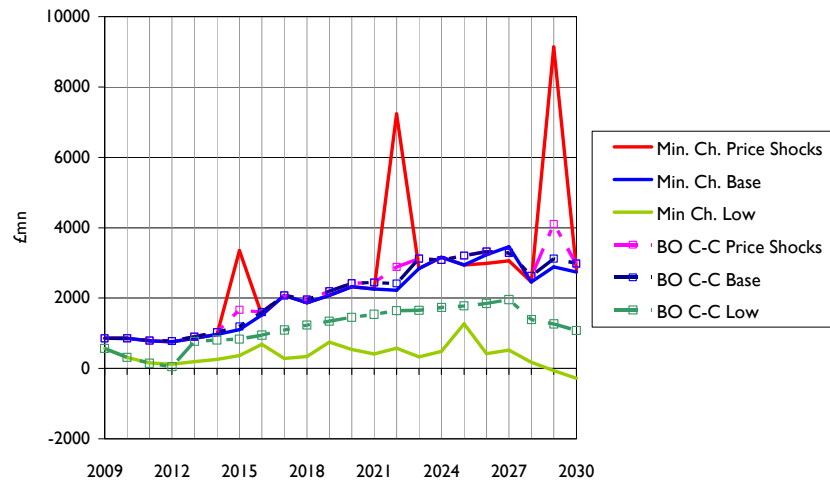
In comparison to the Minimum Change Option, Buy-out Cap/Collar reduces rents at times of price shocks. Conversely under the Low Case rents are higher relative to the Minimum Change Option, driven by the higher ROC price. This is shown for Offshore wind (High) in Figure 41 below.

Figure 41 Offshore wind (High) rent, Buy-out Cap/Collar



In Figure 42 the overall renewables rent reduction in the 'spike' years of the Price Shocks Case is clear. In 2029 there is still some upward spike in rent. In this year the ROC price has floored at zero; to have achieved complete revenue stabilisation, a negative ROC price would have been required.

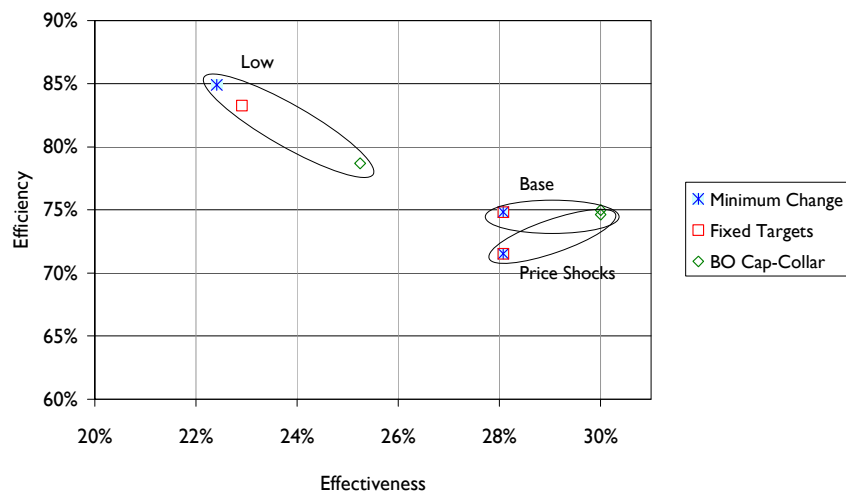
Figure 42 Renewables rent, Buy-Out Cap/Collar



4.7.3 Summary

The most significant impact of the revenue cap and collar is the improvement in effectiveness, as shown in Figure 43. This is the direct result of the lower hurdle rates associated with the lower revenue risk. In the Base and Price Shocks Cases, the effectiveness increases by nearly two percentage points over Minimum Change and Fixed Targets, to 30%. This is achieved at no loss of efficiency. In the Low Case, the improvement in effectiveness is even more marked, rising to 25.2%, an increase of nearly three percentage points over Minimum Change. However, unlike the Base and Price Shocks Cases, there is a reduction in efficiency. The decline in efficiency indicates that the increase in subsidy is greater than the increase in costs of renewables generators. One key reason for this is that with the collar in effect, the revenues of existing renewable generators (or holders of offtake agreements) are higher, but the underlying costs remain the same. A second effect is that new plant that would have been built in the Low Case under Minimum Change now receive a higher price, again increasing rent and decreasing efficiency.

Figure 43 Efficiency v Effectiveness, Buy-out Cap/Collar



4.8 Band Cap/Collar

4.8.1 Overview

The Band Cap/Collar Policy Option adjusts band levels annually dependent on wholesale price. The cap and collar are set similarly to Buy-out Cap/Collar, to reflect the same ± 10 £/MWh range in overall revenues used in the Buy-Out Cap Collar Option (equivalent to approximately ± 0.25 ROC). The key difference is that existing plant are unaffected by this Policy Option. We have also excluded biomass plant as the much greater uncertainty around the impact of stabilisation on risk could reduce or remove any benefit seen by investors.

For new plant the impact on earnings of the Band Cap/Collar is similar to that of the Buy-out Cap/Collar and hence we have assumed the same reduction in hurdle rates relative to the Minimum Change Option shown in Table 6 above.

Table 8 shows summary results for the Band Cap/Collar Option.

Table 8 Band Cap/Collar high level results

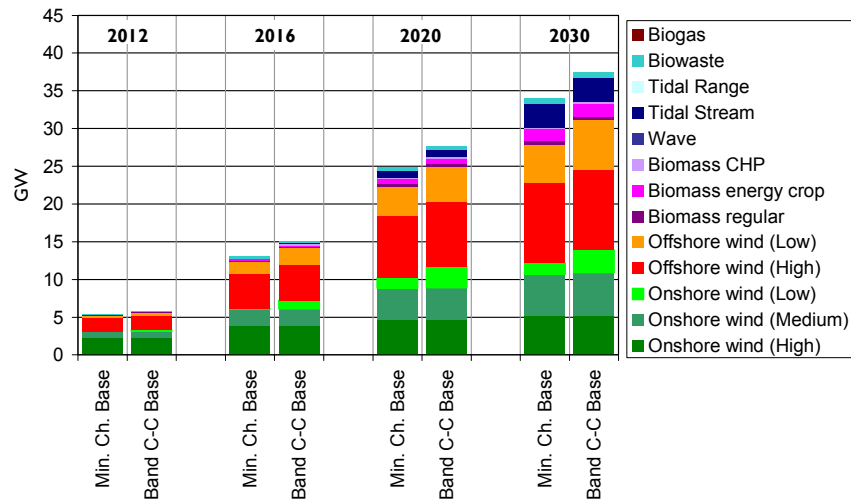
2020	Band Cap/Collar			Difference to Minimum Change		
	Low	Base	Price Shocks	Low	Base	Price Shocks
Renewable Capacity (GW)	28.9	35.6	35.6	+3.0	+2.8	+2.9
Renewable Generation (TWh)	95.7	114.5	114.5	+9.2	+7.1	+7.1
Effectiveness %	24.9%	30.0%	30.0%	+2.5%	+1.9%	+1.9%
Efficiency %	82%	75%	75%	-2.5%	-0.1%	+3.1%

4.8.2 Comparative analysis

Capacity Mix

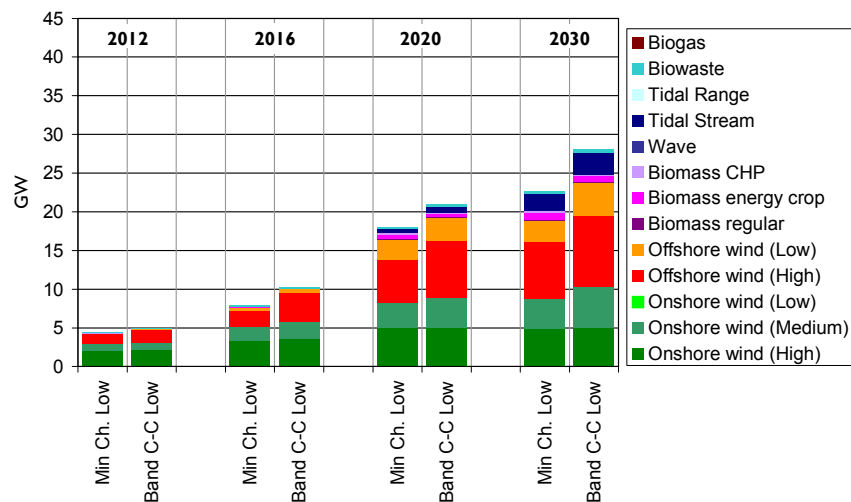
As was the case with the Buy-out Cap/Collar, the lower hurdle rates stimulate greater renewables build in the Base Case, as shown in Figure 44. Again, it is the low yield onshore wind which benefits most.

Figure 44 Renewable build, Base Case, Minimum Change and Band Cap/Collar



The impact of the revenue floor is greatest in situations where the collar comes into effect, as it does in the Low Case, shown in Figure 45.

Figure 45 Renewable build, Low Case, Minimum Change and Band Cap/Collar



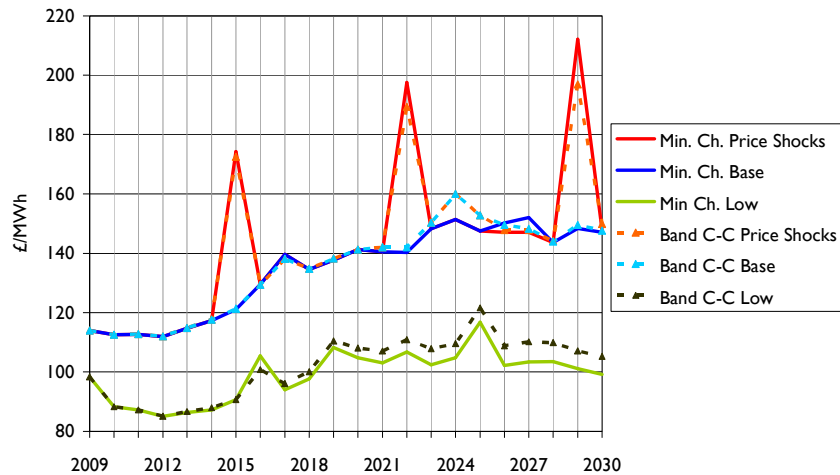
Prices

Other things being equal, the ROC price should be the same under the Band Cap/Collar Option as in the Minimum Change Option, since to the extent that bands are adjusted in response to changing wholesale prices, the Obligation Size should be adjusted to maintain the same level of Headroom. (There are implementation complexities surrounding this which we discuss in Section 5 below.)

Wholesale prices are comparable between Band Cap/Collar and Minimum Change, with the major differences driven by changes in capacity margin. As for the Buy-out Cap/Collar Option, the impact on consumer prices is limited in the Base Case, but the effect of the cap is to reduce consumer prices in the Price Shocks Case in the years that the price shocks are occurring, as can be seen in Figure 46. In the Low

Case, shown in Figure 46 below, consumer prices are higher than in the Minimum Change Option since there are net increases in bands (and the size of the RO increases correspondingly to maintain Headroom) in response to the low wholesale electricity prices.

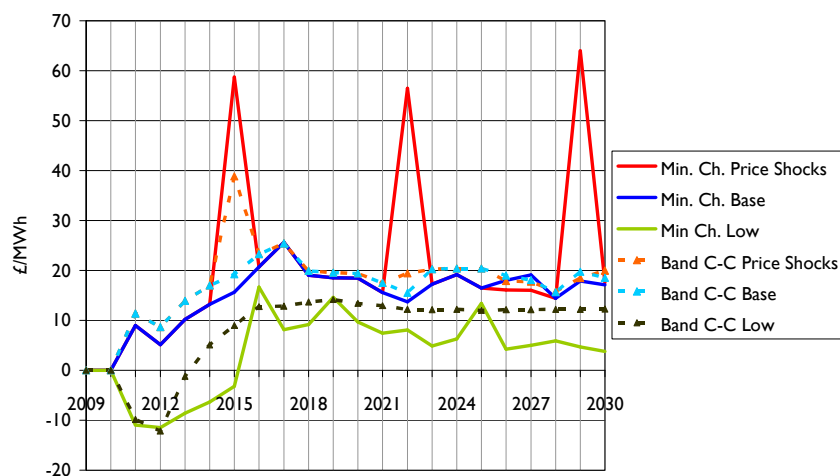
Figure 46 Consumer price, Band Cap/Collar, All Cases



Rents

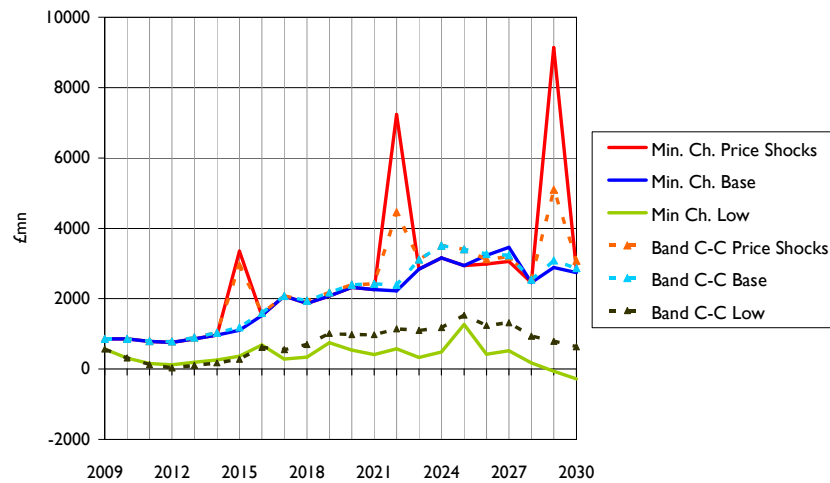
The Band Cap/Collar Option is less effective than the Buy-out Cap/Collar in limiting excessive rents during price shocks, since it only applies to new plant rather than all plant. This reduced effect can be seen in Figure 47, where the rent in 2015 remains high in the Price Shocks Case. Similarly, there is a wider spread in rent between the Low Case and Base Case (typically around 8 £/MWh in the Band Cap/Collar, as opposed to around 6 £/MWh in the Buy-out Cap/Collar), as only the new plant receive the higher levels of subsidy through the band adjustments.

Figure 47 Offshore wind (High) rent, Band Cap/Collar



The effect of partial revenue stabilisation on renewables rent can be seen in the Price Shocks Case in Figure 48. At the times of price shock, renewables rent is reduced dramatically only once new renewable plant dominate the mix. In the Low Case, the uplift in subsidy to compensate for low wholesale prices increases rent in all years.

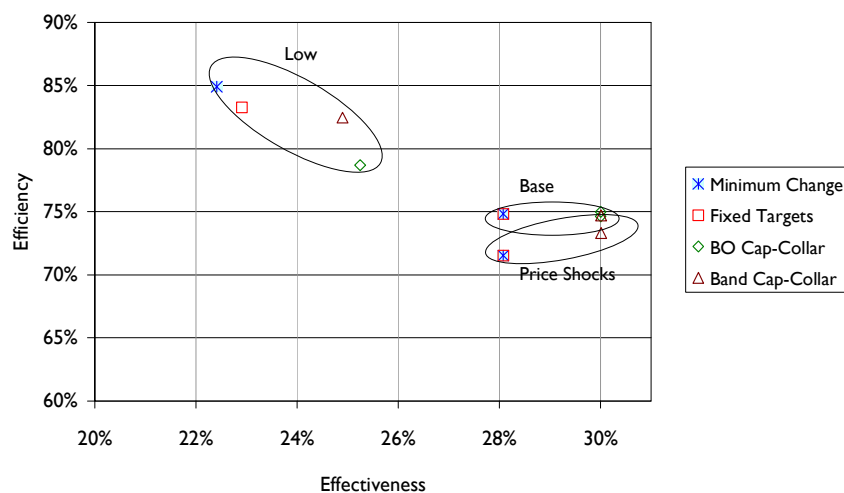
Figure 48 Renewables rent, Band Cap/Collar



4.8.3 Summary

In Figure 49, we add the Band Cap/Collar Option to the Efficiency/Effectiveness chart. As with the Buy-out Cap/Collar, in the Base and Price Shocks Cases we get improved effectiveness for no loss of efficiency due to the lower hurdle rates. The two Options are most differentiated in the Low Case. The Band Cap/Collar is not as effective as the Buy-out Cap/Collar in our modelling, mainly because of differences in biomass hurdle rate assumptions. However, it is more efficient since existing plant do not benefit from the revenue floor when wholesale electricity prices are low.

Figure 49 Efficiency v Effectiveness, Band Cap/Collar



4.9 Band Indexation

4.9.1 Overview

The Band Indexation Option uses the same principles as the Band Cap/Collar in adjusting bands in response to changing wholesale electricity prices, but uses a single reference price rather than a cap and collar range. Hence, it offers a higher degree of revenue certainty, further reducing risk for investors.

Table 9 shows the estimated reduction in hurdle rates relative to the Minimum Change Option from the earnings risk simulations. On average, hurdle rates are a further 0.2% lower than in the Buy-out or Band Cap/Collar Options. (As biomass is excluded from the band indexation, the hurdle rates are unchanged.)

Table 9 Change in hurdle rates due to full revenue stabilisation

Technology	VIUs		IPPs	
	Min	Max	Min	Max
Onshore wind (High)	-1.2%	-1.5%	-1.8%	-2.1%
Onshore wind (Medium)	-1.2%	-1.5%	-1.8%	-2.2%
Onshore wind (Low)	-1.0%	-1.4%	-1.6%	-2.0%
Offshore wind (High)	-1.1%	-1.4%	-1.6%	-2.0%
Offshore wind (Low)	-1.0%	-1.3%	-1.6%	-1.9%
Biomass regular	0.0%	0.0%	0.0%	0.0%
Biomass energy crop	0.0%	0.0%	0.0%	0.0%
Biomass CHP	0.0%	0.0%	0.0%	0.0%
Wave	-0.6%	-0.7%	-0.9%	-1.0%
Tidal Stream	-0.7%	-0.9%	-1.0%	-1.2%
Tidal Range	-0.7%	-0.9%	-1.0%	-1.2%
Biowaste	-0.8%	-1.1%	-1.3%	-1.5%
Biogas	-0.3%	-0.4%	-0.4%	-0.6%

In the Low Case, total revenues are kept at a higher level than the other Policy Options discussed so far, as the stabilisation comes into effect as soon as the wholesale price falls below E_0 , rather than below the collar level. In the Base and Price Shocks Cases, effectiveness and efficiency are comparable to the Cap/Collar approaches.

Table 10 Band Indexation high level results

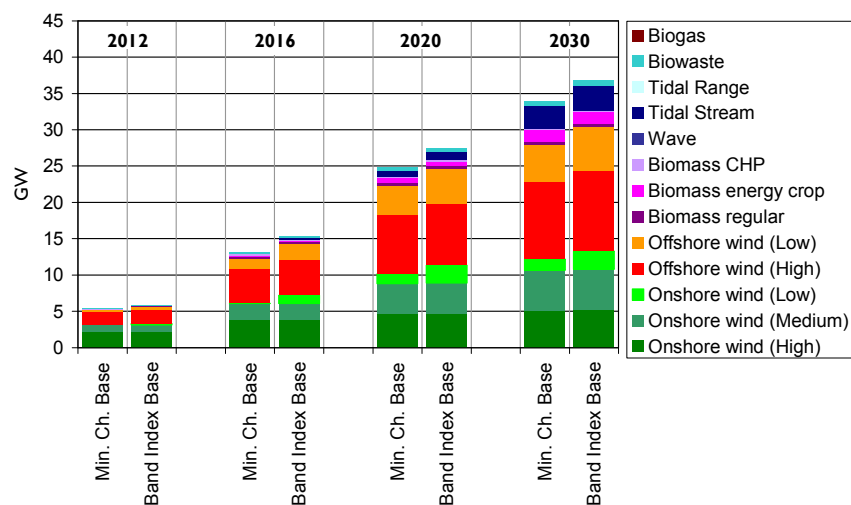
2020	Band Index			Difference to Minimum Change		
	Low	Base	Price Shocks	Low	Base	Price Shocks
Renewable Capacity (GW)	32.4	35.3	35.6	+6.4	+2.6	+2.8
Renewable Generation (TWh)	104.0	114.1	114.5	+17.4	+6.6	+7.1
Effectiveness %	27.1%	29.9%	30.0%	+4.7%	+1.8%	+1.9%
Efficiency %	80%	76%	73%	-5.1%	+1.0%	+1.8%

4.9.2 Comparative analysis

Capacity Mix

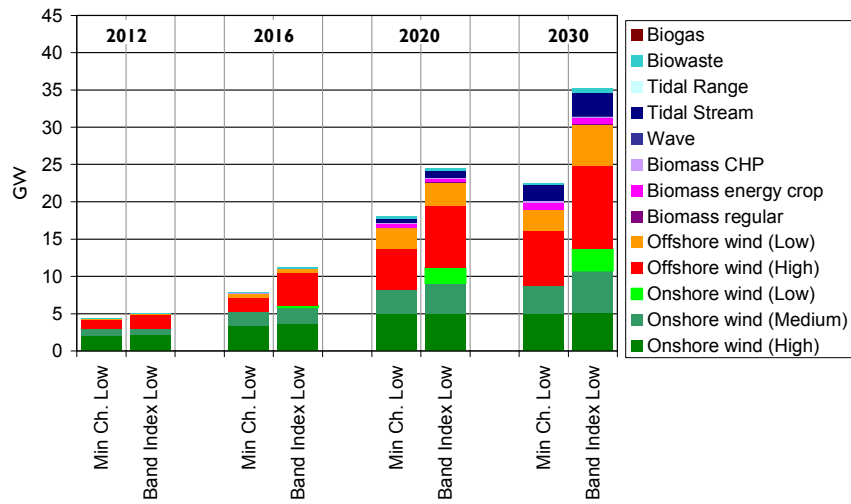
Figure 50 compares the renewables build under the Band Indexation Option relative to the Minimum Change Option in the Base Case. By 2020, renewables output is 29.9% under the Band Indexation Option compared to 28.1% under Minimum Change. However, the lower hurdle rates of the Band Indexation Option relative to the Band Cap/Collar do not stimulate renewables deployment further, because build is limited by build rates and supply curves.

Figure 50 Renewable build, Base Case, Minimum Change and Band Indexation



In the Low Case, the Band Indexation Option has a greater effect on renewables build than the Band Cap/Collar since stabilisation keeps revenues at a higher level compared to the collar. The main difference is that low yield onshore wind sites become economic. Figure 51 compares the renewables build in the Band Indexation Option to the Minimum Change in the Low Case. By 2020, renewables output is nearly 5% higher under the Band Indexation Option than Minimum Change, and over 2% higher than under the Band Cap/Collar option.

Figure 51 Renewable build, Low Case, Minimum Change and Band Indexation

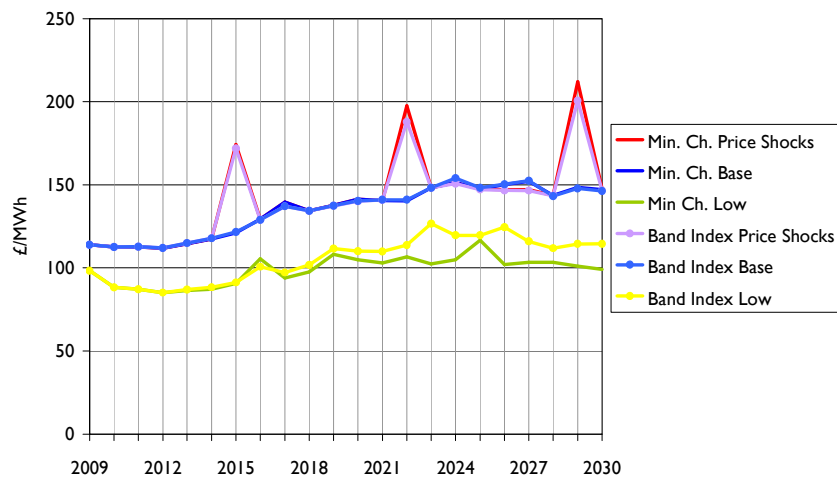


Prices

Under this Option, the ROC price is not being used as the means to achieve revenue stabilisation, and is at Buy-out + Headroom level once the policy is implemented in 2013.

Figure 52 shows that consumer prices are reduced in high price years under the Price Shocks Case with the Band Indexation Option relative to Minimum Change. There is a clear increase in the Low Case, driven by the increased deployment of renewables, and associated increase in subsidy.

Figure 52 Consumer prices, Band Indexation

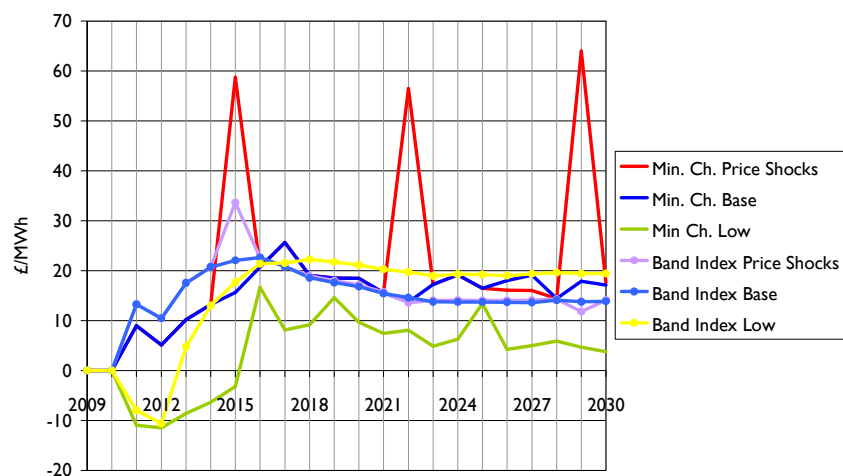


Rents

Figure 53 compares the rents for Offshore wind (High) under the Band Indexation and Minimum Change Options. Unsurprisingly the revenue stabilisation for new plant under the Band Indexation Option leads to

a much narrower range of outcomes across the Cases than the Minimum Change Option. However, rents are actually higher under the Low Case than the Base Case with the Band Indexation Option. This is because ROC revenues have been adjusted to offset the reduction in wholesale electricity prices, and yet renewables capital costs are also lower. In principle this could be addressed through band changes, although lack of information and long leadtimes will always make such adjustments difficult for policy makers.

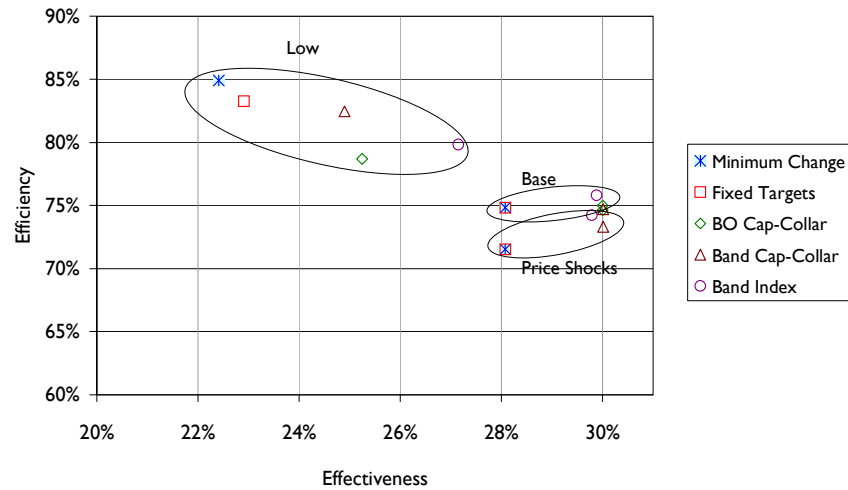
Figure 53 Offshore wind (High) rent, Band Indexation



4.9.3 Summary

The Band Indexation Option has been added to the Efficiency/Effectiveness chart in Figure 54. In the Base and Price Shocks Cases, the effectiveness and efficiency of the Band Indexation Option is broadly similar to the two cap/collar options. The Band Indexation Option is significantly more effective in the Low Case than either the Band Cap/Collar or Buy-out Cap/Collar Options because the fixed revenue level is higher than the collars in these Options. The trade-off is that the Band Indexation Option is less efficient than the Band Cap/Collar Option due to higher revenues for lower cost plant. However, it appears more efficient than the Buy-out Cap/Collar since under this latter Option all plant, and not just new plant, benefit from the higher support levels under the Low Case.

Figure 54 Efficiency v Effectiveness, Band Indexation



4.10 Contract for Difference

4.10.1 Overview

In terms of earnings expectations for renewable generators, the Contract for Difference Option is very similar to the Band Indexation approach. The two main differences between the Contract for Difference Option compared to the Band Indexation Option are:

- no floor in times of very high power price, meaning that there could theoretically be a net negative subsidy for some technologies at these times; *and*
- an additional revenue stream associated with ROC price scarcity signal where output does not meet the annual fixed targets.

(The latter difference was a design choice; a CfD could equally be introduced without annual fixed targets for the RO.)

It is assumed that investment risk is the same under the CfD option and the Band Indexation Option, and hence the same hurdle rates were used. As a result, the renewables build is very similar between these Options in the Base and Price Shocks Cases, and renewables output almost reaches 30% by 2020. Although, we have modelled the CfD Option with fixed targets rather than Headroom, there is also little difference between CfD and Minimum Change in the Low Case. This is because the effect of the revenue stabilisation is such that, unlike in the Fixed Targets Option, build keeps pace with the increasing targets and the amount of revenue recycling is limited.

Table 11 presents the summary results for the CfD Option.

Table 11 Contract for Difference summary results

2020	CfD			Difference to Minimum Change		
	Low	Base	Price Shocks	Low	Base	Price Shocks
Renewable Capacity (GW)	32.4	35.3	35.2	+6.5	+2.6	+2.5
Renewable Generation (TWh)	104.1	114.1	113.7	+17.6	+6.6	+6.3
Effectiveness %	27.2%	29.9%	29.8%	+4.8%	+1.8%	+1.7%
Efficiency %	80%	76%	74%	-5.4%	+1.0%	+2.9%

4.10.2 Comparative analysis

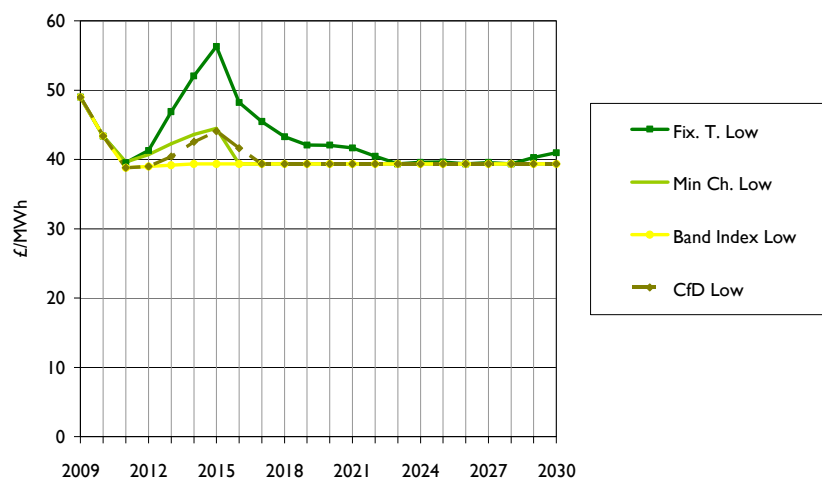
Capacity Mix

With the economics of renewable investment very similar under CfD compared to Band Indexation, the new renewable build is very similar. There is a small increase in build compared to Minimum Change across all technologies in the Base and Price Shocks Cases. In the Low Case, the Option results in an extra 6.5 GW of capacity, including the development of low yield onshore wind sites, which are not economic in the Minimum Change Low Case.

Prices

In the Base and Price Shocks Cases, there is no difference in ROC price compared to Minimum Change and Fixed Targets. This is because the rate of renewable deployment is sufficient to trigger the Headroom mechanism. However, differences are observed in the Low Case. The rate of renewable deployment in the CfD Option is much quicker than under Fixed Targets, so there is a much smaller increase in ROC price. In 2015, with higher targets compared to Minimum Change, the percentage of the Obligation met is almost identical (as evidenced by the very similar ROC price). However, the rate of deployment is much higher in the CfD Option as the Obligation is completely met in 2017 when ROC price returns to Buy-out + Headroom level.

Figure 55 ROC Prices, Low Case, Option comparison

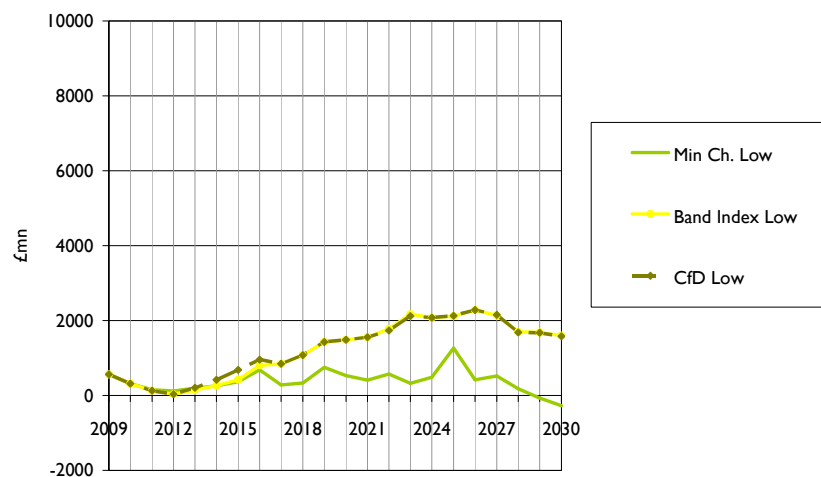


Rents

The slighter higher ROC prices (resulting from the larger Obligation size in some years) lead to a small increase in the overall rent for renewables plant under the CfD Option when compared to the Band Indexation Option, as shown in Figure 56 below. (Had the CfD Option been modelled without fixed targets there would be no differences between the Options.)

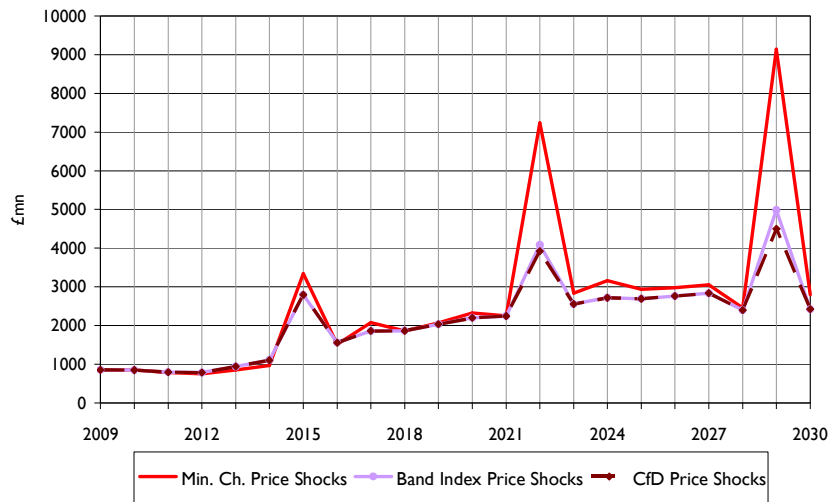
The rent under the Minimum Change Option is shown for comparison and is much lower since renewables are exposed to the lower electricity prices under this Option. The additional revenues, combined with a lower cost base due to lower hurdle rates, allow more expensive renewables to be built, but as a consequence less expensive renewables, which would have been built anyway, benefit from greater rents.

Figure 56 Renewables rent, Low Case, Option comparison



There is also a small difference in the renewables rent between the CfD and Band Indexation Option under the Price Shocks Case since bands cannot go negative under the latter option and hence renewables plant can never earn less than the wholesale price. However, in theory renewables plant covered by the CfD Option could be subject to a net negative subsidy if the wholesale price rose above the sum of the CfD contract strike price and ROC revenues. The effect is small but can be seen in the latter two shocks in Figure 57 below, where rents are slightly lower under the CfD Option compared to Band Indexation.

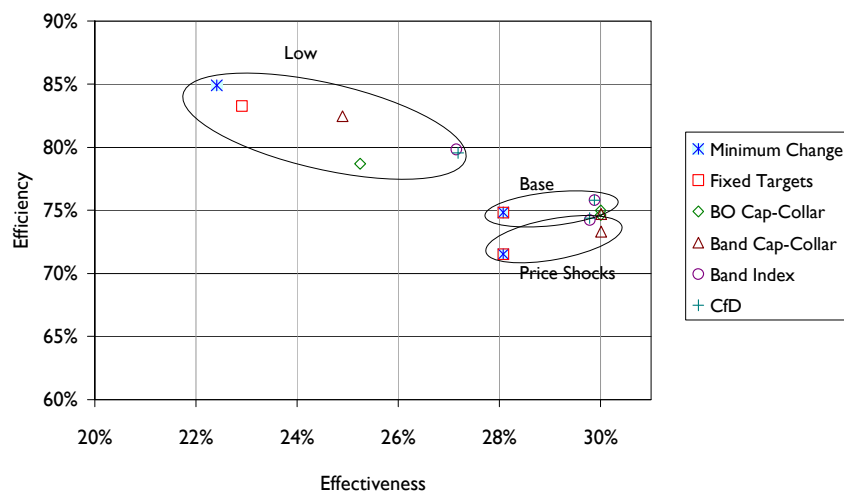
Figure 57 Renewables rent, Price Shocks Case, Option comparison



4.10.3 Summary

Figure 58 adds the CfD Option to the Efficiency/Effectiveness chart. For the reasons discussed above there is very little difference between the CfD and Band Indexation Options. Both get close to achieving the 28% renewables target even in the Low Case.

Figure 58 Efficiency v Effectiveness, Contract for Difference



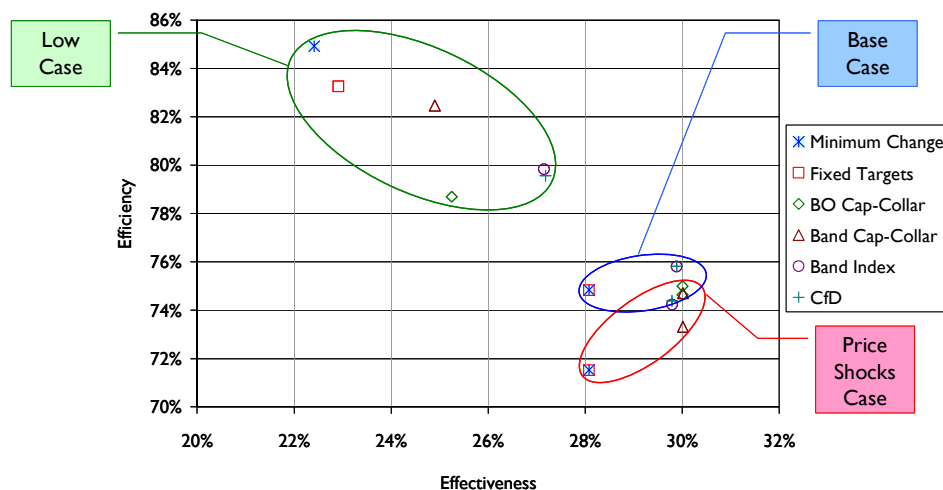
4.11 Results summary

4.11.1 Summary of metrics

The key assumption of the Minimum Change Base Case is that bands have been set in 2013 (with perfect foresight) in order to deliver 28% renewable generation in 2020 in the model. We have then maintained these bands across all Options modelled to provide a common base for comparison. (In practice, policy makers may make banding changes in response to changing market conditions, albeit of course without perfect foresight.)

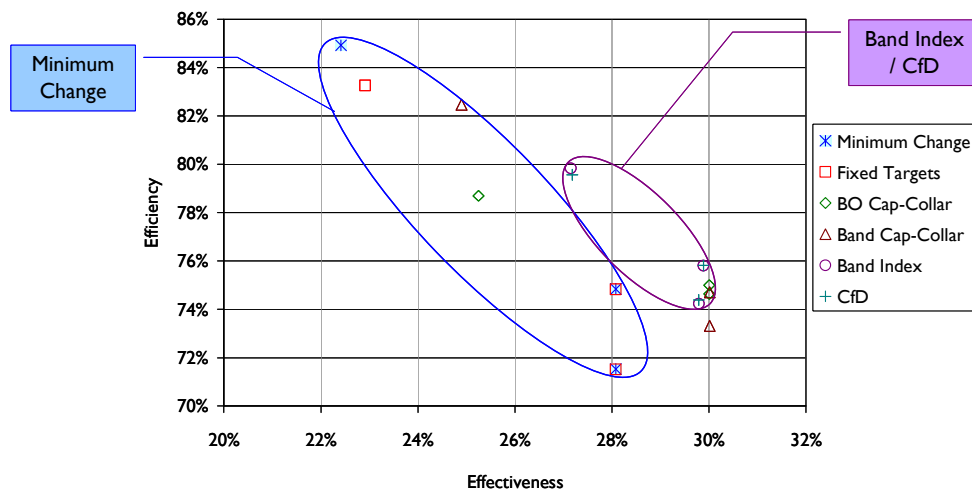
In Figure 59 we compare the key metrics between Options under each Case. The impact of the revenue stabilisation options can be clearly seen. In the Base Case, the efficiency is comparable to Minimum Change, yet there is a near two percentage point increase in effectiveness. This is the direct result of assumed easier financing under these options. In the Price Shocks Case, the revenue stabilisation provides similar improvements in effectiveness, while increasing efficiency, primarily because rents are limited during periods of price shock. There is more of a divergence in the Low Case. All the revenue stabilisation options deliver substantially more renewables since, together with lower risk, expected revenues are higher as the low wholesale electricity prices are compensated by a material increase in subsidisation. The Band Indexation and CfD Options fall just one percentage point short of the 28% target. However, this improvement in effectiveness comes with a trade-off in terms of lower efficiency (relative to Minimum Change). This is because existing plant and lower cost new plant, that would have been built without revenue stabilisation, make more rent.

Figure 59 Efficiency vs Effectiveness, all Options, all Cases



In Figure 60, we present the same data but annotated to highlight the difference between Cases for the same Option (ringed illustratively for the Minimum Change and Band Index/CfD Options). Under Minimum Change, the modelled Cases show a wide scatter both in effectiveness and efficiency. The Band Indexation and CfD Options demonstrate a reduced range in both metrics. This suggests that the revenue stabilisation options would reduce the range of uncertainty surrounding how the RO performs.

Figure 60 Efficiency vs Effectiveness, selected Options



These key metrics are summarised in Table 12 below.

Table 12 Efficiency and Effectiveness, all Policy Options

	Effectiveness			Efficiency		
	Base	Price Shocks	Low	Base	Price Shocks	Low
Minimum Change	28.1%	28.1%	22.4%	75%	72%	85%
Fixed Targets	28.1%	28.1%	22.9%	75%	72%	83%
BO Cap-Collar	30.0%	30.0%	25.2%	75%	75%	79%
Band Cap-Collar	30.0%	30.0%	24.9%	75%	73%	82%
Band Index	29.9%	29.8%	27.1%	76%	74%	80%
CfD	29.9%	29.8%	27.2%	76%	74%	80%

Three permutations of assumptions for each Policy Option is a small number of Cases on which to draw comprehensive conclusions, and there are many other sensitivities which could be performed. However, the above results suggest that providing revenue stabilisation could increase the effectiveness of the RO relative to the Minimum Change Option, through a combination of reducing investment risk and increasing support levels in low wholesale price outcomes. However, a decrease in efficiency is observed in the Low Case, as the higher revenues lead to higher rents for those plant that would have been built anyway.

4.12 Sensitivities

So far we have presented a set of Cases across a series of Policy Options which can be used to draw some initial conclusions. However, in order to understand the risks around these Options more fully, we have

conducted a number of sensitivities. Here we draw out the key messages from the analysis, leaving a more complete description to Appendix F³².

The sensitivities explore the following risks:

- Lower maximum build rates (Minimum Change Base and Band Indexation Base)
- Hiatus in deployment due to investor concern around policy change (Band Indexation Base)
- Banding changes to deliver different renewable penetrations (Minimum Change Base, Low, ‘High High’ commodity prices and CfD Base)

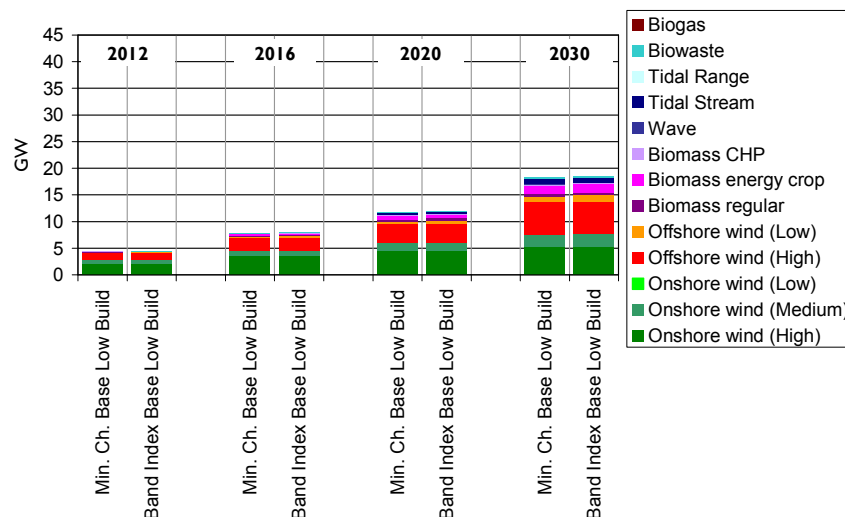
As discussed in Section 3, the effects from any sensitivities applied to Band Indexation can be assumed to be very similar in the Contract for Difference Option and vice versa.

4.12.1 Low maximum build rates

Throughout the analysis presented so far we have utilised the ‘high’ build rates from SKM’s 2008 RES study¹³. These assume an easing of supply chain constraints, shortened planning processes, and more readily available Grid connection. To test how the effectiveness and efficiency of the revenue stabilisation options are affected when the maximum build rates are more constraining, we tested a sensitivity using a lower set of build rates presented by SKM in the same report. We analysed the Band Indexation and, for comparison, the Minimum Change under the Base Case.

Below, in Figure 61, we see that the potential benefits in effectiveness of revenue stabilisation are limited when lower maximum build rates are used. This indicates that the build rates are so tight that they are the major constraining factor in the model and differences in policy are negated.

Figure 61 Renewable build, Low build rates, Minimum Change and Band Index



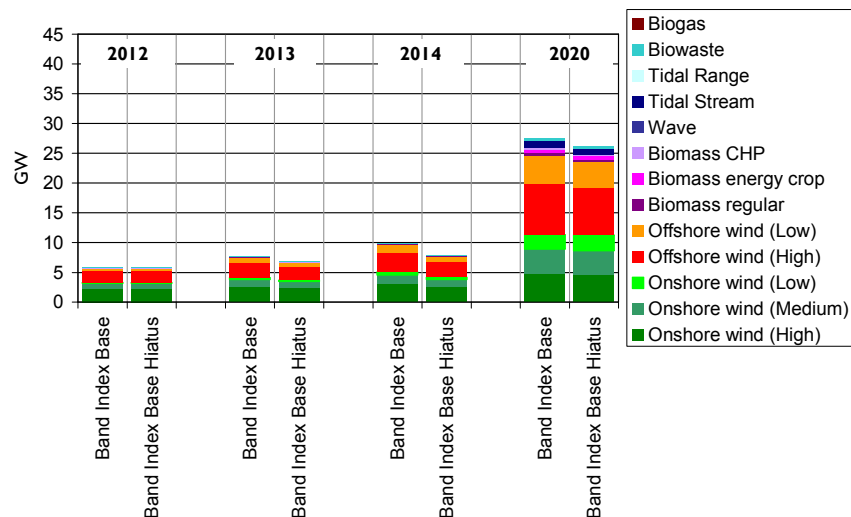
4.12.2 Hiatus in deployment

With the implementation complexity of the revenue stabilisation Options, there is a real risk of a slow down in renewables development while companies consider the impact of the changed policy on their investment plans. To assess the associated risk, we ran a sensitivity in which a hiatus in investment occurs.

³² Sensitivities regarding different EUA prices and a 29% level were also performed. These are not included in the main text, but are described in Appendix F as well.

Our sensitivity assumption is that in the first two years of the policy (2013 and 2014), the maximum build rates are reduced by 50%. The impact of this can be seen in Figure 62, with identical build up to 2012, but 2.1 GW less deployed over the next two years.

Figure 62 Renewable Build, Hiatus³³



Some ‘catching up’ occurs after the transition period, and by 2020 the gap is reduced to 1.2 GW. Even with the hiatus, therefore, the Band Indexation Option (and equivalently the CfD Option) is still more effective than the Minimum Change Base Case.

4.12.3 Banding changes to deliver specific renewable penetration

The premise of the Minimum Change Base Case was to deliver 28% renewable penetration. This required exogenous banding changes in 2013. This set of sensitivities tested banding assumptions in three ways:

- banding required to deliver 24% and 32% renewable penetration in the Minimum Change Base Case;
- banding required to deliver 28% renewable penetration under Low and High High commodity assumptions; *and*
- banding required to deliver 29% renewable penetration under Minimum Change Base and CfD Base.

In Table 13 we present the required changes in banding assumptions to deliver 24% and 32% within the model. To deliver only 24% both on- and offshore wind can be banded down after 2013 given the Base Case assumptions. Delivering an additional 4% to reach 32%, however, requires higher banding assumptions, and an earlier implementation date (2011 instead of 2013), to allow sufficient deployment time. The maximum build rates start to become a constraining factor in trying to meet the more ambitious target. In order to deliver 29%, under Minimum Change Base, the wave and tidal stream are banded up a further half ROC, along with an additional quarter ROC for onshore wind. However, to reduce renewables delivered under CfD to 29% (from 29.8%), all that is required is to leave marine technology bands unchanged in 2013 at 2 ROCs.

³³ Note different years are presented in this chart to other renewable build comparison charts

Table 13 Banding assumptions to deliver differing penetrations

	Minimum Change Base					CfD Base
	Bands (2009)	24% (from 2013)	28% (from 2013)	29% (from 2013)	32% (from 2011)	29% (from 2013)
Onshore Wind	1	0.75	1	1.25	1.25	1
Offshore Wind	1.5	1.25	2	2	2.5	2
Wave	2	2	3	3.5	4.5	2
Tidal Stream	2	2	3	3.5	3.5	2
Tidal Range	2	2	3	3	4.5	2
Biowaste	1	1	1	1	1	1
Biogas	2	2	2	2	3	2

Table 14 shows the banding assumptions required to deliver 28% penetration under Low and High High commodity prices.

With the High High commodity price assumptions, the target could be met with a highest band of 1 ROC and both onshore and offshore wind could be banded below 1 ROC. Indeed onshore wind would barely need a subsidy at all under this Case.

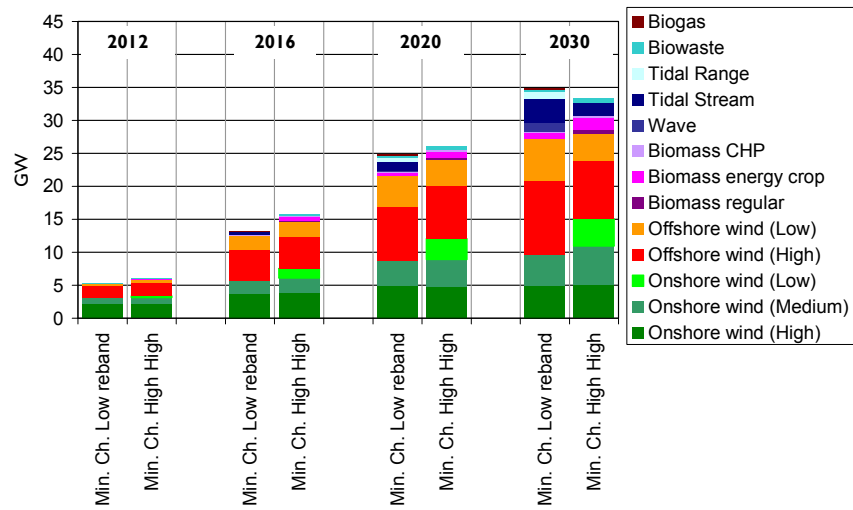
With the Low commodity price assumptions, delivering 28% is very difficult. All of the technologies are banded up from 2011, two years earlier than the Base Case. At the top end, tidal range receives 5 ROCs (or approximately 200 £/MWh in subsidy). The risk of countering low wholesale electricity prices by banding up is that, if prices subsequently rise, excessive rents may be locked in for those plant on high bands.

Table 14 Banding assumptions to deliver 28% penetration under different commodity assumptions

	Minimum Change 28% target			
	Bands (2009)	Low (from 2011)	Base (from 2013)	High High (from 2013)
Onshore Wind	1	1.25	1	0.25
Offshore Wind	1.5	2.5	2	0.75
Wave	2	4.5	3	1
Tidal Stream	2	4	3	1
Tidal Range	2	5	3	1
Biowaste	1	1	1	1
Biogas	2	3.5	2	1

Figure 63 clearly shows that there is more than one way to deliver a specific level of renewable generation, and there will be different costs and benefits associated with different capacity mixes. It also demonstrates that with very high commodity prices, development of renewables is stimulated earlier, even if bands are brought down from current levels. In contrast, banding up in the Low Case leads to higher deployment after 2016 compared to High High.

Figure 63 Renewable build, banding change sensitivities



4.12.4 Sensitivity Summary

In Table 15 we show a summary of key sensitivity results in 2020.

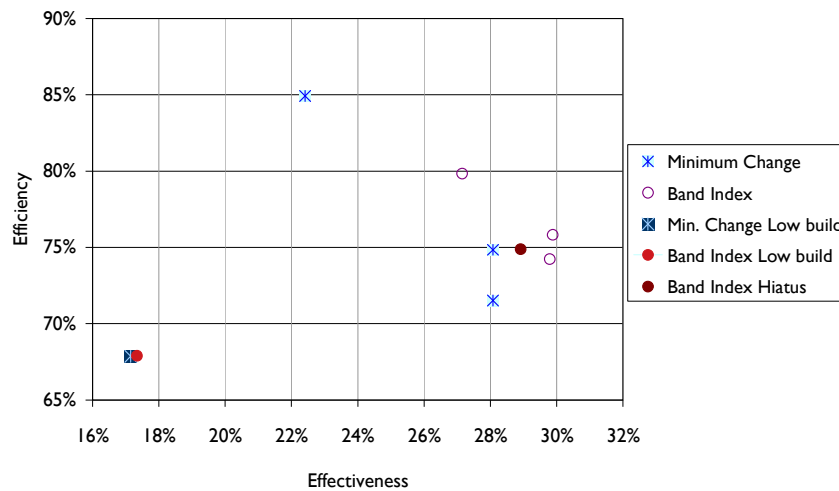
Table 15 Key sensitivity results, 2020

2020	Option & Case	Minimum Change Base	Band Indexation Base	Band Indexation Base	Minimum Change Base			Minimum Change Low	Minimum Change High High	CFD Base
	Sensitivity	Low Build		Hiatus	24% Band Down	29% Band Up	32% Band Up	28% Band Up	28% Band Down	29% Band Up
Renewable Capacity (GW)		18.3	18.5	32.9	26.7	33.1	36.9	31.4	32.7	33.1
Renewable Generation (TWh)		63.2	63.9	106.5	88.8	106.9	118.2	103.4	103.2	107.0
Effectiveness %		17.2%	17.3%	28.9%	24.1%	29.0%	32.1%	28.1%	28.1%	29.1%
Efficiency %		67.9%	67.9%	74.9%	76.6%	74.5%	72.9%	82.8%	65.3%	75.7%

In Figure 64 we plot the efficiency and effectiveness of the first three sensitivities. Clearly, once maximum build rates are reduced, the potential effectiveness gain from revenue stabilisation is largely negated. There is also a notable drop in efficiency, due to higher ROC prices with no additional build, and the proportion of existing (lower cost) plant on the system.

In the Hiatus sensitivity, we see that the effectiveness is still greater than the Minimum Change equivalent, with no worse efficiency. This implies that following the hiatus, build rates and financial incentives provide a sufficient signal to accelerate deployment above and beyond that of Minimum Change, and reducing the longer term impact of the transition slow-down.

Figure 64 Efficiency v Effectiveness, Low Build and Hiatus sensitivities

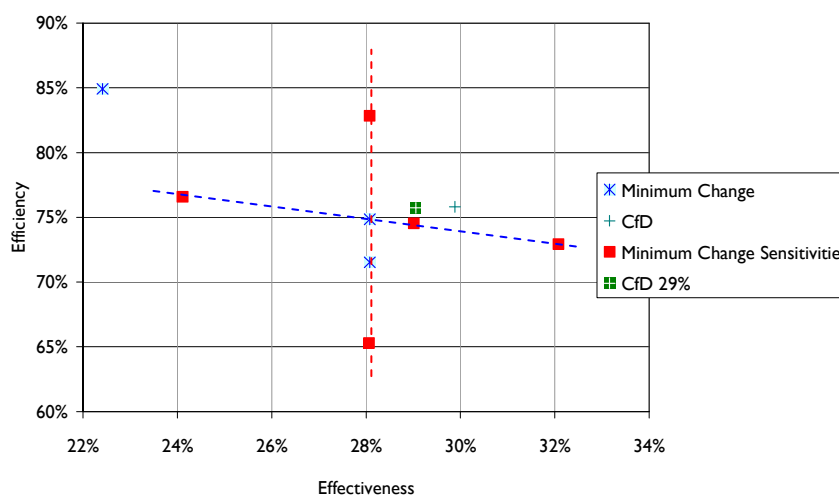


In Figure 65, we incorporate the other six sensitivities which test different banding and commodity price combinations, alongside Minimum Change. These fall into three sets. First are those that meet a specific level of renewable generation under different commodity price assumptions. These line up on the graph on a vertical axis (dotted red line) at the 28% level. The second set shows the effect of banding up or down to meet different penetrations for a single set of commodity prices. These also align on the graph (dotted blue line). Finally, there is a comparison of Minimum Change Base and CfD with banding assumptions to deliver 29% renewable energy.

Along the 28% effectiveness line, what can be seen is that Minimum Change becomes less efficient as commodity prices increase, even though band levels are being reduced to compensate, and vice versa. Along the other axis, we see that as more renewables are deployed, the efficiency falls. This is driven by, amongst other things, the increased rents achieved by cheaper plant when increased subsidies are provided to stimulate increased build.

The comparison between CfD Base and Minimum Change Base demonstrates a continued efficiency gain with a CfD Policy Option, even when effectiveness is forced to be the same.

Figure 65 Efficiency v Effectiveness, Band and commodity price sensitivities



In conclusion, the build rate sensitivities performed demonstrate that tighter annual constraints limit the impact on effectiveness and efficiency of revenue stabilisation options. However (assuming this is not the case), were there to be a hiatus in build resulting from a policy transition, deployment can 'catch up' to limit the overall impact on effectiveness and efficiency by 2020. The other key message from the sensitivities is the challenge faced by the policy maker in using banding to meet a specific renewable electricity target in light of unknown commodity prices.

5 Implementation and investor issues

In Section 3 we identified and described the Phase 1 and Phase 2 Policy Options, and in Section 4 we discussed the quantitative analysis of these Options. Recognising that the Phase 2 Options in particular would constitute major reforms, this section aims to identify the practical issues that would need to be tackled if one of the Options were to be implemented, and the effect this might have on investors.

5.1 Timescales

The Phase 2 options each represent a significant change, either to the RO mechanism itself, or through the requirement for the introduction of a new instrument, and would therefore almost certainly depend on a change in primary legislation. If a decision was taken to implement any of these changes following consultation, then it is possible that the changes would not come into effect before 2013. This is because an election is required by June 2010 and a legislative slot cannot be guaranteed in the first Queen's Speech following the election. In these circumstances, the relevant legislation would not be passed until 2012.

This timetable implies that an element of uncertainty will remain over the precise details of the policy for some time. It is extremely important that, if the Government chooses to adopt one of these options, the announcement and implementation process seeks to minimise the level of residual investor uncertainty. A lengthy implementation time window does, however, allow a sufficient period in which to consider implementation issues and address any complexities that emerge.

5.2 Indexation

The key element of all of the Phase 2 options involves indexation of future revenues to the wholesale electricity price in an attempt to stabilise earnings. The revenue earned by each renewable generator will vary significantly and will be determined by the actual generation profile. It is not therefore possible to achieve this objective precisely and a more realistic goal is to identify an index which provides a good approximation for the average earned income (a time averaged price should be adequate for these purposes) and facilitates effective management of residual energy price risk. In fact, a residual exposure on electricity income may be considered an advantage since it will ensure that incentives remain with the generator to generate when system value is greatest, and to invest to forecast its output accurately.

The key choice for the index is whether it refers to a wholesale price which:

- is derived from electricity forward prices and can be defined ahead of each calendar year (ex-ante);
- represents outturn prices in any year and cannot, therefore, be established until after the end of each year (ex-post); *or*
- is a combination of the above.

An ex-ante approach would involve the use of a forward index which could be averaged across the year. This has the advantage of enabling the indexed parameters to be fixed in advance of each year, thereby providing a level of certainty. For a generator to minimise exposure in these circumstances, forward hedging would be required with a pattern to match the averaging used in the index, as outturn prices can differ markedly from those at the year-ahead stage. In this case, the degree of revenue stabilisation will be limited by volume uncertainty depending on how accurately actual generation can be forecast when the index fixes.

An ex-post approach can employ an annual time-averaged price derived from day-ahead (or within-day) half-hourly spot prices. However, the indexed parameters will not be fixed until after the year end, thereby leaving a degree of revenue uncertainty. In order to minimise residual risk, renewable generators would be incentivised to sell their output in the day-ahead markets. This could significantly increase liquidity in the day-ahead markets, but may reduce the incentive to hedge forward.

It is possible to adopt a combination of ex-ante and ex-post indices. Such an approach could be used to approximate a typical hedging strategy, but may appear unnecessarily complicated from the perspective of a small renewable generation company.

Price indices are typically derived from four types of processes:

- *OTC price reporting:* For over-the-counter trading, price reporting services compile closing price estimates by a daily survey of trading companies. Prices are requested for standard products and an averaging methodology is applied to derive a single number. Methodologies are published, including mechanisms to exclude outliers. In liquid markets, the resulting prices are considered robust despite the lack of a screen-based capture process. The three main price reporting services in the UK energy market are Platts, Argus and Heren which each publish prices for a range of standard contracts from day-ahead to seasons up to three years out. In some cases, estimates of traded volumes are also reported. In volume terms, there is good liquidity in day-ahead contracts. Outside the prompt, monthly contracts tend to be the most commonly traded, but only up to about three months out. Longer term trading focuses on season contracts.
- *Broker reporting:* Some brokers publish indices derived from contracts concluded by the company, often through on-line platforms, over certain time periods. This can include indices based on transactions during a particular time window, or across the course of a trading day. The range of contracts is usually more limited than the price reporting services.
- *Auctions:* Day-ahead auctions are common on the continent. Most are on an hourly or half-hourly basis, with indices derived based on averages across appropriate hours (covering base load and peak). Until recently, however, day-ahead auctions have not been a feature of the GB market. In December 2008, the APX Group started a day-ahead auction, but volumes are low. Separately, a process led by the Futures and Options Association (FOA) (see below) is also planned to deliver a day-ahead auction, in September 2009. It remains to be seen whether either of these will attract significant liquidity.
- *Exchanges:* The APX has operated a prompt UK power exchange since 2000. Participants are able to bid or offer for half-hourly contracts on a rolling basis, or for blocks (peak, base load etc). Prices from this market are used to derive the 'Market Index Price' (MIP), a half-hourly index used within the Balancing and Settlement Code as a part of cash-out price derivation (setting the price which out-of-balance parties are charged or receive where their imbalance is in the opposite direction to the system as a whole). The Intercontinental Exchange (ICE) offers monthly and quarterly products for base load and peak up to two years out, but trading volumes are very low. In November 2008, the FOA announced the selection of NASDAQ OMX Commodities (NOMXC) and Nord Pool Spot to deliver a spot and cash-settled derivatives power market for GB. This followed a long process driven by the Power Trading Forum within the FOA (made up largely of representatives from the main utilities). This is planned to include a prompt market, an auction market, and a cleared futures exchange. The FOA is anticipating that the current illiquidity in derivatives can be overcome by a direct tie to a reliable exchange-based prompt market which can be used for settlement.

Table 16 shows a summary of available sources versus maturity (broker reporting not included due to intermittent nature):

Table 16 Available prices sources across maturities

	Half-hourly	Daily	Monthly	Quarterly	Seasonal	Annual
Price reporting	n/a	Robust existing price reporting service (Heren, Platts, Argus)				
Auction	Currently very low volumes Possible future development in liquidity		n/a			
Exchange	APX used for MIP	Daily index available	Possible future liquidity (NOMXC)			Could be constructed from underlying products

For an ex-ante approach it would be necessary to use the price reporting indices, and applying an average across the three main price reporting services is probably the most robust approach. For an ex-post methodology it would be possible to use a half-hourly index. The only realistic option for this currently would be the APX exchange. The use of this index as the MIP within the Balancing and Settlement Code sets a precedent for its use as a price index.

This analysis suggests that it should be possible to identify an appropriate price index although the revenue stabilisation will not be perfect. In addition, price reporting services and exchange based offerings continue to evolve and it would be necessary to incorporate sufficient flexibility in fixing the index to adapt to future developments. It should be noted that the adoption of a price index is likely to increase liquidity in the markets that derive this index, as this can minimise party risk, which in turn should increase the reliability of the index.

Once the index has been identified, the Government has to set the level of E_0 , the baseline electricity price (in the case of the CfD, this is the strike price). In the quantitative assessment, the baseline was set once for the entire modelling period. This could be a politically sensitive issue if the Government is seen to be setting the ‘fair value’ of power, even though in fact this is only one part of setting the revenue for renewables and should be seen in the context of the overall subsidy scheme.

5.3 Compatibility with support schemes for small renewables and heat

As described in Section 2.3.3, the Government has taken powers to introduce two new support schemes: a Renewable Heat Incentive (RHI) and a FIT for sub 5 MW renewable generators. Regardless of the extent of the reforms to the RO, there will be issues relating to the interaction of the different schemes. Given that the details of these policies were not announced prior to this study, it has only been possible to assess these issues at a very high level.

The most obvious potential issue with the interaction of the FIT and the RO is what happens at the capacity ‘cut-off point’. Investors may have an incentive to size projects either above or below this point (to the extent that it is feasible to do so), depending on which scheme appears more generous at that point in time, which scheme provides more certainty, and the relative complexities and administrative burdens of the schemes. It is reasonable to expect that the revenue stabilisation under the Phase 2 options would

change this interaction significantly, since the relative attractiveness of each scheme is likely to remain fairly constant through variations in wholesale electricity prices.

The most likely impact of the RHI is that it may change the investment landscape for Biomass CHP. Of the Phase 2 options, only the Buy-out Cap/Collar would directly affect the revenues of Biomass CHP since it is assumed that biomass is excluded from the other options.

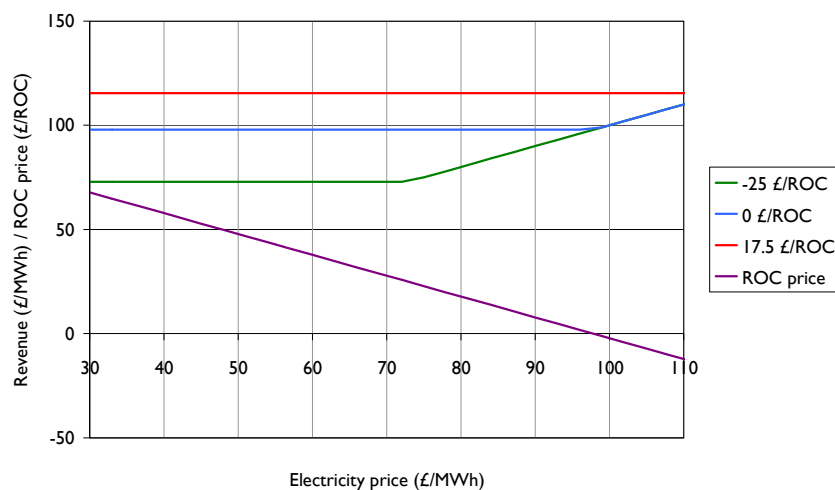
5.4 Other implementation issues

A number of detailed design issues would need to be addressed for each of the Phase 2 Options. The key issues are listed below:

Buy-out Cap/Collar

- If it is decided to adopt a principle of ‘no negative subsidies’, this cannot be achieved merely by placing a floor of zero on the Buy-out price when absolute bands are used. For example, a technology ‘banded down’ with an absolute band of -5 £/MWh would already be in a negative subsidy situation once the ROC price was lowered past 5 £/ROC. Likewise, a technology ‘banded up’ by 5 £/MWh will still be receiving subsidies until the ROC price falls to -5 £/ROC. To handle this precisely, it would be necessary to allow the Buy-out price to become negative and impose a ‘no negative subsidy’ rule on each band at the appropriate point. This is illustrated in the Figure 66 (note that for clarity this chart shows the case of full stabilisation rather than the cap collar option that was modelled).

Figure 66 Pay off diagram for Buy-out adjustment with no net negative subsidies



- The introduction of absolute bands means that the revenue for a generator can no longer be channelled by issuing a higher or lower number of ROCs. A separate cashflow mechanism would have to be created to collect and distribute premia and discounts. In the likely event that net banding exceeds one, there would be a shortfall in this fund which would need to be levied on consumers via suppliers.

- The existing ability to carry over ROCs between years may need to be re-considered to avoid perverse incentives associated with annual changes in ROC price. If this flexibility were reduced or removed, Headroom may need to be increased to reduce the risk of an oversupplied year (which the banking mechanism can currently be used to manage).
- Some 'scarcity' effects will remain even with Headroom, due to the annual variability in renewables output. In years where renewables output was below average, and the Obligation size was set ex-ante, the ROC price will tend to rise above 'Buy-out + Headroom' level, reducing the effectiveness of the stabilisation. If the Obligation size is set ex-post, these effects could be removed via a correction after the year.
- Biomass generators have significant variable costs and stabilising revenues for biomass could potentially increase risks. However it is not possible to exclude biomass generators from this Option.

Band indexation

- The number of ROCs will vary with electricity price. The use of an ex-ante price index would allow the Obligation size to be fixed at the year-ahead stage. However, in the case of an ex-post index the Obligation size would only be fixed at the end of the year. Parties should be able to estimate this as electricity prices evolve through the year, so the ROC price should be unaffected. However it would complicate the trading of ROCs and the administration of the scheme.
- The 'no negative subsidies' rule can be achieved by imposing a floor of zero on band scalars.
- The existing ability to carry over ROCs between years may need to be re-considered to avoid distortions that may arise when Obligation sizes are varying significantly year-to-year. If this flexibility were reduced or removed, Headroom may need to be increased to reduce the risk of an oversupplied year (which the banking mechanism can currently be used to manage).
- Some 'scarcity' effects will remain even with Headroom. In years where renewables output was below average, and the Obligation size was set ex-ante, the ROC price will tend to rise and the effect will be magnified or dampened depending on the adjusted band level, reducing the effectiveness of the stabilisation. If the Obligation size is set ex-post, these effects could be removed via a correction after the year.

CfD option

- The key issue for this option is that the CfD would require a separate settlement mechanism outside the RO. This would require an 'Agency' entity to manage the payments between generators and suppliers. This Agency would not need to take on any wholesale price exposure, nor would it deal with physical electricity. However, it would require working capital and bear counterparty risk. Both of these issues would impose extra costs on top of basic administration costs; the size of the cost could be reduced with regular settlement (e.g. monthly).
- The cashflows associated with the CfDs would be passed on directly to suppliers. This would create price and volume risk that they would need to manage. However the exposure would not be dissimilar to entering into PPAs directly with renewables generators as they do currently.
- Smaller renewables generators would likely still seek offtake agreements with larger players to manage the physical electricity on their behalf. However, rather than fixed price as might be the case currently, these agreements would likely be linked to the CfD index price thus preserving the revenue stabilisation offered by the CfD.

- If a large proportion of generation was on a fixed contract price, this would have the potential in the future to distort the operation of the forward markets. However, it is unlikely that this proportion would ever go above 25% of electricity generated, since over time CfD contracts would begin to expire, keeping the overall proportion down.

5.5 Implications for investment

One of the primary motivations for introducing the Phase 2 options would be to facilitate more efficient financing of renewables projects through a reduction in the perception of earnings risk. Currently, large vertically integrated suppliers are more able to manage this earnings risk than small independent developers, due to their integrated business model. Vertically integrated players may benefit less from stabilisation schemes and so lose a competitive advantage.

In addition, it is important that the rate of growth in renewables is not adversely affected by introducing a change to the RO mechanism. For these objectives to be achieved, the following conditions need to be met:

- Investors must have confidence in the future integrity of the mechanism. This involves:
 - Confidence, based on experience, that the Government applies the ‘grandfathering’ principle when new policies are introduced such that the returns made on historic investments are not adversely affected by policy change
 - The objectives of the new mechanisms are clear and the rules employed appear credible and capable of withstanding the test of time
- It must be easy to explain the impact of the new mechanisms to investment committees/Boards and, in particular, it is important that large value swings do not emerge from complex and detailed rules
- The changes must be implemented in such a way that:
 - The objective and mechanisms are quickly defined and understood so that investors do not put investment programmes on hold whilst they absorb the changes
 - The new rules do not provide financial incentives for investors to delay investments to take advantage of the policy changes

Under Buy-out Cap/Collar, existing generators will be affected by moving to absolute bands and changes to the Buy-out price. It is not, therefore, possible to adhere to the ‘grandfathering’ principle under this option. Concerns could be minimised by placing a cap and collar symmetrically around expected electricity prices and making absolute bands as close as possible to current band differentials. However, there may be issues with some existing PPAs which may have separated sales of ROCs and electricity.

It should be possible to more accurately ‘grandfather’ the value of historic investments under both the band adjustment options, provided the Obligation size is adjusted appropriately, and through the CfD approach since existing plant would be unaffected.

A particular challenge for the Phase 2 options, with the exception of the CfD option, relates to the complicated formulae used to achieve the desired revenue stabilisation and the fact that the extent of the stabilisation will be imperfect. In particular, it may be interpreted by investors that Government is trying to implement a FIT within the RO framework and the imperfect nature of the solution may suggest that further and more radical changes might be implemented at a later date. Another concern may be that investors perceive that the primary objective of the change is to reduce rents at times of high wholesale price rather than reduce the financing costs for new projects. This may lead them to adopt more

conservative revenue forecasts than would have otherwise been the case. Both of these issues present less of a concern for the CfD option where the underlying philosophy of the RO remains intact (and particularly if the revenue stabilisation component is provided by an optional CfD for investors rather than an embedded feature of the RO – see Section 5.6). Another potential advantage of this approach from an investor perspective is the contractual nature of the CfD which provides the revenue stabilisation. This provides a much greater degree of confidence about the future integrity of the mechanism since it is underpinned by contract law rather than being part of the overall market framework.

The complicated rules employed in the Buy-out price and banding adjustments, coupled with the imperfect nature of the revenue hedge, may lead investors to conclude that unforeseen issues will arise following implementation of the mechanism and these problems will need to be corrected by an ongoing programme of further reform.

Finally, the protracted implementation timescales would run the risk of reducing the rate at which investors push projects forward as they wait to see the details of the ultimately approved scheme. However, provided that firm commitments are given to the principle of grandfathering (which would preclude the Buy-out Cap/Collar), and in light of the other obstacles to renewables development, it should be possible to avoid any material investment hiatus.

5.6 Optionality

A Policy Option which allows investors to choose (at commissioning date) between stabilisation or wholesale price exposure might have advantages because it would provide revenue stabilisation for those parties that require it to proceed with projects, whilst allowing other parties to be largely unaffected. However it would reduce the efficiency of the option because not all plant would be covered by revenue stabilisation. Table 17 summarises how the optionality would affect each Policy Option, in principle.

Table 17 Optionality considerations

	Buy-out price indexation	Band indexation	CfD
Possible to make optional	No	Yes (in theory)	Yes
Impact on implementation	N/A	Would create very complex option and increase difficulty of setting the Obligation size	No significant change in complexity
Impact on investor issues	N/A	Investors will still be part of a scheme which includes stabilisation for some plant, even if they opt out	Would allow investors to continue with no change if desired
Impact on effectiveness	N/A	Effectiveness should be similar to a mandatory scheme because investors can still take the option if they want to. It would reduce risk of a hiatus in build.	
Impact on efficiency	N/A	Less able to minimise rents because uptake of revenue stabilisation would be lower	

Overall it appears that the CfD option is the Policy Option most suitable for being implemented as optional rather than mandatory. It should be equally effective as a mandatory scheme, but likely to be less efficient in high wholesale price worlds since plant that have not opted for the CfD could enjoy high economic rents.

5.7 Comparison between options

The analysis outlined above suggests that there is a significant implementation challenge associated with the Phase 2 options although none of the issues identified appears insurmountable. Investor reaction is likely to vary and, in the short term, the changes may be subject to vocal criticism or support. Small-scale renewables developers may see advantage in the revenue stabilisation options since these could help in raising project debt, particularly in the current climate. Larger players, who have the means to manage price risk by integrating renewables into their broader generation and supply portfolios, and who have greater access to finance, may prefer less changes to the RO.

There are differences between the schemes and these are summarised in Table 18.

Table 18 Comparison between options

	Buy-out price adjustment	Band adjustment	CfD option
Implementation issues	Complicated to define detailed rules; need for separate cashflow mechanism to deal with Absolute bands	Complicated rules required to define obligation size and band scaling	Need for separate settlement & cashflow mechanism
Investor issues	Difficult to adhere to grandfathering principle; difficult to understand and explain	Difficult to understand and explain	Easy to understand, but still a significant change and may undermine commercial PPA arrangements

6 Conclusions

A minimum set of changes is required

There is a minimum set of changes that must be made to the RO to enable subsidies to grow from around £1bn per annum now to as much as £6bn per annum by 2020, to accommodate the significantly greater amount of renewables generation that will be required to comply with the EU RES 2020 Directive. In particular, the current 20% cap on Obligation size will need to be lifted. Under our Minimum Change Option in the Base Case the Obligation size would need to exceed 50% by 2020. Also, as already indicated by the Government, the term of the RO will need to be extended to provide sufficient incentive to investment in renewables up to and beyond 2020. With these changes in place, necessary adjustments to banding, and with a Headroom mechanism successfully removing the risk of price collapse, our modelling suggests that a 28% 2020 target for large scale renewables generation could be achievable under our Base Case assumptions, provided current external constraints can be alleviated including the availability of finance.

As the level of wind (and other intermittent) capacity increases, so does the uncertainty with regard to year-on-year variation in renewable output. This, together with the introduction of banding, makes the setting of the Obligation size more challenging once the existing annual fixed targets expire, and Headroom is required to support the ROC price. Under a range of assumptions regarding offshore wind banding and the correlation between annual onshore and offshore wind variation, we estimate that the Headroom needed to limit the risk of a price collapse by 2020 lies between approximately 10% and 12%, and as such it may be necessary to increase the current 8% level over time.

If the RO were extended (say to 2037/38) a defined participation period would most likely be used to limit the years that a new plant would remain within the scheme. Whilst this would need to be close to the economic life of the project, the specific choice (say 17 or 20 years) will only have a material impact on the cost of the RO after 2030 (the overall impact on an NPV basis would be around 5% on RO cost and technology subsidy alike), and the overriding concern for investors is likely to be that this participation period is certain.

Implementing only a minimum set of changes, however, provides no guarantee that a particular target will be met, and the risk of a shortfall would increase significantly should commodity prices fall below those assumed in the Base Case, unless there was a corresponding drop in the capital cost of renewable technologies. For example, in our Low Case, renewables output in 2020 fell 5.7 percentage points below the 28% target under the Minimum Change Option. Re-banding is a poor lever in these circumstances due to the time required for reviews compared to commodity price movements (evidenced in particular in 2008), and the risk of economic rents once band levels for existing plant are locked in.

The Price Shocks Case demonstrated the other potential downside of the Minimum Change Option, namely that consumers could be exposed to excessive costs if wholesale electricity prices were to spike, whilst generators enjoyed supernormal profits.

Managing risk under Minimum Change

Banding in the RO has been implemented to differentiate the level of support between technologies. The intention is that these bands can be revised infrequently (for new projects) to reflect changes in cost relativities between technologies. However, it is clear that there are risks on the revenue side as well as the cost side, because of the exposure to volatile wholesale electricity price. We do not consider re-banding to be an appropriate tool for managing this wholesale price variability, since once the band is set it is grandfathered for the duration of the support and yet electricity prices could rise or fall. Hence, if bands

were increased in response to a period of low electricity prices, but then were to rise, economic rents could be locked in for generators, and consumers would be exposed to unnecessarily high costs.

It has been suggested that there may be a natural hedge for generators (and by extension for consumers) assuming there were a positive correlation between wholesale prices and capital costs. If commodity (and hence electricity) prices were to fall, capital costs could also fall, and vice versa. It is not yet clear from limited historic evidence that a strong correlation exists, but more importantly, because capital costs are sunk at the start of the project, whereas wholesale price variability endures through the project, this does not remove the enduring revenue exposure for generators, or risk of excessive costs for consumers.

Larger players may be able to manage the wholesale price risk within their wider portfolios, whereas independent developers may struggle to raise finance for their projects given the revenue risk, without signing long term PPAs with larger players.

Scarcity signal of limited benefit

One approach to modifying the RO would be to extend fixed annual targets through to 2020, in addition to a Headroom mechanism. In situations where renewables deployment fell below target, this would create a scarcity signal by increasing the recycled revenues. However, modelling results from the Low Case indicate that fixed targets make only a relatively small difference in effectiveness, whilst disproportionately increasing rents and reducing efficiency. Qualitatively, there are arguments for and against setting a fixed trajectory to the 2020 target. We believe that investors, and lenders in particular, tend to discount the recycled component of RO revenue in project evaluations, limiting the impact a scarcity signal could have on deployment. On the other hand, setting fixed targets may reinforce perception of the Government's commitment to meeting the 2020 target, a qualitative benefit with regard to investor confidence.

Revenue stabilisation schemes can reduce rents and increase effectiveness...

It would be possible to implement a more radical set of changes to the RO whereby the level of subsidy was adjusted year-by-year to offset changes in generator income from varying wholesale electricity prices, stabilising (to a greater or lesser extent) their overall expected revenues. This has the potential advantages of reducing earnings risk for investors, and limiting the risk to consumers of excessive costs.

The reduced earnings risk may make financing easier (captured in our modelling through lower hurdle rates) and hence, other things being equal, will tend to increase the renewable capacity achieved in 2020. Furthermore, assuming that target revenue levels are maintained through the scheme even for sustained falls in commodity prices, then the effectiveness risk posed in circumstances similar to our Low Case is substantially reduced. Whilst none of the options met the 28% target under the Low Case in our modelling, revenue stabilisation reduced the shortfall from 5.7% to only 0.8%.

The modelling also demonstrates that the potential benefits of revenue stabilisation in reducing generator rents in situations where commodity prices spike for a short period. These short duration prices may not increase investors' expectations of future earnings, and hence have little impact on renewables deployment, and yet could increase costs for consumers measurably. Revenue stabilisation can hence limit the impact of price spikes on consumers with little negative impact on investment.

When effectiveness and efficiency metrics are considered together, revenue stabilisation options tend to show a reduction in the spread of outcomes across different commodity price scenarios. Where commodity prices are lower, stabilisation options perform better on effectiveness compared to Minimum Change, but efficiency appears relatively poorer. This is because in general the increased subsidy level that brings on additional build under revenue stabilisation exceeds the actual additional resource costs, increasing the costs to consumers relatively more.

...but face significant implementation hurdles

Revenue stabilisation options face a significant barrier as they would all require primary legislation changes prior to implementation. They therefore need to show very material benefits to be realistically considered. Means of stabilisation utilising the existing mechanisms within the RO (such as Buy-out or band indexation) lead to very complex formulations, and the inability to grandfather would appear to rule out Buy-out adjustment schemes as viable options.

This complexity also creates a material risk of heightened investor uncertainty during a transition period, creating a possible hiatus in project development. Our modelling of a simple sensitivity suggested that, whilst this might undermine the benefits of stabilisation, the revenue stabilisation options might still be more effective than the Minimum Change Option.

There could be a material impact on the overall wholesale market associated with the introduction of a stabilisation scheme. The manner in which the electricity price index was defined (for example, whether it was calculated ex-post or ex-ante) could affect associated hedging strategies for generators (or PPA counterparties), which in turn (as penetration increases) may have a material impact on trading patterns and liquidity, some of which might be positive.

Interactions with the sub-5 MW Feed-in Tariff and the Renewables Heat Incentive will also need to be considered carefully.

A wholesale price CfD provides a simpler option

A CfD scheme, in which renewables generators are offered financial contracts swapping a wholesale price index for a fixed price, is conceptually a much simpler solution for stabilising the electricity portion of revenues, and leaves the RO itself unchanged. Independent developers may find it easier to raise finance for projects under a scheme where electricity revenues are stable and transparent. However, integrated players may prefer to retain wholesale price risk on their renewables plant since this may offset risks elsewhere in their portfolios. It would be possible to make the CfD approach optional, accommodating the preferences of different types of investors. Making the CfD scheme optional would likely lead to a similar level of effectiveness, since it would be available to parties that needed it for their projects to progress, but there may be some loss of efficiency in high price outcomes as not all projects will be covered by revenue stabilisation.

It would be possible to maintain a scarcity signal through the RO if desired (something difficult to achieve with Band Adjustment or Buy-Out options). However, the CfD approach would still require primary legislation and an entirely new cashflow and settlement mechanism for generators and suppliers, with an agency to administrate it.

On balance we believe that if stabilisation is seen as desirable, a CfD is the most practical way to achieve this within the current framework of the RO and electricity market arrangements. However, we have identified a range of implementation issues that would need to be considered in more detail to determine whether they pose significant challenges.

There is a high degree of sensitivity to key assumptions

The outcomes that we have described are very sensitive to a number of factors, and these conclusions should be considered in that context.

Maximum build rate constraints are a critical issue. Most of our modelling has assumed that build rates are able to increase significantly due to improvements in planning and grid access, and supply chain development. Were this not to be the case, the associated constraints could lead to output from large scale renewables in 2020 far below target (17% in our sensitivity compared to a target of 28%). Under

these circumstances, revenue stabilisation options offer no benefit in improving the potential effectiveness of the RO.

A higher or lower target scenario has implications for the overall cost and efficiency of the RO, with cost increasing and efficiency decreasing as higher targets are imposed. This would have to be balanced against the relative costs of achieving more or less renewables in the heat and transport sectors in order to meet the renewables target.

Meeting a given target under lower commodity price assumptions requires more subsidy, as revenues from the wholesale market are lower, but efficiency can be higher because there is less chance of rents for generators (if band levels turn out to have been correctly set). Conversely a high commodity price world reduces the required subsidy, but the efficiency may be lower where the reduction only partially offsets the revenue gains from the wholesale market.

Capital cost assumptions are also of course important. Whilst the banding mechanism provides a policy lever for accommodating changes here, it is a relatively inflexible tool given the variability that has been seen over the last few years. In the modelling context, our specific assumption set has capital costs changing relatively gradually over time (as we were not seeking to test the effectiveness of banding). For the purposes of modelling, we have derived banding assumptions that would deliver 28% generation from large scale renewables by 2020 under the Minimum Change Option in the Base Case, and then held the banding assumptions constant across all the other Options and Cases. The full set of results then shows a range of levels of renewables deployment. Re-banding in the light of changing circumstances could improve the effectiveness or efficiency of the RO, although, likewise, incorrect banding decisions (for example, if capital cost forecasts turned out to be inaccurate) could have the opposite effect.

Finally, for significant policy changes, the time at which investors start assuming that a forthcoming policy change can be firmly relied on is an essential element of the effectiveness of a scheme. This is particularly so because of the short time remaining to 2020 and the build rate constraints discussed above. In our modelling we have assumed that this occurs two years prior to policy implementation. If the Government were successfully able to bring this forward (even with the implementation date unchanged), this could significantly improve the associated benefits. We estimate that a one year difference could lead to an effectiveness benefit of perhaps 1-2% for revenue stabilisation schemes.

A Appendix: Stabilisation schemes

This Appendix provides a supplementary set of pay-off diagrams reflecting different stabilisation schemes considered in the qualitative evaluation of Phase 2 Options, other than those already described in Section 3.3.3 that were chosen for the quantitative assessment.

These represent different permutations of adjustments to the Buy-out price or bands, with and without caps and collars, and with and without a scarcity signal. We show diagrams for:

- scalar on Buy-out price;
- scalar on Buy-out price with absolute bands;
- adder on Buy-out price;
- adder on Buy-out price with absolute bands and scarcity signal;
- adjusted bands with scarcity signal;
- adder on Buy-out price with cap/collar;
- adder on Buy-out price with cap/collar and scarcity signal;
- adjusted bands with cap/collar; *and*
- adjusted bands with cap/collar and scarcity signal.

Figure 67 shows a pay-off diagram associated with introducing a simple scalar on the Buy-out price. The diagram shows the total (wholesale electricity and ROC) revenue (y-axis) for a range of bands (with the green, blue and red lines showing 0.25, 1 and 1.5 ROC bands respectively) as the electricity price changes (x-axis). It leads to non-linear revenues and changing relativities between bands as the electricity price changes.

Figure 67 Scalar on Buy-out price

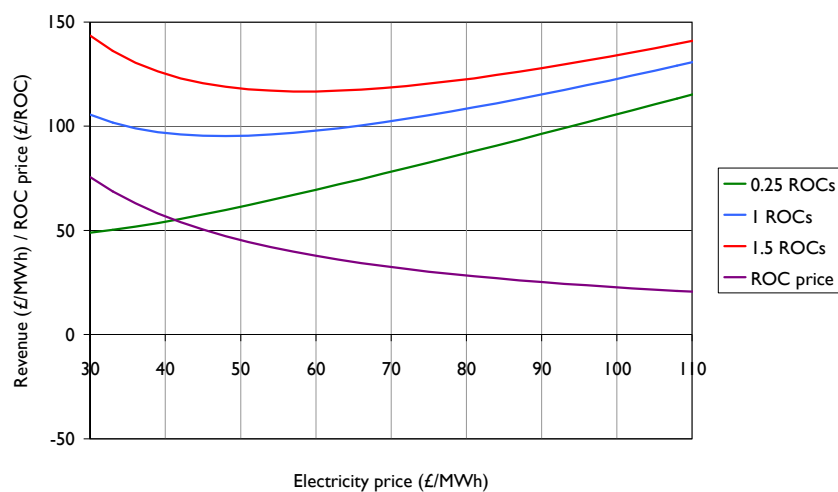


Figure 68 shows the effect of using absolute bands (applied as a fixed premium or discount in £/ROC for each technology group). The relativities between the bands stay the same regardless of electricity price. The non-linearity of revenue with electricity price remains.

Figure 68 Scalar on Buy-out price, absolute bands³⁴

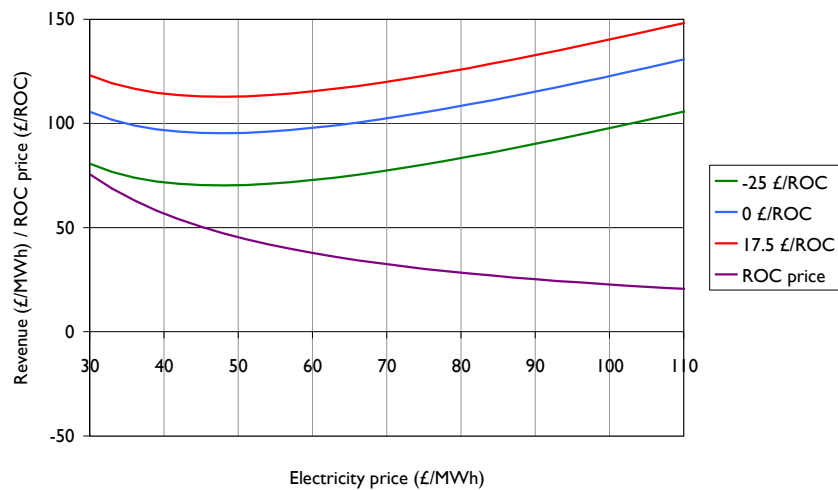


Figure 69 shows the effect of adjusting the Buy-out price with an adder (positive or negative) so that the sum of Buy-out price and electricity revenue is constant (rather than using a multiplicative scalar). This keeps revenues stable for plant in the 1 ROC/MWh band (for a given scarcity level) but does not stabilise revenues for other bands. ROC bands higher than one see a perverse situation where revenue falls as the electricity price rises.

Figure 69 Adder on Buy-out price

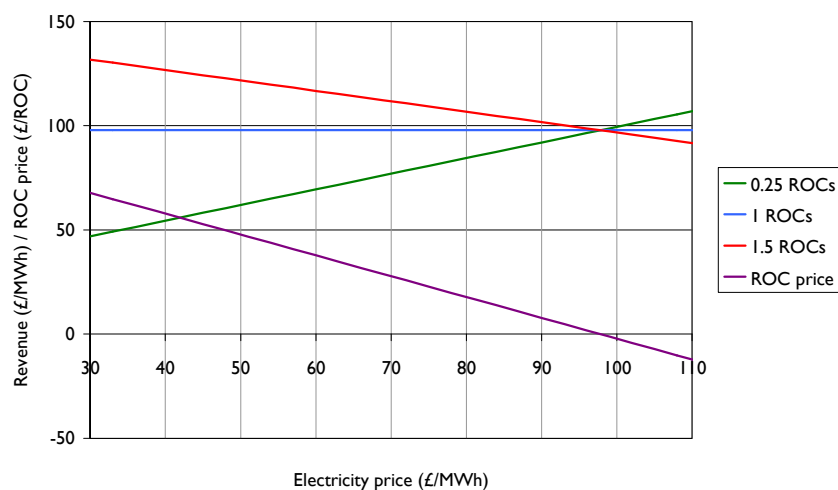


Figure 70 shows the pay-off for a scheme with a Buy-out price adjusted as described above, but in addition introducing fixed premia/discounts and shows outcomes associated with a range of ROC scarcity that might be associated with a fixed annual target size. The revenue is stable for all bands at one level of scarcity, but if there is a strong scarcity signal the revenues are not constant.

³⁴ In this case the number in the legend represents the absolute premium or discount in terms of £/ROC

Figure 70 Adder on Buy-out price, absolute bands, scarcity signal³⁵

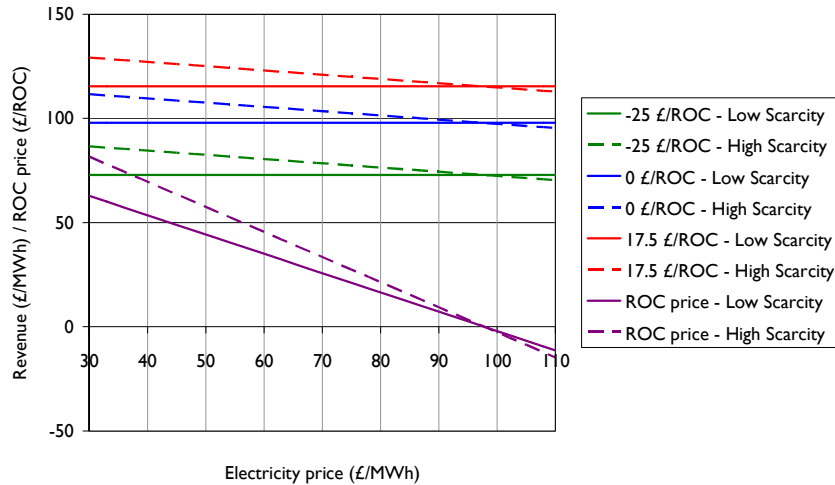


Figure 71 shows the effect of adjusting the bands to stabilise revenue. This can keep revenues constant for all new plant if the scarcity signal is low. However if the annual target is fixed as in this example, the scarcity signal can lead to revenues declining as the electricity price increases.

Figure 71 Adjusted bands, scarcity signal

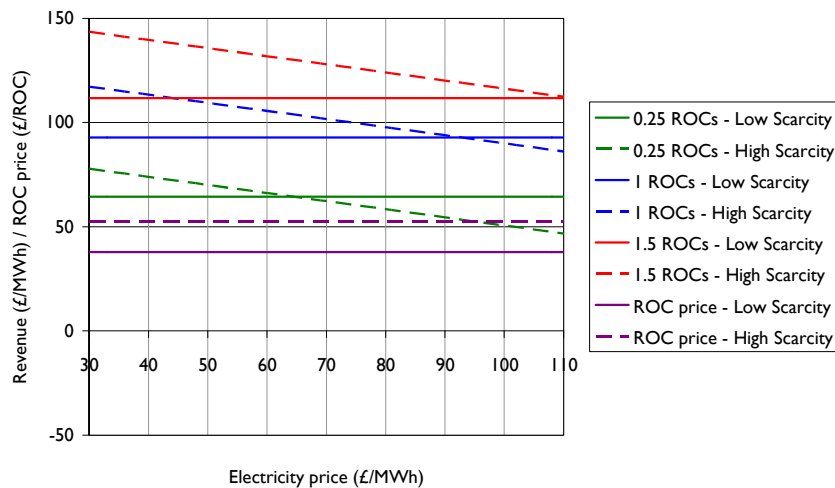


Figure 72 shows the impact of using the adjusted Buy-out price to create a cap and collar on total revenues. This works well for the 1 ROC/MWh band but creates perverse revenues for other bands.

³⁵ In this case the number in the legend represents the absolute premium or discount in terms of £/ROC

Figure 72 Adder on Buy-out price, Cap and collar

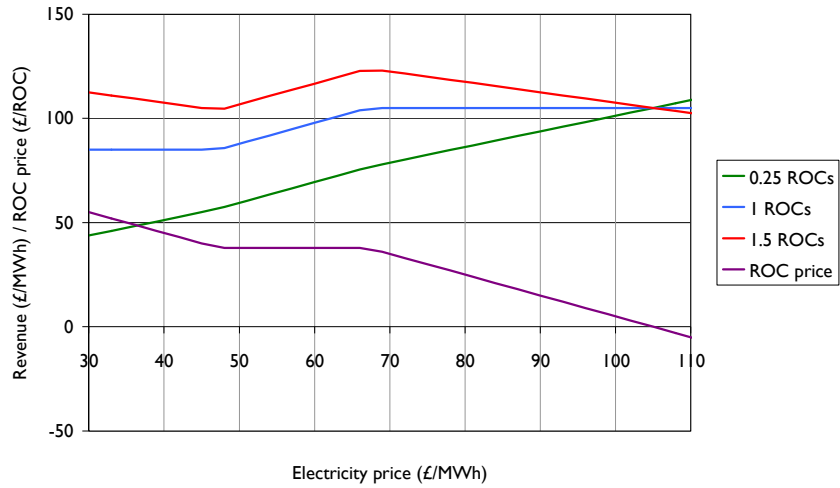


Figure 73 shows the effect of a scarcity signal, which compounds the perverse revenues for bands other than the 1 Roc/MWh band.

Figure 73 Adder on Buy-out price, Cap and collar, scarcity signal

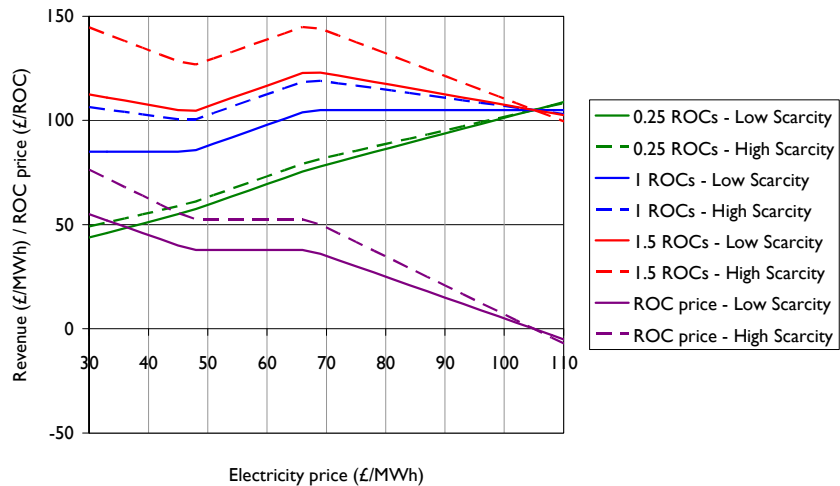


Figure 74 shows that a cap and collar using band adjustment could provide the required pay-off. However, the size of the obligation must be adjusted in line with changing bands to prevent perverse ROC price signals being created.

Figure 74 Adjusted bands, Cap and Collar

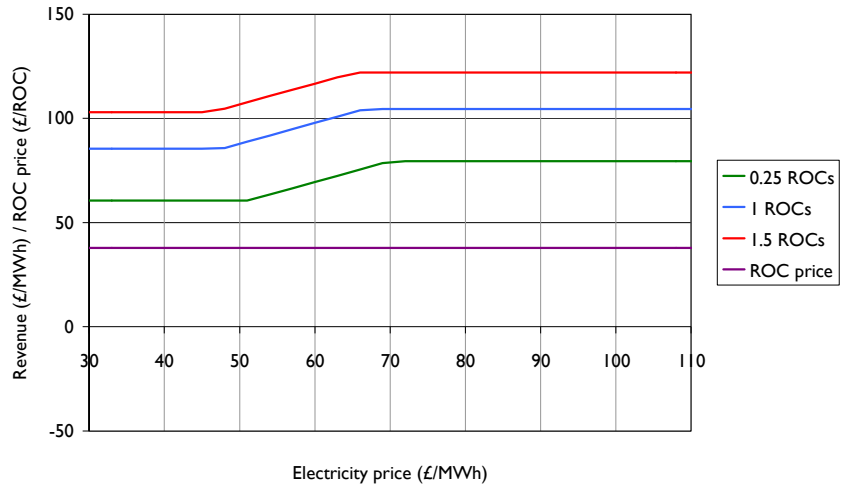
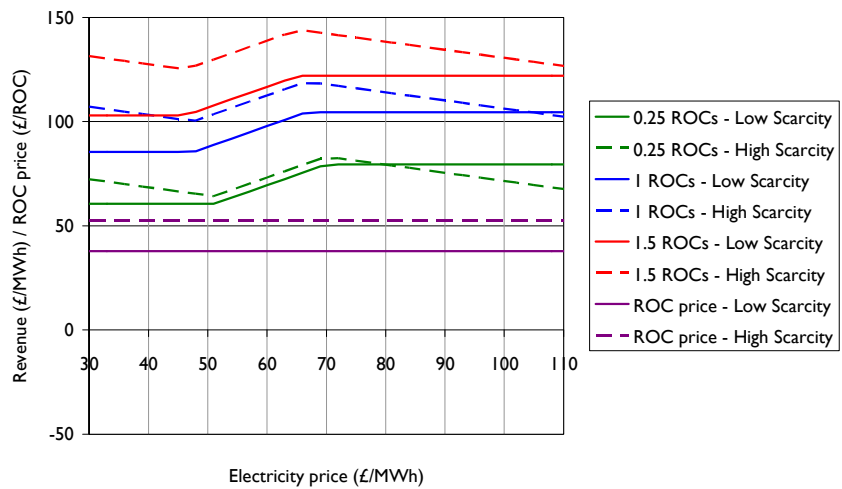


Figure 75 shows that introducing a scarcity signal into the cap and collar mechanism would distort the payoff and relativities between the bands.

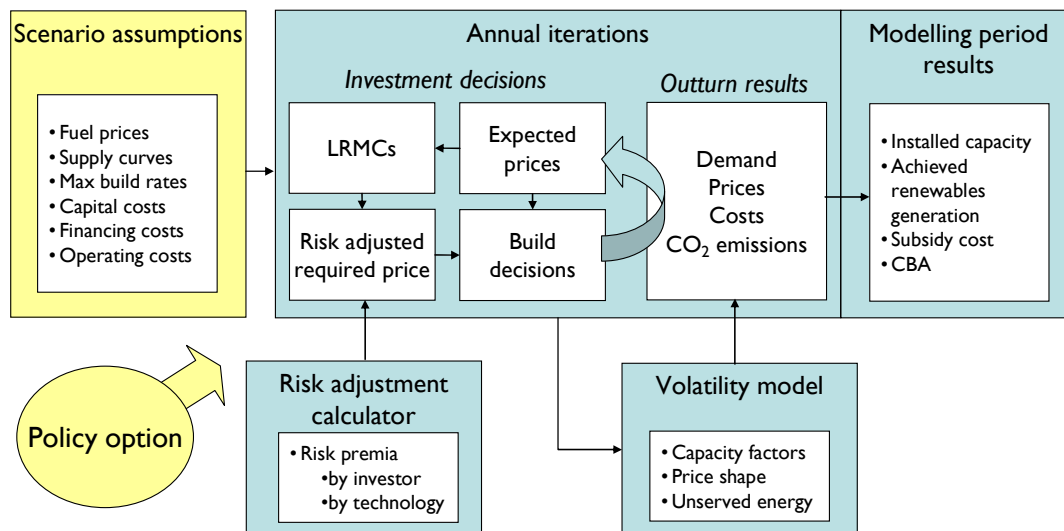
Figure 75 Adjusted bands, Cap and Collar, scarcity signal



B Appendix: Modelling framework

An overview of the modelling framework used for the study is shown schematically in Figure 76.

Figure 76 Modelling framework



At the heart of the framework lies an **investment decisions** simulator. This computes the risk-adjusted long run marginal costs (LRMCs) of all generation technologies by player type. Where these are less than expected revenues (given assumed load factors and future price expectations), players move new plant first to a planning stage, and subsequently, if still economic, to a committed development phase. On an annual basis, **outturn results** for demand, prices, generation output and carbon emissions are computed. These in turn feed back to expected prices for the following year's iteration.

The LRMCs used in the build decision algorithm are risk-adjusted in the **risk adjustment calculator** by computing a distribution of gross margins for each investment under the full range of uncertainties in revenues and project costs. The **volatility model** analyses the market at an hourly level for each year by simulating demand, spot fuel prices, forced outages and renewables output. It produces annual price duration curves and estimates of price volatility and volumes of short term demand side response and expected energy unserved. It is used to calibrate the expected price and renewables 'capacity credit' functions within the investment decisions simulator (explained in Appendix E).

The modelling approach provides a comprehensive framework for the quantitative assessment of different support schemes and the impact of sensitivities. However, as with any modelling exercise, the limitations of the approach should be carefully considered. Key points to note include:

- We model to 2030, yet the key focus of any policy changes is to 2020 and we make no assumptions about revisions to policy or targets post-2020. In practice, these are likely to evolve within the context of the UK Government's legally binding commitment to an 80% reduction in CO₂ by 2050.
- The modelling requires multiple input assumptions including variables that are very uncertain such as commodity prices, future capital costs of plant, and maximum build rates.

- Sensitivities have been used to test these uncertainties, but it was not possible to model all the possible and relevant sensitivities. One area that we have not tested is the risk of a systematic failure of emerging renewables technologies to achieve the operational availability levels expected.
- The modelling approach is dynamic and evolves prices and investment/retirements decisions through time in each run. This results in year on year variability as would be expected in reality. However, care should be used when comparing the results in individual years.
- The model estimates different hurdle rates for different technologies by simulating gross margin risk for a set of different investor types over the project lifetime. This is a simplified way to capture the complex interaction of factors that determine the cost of capital for different players in different technologies under different support schemes.
- We do not explicitly model specific transmission upgrade projects. We implicitly capture the cost impact of necessary transmission investments within the supply curve defined for each technology.
- We model plant operation on an unconstrained basis. In reality, transmission constraints could reduce the output from renewables plant and impact on the achievement of the renewables target.
- The model captures the evolution of market prices over time, and the impact on investment and retirements, in an internally consistent manner, taking into account the capacity margin and the mix and penetration of renewables on the system. However, there is huge uncertainty surrounding the market dynamics in a world of significantly higher renewables output.
- The model captures short term demand side response in determining expected energy unserved and peak prices. However, it does not include longer term demand side elasticity or changing shape in demand in response to evolving price signals.
- It has been necessary to divide the total biomass resources into volumes available separately to the electricity and heat sectors (as these are being considered in separate studies). The model does not consider how interactions between support schemes affect the demand for biomass in each sector.
- The model only covers the GB electricity market, and excludes Northern Ireland.

C Appendix: Modelling assumptions

In this Appendix we first summarise the sources for the key assumptions used in the quantitative assessment, and then provide details on the specific values used.

C.1 Main sources

Sources for key assumptions are as follows:

- **Demand.** Based on the January 2009 *Updated Energy Projections 35*, provided by DECC. This includes the effect of Energy White Paper energy efficiency measures. In the near term demand is relatively flat before returning to growth in 2012 through to 2020. After 2020, the rate of growth increases.
- **Renewables resource potential.** Based a Green-X study³⁶ which reviewed renewable electricity potential across Europe. The resource potential for onshore wind has been doubled to reflect a higher availability of low wind speed sites than assumed in that study.
- **Maximum build rates.** Based on the high scenario developed by SKM¹³ in its study of constraints to renewables deployment.
- **EU Emissions Directives.** The Large Combustion Plant Directive (LCPD) and Industrial Emissions Directive (IED) are two major EU pieces of legislation restricting emissions from the power sector. In line with the LCPD, we assume that all opted-out plant close by 2015. We assume some flexibility³⁷ in the IED once it is enforced to allow some coal and gas plant to avoid fitting Selective Catalytic Reduction (SCR) to reduce NO_x emissions, but accepting constraints requiring lower load factor operation.
- **Carbon Capture and Storage (CCS)**³⁸. We assume that a single 500 MW demonstration CCS plant is developed and commissioned from 2014. We make no assumptions about mandatory CCS or an Emissions Performance Standard.
- **Biomass supply.** DECC provided a detailed biomass supply curve available for large thermal plant, along with international prices of biomass. These have been converted into a simplified stepped supply curves for regular biomass and energy crops. We assume that the total biomass available for import into GB is equivalent by energy to 50% of indigenous GB supply (illustrated in Section C.7). These imports are assumed to be available at the international price. We constrain build of biomass in light of this supply curve.

³⁶ Green-X, *Deriving optimal Promotion strategies for Increasing the Share of RES-E in a Dynamic European Electricity Market. Dynamic cost-resource curves Work Package 1*. 2003

³⁷ We did not explicitly model the Transitional National Plan (TNP) or Limited Lifetime Derogations which are currently being considered by the Commission since these options emerged subsequent to the modelling work,

³⁸ The assumptions on CCS pre-dated the Government's recent announcement to support up to four CCS demonstration projects by 2020.

C.2 Technologies modelled

The renewable technologies modelled are shown in Table 19 together with the assumptions used for annual availability (or capacity factors)³⁹.

Table 19 Renewable technologies modelled

Technologies modelled	Annual Availability
Onshore wind (High)	29%
Onshore wind (Medium)	27%
Onshore wind (Low)	21%
Offshore wind (High)	41%
Offshore wind (Low)	35%
Biomass regular	80%
Biomass energy crop	80%
Biomass CHP	80%
Wave	30%
Tidal Stream	35%
Tidal Range	23%
Biowaste	73%
Biogas	61%

We have divided onshore wind into three categories (yields), and offshore wind into two categories, based on different wind speeds.

Biomass schemes are divided into regular, energy crop, and combined heat and power (CHP) since the cost structures of these technologies are different and they qualify for different bands.

Tidal generation technologies are classified into two types, tidal stream and tidal range. Tidal range (also known as tidal impoundment), creates a height difference (head) by impounding water behind a barrage or in a lagoon. Generation occurs by using the head to force water through turbines, in a similar manner to conventional hydro. Tidal stream devices typically work in an analogous way to a wind turbine, generating power from fast moving tidal water.

The biogas technology represents schemes that use sources such as farm slurries and agricultural residues. Biowaste is generation from the biodegradable fraction of waste.

Landfill gas, sewage gas and hydro are not modelled explicitly within the investment decision framework, because these opportunities have largely been exploited and are opportunity constrained. We make explicit assumptions regarding output from these technologies, and hold these constant across all schemes and sensitivities:

- Landfill gas: 4.8 TWh/annum in 2009, rising to 4.9 TWh/annum in 2010 and declining to 3.66 TWh/annum in 2020 as existing sites become depleted⁴⁰

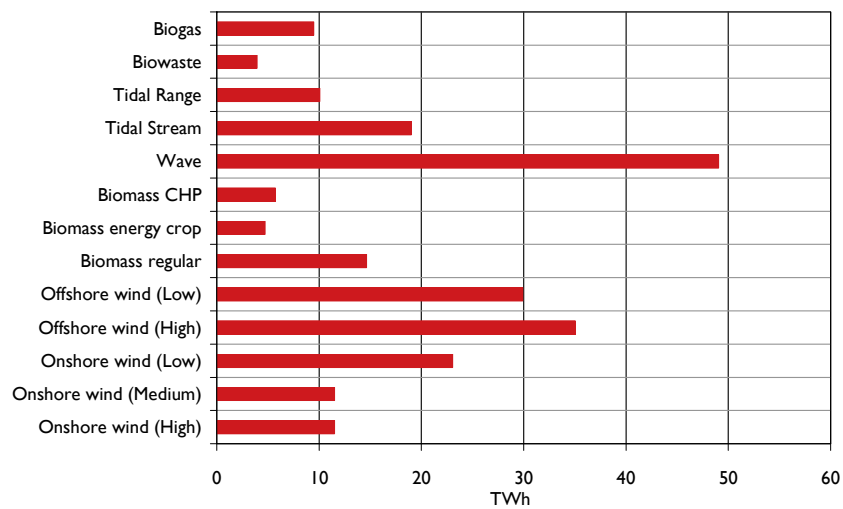
³⁹ The capacity factors take into account annual maintenance as well as resource availability.

⁴⁰ Ernst & Young, *Impact of banding the Renewables Obligation - Costs of Electricity Production*, 2007, prepared for the Department of Trade and Industry.

- Sewage gas: rising to 0.7 TWh/annum in 2010 and held constant for the rest of the modelling period⁴¹
- Hydro: 1.3 TWh/annum of new small and medium hydro generation by 2020

Figure 77 shows the total resource potential for the major technologies in 2020 as derived by Redpoint from the Green-X study. These total potentials take no account of build rate constraints which will restrict the speed at which these resources can be exploited.

Figure 77 Renewables resource availability in 2020



⁴¹ Assumption supplied by DECC.

C.3 Demand

Figure 78 GB annual demand

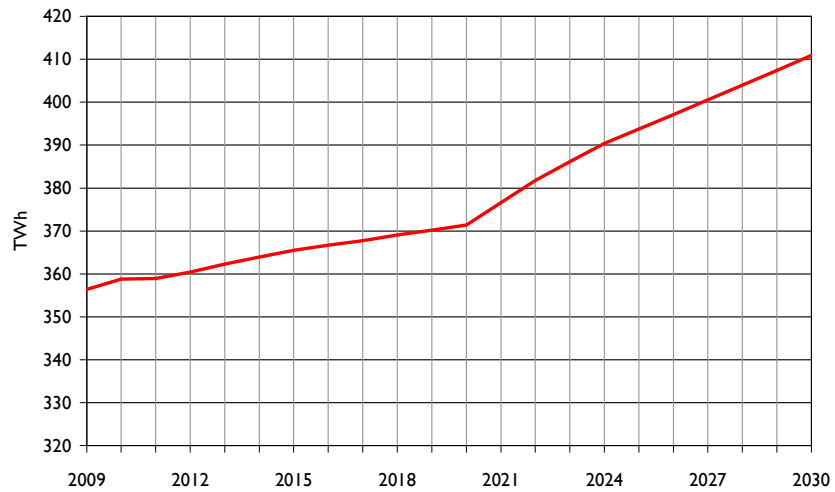
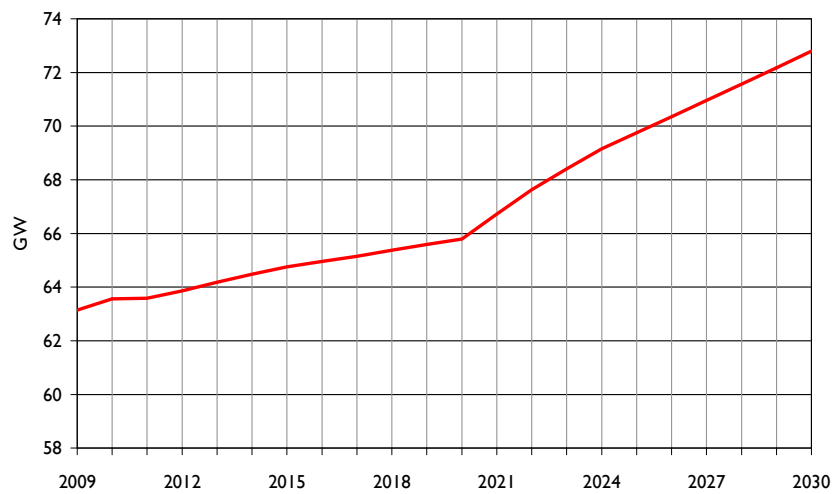
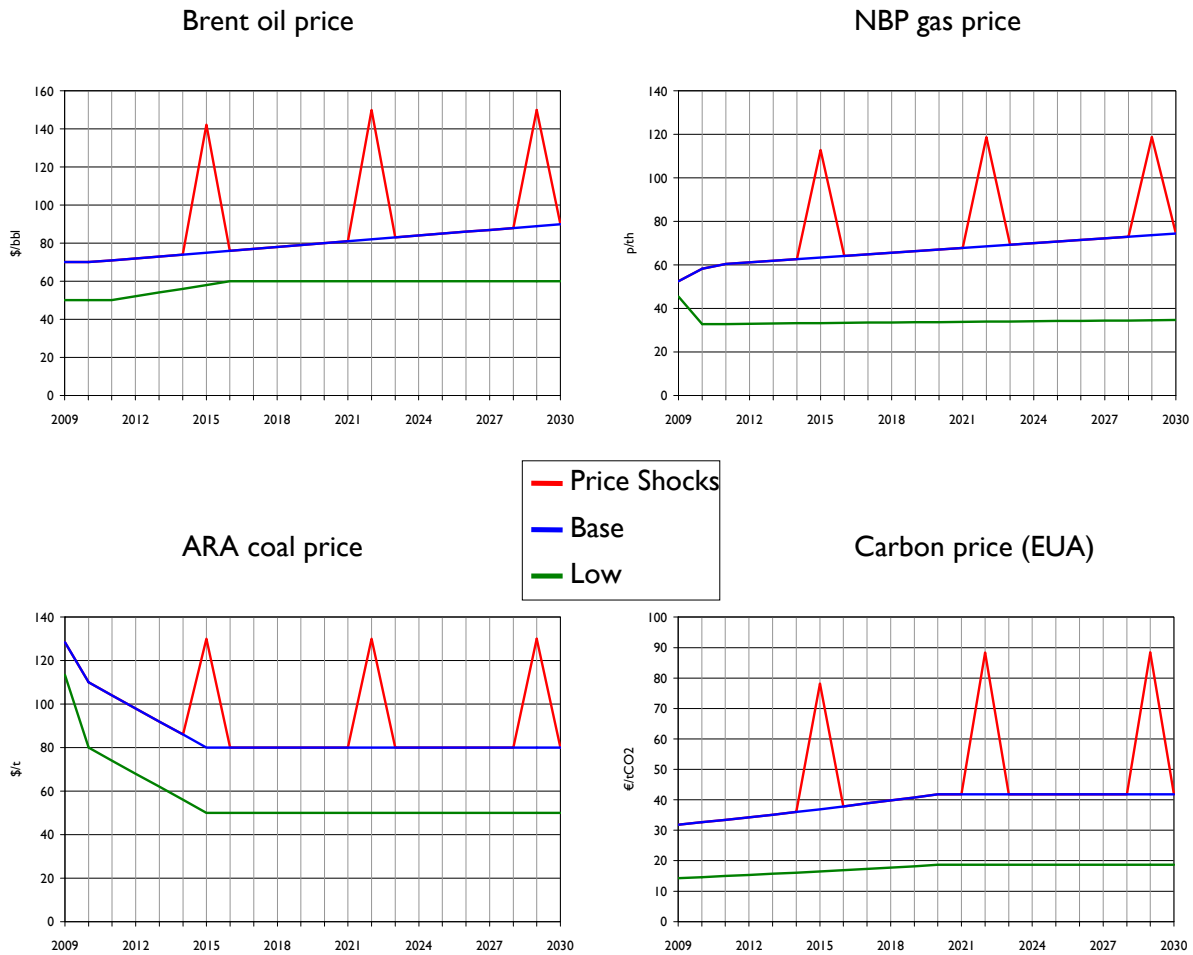


Figure 79 GB peak demand



C.4 Fuel and carbon prices

Figure 80 Fuel and carbon prices



C.5 Exchange rates

Exchange rates	
\$/£	1.60
€/£	1.43

C.6 Renewables plant capital costs

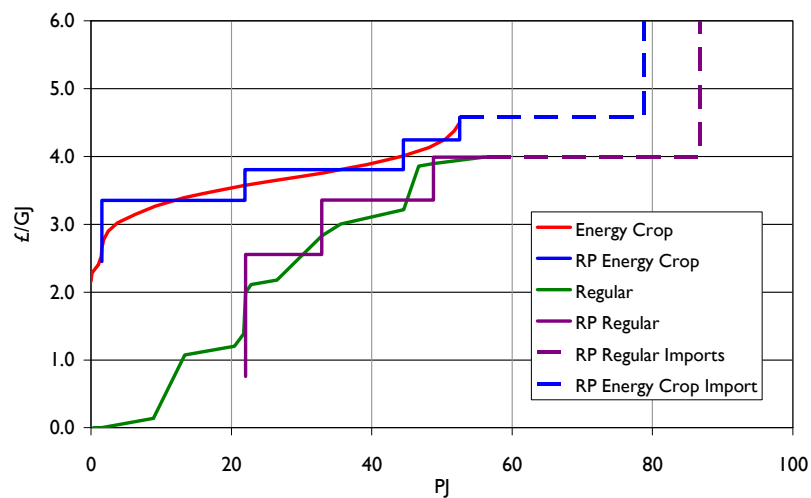
Table 20 Renewables plant baseline capital costs

£/kW	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind (High)	1208	1239	1227	1257	1246	1234	1262	1250	1238	1226	1214	1202
Onshore wind (Medium)	1208	1197	1186	1175	1205	1193	1182	1210	1199	1187	1214	1202
Onshore wind (Low)	1208	1197	1186	1175	1164	1153	1142	1131	1120	1109	1098	1087
Offshore wind (High)	2372	2349	2327	2538	2513	2488	2689	2662	2634	2827	2797	2768
Offshore wind (Low)	2372	2349	2327	2304	2281	2259	2236	2438	2413	2388	2363	2338
Biomass regular	2360	2317	2274	2231	2188	2145	2103	2060	2017	1974	1931	1888
Biomass energy crop	2360	2317	2274	2231	2188	2273	2227	2304	2256	2325	2275	2336
Biomass CHP	3068	3012	2956	2901	2845	2789	2733	2678	2777	2718	2659	2600
Wave	4072	3924	3776	3628	3480	3332	3184	3035	2887	2739	2591	2443
Tidal Stream	4071	3923	3775	3627	3479	3331	3183	3035	2887	2739	2591	2443
Tidal Range	3420	3327	3233	3140	3047	2954	2860	2767	2674	2581	2487	2394
Biowaste	3413	3413	3413	3615	3615	3615	3817	3817	3817	4020	4020	4020
Biogas	6474	6474	6474	6474	6474	6474	6474	6474	6474	6474	6474	6474

These baseline capital costs are converted into supply curves (showing an increasing capital cost with capacity deployed) using Redpoint assumptions.

C.7 Biomass supply curve

Figure 81 Indigenous biomass and biomass available for import



C.8 Conventional plant capital costs

Table 21 Conventional plant capital costs

£/kW	2009	2020
CCGT	585	585
Coal (ASC)	1238	1238
Coal (IGCC)	1665	1665
Coal (ASC + CCS)	2157	2157
Nuclear	2000	1800
OCGT	333	333

C.9 Other plant assumptions

Table 22 Plant characteristics

	Annual Fixed Costs £/kW/yr	Variable Operating costs £/MWh	Economic Lifetime	Efficiency of plant commissioned in 2009	Efficiency of plant commissioned in 2020	Annual availability
CCGT	15.0	2	20	53%	55%	83%
Coal (ASC)	24.0	1.6	25	45%	46%	83%
Coal (IGCC)	32.7	2	25	46%	50%	83%
Coal (ASC + CCS)	39.0	12.6	25	33%	38%	83%
Nuclear	40.0	5	30	36%	36%	87%
Onshore wind (High)	40.0	0	20	100%	100%	29%
Onshore wind (Medium)	40.0	0	20	100%	100%	27%
Onshore wind (Low)	40.0	0	20	100%	100%	21%
Offshore wind (High)	68.0	0	20	100%	100%	41%
Offshore wind (Low)	68.0	0	20	100%	100%	35%
Biomass regular	62.0	1.1	20	28%	28%	80%
Biomass energy crop	62.0	1.1	20	28%	28%	80%
Biomass CHP	83.0	1.1	20	16%	16%	80%
Wave	106.0	0	20	100%	100%	30%
Tidal Stream	85.0	0	20	100%	100%	35%
Tidal Range	54.0	0	30	100%	100%	23%
Biowaste	97.0	0	20	100%	100%	73%
Biogas	90.0	0	20	100%	100%	61%
OCGT	13.0	2	20	37%	40%	90%

C.10 Maximum build rate constraints

Table 23 Maximum build constraints, High

Max build, MW/annum	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind	600	700	800	900	1000	1100	1200	1300	1400	1500	1500	1500
Offshore wind	660	870	1090	1310	1400	1400	1600	1600	1600	1800	1800	1800
Biomass regular	50	50	50	50	50	50	50	50	50	50	50	50
Biomass energy crop	100	100	100	100	100	100	100	100	100	100	100	100
Biomass CHP	30	30	30	30	30	30	30	30	30	30	30	30
Wave	0	25	35	45	55	65	75	85	95	100	110	150
Tidal Stream	0	60	120	180	240	240	240	240	240	240	240	240
Tidal Range	0	0	0	35	75	120	200	200	200	200	200	200
Biowaste	60	60	60	60	60	60	60	60	60	60	60	60
Biogas	60	60	60	60	60	60	60	60	60	60	60	60

Table 24 Maximum build constraints, Low

Max build, MW/annum	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind	450	450	450	450	450	450	450	450	450	450	450	450
Offshore wind	300	300	300	350	350	350	350	350	350	350	350	350
Biomass regular	50	50	50	50	50	50	50	50	50	50	50	50
Biomass energy crop	100	100	100	100	100	100	100	100	100	100	100	100
Biomass CHP	30	30	30	30	30	30	30	30	30	30	30	30
Wave	0	0	0	0	0	0	0	0	0	25	35	45
Tidal Stream	0	60	60	60	60	60	60	60	60	60	60	60
Tidal Range	0	0	0	0	0	0	0	0	0	0	0	35
Biowaste	20	20	20	20	20	20	20	20	20	20	20	20
Biogas	20	20	20	20	20	20	20	20	20	20	20	20

C.11 Plant retirements

Table 25 Nuclear Retirements

Plant	Capacity (MW)	Year
DUNGENESS	1110	2018
HARTLEPOOL	1210	2019
HEYSHAM 1	1150	2019
HEYSHAM 2	1250	2028
HINKLEY POINT	1220	2016
OLDBURY ⁴²	434	2009
SIZEWELL B	1190	2045
WYLFA	980	2012
HUNTERSTON	1190	2016
TORNESS	1250	2028

⁴² Oldbury has recently had its operational life extended to 2010

Table 26 Large Combustion Plant Directive retirements

Plant	Capacity (MW)	Year
DIDCOT A	1960	2014
FAWLEY	518	2015
GRAIN	650	2015
LITTLEBROOK	1370	2014
LITTLEBROOK GT	105	2014
TILBURY GT	34	2013
FERRYBRIDGE (2 of 4 units)	980	2012
IRONBRIDGE	964	2012
KINGSNORTH	2000	2013
TILBURY	1075	2013
COCKENZIE	1200	2015

D Appendix: Hurdle rate calculations

The hurdle rate (or cost of capital) for each investment is calculated on a risk adjusted basis for each type of investor (vertically integrated companies, independent developers, consortia). This is estimated by simulating the gross margin for the asset over its lifetime taking into account risk factors on both the revenue and cost sides. The revenue risk across the different policy options is quite different, which drives the different hurdle rates across the schemes.

Figure 82 Simulation of gross margin at risk



The gross margin at risk for each investment is calculated as the difference between the mean gross margin and the gross margin at the 99% percentile ('worst case'), given by B-C (Figure 82). The gross margin at risk simulation is used to determine the proportion of 'risky' capital given by $(B-C)/A$, and proportion of 'safe' capital given by $(1-(B-C)/A)$.

For simplicity we assume that safe capital is priced at the company cost of debt (risk free rate + debt premium⁴³), whereas risky capital is priced at a higher level⁴⁴. We assume that the cost of this risky capital is related to the costs of equity for each company, whether the actual financing comes from higher priced debt or is financed with equity⁴⁵. This is calculated as the risk free rate + equity premium * equity beta *

⁴³ Debt premium varies by company type from 2% to 4.5%. Risk free rate is assumed to be 5.25%.

⁴⁴ We recognise that in reality projects are financed in a multitude of different ways with different types of debt at different costs. We also recognise that vertically integrated companies may not raise equity and debt specifically to fund individual projects, and hence the same cost of capital may apply to different investments. However, we assume that these companies will be targeting a higher rate of return on more risky investments and hence this approach is theoretically valid.

⁴⁵ On the assumption that companies would use equity rather than debt to finance projects where the cost of debt for a risky project exceeds the cost of equity.

investment beta. The equity premium and equity beta are derived from analysis of financial reports of individual companies. The investment beta has been set to calibrate hurdle rates produced by the model for mature technologies against benchmarks from recent known investments, for example around 10% (post tax nominal) for CCGTs. This leads to a cost of risky capital between 12% and 19% depending on the player type.

There are a range of risks on both the cost and revenue side, including:

- **Policy risk.** The risk that revenues for existing projects are affected by future changes in policy. We do not explicitly reflect policy risk, and assume that renewables investors put credibility in the Government's commitment to 'grandfathering'.
- **Subsidy risk.** The risk that the value of the subsidy changes over time. This is reflected in our ROC price distribution.
- **Electricity price risk.** The risk from uncertainty in future levels of wholesale electricity price, directly modelled.
- **Forecasting/balancing risk.** The risk associated with the costs of managing the variability and unpredictability of output, directly modelled.
- **Locational / transmission charging risk.** The risk that use of system charges and costs associated with congestion management will change over time. This is implicitly captured within our non-fuel operating cost distributions.
- **Project risk.** The risks from cost overruns, late delivery, breakdowns or poor availability. These are captured through our capital cost, construction and availability distributions.

Under the Phase 1 Options, renewables are exposed to all of these risks (although the subsidy risk is limited due to the Headroom mechanism). The aim of the Phase 2 Options is to reduce exposure of renewable generators to one of these risks, the electricity price risk. The cap/collar Options remove the extremes of the electricity price risk, whereas the full stabilisation Options (Band Indexation and CfD) completely remove the electricity price risk.

The reduction or removal of the electricity price risk tightens the distribution of gross margins and reduces the proportion of risky capital, reducing the hurdle rates.

The tables below outline the assumptions used in the gross margin simulations.

Table 27 Plant variable distributions

Variable	Capital costs		Construction		Annual availability		Variable costs	Balancing costs	Fixed costs
	Triangular		Triangular		Triangular		Normal	Normal	Normal
Distribution type	Min	Max	Min	Max	Min	Max	Stand. Dev.	Stand. Dev.	Stand. Dev.
CCGT	-10%	+10%	-10%	+10%	-5%	+5%	10%	10%	10%
Coal (ASC)	-10%	+10%	-10%	+10%	-5%	+5%	10%	10%	10%
Coal (IGCC)	-10%	+20%	-10%	+20%	-5%	+5%	10%	10%	10%
Coal (ASC + CCS)	-10%	+50%	-10%	+50%	-20%	+5%	20%	10%	20%
Nuclear	-10%	+40%	-10%	+40%	-10%	+5%	30%	10%	30%
Onshore wind (High)	-10%	+10%	-10%	+10%	-5%	+5%	0%	100%	10%
Onshore wind (Medium)	-10%	+10%	-10%	+10%	-10%	+5%	0%	100%	10%
Onshore wind (Low)	-10%	+10%	-10%	+10%	-15%	+5%	0%	100%	10%
Offshore wind (High)	-10%	+10%	-10%	+10%	-5%	+5%	0%	100%	20%
Offshore wind (Low)	-10%	+10%	-10%	+10%	-10%	+5%	0%	100%	20%
Biomass regular	-10%	+20%	-10%	+20%	-5%	+5%	10%	10%	10%
Biomass energy crop	-10%	+20%	-10%	+20%	-5%	+5%	10%	10%	10%
Biomass CHP	-10%	+20%	-10%	+20%	-5%	+5%	0%	10%	10%
Wave	-10%	+50%	-10%	+50%	-10%	+5%	0%	50%	10%
Tidal Stream	-10%	+50%	-10%	+50%	-5%	+5%	0%	50%	10%
Tidal Range	-10%	+50%	-10%	+50%	-5%	+5%	0%	50%	10%
Biowaste	-10%	+50%	-10%	+50%	-5%	+5%	0%	50%	10%
Biogas	-10%	+50%	-10%	+50%	-5%	+5%	10%	10%	10%
OCCGT	-10%	+10%	-10%	+10%	-5%	+5%	5%	10%	5%

Table 28 Price variable distributions

Variable	Gas	Coal	Biomass reg	Biomass ec	Gas oil	Fuel oil	Uranium	Carbon
Distribution type	Lognormal	Lognormal	Lognormal	Lognormal	Lognormal	Lognormal	Lognormal	Normal
Standard Deviation	+40%	+20%	+20%	+20%	+20%	+20%	30%	30%

The ROC price is modelled as a triangular distribution, with the parameters shown in Table 29. (In the Band Cap/Collar, and Band Indexation Options, this distribution is overridden by the adjustments made due to the stabilisation methodology.)

Table 29 ROC Price distributions

Variable	ROC price	
Distribution type	Triangular	
Parameter	Min	Max
Phase I Options only	-8%	+8%

Other assumptions made are shown in Table 30.

Table 30 Other assumptions

Variable	Description
Nuclear decommissioning costs	Triangular distribution: Min -10%; Max +100%
Probability of EU ETS post 2012	100%
Gas / coal correlation	50%

Electricity price distributions are created within the model based on a simplified capacity stack, taking into account the distributions of fuel price variables and the volatility of capacity margins.

E Appendix: Renewables output modelling

E.1 Overview

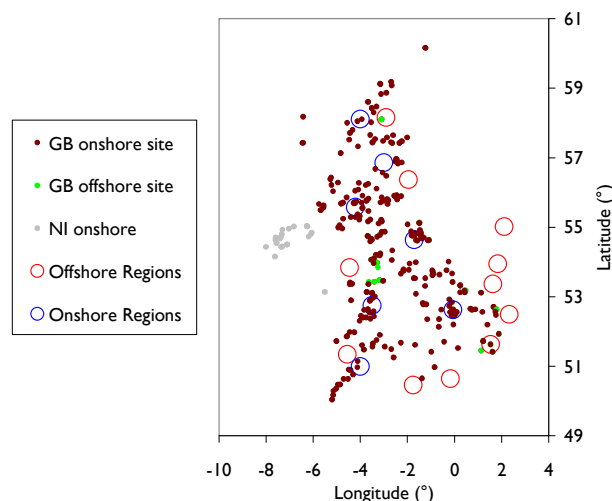
In this Appendix we provide more details of how the variability of output from non-dispatchable intermittent renewables sources is modelled within the Volatility Model. The assumptions used impact the analysis of expected energy unserved and price duration curves, and the capacity credits used in the calculation of the de-rated peak capacity margins.

E.2 Wind

Volatility in wind output is simulated taking into account the different locations of wind plant, as well as the various seasonal patterns in output.

Correlation of wind output across the country is handled by allocating each wind farm notionally to different onshore and offshore ‘regions’. The midpoints of the regions have been determined using the locations of operational and planned wind farms listed on the British Wind Energy Association website, with each of these existing wind plant then allocated to the region closest to its location. The total capacity allocated to a given region then determines the average proportion of new plant that will be added to that region within the simulation framework⁴⁶

Figure 83 Regions used for modelling output of wind plant⁴⁷



Output for each region, each day, is simulated using Weibull distributions, as per Gross et al (2006)⁴⁸. The output across different regions is correlated through a function based on the approximate distance between the regions, parameterised using data published by Sinden (2007)⁴⁹.

⁴⁶ The locations and capacities of the offshore wind regions were modified using data relating to the tenders for offshore development in Rounds 1-3. Thus there is a prevalence of offshore wind capacity off the east coast of GB.

⁴⁷ Source: British Wind Energy Association (<http://www.bwea.com/>), Redpoint analysis

The output is simulated around average levels which vary by month, according to the profile of historic UK capacity factors published by Sinden. The output within individual days also change rapidly from hour to hour, consistent with the rates of change in observed hourly wind output data, but as the number of days simulated increases, the average output levels for each hour of the day tend towards the seasonally-varying long-run hourly profiles in Sinden's paper.

The aggregation of wind plant to regions rather than simulating output from individual wind farms will tend to err on the side of conservatism and underestimate the diversity benefit and capacity credit of wind. This method was employed as correlating wind output across hundreds of individual wind farms, as well as simulating the rest of the GB market, would have increased the processing time within a Monte Carlo simulation framework to an impractical level.

E.3 Wave

The hourly output of wave plant is simulated following a similar logic to wind power. Individual wave plant are allocated to five different regions, located around the coast of Scotland and off the south-west of England, with the resource potential in each of the five regions based on information in a report on the variability of marine resources in the UK published by the Environmental Change Institute (ECI, 2005)⁵⁰. The output of the wave plant is correlated using a similar function to the wind plant (i.e. based on distance between regions), with the correlations calibrated against information in the ECI report. Average output levels for each month are profiled according to the same report; the outputs for each region are also sampled from a Weibull distribution⁵¹.

E.4 Tidal Stream

Unlike wave and wind, the output from tidal power plant can be predicted in advance. While tidal power output from any single plant varies dramatically during the day, the timing and scale of tides is very different across the country, providing a diversity benefit. However, due to the likely prevalence of development in one particular region (the Pentland Region in northern Scotland)⁵², the hourly patterns in output are likely to be dominated by the tides in this region.

With a cycle repeating approximately each month, tidal plant experience two peak output periods (mean capacity factor approximately 65% per day) and two trough output periods (approximately 15%). This is referred to as the Spring-Neap tidal cycle⁵³. The high-low tidal cycle also repeats approximately every

⁴⁸ Sinden, G. (2007). Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. *Energy Policy* **35**(1), 112-127.

⁴⁹ Gross, R., Heptonstall, P., Anderson, D., Green, T., Leach, M. and Skea, J. (2006). The Costs and Impacts of Intermittency. UK Energy Research Centre, London.

⁵⁰ Environmental Change Institute (2005). Variability of UK Marine Resources. Report commissioned by the Carbon Trust.

⁵¹ Such assumptions are unlikely to have a material impact on the results of this study, due to the relatively small amount of wave power that can be deployed by 2020.

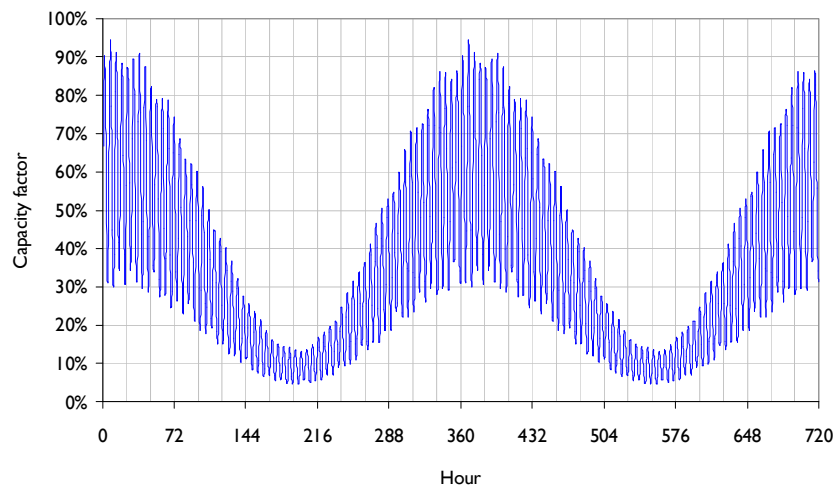
⁵² This information comes from the Environmental Change Institute report. Recent advances in tidal stream generating technology may facilitate power generation in a wider variety of locations.

⁵³ The half-yearly cycle that gives rise to the largest Spring tides, approximately at the time of the March and September equinoxes, has not been modelled.

12.25 hours. Within each day, therefore, output is maximised approximately four times (there are two low and two high tides, and output is maximised in between the low and high tides).

These cycles combine to give an output profile stylised from the Environmental Change Institute report, shown in Figure 84.

Figure 84 Tidal stream aggregate capacity factors across a month



Within its Monte Carlo simulation framework, the Volatility Model simulates the aggregate output from all installed tidal stream plant for single days. Because the timing of Spring tides falls within approximately the same two-hour window in each Spring-Neap cycle, approximately the same output cycle repeats itself every fifteen days. Therefore, for each of the individual days simulated, one of the fifteen daily output profiles is selected. The same point in the Spring-Neap cycle is selected for both stream and range capacity. The profiles simulated also maintain the correct timing relationship between the hourly profiles across the stream and range capacity.

E.5 Tidal Range

Tidal range plant in GB may be spread across a number of locations, and use a range of different technologies and configurations. For this reason, we assume that the output from tidal range projects is well diversified and hence for simplicity have assumed that it is constant across the day simulated.

The capacity credit of tidal range has been calculated in the same way as those of the other intermittent renewable plant. The assumption that aggregate tidal range output is constant across the day (and varies only with the Spring-Neap cycle) results in its capacity credit being approximately equal to its annual capacity factor.

F Appendix: Sensitivities

In this Appendix we present further results to supplement the analysis presented in Section 4.12, which provided high level commentary on renewable build, efficiency, effectiveness and the banding assumptions to deliver specified levels of renewable generation. In particular we provide results on prices, rents and capacity margins. Cost Benefit Analysis is presented in Appendix H.

F.1 Build rate sensitivities

F.1.1 Low maximum build rates

Throughout the main body of analysis, we assume High build rates¹³, but we can stress the effectiveness of revenue stabilisation options under the constraint that the maximum rate of renewable deployment is lower. This sensitivity was applied to the Minimum Change Base and Band Indexation Base Cases.

We showed in Section 4.12.1 that this assumption drastically reduces the deployment of renewables and also limits the additional benefits of revenue stabilisation, as shown in Table 31.

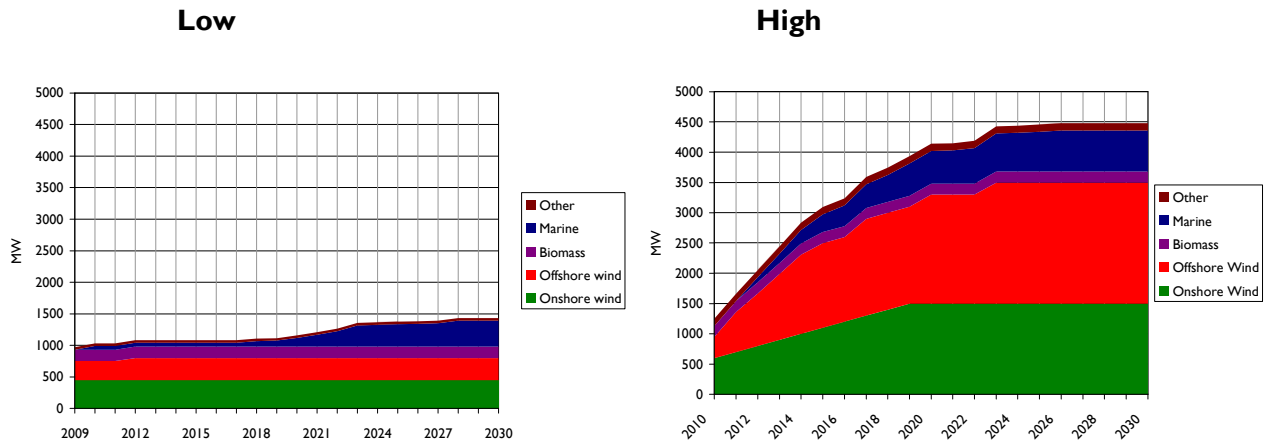
Table 31 High level results

2020	Policy Option & Case	Minimum Change	Band Indexation	Difference to	
	Sensitivity	Low Build	Low Build	Minimum Change Low	Band Indexation Base
Capacity (GW)		19.6	19.8	-6.4	-15.5
Generation (TWh)		67.2	67.9	-10.0	-40.3
Effectiveness %		17.2%	17.3%	-5.3%	-12.5%
Efficiency %		67.9%	67.9%	-17.1%	-7.9%

Build rates

Figure 85 compares the maximum annual build rate in the Low Maximum Annual Build Rate Sensitivity to the High rates used in the core analysis. This clearly explains the reduction in build across the modelled horizon.

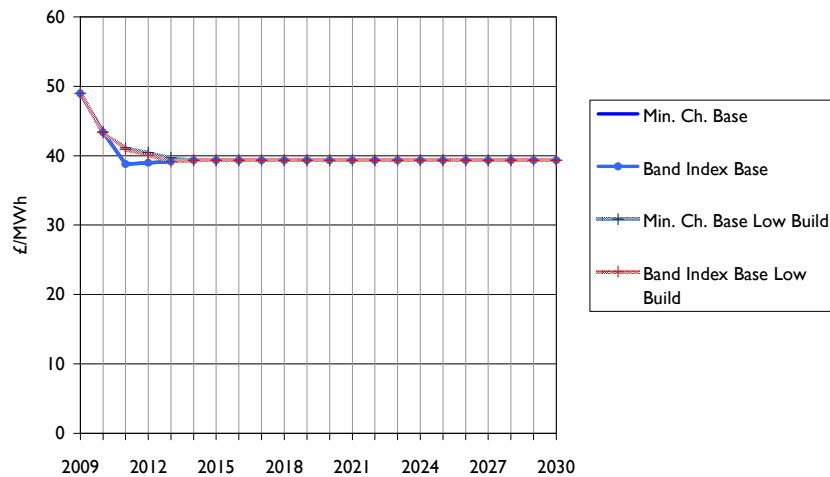
Figure 85 Maximum annual build rates



Prices

After 2013, there is no difference in ROC pricing compared to the Buy-out + Headroom level of Minimum Change - under Band Indexation the ROC price essentially becomes fixed as the bands become dynamic. There are small changes prior to 2013, as shown in Figure 86, as the reduced deployment leads to a larger scarcity signal.

Figure 86 ROC Price, Low build sensitivity



The reduction in renewable build tends initially to increase wholesale prices, as shown in Figure 87. The renewable build is not initially completely replaced with the equivalent level of thermal capacity, decreasing capacity margins (see Figure 88) through to 2020. Thermal build responds later and capacity margins increase post 2023. This leads to a reduced wholesale price over the same time period.

Figure 87 Wholesale price, Low build sensitivity

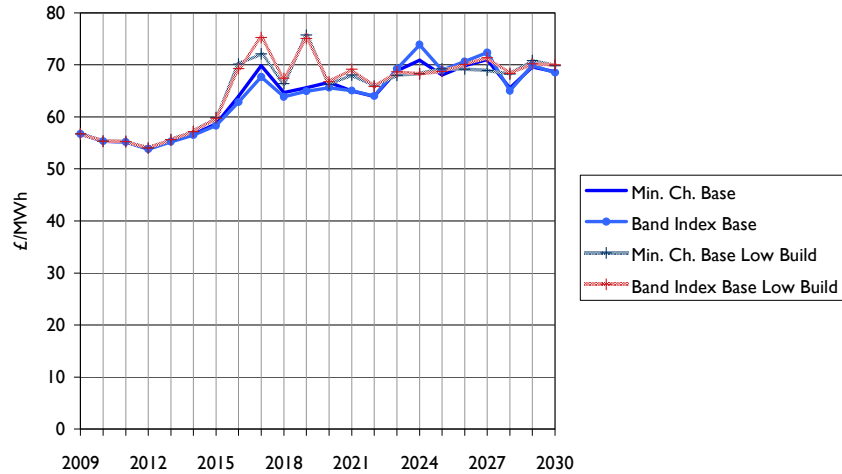
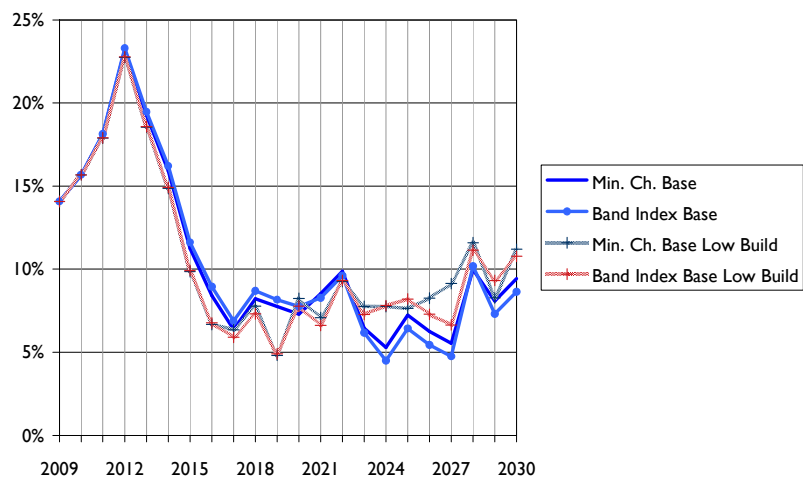
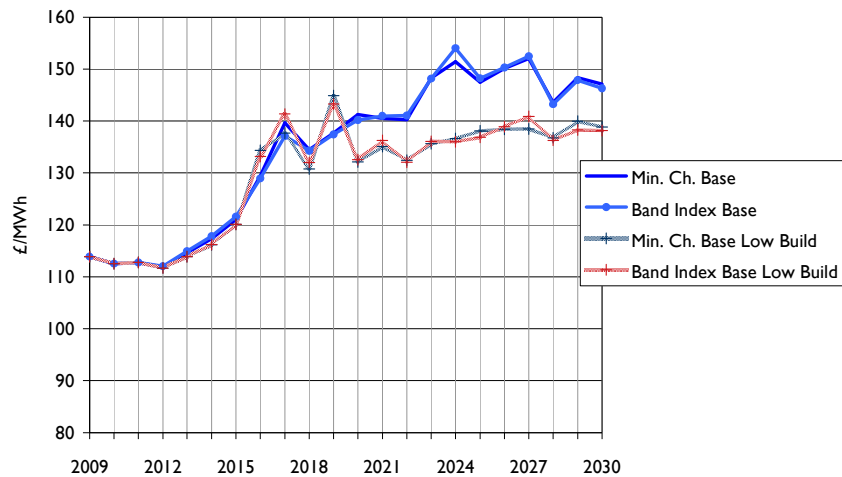


Figure 88 De-rated capacity margins, Low build sensitivity



The impact on consumer price is mixed, as shown in Figure 89. Prior to 2020, the increased wholesale prices are approximately offset by the decrease in renewable subsidy. However, once the wholesale price returns to a level similar to Minimum Change, the reduction in subsidies provided to renewable generators causes an approximate 10 £/MWh reduction in consumer bills.

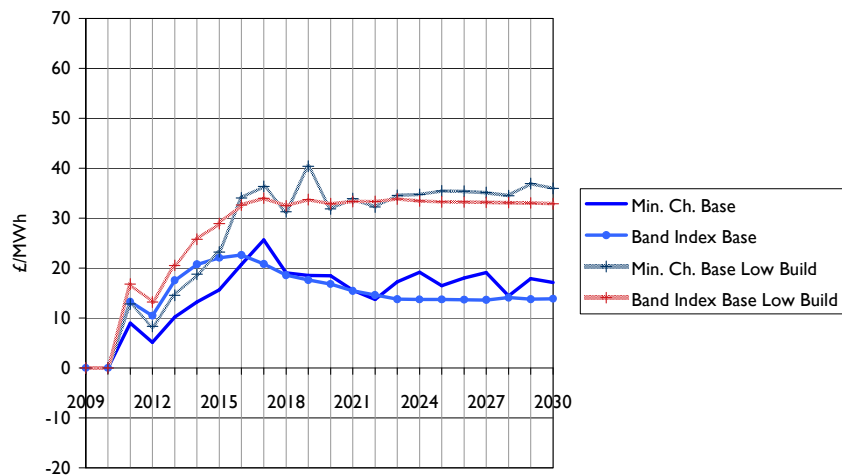
Figure 89 Consumer prices, Low build sensitivity



Rents

In Figure 90, we show the rent earned by high yield offshore wind sites. It is clear that the average level of rent achieved is much higher under low build rates, and in the long term the level of rent is approximately the value of one ROC. This is due to a greater proportion of low cost sites receiving the same subsidy (on a £/MWh basis), increasing rents.

Figure 90 Offshore Wind (High) rent, Low build sensitivity



The total amount of renewable rent in the system is of course reduced with lower renewable deployment.

F.1.2 Hiatus in deployment

With all changes to policy, there is a risk to rate of deployment in the transition to the new arrangements. For this sensitivity, we assumed a 50% reduction in maximum deployment in the year of policy implementation and the year after (2013 and 2014).

The high level results are shown in Table 32, and demonstrate a reduction in build to 2020.

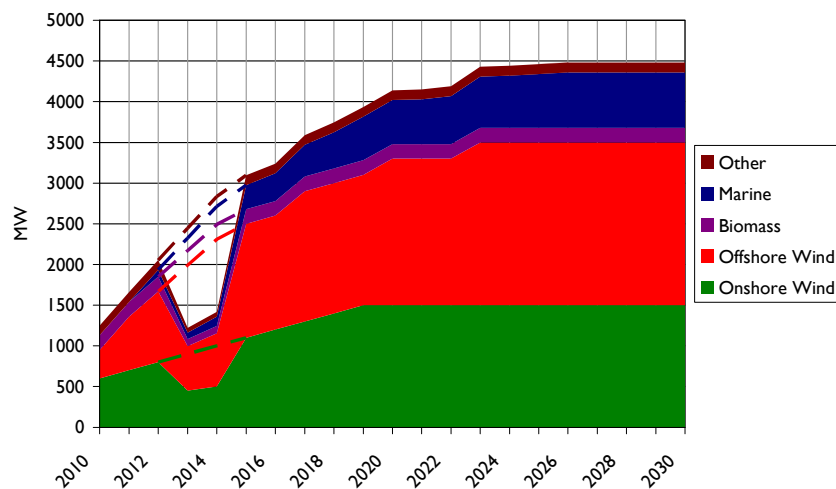
Table 32 High level results, Band Indexation Base Hiatus

2020	Policy Option & Case	Band Indexation Base	Difference to
	Sensitivity	Hiatus	Band Indexation Base
	Capacity (GW)	34.2	-1.2
	Generation (TWh)	110.5	2.3
	Effectiveness %	28.9%	-1.0%
	Efficiency %	74.9%	-0.9%

Build rates

In Figure 91 the assumed build rates are presented, alongside those used in the core analysis. There is a significant reduction in 2013 and 2014, which has a particularly high impact on offshore wind as it is during this period that the maximum rate of deployment is increasing quickest.

Figure 91 Maximum build rates, Hiatus Sensitivity



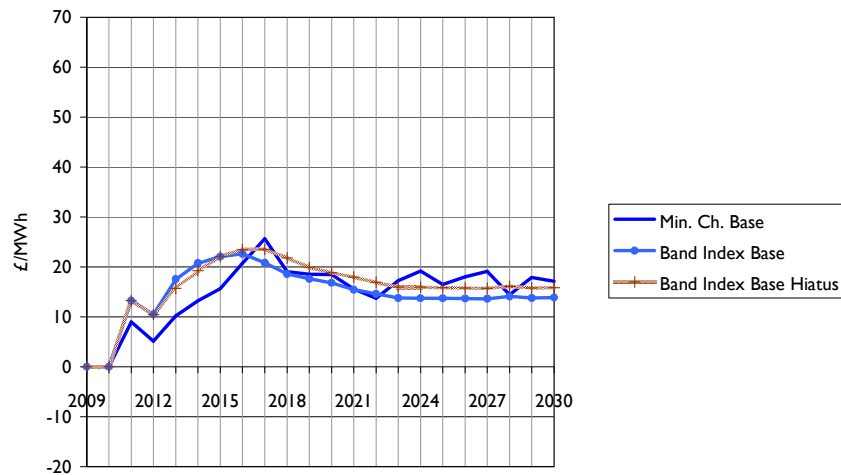
Prices

The slight reduction in renewable development through to 2020 under the Hiatus assumptions has negligible impact on either wholesale or consumer prices. The ROC price is identical as Headroom is triggered before 2013, and after 2013, the band is changed to maintain a fixed ROC price.

Rent

Despite the minimal changes in revenue streams for renewable generators, the rent is slightly increased (approximately 2 £/MWh), as shown in Figure 92. This is due to the lower deployment of offshore wind (high) and therefore the average development cost is reduced, increasing rent.

Figure 92 Offshore wind (high) rent, Hiatus sensitivity



F.2 Banding and commodity price sensitivities

This section provides more detail in relation to Section 4.12.3 and is broken down into four parts:

- F.2.1 explores the banding changes required to deliver 28% against Low and High High commodity assumptions.
- F.2.2 explores the band changes required to deliver 24% and 32% renewable penetration in the Minimum Change Base Case.
- F.2.3 compares Minimum Change and CfD Policy Options under the Base Case assumptions, with banding changed to deliver 29%.
- F.2.4 explores a different carbon price projection and delivery of 29% renewables.

F.2.1 Minimum Change, Low 28 and High High 28

Capacity Mix

Under the Minimum Change Low 28% Case, CCGT is the only new thermal capacity built, just as in the Minimum Change Low Case. However, the High High commodity prices are such that Carbon Capture and Storage (CCS) is economic (Figure 93), with first deployment (above and beyond the demonstration plant) in 2021, and a total of 14.5 GW of CCS by 2030. This is developed at the expense of some CCGT, but the capacity margin eases significantly post 2020, as shown in Figure 94.

Figure 93 Thermal build, High High 28% sensitivity

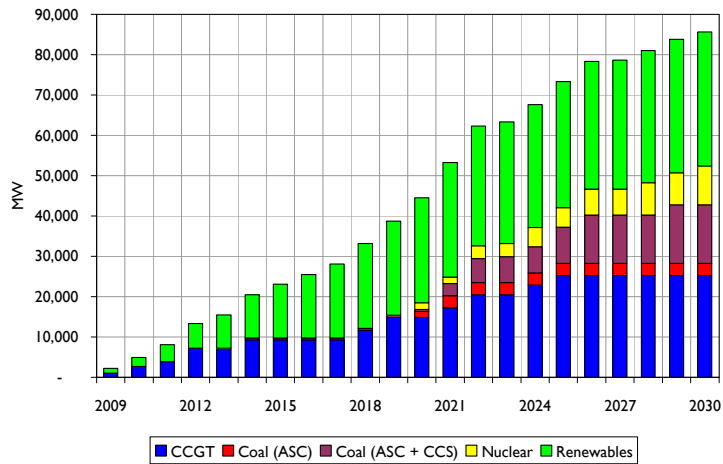
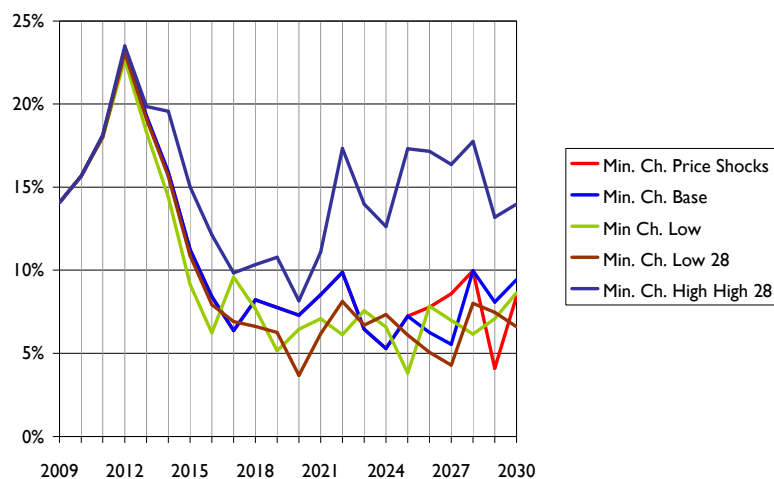


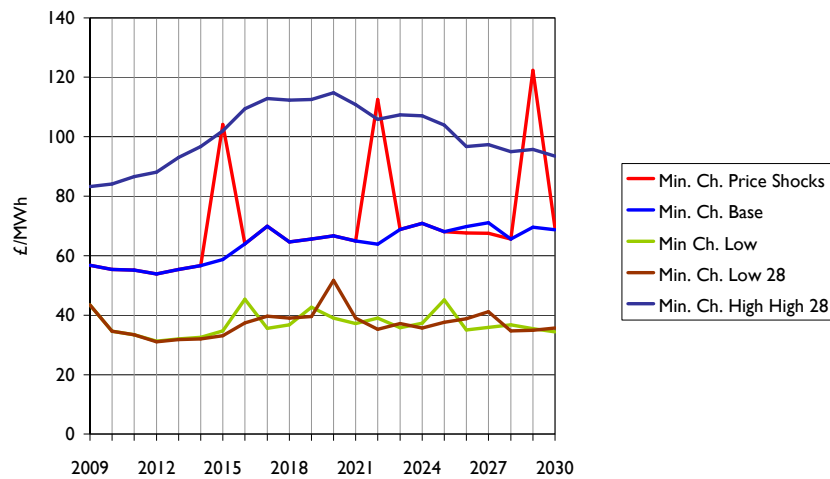
Figure 94 Capacity margins, Low 28% and High High 28%



Prices

In Figure 95 we see in the Low Case that there is no change in the trend of wholesale prices between banding up to deliver 28% and not. The annual fluctuations are primarily driven by the capacity margin changes discussed above. The differences in the High High Case can best be considered in the ‘price spike’ years of the Price Shocks Case (when commodity price assumptions are in fact from High High). There are two main effects driving the differences – capacity margins and plant mix. In the first price shock in 2015, the wholesale prices are very similar. However, in 2022, and more so in 2029, the High High 28% sensitivity has lower wholesale prices. Part of this is due to higher capacity margins, but more importantly, the change in the supply curve due to CCS penetration. By developing CCS and nuclear, alongside 28% renewables, the impact of the carbon price on the wholesale electricity price is reduced as the majority of plant is not exposed (or has only a small exposure). This helps suppress the price, by over 20 £/MWh in 2029.

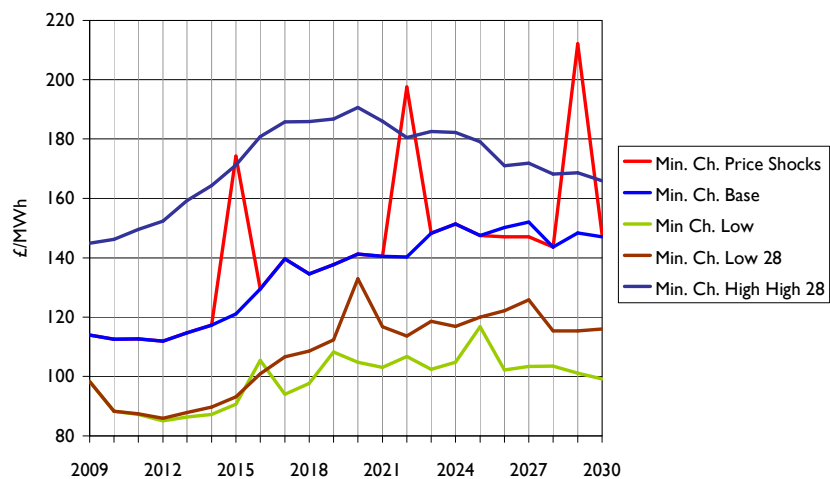
Figure 95 Wholesale prices, Low 28% and High High 28%



With these sensitivities set to deliver 28% renewable generation in 2020, there is no difference in the ROC prices, set at Buy-out + Headroom in 2011 and beyond.

Consumer prices exhibit similar trends to the wholesale price. In the High High Case, we see consumer prices fall post 2020 with the development of CCS. In the Low 28% Case, it can be seen that the additional cost of renewables through subsidies is passed onto the consumer.

Figure 96 Consumer prices, Low 28% and High High 28%



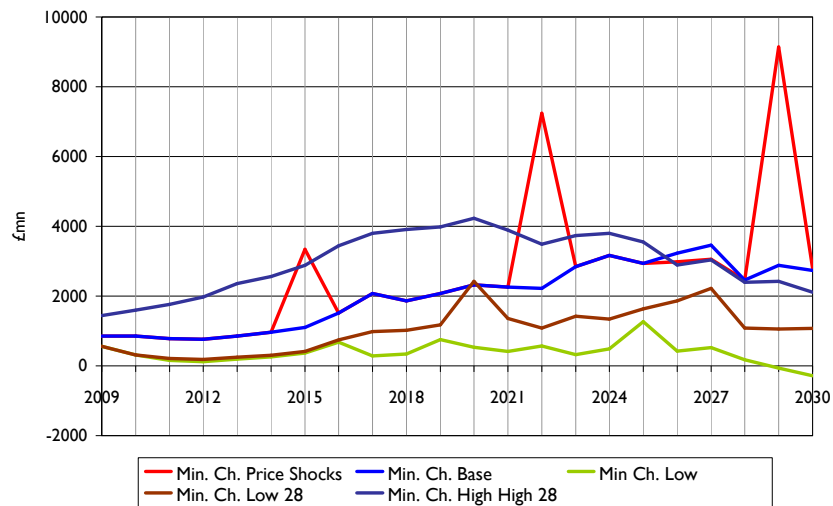
Rent

In the Low 28% Case (Figure 97), we see identical renewables rent levels to 2016, but increasing after that. This is due to the additional plant required to deliver 28%, as opposed to 22.4% observed in the standard Low Case. All of the plant that were developed in the standard Low Case do not require additional subsidy to be developed, but will nevertheless benefit from the additional subsidy required to deliver 28%.

With the High High commodity prices, little subsidy is required: the majority of revenue for a renewable generator is from wholesale power prices. Post 2020, with wholesale prices declining, and little subsidy

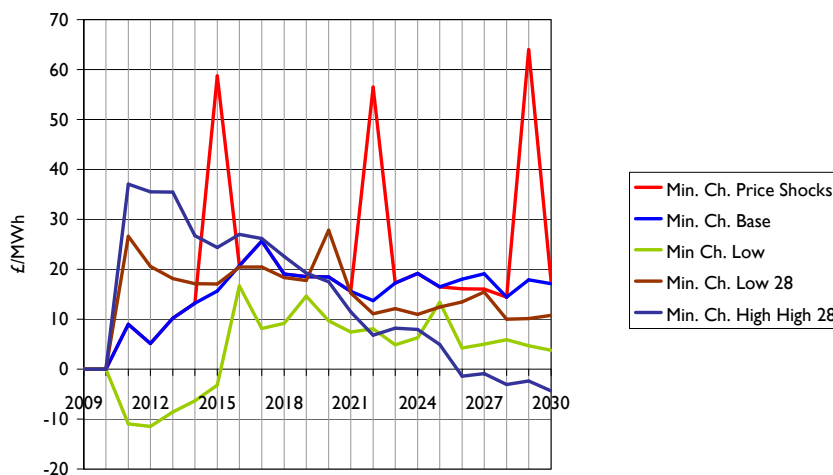
available, rent in the system reduces. This effect is so stark that by 2030, there is less rent in the system under High High assumptions than under Base Case assumptions, although it should be noted that total rent across the 22 years is greater under High High assumptions.

Figure 97 Renewables rent, Low 28 and High High 28



This is demonstrated further in Figure 98, with high yield offshore wind sites actually having negative rent levels by 2030 in the High High sensitivity. This indicates that the falling wholesale price (driven by CCS expansion rather than falling commodity prices) stop it being economic. To stimulate further investment at this point would require banding up of the technology.

Figure 98 Offshore wind (high) rent, Low 28 and High High 28



F.2.2 Minimum Change Base, 24% and 32%

Capacity Mix

Under these sensitivities, the only changes to the capacity mix are the relative levels of renewable and ASC build. With higher deployment of renewables, the need for thermal plant is reduced, and this is seen with a

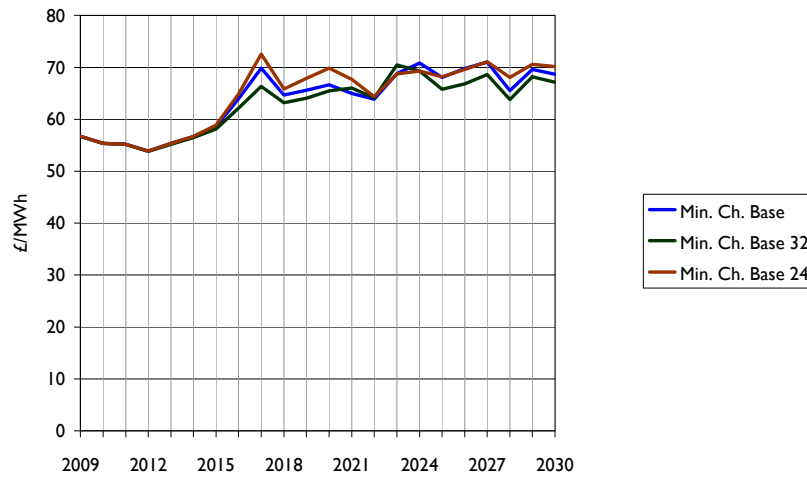
reduction of 0.5 GW of ASC coal in the 32% Case, yet no change in the 24% Case. CCGT and Nuclear build are unchanged.

Prices

With Headroom being the mechanism to support ROC prices above the target trajectory (15.4% in 2015), the differing renewable generation levels all operate under the same ROC price of Buy-out + Headroom, despite the different levels of penetration.

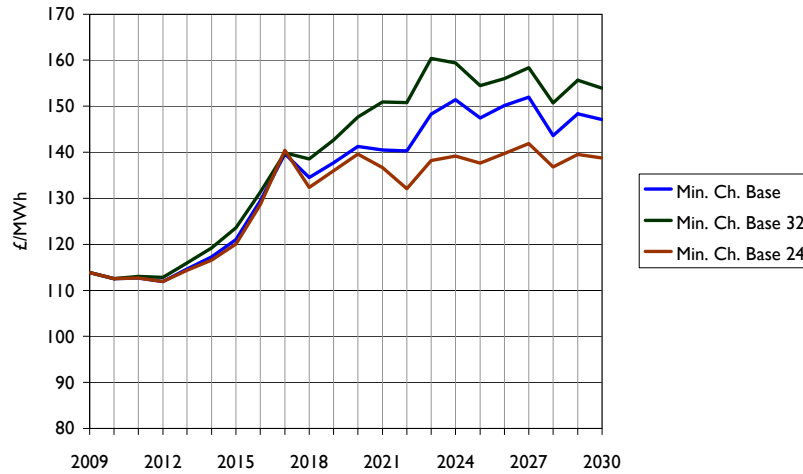
Figure 99 shows the comparison of wholesale prices. The differences in wholesale price up to 2020 are driven by different capacity margins. The increased renewable build of the 32% sensitivity results in increased capacity margin, and thus lower prices. This increased renewable build displaces some thermal build relative to the 28% Case, which then causes a relative drop in capacity margin later, driving up the price. This logic can be applied in reverse to the 24% Case.

Figure 99 Wholesale price, Minimum Change Base, 24% and 32%



The differences in the wholesale price are relatively small, of the order 2-5 £/MWh in any one year between the sensitivities. However, in Figure 100 we can see that there are significantly larger changes in consumer prices. This is due to the changes in banding required to deliver the changed level of renewables and the commensurate change in the size of the Obligation.

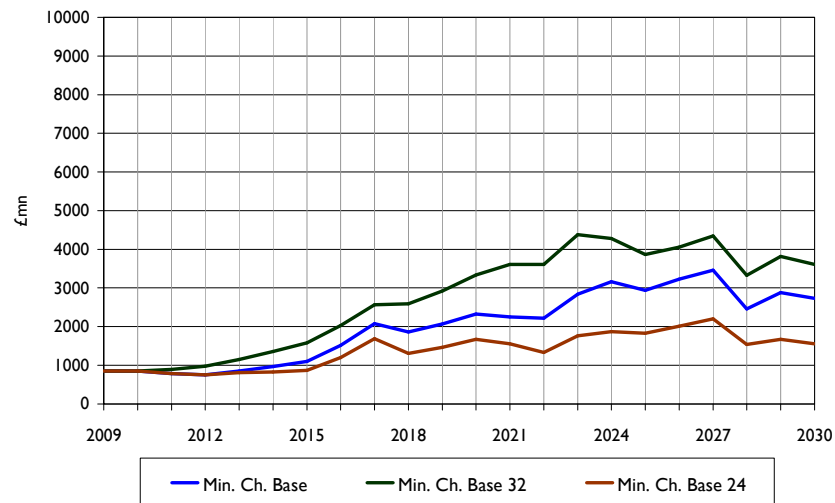
Figure 100 Consumer Prices, Minimum Change Base, 24% and 32%



Rent

As expected, the level of total renewable rent is higher for higher penetrations of renewables, as shown in Figure 101.

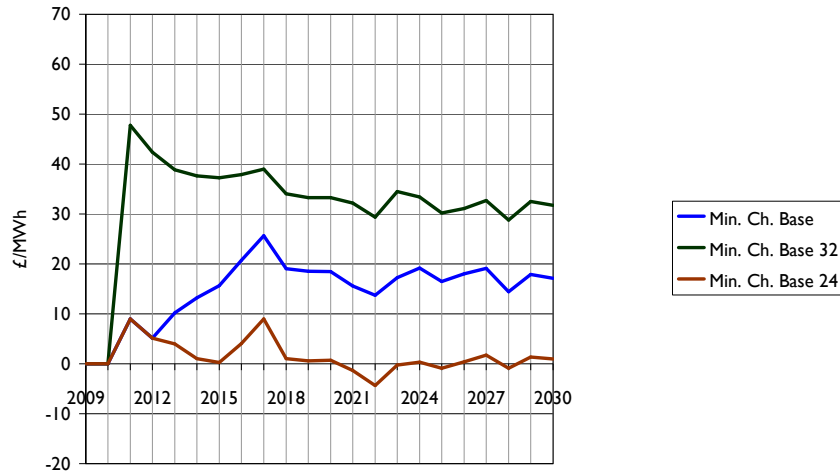
Figure 101 Renewables rent, Minimum Change Base, 24% and 32%



Along with renewables rent being higher for more renewables, we see the same effect at the technology level, shown in Figure 102. With Offshore Wind banded up to 2.5 ROCs from 2011 in the 32% Case, the level of rent from 2011 to 2017 is above 1 ROC. Therefore, the plant commissioned in this period would not require the additional ROCs to be economic. However, to deliver the additional 4%, the subsidy must be high enough, and the price signal early enough, to incentivise the marginal offshore wind. The effect of lead times can be seen as rents decrease beyond 2020 as the more expensive plant begin generating.

In the 24% Case, with offshore wind being banded down to 1.25 ROCs in 2013, the economics become marginal and we see rent levels around zero.

Figure 102 Offshore wind (High) rent, Minimum Change Base, 24% and 32%



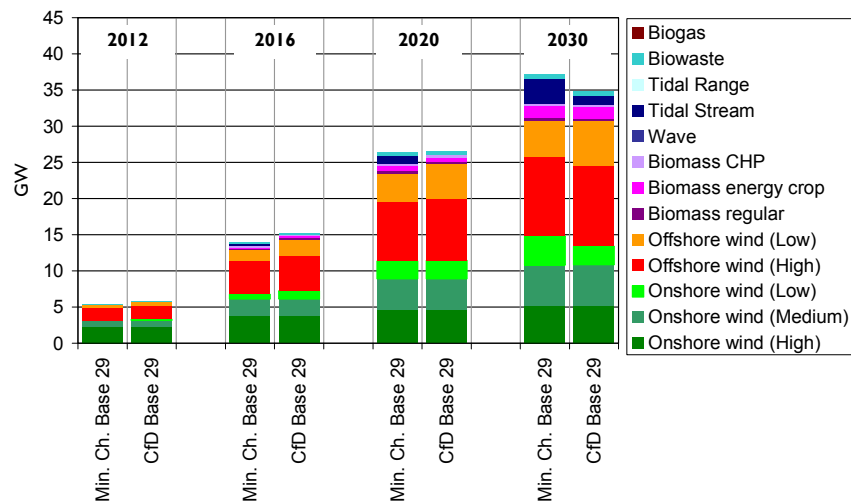
F.2.3 Minimum Change Base and CfD Base, 29%

Capacity Mix

Figure 103 shows the cumulative renewables new build in selected years. Banding levels have been set such that the total amount of new capacity in 2020 is very similar, but the technology mix is somewhat different. The effect of the higher banding for Marine technologies can be seen in the Minimum Change 29%, whereas the CfD 29% has a higher penetration of offshore wind.

The Minimum Change 29% has a higher penetration of renewables by 2030. In particular, significant tidal stream capacity is built between 2020 and 2030.

Figure 103 Capacity mix, Minimum Change Base and CfD Base, 29%

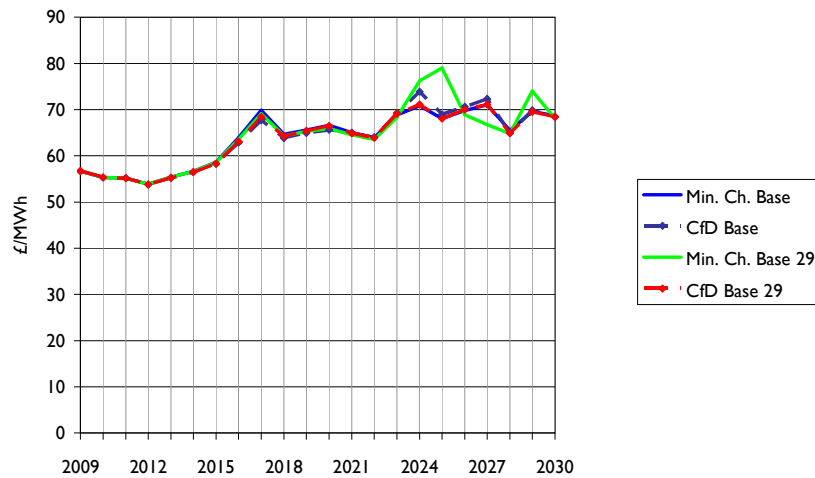


Prices

With Headroom being the mechanism to support ROC prices above the target trajectory (15.4% in 2015), the differing renewable generation levels all operate under the same ROC price of Buy-out + Headroom, despite the different levels of penetration.

The only differences in wholesale prices occur in Minimum Change Base 29% after 2024. This is driven by capacity margin effects.

Figure 104 Wholesale price, Minimum Change Base and CfD Base 29%

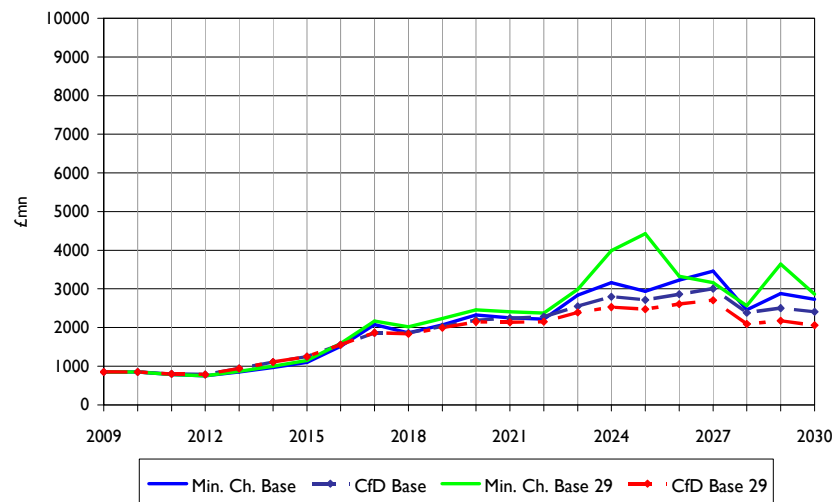


The wholesale price changes in Minimum Change 29% are passed through to the consumer price, but apart from that there is no significant difference as the renewable build levels are similar.

Rent

Figure 105 shows renewables rent, with little difference until after 2022, when the increasing build in the Minimum Change case results in an increase for a few years.

Figure 105 Renewables rent, Minimum Change Base 29, CfD 29



F.2.4 Minimum Change Base 29% EUA

As can be seen in Figure 106, this sensitivity uses a lower carbon price through to 2020, before rising steeply to 70 £/t in 2030. (Note the chart is presented in £/t.) The exchange rate assumptions are also slightly different (Table 33).

Figure 106 EUA Assumptions

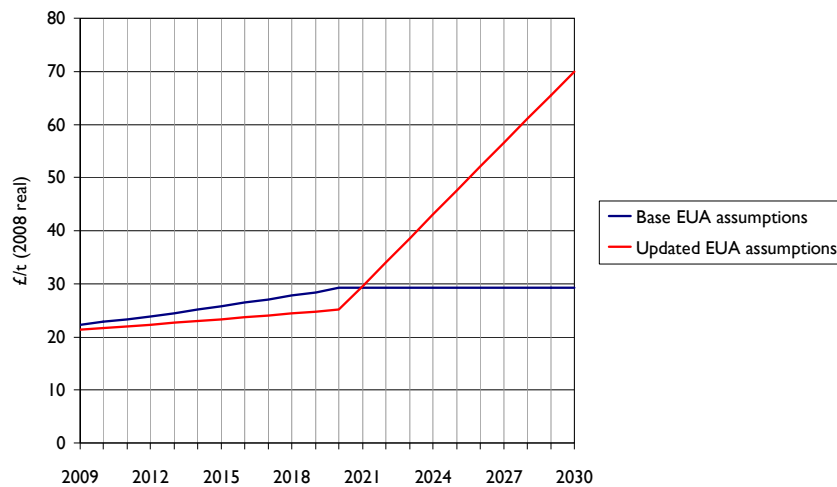


Table 33 Foreign Exchange assumption

	€£
Base	1.43
Updated	1.39

In order to deliver the 29% level of renewables, the banding assumptions were made as shown in Table 34. The only difference relative to Minimum Change Base 29% is an increase of the Wave band in 2013, to 4 ROCs per MWh.

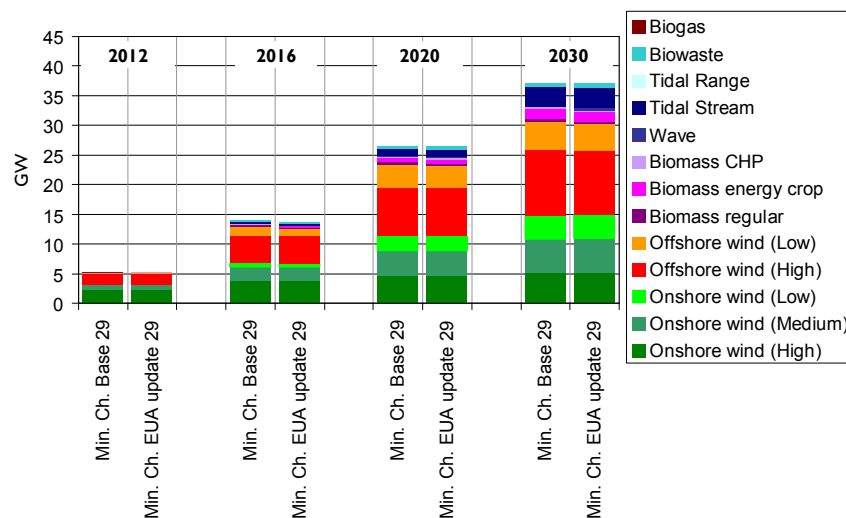
Table 34 Banding assumptions, 29%

	2013		2018	
	Minimum Change Base 29%	Minimum Change EUA update 29%	Minimum Change Base 29%	Minimum Change EUA update 29%
Onshore Wind	1.25	1.25	1.25	1.25
Offshore Wind	2	2	2	2
Wave	3.5	4	3	3
Tidal Stream	3.5	3.5	3	3
Tidal Range	3	3	3	3
Biowaste	1	1	1	1
Biogas	2	2	2	2

Capacity Mix

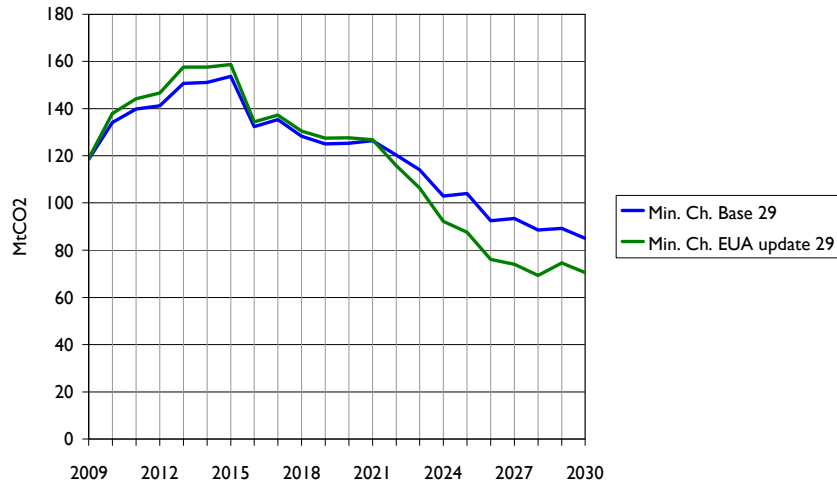
In comparison to the Minimum Change 29% Case, the thermal mix is identical until 2029 when slightly more CCGT is deployed. Renewable build is similar as well, as shown in Figure 107.

Figure 107 Renewable build, Minimum Change 29 EUA



Although the capacity mix is very similar with the differing EUA prices, the generation mix is different. With a lower carbon price up to 2020, coal is favoured which increases emissions. After 2020, the increasing carbon price favours gas-fired plant, with a corresponding decrease in emissions as coal is displaced. This is shown in Figure 108.

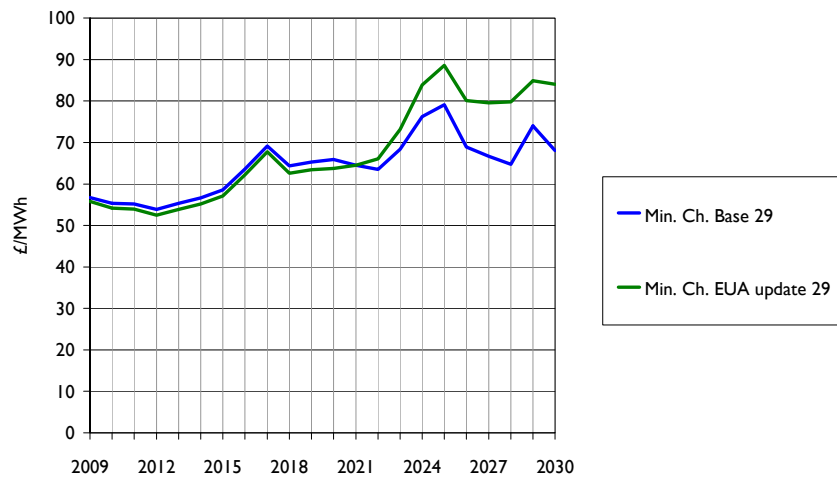
Figure 108 Carbon Emissions, Minimum Change 29 EUA



Prices

Wholesale prices mirror the change in EUA price. A lower EUA price sees a lower wholesale price up to 2020. Beyond then, wholesale prices rise as the cost of thermal generation increases. These differences flow through to consumer prices.

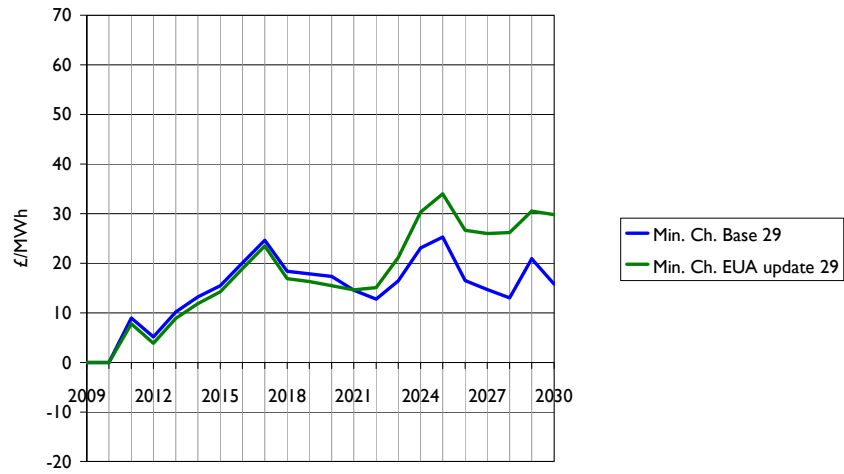
Figure 109 Wholesale price, Minimum Change Base 29 EUA



Rents

With the only major difference being the change in wholesale price driven by the changed EUA prices, this is clearly the driver for the change in rent, shown in Figure 110.

Figure 110 Offshore wind (High) rent, Minimum Change 29 EUA



G Appendix: Status Quo modelling

A ‘Status Quo’ run was performed that models the market under the assumption that there is little change to present policy. In particular, we assume:

- The RO is maintained to 2027 (in line with the previous study, and not updated to account for the 2008 Energy Bill);
- Low build rates;
- Obligation size limited to 20%;
- ROC prices can ‘ski-slope’ (if the ROC market is long, prices do not collapse)⁵⁴
- Headroom remains at 8% (compared to a rise to 10% in Minimum Change)
- 2009 banding changes implemented; no banding changes later.

The analysis performed here is compared to the Minimum Change Policy Option, and run against five different cases: Low, Base, Price Shocks, High High and EUA.

The high level results are shown in Table 35. The Status Quo is both less effective and less efficient than the Minimum Change.

Table 35 Status Quo, high level results

2020	Status Quo				
	Low	Base	Price Shocks	High High	EUA
Capacity (GW)	14.2	17.4	17.4	19.7	17.1
Generation (TWh)	47.6	62.5	62.4	66.3	61.7
Effectiveness %	11.8%	15.9%	15.9%	16.9%	15.7%
Efficiency %	75%	67%	64%	58%	65%

Below, we review the results of each Case in turn, and then compare results across Cases.

⁵⁴ This is not strictly Status Quo, but the powers to do this are in the Energy Bill.

G.1 Status Quo Base

The reduction in renewable deployment, compared to Minimum Change, is obvious in Figure 111. There is an increase in CCGT build to accommodate the shortfall. Nuclear build remains the same.

Figure 111 New plant build, Base

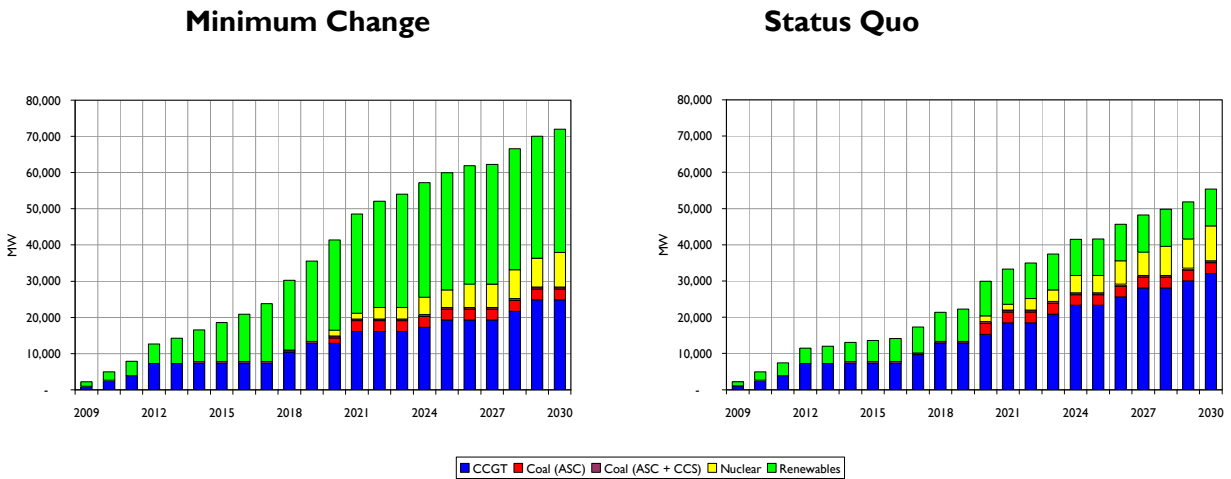
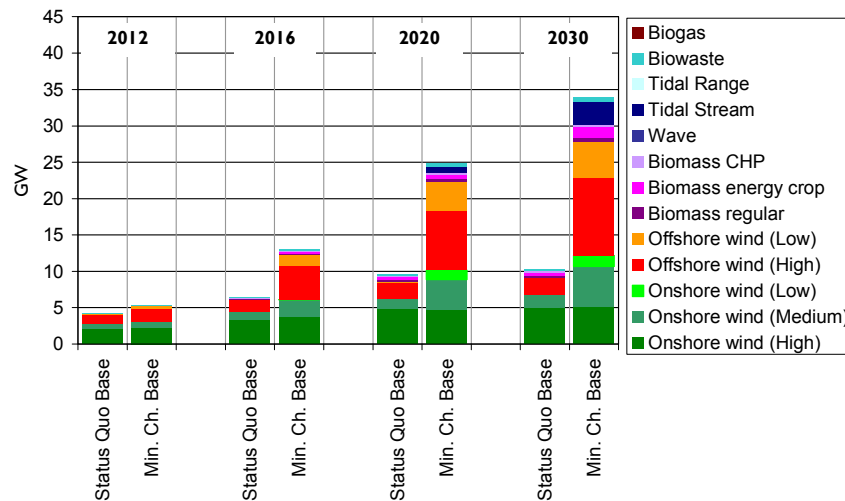


Figure 112 shows the renewable capacity mix. There is no low yield onshore wind being built, and drastically reduced levels of all other wind yields. Biomass and marine are also reduced.

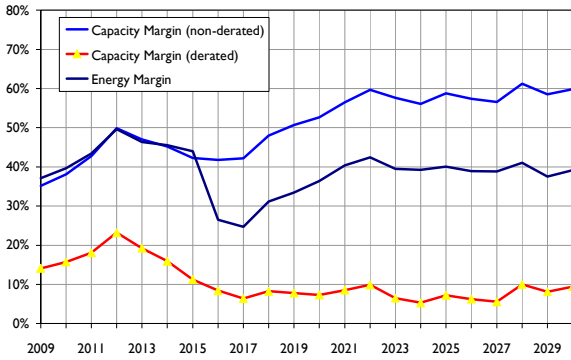
Figure 112 Renewable plant build, Base



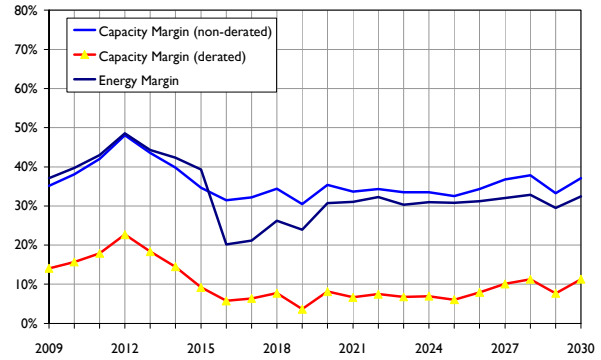
As seen in Figure 113, although the de-rated capacity margins are similar, the energy margin is significantly lower in Status Quo.

Figure I 13 Capacity margin, Base

Minimum Change



Status Quo



G.2 Status Quo Price Shocks

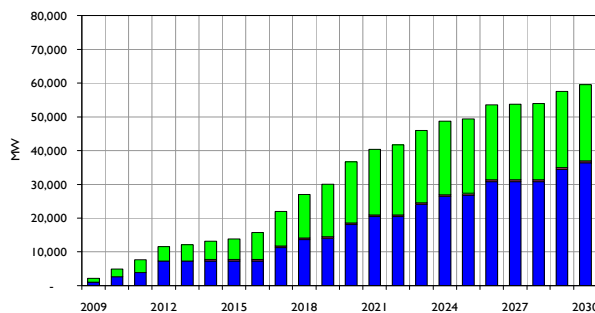
As with other analysis performed throughout this report, the Price Shocks Case shows no significant build differences to the Base Case. The only difference to the Base Case is the rents achieved by plant in times of price shock, and that the consumer price is dominated by wholesale movements.

G.3 Status Quo Low

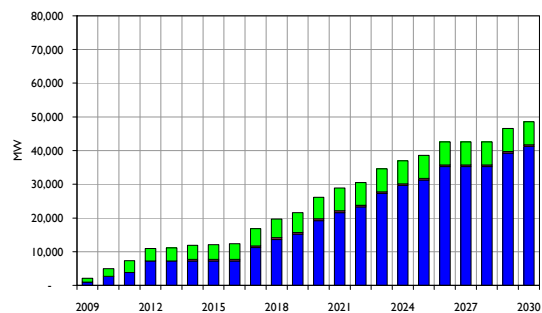
As in Minimum Change, there is a severe reduction in renewable build in the Low Case, and no diversity of thermal build.

Figure I 14 Plant build, Low Case

Minimum Change



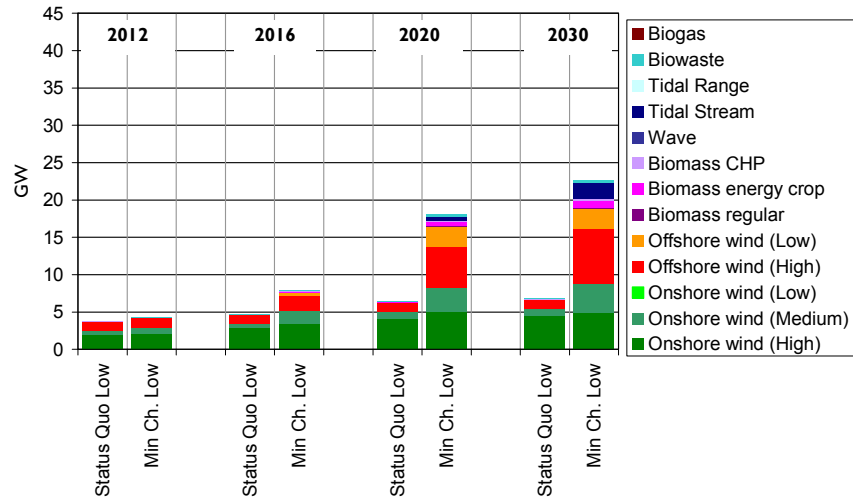
Status Quo



■ CCGT ■ Coal (ASC) ■ Coal (ASC + CCS) ■ Nuclear ■ Renewables

The Status Quo Low Case renewables build is almost wholly Onshore wind (High), as shown in Figure I 15.

Figure I 15 Renewables build, Low



G.4 Status Quo High High

Figure I 16 shows plant build in the High High Case. The high carbon price means CCS becomes economic and grows from 2021 onwards. The renewable mix is shown in Figure I 17.

Figure I 16 Plant build, High High

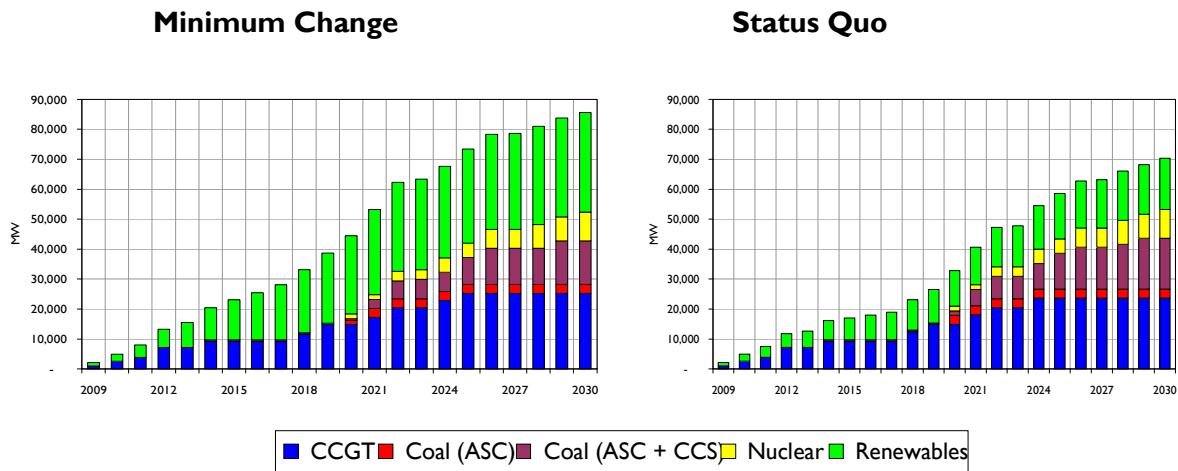
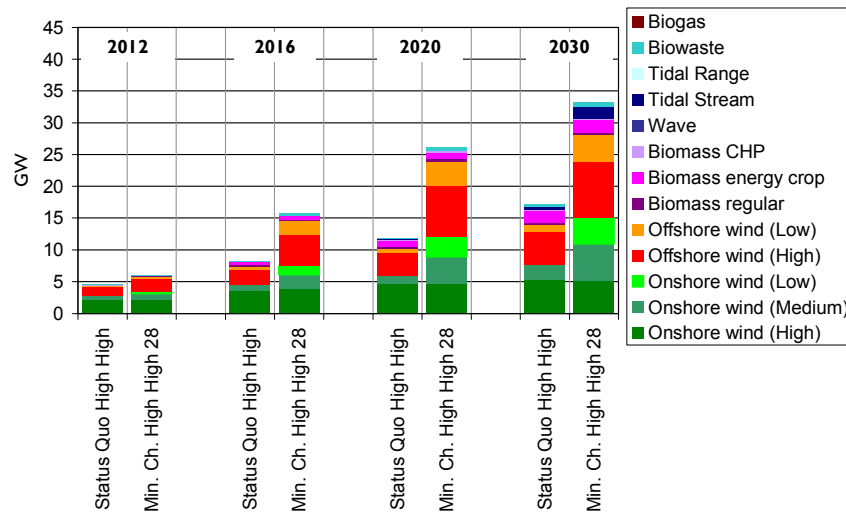


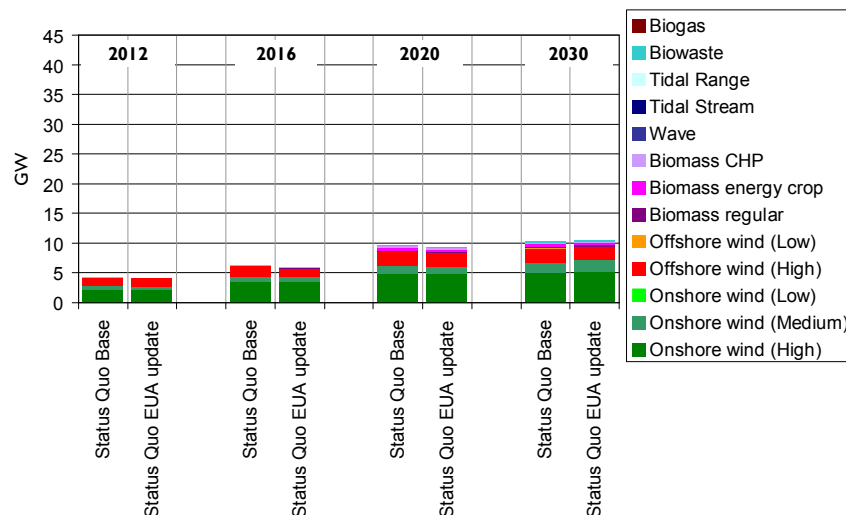
Figure I 17 Renewable build, High High



G.5 Status Quo, updated EUA prices

The updated carbon prices (shown in Figure I 06), cause a reduction of 300 MW in renewable build through to 2020. By 2030, the increasing carbon prices reverse this slower build, and there is 250 MW more renewables, a swing of over 500 MW during that decade. This is shown below in Figure I 18.

Figure I 18 Renewable build, Status Quo EUA

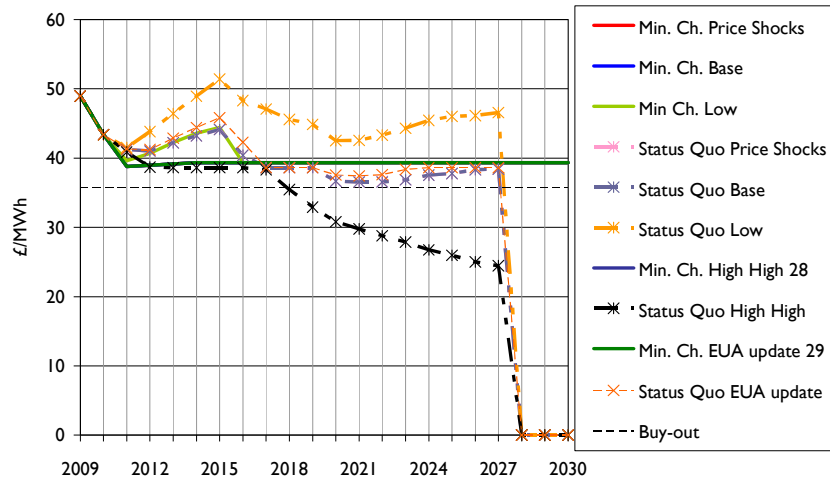


G.6 Comparative analysis

Prices

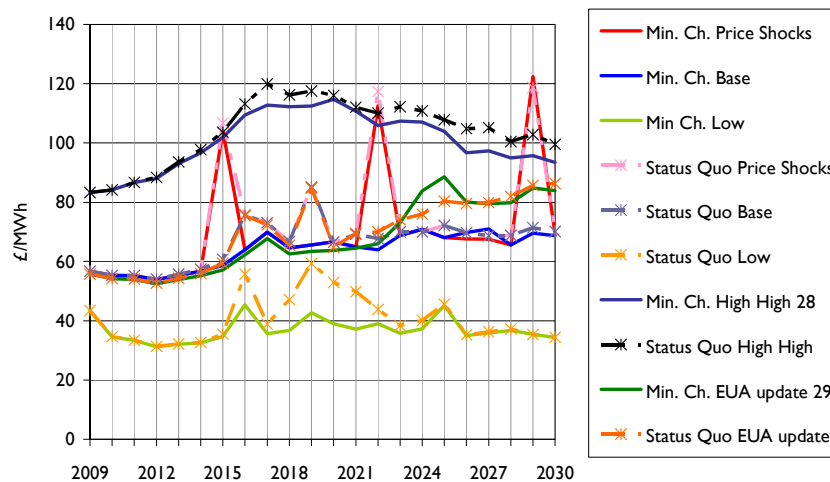
Lower build in most Status Quo Cases supports the ROC price above Buy-out (until the end of the scheme in 2027). The other feature is the cap on Obligation size at 20%; once that has been surpassed the ROC price is not supported as it is in the Minimum Change and thus falls below the buy out price (supported by the ski-slope mechanism). This is very evident in the High High Case with ROCs being valued at 70% of Buy-out by the end of the RO in 2027.

Figure 119 ROC price, Status Quo



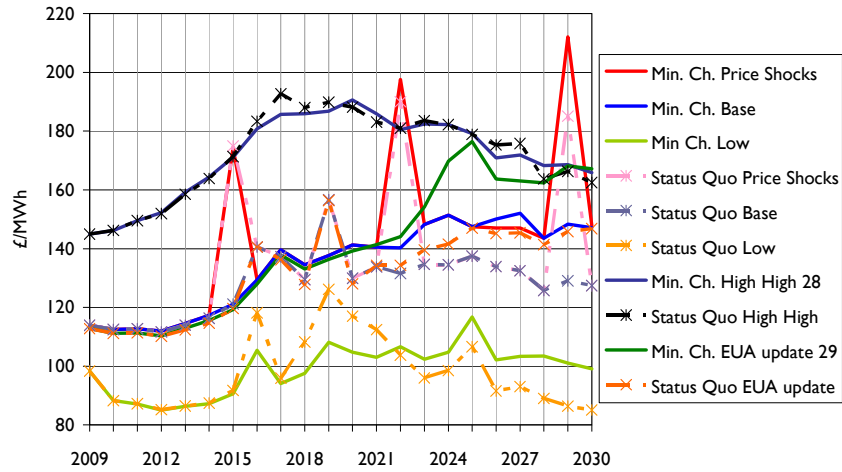
The wholesale prices follow similar trends to the Minimum Change Option, with the differences driven by capacity margin effects.

Figure 120 Wholesale prices, Status Quo



It can be seen in Figure 121 that these wholesale prices are not the sole driver of the consumer price. The smaller RO means a lower cost of subsidy, and the lack of renewable deployment means that consumers are paying much less under Status Quo than under Minimum Change assumptions. The exception is the High High Case in which the lower subsidy under Status Quo is offset by the higher wholesale price so that consumers are approximately indifferent to the Policy Option.

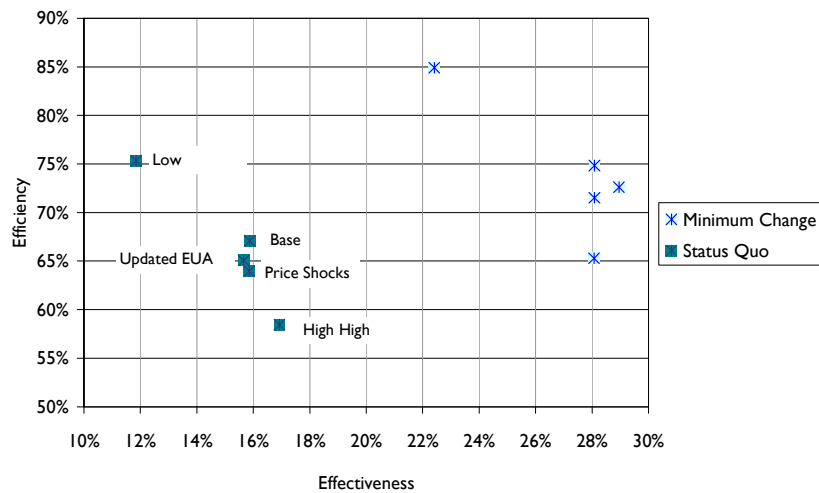
Figure 121 Consumer Prices, Status Quo



G.7 Summary

Figure 122 summarises the efficiency and effectiveness of the Status Quo runs compared to the Minimum Change equivalents. It is clear that the effectiveness is restricted, and efficiency reduced.

Figure 122 Efficiency v Effectiveness, Status Quo



H Appendix: Supplementary Analysis

H.1 Duration of Support Period

To test the impact of the duration of support for projects provided by the Renewables Obligation, we made a simple comparison between 17 year and 20 year coverage. 17 years is the support period for sites coming online in 2020, with the extension of the RO to 2037, as announced in the 2008 Pre-Budget report and confirmed in the Government Response published with the draft Renewables Obligation Order 2009 (see Section 2.3.3). 20 years is typically the economic life under which projects are planned and sanctioned.

It is obviously the case that a 20 year duration will increase the lifetime subsidy for the plant, although on an NPV basis the difference is substantially reduced due to the discounting affect on the final 18-20 year period. We used our Minimum Change Base Case results to quantify this, looking at projects that become operational in 2010, 2015 and 2020 respectively.

The results are shown in Table 36, where we compare the cumulative subsidy on an NPV basis with the long run marginal cost (LRMC) of the asset. The changes in the LRMC over time are a result of the assumptions we have made on changing capital costs, combined with a stepping up of the supply curve as total cumulative capacity increases. The subsidy is based on the ROC prices generated by the model, combined with the standard Minimum Change banding assumptions.

Table 36 Subsidy levels for different banded technologies for different support periods

Technology		2010	2015	2020
Onshore Wind (High)	LRMC	£/MWh 71.5	75.0	75.0
	20 yr Subsidy	£/MWh -37.3	-38.0	-32.9
	17 yr Subsidy	£/MWh -33.6	-34.3	-32.9
	Increase in subsidy relative to LRMC	% 5.2%	5.0%	0.0%
Offshore Wind (High)	LRMC	£/MWh 110.9	116.4	121.4
	20 yr	£/MWh -74.8	-76.2	-63.0
	17 yr	£/MWh -67.5	-68.7	-63.0
	Increase in subsidy relative to LRMC	% 6.6%	6.4%	0.0%
Wave	LRMC	£/MWh 221.1	189.3	157.7
	20 yr	£/MWh -110.6	-113.7	-95.0
	17 yr	£/MWh -99.5	-102.5	-95.0
	Increase in subsidy relative to LRMC	% 5.0%	5.9%	0.0%

We see that the change in subsidy prior to 2020 is of the order 5-7% of the LRMC. In absolute terms, the maximum change is approximately 10 £/MWh (for a 3 ROC band). In 2020, the subsidy levels converge as it is 17 years before the end of the RO and as such 20 years of support can not be guaranteed.

The impact of duration choice is hence within the granularity of ROC banding, but providing 20 years of support could provide a helpful extra incentive to marginal projects prior to 2020, and hence aid overall deployment. In all the modelling, we have assumed 20 years of support.

H.2 Required Headroom Under the RO

H.2.1 Introduction

In this Section we examine the Headroom required under the Renewables Obligation (RO). The Headroom mechanism is designed to prevent a collapse in the ROC price by setting the Obligation size such that the possibility of it being exceeded by the actual supply of ROCs in a given year is kept very low. As the Obligation size is set in advance, there is uncertainty in outturn ROCs due both to the inability to forecast perfectly the actual build profile of renewables, and to the unpredictability of the generation output, particularly for intermittent plant such as wind and wave. The Obligation size is therefore calculated by scaling up the expected average output by a Headroom percentage.

The analysis below examines the level required to ensure ‘adequately’ against an oversupply of ROCs. In keeping with the standard proposed by the British Wind Energy Association (BWEA)⁵⁵, ‘adequacy’ here is defined as keeping the expected frequency of an oversupply to one year in ten, on the basis that, at this level, oversupply could be managed through the banking mechanism. (As noted in Section 5.4, it is possible that some Phase 2 options we have considered might require the banking mechanism to be reviewed. If so the Headroom adequacy level may need to be adjusted accordingly.)

H.2.2 Methodology

To examine the Headroom required, we utilise as a starting point the renewables build profile of the Minimum Change Base Case. In 2020, this profile includes approximately 12 GW of onshore wind and 13GW of offshore wind. Combined, this 25 GW of wind capacity makes up 81% of the total renewable capacity of 31 GW. The associated output is shown in Table 37. Onshore and offshore wind, combined, generate 73.4 TWh, or 73%.

⁵⁵ <http://www.bwea.com/pdf/070906%20Appendix%20A%20Numerical%20analysis.pdf>

Table 37 Expected generation of renewables technologies, 2020

Renewable Technology	Expected Generation in 2020, TWh	Percentage of Total 2020 Renewables Generation
Bioenergy	11.4	11.4%
Co-firing	3.2	3.2%
Hydro	0.2	0.2%
Offshore wind	44.1	43.9%
Onshore wind	29.3	29.2%
Other ⁵⁶	9.3	9.2%
Tidal/Wave	2.9	2.9%
Total	100.4	100.0%

To calculate the required Headroom, a given level of variability on annual output above average levels is applied to each of the renewables technologies, together with correlation parameters. Renewable output is simulated, adjusted by the appropriate technology band levels, and aggregated across all technologies. This sum is, in turn, divided by the expected average total ROC output to determine the Headroom percentage required.

In its analysis, the BWEA references as the usual assumption a one in ten probability of variability of output from a single wind power site exceeding a level 15% above annual average output, and we have utilised this as the starting point in our analysis. For the remaining (non-wind) non-dispatchable renewable technologies, we have assumed a one in ten probability of annual output exceeding 15% of average and, on all dispatchable renewable technologies, a one in ten probability of variability exceeding 1% is assumed.

The correlation in annual output levels is also an important consideration. Generally, higher correlations will tend to increase Headroom needs, and vice versa (since for lower correlations, variations will tend to 'average out' more across the system). To avoid overcomplicating the analysis, we have implicitly assumed perfect correlation between all onshore wind sites, and between all offshore wind sites. As in practice these correlations will be less than perfect, our results are somewhat conservative (erring on the side of higher Headroom).

To test the robustness of Headroom results to key assumptions, we have explored variations in the following through sensitivities:

- banding assumptions;
- the variability of annual wind output;
- the correlation between onshore and offshore wind annual output; *and*

⁵⁶ Includes renewable technologies such as landfill gas and solar PV.

- the relative balance of onshore and offshore wind.

We then look at how the ratio of wind to other renewables may change through time and the implication for the potential evolution of Headroom.

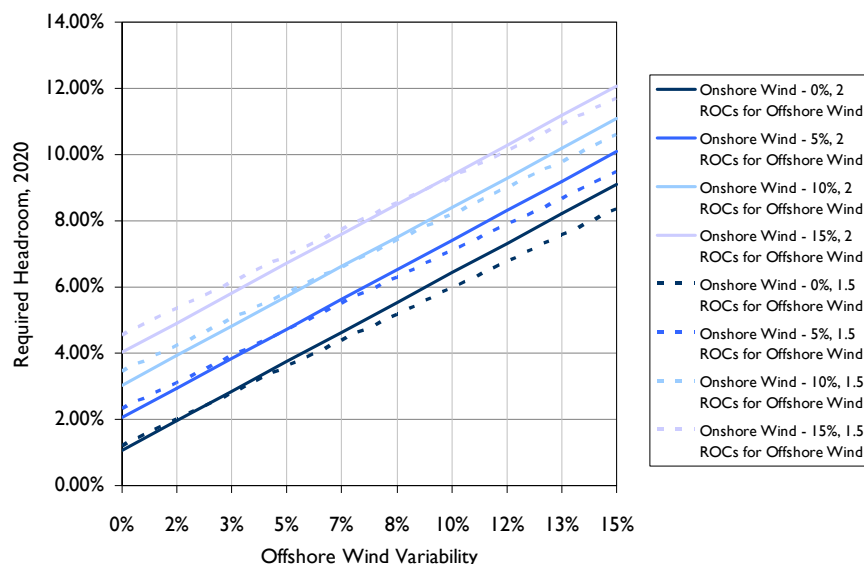
H.2.3 Sensitivity to variability in wind output

In the Minimum Change Base Case in 2020, output from renewables is expected to be approximately 100 TWh, of which 73.4 TWh is wind. Using the assumptions above, there is a one in ten probability that wind output could vary by more than 11 TWh (15%), if there was full correlation between all wind sites. This is approximately 11% of expected average renewables output. With banding, however, the corresponding variation in ROCs will be more pronounced, as that associated with the 43.9 TWh of offshore wind will receive 2 ROCs rather than 1.

We assessed the possible range of required Headroom associated with wind output by testing various combinations of onshore and offshore wind variability, under different assumptions of offshore wind bands.

The results are shown in Figure 123. Each line displays the relationship between variability in the output of offshore wind (which runs along the x-axis) and the required Headroom (the y-axis), given a constant variability in onshore wind output. Four different onshore wind variability levels are shown (represented by different colours): 0%, 5%, 10%, and 15%. Each of these four wind variations is considered for offshore wind receiving 2 ROCs (represented by solid lines) and 1.5 ROCs (represented by the dotted lines). (Other technology bands are held at Minimum Change levels.) Correlation between the variability on onshore and offshore wind output is set to 100%.

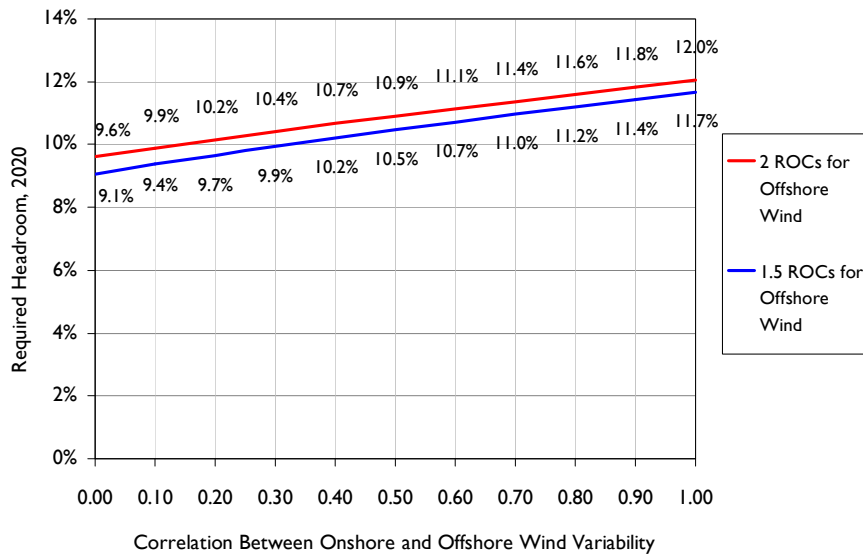
Figure 123 Required Headroom under alternative onshore and offshore wind variabilities



When variability for onshore and offshore output are both 15%, the required Headroom is just over 12% when offshore wind receives 2 ROCs, and just over 11.5% when offshore wind receives 1.5 ROCs. (When there is no wind variability the required Headroom is not zero, due to the variation on non-wind renewables.)

In practice, correlation between onshore and offshore wind variability may be less than 100%. In Figure 124, we show the required Headroom under various correlation coefficients between onshore and offshore wind for alternative banding scenarios: offshore wind receiving 2 ROCs (the red line) and offshore wind receiving 1.5 ROCs (the blue line). Onshore and offshore wind variability is held at 15%.

Figure 124 Impact of the correlation coefficient between onshore and offshore wind variability on the required Headroom

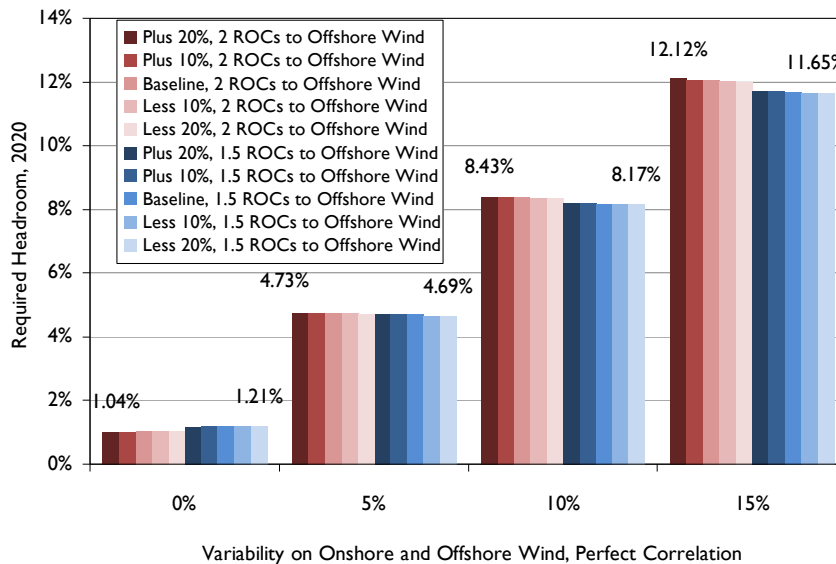


The range in the calculated required Headroom is 9% to 12%. A Headroom of 10% would cover correlations up to 0.2 (with 2 ROCs for offshore wind) while a Headroom of 11% would covers for correlations up to 0.6.

H.2.4 Robustness to alternative wind portfolios

Next, we examine the impact of changes in the relative ratio between onshore and offshore wind, holding the combined output of wind constant. This is relevant because of the differences in banding between the two. In the Minimum Change Base Case, expected onshore wind output in 2020 is 29.3 TWh and offshore wind output is 43.9 TWh, a ratio of approximately 1.5. Figure 125 displays the impact of changes to this ratio, which is adjusted upwards and downwards by steps of 10% and 20%, for offshore banding of both 1.5 and 2, and for different wind variability levels. We have set correlation between onshore and offshore wind to 100%.

Figure 125 Required Headroom under varying ratios of offshore to onshore wind



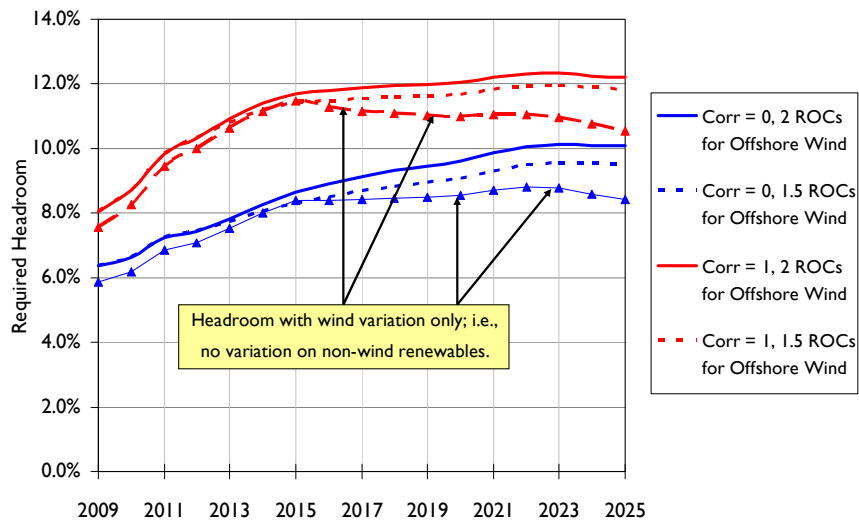
The relative split between onshore and offshore wind has a relatively small impact on the required Headroom. When offshore wind receives 2 ROCs and wind variability on onshore and offshore wind is assumed to be 15 percent and perfectly correlated, increases to the relative proportion of offshore wind increase the required Headroom by half a percentage point for a 20% change.

H.2.5 Headroom evolution

Lastly, we examine Headroom requirements as the capacity mix, and hence the proportion of wind to overall renewables, varies through time. In our Minimum Change Case, this proportion starts at 50% in 2009, peaks at 77% in 2015, and declines to 73% by 2020.

We again use a variability of 15% on both onshore and offshore wind, and show results for correlations of zero and one, and banding of 1.5 and 2 for offshore wind. The results are shown in Figure 126. We also show Headroom associated with wind variability only (with a 2 ROC offshore wind band), depicted by the dashed lines marked with triangles (red for a correlation of one and blue for a correlation of zero).

Figure 126 Required Headroom over time



Required Headroom grows steadily from 2009 to 2015, with a relatively small contribution from non-wind renewables. Between 2015 and 2020, the maximum required Headroom flattens and never rises above 12%, although the minimum required Headroom (with zero correlation) continues to rise (from around 8% to 10% percent). Beyond 2020, required Headroom falls between 10% and 12%.

H.2.6 Conclusion

Differing assumptions on variability on onshore and offshore wind output produce relatively large differences in the required Headroom. Using assumptions consistent with BWEA analysis (adequacy set at an expected oversupply in one year in ten, and 15% variability from a single wind site), our modelling suggests that Headroom will need to rise to between 10% and 12% in 2020, depending on correlation between annual variability between different wind sites. This range is robust to a number of potential outcomes, including the ratio of wind to all renewables, and the relative balance between onshore and offshore wind.

I Appendix: Cost Benefit Analysis

I.1 Approach to cost benefit analysis

The costs and benefits of each of the Policy Options are measured against the Minimum Change as the reference Option. They are calculated annually and as a net present value (NPV) for the period 2009-2030 using the Green Book real discount rate of 3.5%. It is important to note that the NPV measure extends ten years beyond 2020 and hence the results are influenced not just by what happens between now and 2020, but also by the impact of the different support schemes beyond 2020. Conversely, with the support for renewables extended to 2037/38, the NPV analysis does not capture the costs in the final seven years of the scheme.

The primary measures within the cost benefit analysis are as follows:

- **Cost of carbon dioxide emissions.** The change in value of carbon dioxide emissions as measured using the cost of EU Allowances (EUAs). A positive number represents a decrease in carbon dioxide emissions (i.e., a saving in EU ETS allowance costs to the GB power sector).
- **Resource costs.** The change in the costs of generating electricity, including changes in investment costs, fuel costs, variable and fixed operating costs and system balancing costs. It excludes changes in the costs of carbon which are captured above. A negative number represents an increase in resource costs.
- **Consumer surplus.** The change in welfare to consumers, which is a combination of the change in wholesale electricity prices, change in the net subsidy to renewables, the change in system balancing costs and the change in scheme administration costs. A negative number represents a reduction in consumer surplus or an increase in the costs to consumers.
- **Producer surplus.** The change in the profits made by electricity producers measured as the change in the difference between revenues (wholesale prices and net subsidies) and generation costs. This is broken down by economic rents made in renewable and non-renewable generation portfolios. A positive number represents an increase in the producer surplus.
- **Treasury receipts.** The change in tax receipts to the Treasury which is the combination of changes in revenues under the Climate Change Levy and the change in VAT on domestic consumer bills. (VAT is not relevant for the I&C sector as it can be reclaimed.) A negative number represents a loss of revenue to the Treasury.
- **Net welfare.** The change in welfare to the economy as a whole which is the sum of the changes in consumer surplus, producer surplus and treasury receipts. It is also equivalent to the sum of the change in carbon dioxide emissions less the change in resource costs. A negative number represents a loss in net welfare to the economy.

A number of ancillary measures are captured within the cost benefit analysis but are not quantified financially. These are as follows:

- **Impact on security of supply.** The change in expected energy unserved. Expected energy unserved is a probabilistic assessment of the electricity demand that cannot be met in each year due to situations where demand exceeds supply. If, for example, we expect on average there will be two hours where demand will exceed supply by 500 MW, expected energy unserved for that year would be 1 GWh.

- **Fuel usage.** The change in consumption of gas, coal and oil in electricity generation measured in millions of tonnes of oil equivalent.
- **Carbon abatement cost.** The average cost of abating each tonne of carbon dioxide saved relative to the Minimum Change⁵⁷.

All costs and prices shown in the quantitative assessment are in 2008 real terms.

A key point that must be understood in the evaluation of any policy in relation to renewables is that new renewables are more expensive than conventional thermal plant, under the Base Case assumptions. Therefore, in undertaking cost benefit analysis, the more effective the policy in deploying renewables, the lower the net welfare. Thus, without a penalty for missing the renewable target or the evaluation of unquantified impacts of diversifying the generation portfolio (such as security of supply benefits), more renewables always appears to be a more expensive option.

1.2 Fixed Targets

Table 38 shows the cost benefit analysis for the Fixed Targets Option relative to Minimum Change. In the Base and Price Shocks Cases, the differences between the two Options are minimal. There are more differences in the Low Case. With increased renewable deployment under the Fixed Targets Option, consumers are required to pay more renewable subsidy, which is the main driver of the difference in consumer surplus. Wholesale prices are slightly higher, which feeds through into increased rents for both renewable and non-renewable generators. The increase in generation costs is driven by the increased penetration of renewables. Climate Change Levy (CCL) revenues are reduced as more Levy Exemption Certificates (LECs) are issued to renewable generators. Conversely, with consumers paying more, the Treasury receives more VAT receipts. The increase in renewables leads to a decrease in fossil generation and there is an increase in carbon saved.

Overall there is a £2bn reduction in net welfare as the increase in renewables leads to higher costs which outweigh the benefits in carbon reductions.

⁵⁷ This is the absolute cost not the incremental cost above the EUA cost.

Table 38 CBA, Fixed Targets

Change in annual welfare, NPV £m (real 2008)		Fix. T. Price Shocks	Fix. T. Base	Fix. T. Low
Net Welfare	Carbon saved	0	0	107
	Less increase in resource costs	0	0	-2,377
	Less increase in unserved energy	0	0	-14
	Less increase in demand side response	0	0	-2
	Change in Net Welfare	0	0	-2,287
Consumer Surplus	Change in wholesale price	0	0	-193
	Change in balancing costs	0	0	-126
	Change in unserved energy	0	0	-14
	Change in demand side response	0	0	-2
	Change in net renewables subsidy	-17	-17	-4,845
	Change in administration costs	0	0	-1
	Change in CCL	0	0	98
	Change in VAT	0	0	-84
	Change in Consumer Surplus	-17	-17	-5,166
Producer Surplus	Change in wholesale price	0	0	193
	Change in balancing revenues	0	0	126
	Change in net renewables subsidy	17	17	4,845
	Change in generation costs	0	0	-2,270
	Change in Producer Surplus	17	17	2,894
	<i>Change in renewables rent</i>	<i>17</i>	<i>17</i>	<i>2,455</i>
<i>Change in non-renewables rent</i>	<i>0</i>	<i>0</i>	<i>439</i>	
Treasury Receipts	Change in CCL	0	0	-98
	Change in VAT	0	0	84
	Change in Treasury Receipts	0	0	-14
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide (MtCO ₂)	0	0	-1
	Cost per tonne CO ₂ avoided (£/tCO ₂)	0	0	249
Fuel use	(mtoe)	0.00	0.00	-0.23
	Annual change in use of coal (mtoe)	0.00	0.00	-0.14
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	0
Renewables	Qualifying renewables generation in 2020	28.1%	28.1%	22.9%

I.3 Buy-out Cap/Collar

Table 39 shows the cost benefit analysis of the Buy-out Cap/Collar Option relative to the Minimum Change. In all Cases the net welfare appears lower under the Buy-out Cap/Collar option, a consequence of the greater renewables deployment.

There are differences in Producer Surplus between the Base Case and the Price Shocks Case. In the Base Case, the lower hurdle rates under the Buy-out Cap/Collar Option lead to an increase of around £3.5 bn, since the investment costs are reduced relative to the level of subsidy. However, under the Price Shocks Case, this benefit to producers is more than offset by the revenue cap which limits the upside during price shocks. The decrease in Consumer Surplus in the Low Case reflects the greater amount of renewables build (which ultimately consumers have to pay for) and also the increase in net subsidy resulting from the higher ROC prices when the collar comes into effect.

Table 39 CBA, Buy-out Cap/Collar

<i>Change in annual welfare, NPV £m (real 2008)</i>		BO C-C Price Shocks	BO C-C Base	BO C-C Low
Net Welfare	Carbon saved	1,209	990	770
	Less increase in resource costs	-2,312	-2,543	-10,128
	Less increase in unserved energy	-39	-42	0
	Less increase in demand side response	-2	-3	1
	Change in Net Welfare	-1,144	-1,598	-9,358
Consumer Surplus	Change in wholesale price	-1,794	-2,062	1,699
	Change in balancing costs	-652	-648	-1,144
	Change in unserved energy	-39	-42	0
	Change in demand side response	-2	-3	1
	Change in net renewables subsidy	4,169	-2,376	-19,301
	Change in administration costs	-2	-2	-4
	Change in CCL	290	288	623
	Change in VAT	33	-80	-300
	Change in Consumer Surplus	2,003	-4,924	-18,427
Producer Surplus	Change in wholesale price	1,794	2,062	-1,699
	Change in balancing revenues	652	648	1,144
	Change in net renewables subsidy	-4,169	2,376	19,301
	Change in generation costs	-1,101	-1,551	-9,355
	Change in Producer Surplus	-2,824	3,535	9,392
	<i>Change in renewables rent</i>	<i>-5,051</i>	<i>1,186</i>	<i>9,900</i>
<i>Change in non-renewables rent</i>	<i>2,227</i>	<i>2,349</i>	<i>-508</i>	
Treasury Receipts	Change in CCL	-290	-288	-623
	Change in VAT	-33	80	300
	Change in Treasury Receipts	-323	-209	-323
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide (MtCO ₂)	-3	-3	-5
	Cost per tonne CO ₂ avoided (£/tCO ₂)	131	131	185
Fuel use	(mtoe)	-1.15	-1.15	-1.51
	Annual change in use of coal (mtoe)	-0.14	-0.14	-0.43
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	-1
Renewables	Qualifying renewables generation in 2020	30.0%	30.0%	25.2%

I.4 Band Cap/Collar

Table 40 shows the cost benefit analysis for the Band Cap/Collar Option relative to the Minimum Change Option. The results in terms of net welfare are similar to the Buy-out Cap/Collar Option. However, consumers are relatively better off and producers worse off with the Band Cap/Collar under the Low Case, and vice versa in the Price Shocks Case. This reflects the fact the Band Cap/Collar Option only affects new plant and hence the effect of the cap and collar is less.

Table 40 CBA, Band Cap/Collar

<i>Change in annual welfare, NPV £m (real 2008)</i>		Band C-C Price Shocks	Band C-C Base	Band C-C Low
Net Welfare	Carbon saved	1,333	1,101	781
	Less increase in resource costs	-2,946	-3,298	-10,043
	Less increase in unserved energy	-14	-12	9
	Less increase in demand side response	-1	0	3
	Change in Net Welfare	-1,628	-2,209	-9,250
Consumer Surplus	Change in wholesale price	394	809	2,661
	Change in balancing costs	-711	-707	-1,253
	Change in unserved energy	-14	-12	9
	Change in demand side response	-1	0	3
	Change in net renewables subsidy	603	-3,723	-13,481
	Change in administration costs	-2	-2	-3
	Change in CCL	317	316	586
	Change in VAT	10	-55	-190
	Change in Consumer Surplus	597	-3,374	-11,669
Producer Surplus	Change in wholesale price	-394	-809	-2,661
	Change in balancing revenues	711	707	1,253
	Change in net renewables subsidy	-603	3,723	13,481
	Change in generation costs	-1,611	-2,194	-9,259
	Change in Producer Surplus	-1,897	1,427	2,814
	<i>Change in renewables rent</i>	<i>-2,506</i>	<i>1,300</i>	<i>4,192</i>
<i>Change in non-renewables rent</i>	<i>609</i>	<i>127</i>	<i>-1,378</i>	
Treasury Receipts	Change in CCL	-317	-316	-586
	Change in VAT	-10	55	190
	Change in Treasury Receipts	-327	-261	-396
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide (MtCO ₂)	-3	-3	-4
	Cost per tonne CO ₂ avoided (£/tCO ₂)	132	132	205
Fuel use	(mtoe) Annual change in use of coal	-1.12	-1.12	-1.35
	(mtoe) Annual change in use of oil	-0.19	-0.19	-0.34
	(mtoe) Annual change in use of oil	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	0
Renewables	Qualifying renewables generation in 2020	30.0%	30.0%	24.9%

I.5 Band Indexation

The cost benefit analysis of the Band Indexation Option relative to Minimum Change is shown in Table 41. The net welfare losses under the Base and Price Shocks Cases are lower than the corresponding results for the Buy-out Cap/Collar and Band Cap/Collar Options. This in part reflects the lower hurdle rates under the Band Indexation Option, which reduce renewables investment costs. However, the net welfare loss in the Low Case is greater due to the higher deployment of renewables.

The higher degree of revenue stabilisation with the Band Indexation Option means that consumers do relatively better in the Price Shocks Case, but worse in the Low Case, than under the cap/collar options, and vice versa for producers.

Table 41 CBA, Band Indexation

<i>Change in annual welfare, NPV £m (real 2008)</i>		Band Index Price Shocks	Band Index Base	Band Index Low
Net Welfare	Carbon saved	1,263	1,089	1,414
	Less increase in resource costs	-1,527	-1,895	-18,576
	Less increase in unserved energy	2	-14	-11
	Less increase in demand side response	1	-1	1
	Change in Net Welfare	-261	-820	-17,172
Consumer Surplus	Change in wholesale price	1,616	125	1,439
	Change in balancing costs	-677	-702	-2,394
	Change in unserved energy	2	-14	-11
	Change in demand side response	1	-1	1
	Change in net renewables subsidy	4,514	195	-26,693
	Change in administration costs	-2	-2	-6
	Change in CCL	303	314	1,089
	Change in VAT	95	-1	-440
	Change in Consumer Surplus	5,852	-85	-27,016
Producer Surplus	Change in wholesale price	-1,616	-125	-1,439
	Change in balancing revenues	677	702	2,394
	Change in net renewables subsidy	-4,514	-195	26,693
	Change in generation costs	-262	-804	-17,156
	Change in Producer Surplus	-5,715	-422	10,492
	<i>Change in renewables rent</i>	<i>-5,209</i>	<i>-1,140</i>	<i>10,015</i>
	<i>Change in non-renewables rent</i>	<i>-506</i>	<i>718</i>	<i>477</i>
Treasury Receipts	Change in CCL	-303	-314	-1,089
	Change in VAT	-95	1	440
	Change in Treasury Receipts	-398	-313	-649
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide (MtCO ₂)	-3	-3	-8
	Cost per tonne CO ₂ avoided (£/tCO ₂)	86	93	190
Fuel use	(mtoe) Annual change in use of coal	-1.00	-1.05	-2.42
	(mtoe)	-0.16	-0.16	-0.85
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	-1
Renewables	Qualifying renewables generation in 2020	29.8%	29.9%	27.1%

I.6 Contract for Difference

The cost benefit analysis for the CfD Option relative to the Minimum Change Option is shown in Table 42. The results are very similar to the Band Indexation Option, with minor differences in the Consumer and Producer Surpluses resulting from the small differences in renewables rents described in Section 4.10.

Table 42 CBA, Contract for Difference

<i>Change in annual welfare, NPV £m (real 2008)</i>		CfD Price Shocks	CfD Base	CfD Low
Net Welfare	Carbon saved	1,263	1,089	1,435
	Less increase in resource costs	-1,527	-1,895	-18,907
	Less increase in unserved energy	2	-14	-4
	Less increase in demand side response	1	-1	3
	Change in Net Welfare	-261	-820	-17,473
Consumer Surplus	Change in wholesale price	1,616	125	2,067
	Change in balancing costs	-677	-702	-2,394
	Change in unserved energy	2	-14	-4
	Change in demand side response	1	-1	3
	Change in net renewables subsidy	4,839	195	-27,507
	Change in administration costs	-2	-2	-6
	Change in CCL	303	314	1,106
	Change in VAT	101	-1	-443
	Change in Consumer Surplus	6,182	-85	-27,178
Producer Surplus	Change in wholesale price	-1,616	-125	-2,067
	Change in balancing revenues	677	702	2,394
	Change in net renewables subsidy	-4,839	-195	27,507
	Change in generation costs	-262	-804	-17,465
	Change in Producer Surplus	-6,040	-422	10,369
	<i>Change in renewables rent</i>	<i>-5,533</i>	<i>-1,140</i>	<i>10,418</i>
	<i>Change in non-renewables rent</i>	<i>-506</i>	<i>718</i>	<i>-49</i>
Treasury Receipts	Change in CCL	-303	-314	-1,106
	Change in VAT	-101	1	443
	Change in Treasury Receipts	-404	-313	-663
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide (MtCO ₂)	-3	-3	-9
	Cost per tonne CO ₂ avoided (£/tCO ₂)	86	93	190
Fuel use	(mtoe)	-1.00	-1.05	-2.44
	Annual change in use of coal (mtoe)	-0.16	-0.16	-0.85
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	-1
Renewables	Qualifying renewables generation in 2020	29.8%	29.9%	27.2%

I.7 Low build and Hiatus sensitivities

The cost benefit analysis for the Low Build and Hiatus sensitivities relative to the Minimum Change Option is shown in Table 43. With no penalty for missing the renewables target, the decrease in renewables deployment leads to an increase in net welfare of the system in these sensitivities, of over £20 bn with Low Build.

Table 43 CBA, Low build and Hiatus sensitivity

Change in annual welfare, NPV £m (real 2008)		Min. Ch. Base Low Build	Band Index Base Low Build	Band Index Base Hiatus
Net Welfare	Carbon saved	-4,667	-4,591	467
	Less increase in resource costs	25,235	26,340	2,025
	Less increase in unserved energy	-11	-23	-18
	Less increase in demand side response	-4	-6	-2
	Change in Net Welfare	20,554	21,720	2,472
Consumer Surplus	Change in wholesale price	-7,338	-9,305	-1,352
	Change in balancing costs	3,554	3,502	-283
	Change in unserved energy	-11	-23	-18
	Change in demand side response	-4	-6	-2
	Change in net renewables subsidy	25,067	26,497	3,193
	Change in administration costs	10	10	-1
	Change in CCL	-1,781	-1,747	123
	Change in VAT	323	314	28
Change in Consumer Surplus	19,821	19,242	1,689	
Producer Surplus	Change in wholesale price	7,338	9,305	1,352
	Change in balancing revenues	-3,554	-3,502	283
	Change in net renewables subsidy	-25,067	-26,497	-3,193
	Change in generation costs	20,558	21,739	2,493
	Change in Producer Surplus	-725	1,045	934
	Change in renewables rent	-2,124	-2,220	-462
Change in non-renewables rent	1,398	3,264	1,397	
Treasury Receipts	Change in CCL	1,781	1,747	-123
	Change in VAT	-323	-314	-28
	Change in Treasury Receipts	1,458	1,434	-151
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide (MtCO ₂)	20	20	-2
	Cost per tonne CO ₂ avoided (£/tCO ₂)	153	160	-64
Fuel use	(mtoe)	4.84	4.75	-0.35
	Annual change in use of coal (mtoe)	2.42	2.42	-0.26
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	0
Renewables	Qualifying renewables generation in 2020	17.2%	17.3%	28.9%

I.8 Band Changes sensitivities

The cost benefit analysis for Minimum Change 24%, 29% and 32% relative to Minimum Change 28% are shown in Table 44.

Please note that Minimum Change with High High and updated EUA 29 commodity price assumptions are not shown in the CBA as there was no relevant counterfactual (which would require identical commodity prices).

Table 44 CBA, Band change sensitivities

Change in annual welfare, NPV £m (real 2008)		Min. Ch. Base 32	Min. Ch. Base 24	Min. Ch. Low 28	Min. Ch. Base 29	CfD Base 29
Net Welfare	Carbon saved	2,471	-2,303	1,553	499	472
	Less increase in resource costs	-16,840	14,124	-29,975	-2,800	1,435
	Less increase in unserved energy	10	-6	-35	-48	0
	Less increase in demand side response	3	-2	0	-4	0
	Change in Net Welfare	-14,355	11,814	-28,456	-2,353	1,908
Consumer Surplus	Change in wholesale price	5,282	-4,306	-1,102	-2,964	1,051
	Change in balancing costs	-1,506	2,021	-2,691	-418	-356
	Change in unserved energy	10	-6	-35	-48	0
	Change in demand side response	3	-2	0	-4	0
	Change in net renewables subsidy	-25,348	21,180	-35,578	-4,222	3,737
	Change in administration costs	-4	5	-7	-1	-1
	Change in CCL	707	-874	1,229	177	169
	Change in VAT	-346	299	-632	-123	76
Change in Consumer Surplus	-21,201	18,316	-38,815	-7,603	4,677	
Producer Surplus	Change in wholesale price	-5,282	4,306	1,102	2,964	-1,051
	Change in balancing revenues	1,506	-2,021	2,691	418	356
	Change in net renewables subsidy	25,348	-21,180	35,578	4,222	-3,737
	Change in generation costs	-14,365	11,817	-28,415	-2,299	1,908
	Change in Producer Surplus	7,207	-7,078	10,956	5,305	-2,524
	Change in renewables rent	9,425	-7,732	8,088	2,399	-2,449
Change in non-renewables rent	-2,218	654	2,868	2,906	-75	
Treasury Receipts	Change in CCL	-707	874	-1,229	-177	-169
	Change in VAT	346	-299	632	123	-76
	Change in Treasury Receipts	-362	576	-597	-54	-245
Ancillary metrics, 2020						
Carbon	Annual change in carbon dioxide (MtCO ₂)	-8	6	-8	-2	-2
	Cost per tonne CO ₂ avoided (£/tCO ₂)	229	232	336	225	-68
Fuel use	Annual change in use of gas (mtoe)	-1.72	2.43	-3.47	-0.54	-0.57
	Annual change in use of coal (mtoe)	-1.03	0.21	-0.01	-0.09	-0.08
	Annual change in use of oil (mtoe)	0.00	0.00	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	1	7	0	0
Renewables	Qualifying renewables generation in 2020	32.1%	24.1%	28.1%	29.0%	29.1%

I.9 Status Quo

Table 45 shows the cost benefit analysis of the Minimum Change Options for five Cases, compared to the Status Quo. (Note that this is different from the previous CBAs, which have all been presented relative to Minimum Change.) The Minimum Change Option has a negative net welfare impact due to the costs associated with higher renewables penetration.

Table 45 Cost Benefit Analysis of Minimum Change compared to Status Quo

Change in annual welfare, NPV £m (real 2008)		Min. Ch. Price Shocks	Min. Ch. Base	Min Ch. Low	Min. Ch. High High 28	Min. Ch. EUA update 29
Net Welfare	Carbon saved	6,408	5,407	2,072	8,384	9,081
	Less increase in resource costs	-29,432	-32,416	-27,395	-14,963	-35,904
	Less increase in unserved energy	73	75	232	20	46
	Less increase in demand side response	14	13	34	11	12
	Change in Net Welfare	-22,936	-26,921	-25,057	-6,548	-26,765
Consumer Surplus	Change in wholesale price	16,177	15,779	24,310	18,329	13,325
	Change in balancing costs	-4,251	-4,251	-2,430	-3,397	-4,597
	Change in unserved energy	73	75	232	20	46
	Change in demand side response	14	13	34	11	12
	Change in net renewables subsidy	-38,430	-38,441	-24,853	-14,770	-42,584
	Change in administration costs	-13	-13	-9	-10	-14
	Change in CCL	2,288	2,287	1,657	1,763	2,484
	Change in VAT	-401	-408	-21	32	-520
Change in Consumer Surplus	-24,544	-24,959	-1,081	1,978	-31,848	
Producer Surplus	Change in wholesale price	-16,177	-15,779	-24,310	-18,329	-13,325
	Change in balancing revenues	4,251	4,251	2,430	3,397	4,597
	Change in net renewables subsidy	38,430	38,441	24,853	14,770	42,584
	Change in generation costs	-23,010	-26,996	-25,314	-6,568	-26,809
	Change in Producer Surplus	3,494	-83	-22,341	-6,731	7,048
	<i>Change in renewables rent</i>	<i>10,330</i>	<i>7,023</i>	<i>-2,361</i>	<i>3,043</i>	<i>12,280</i>
<i>Change in non-renewables rent</i>	<i>-6,835</i>	<i>-7,106</i>	<i>-19,980</i>	<i>-9,774</i>	<i>-5,232</i>	
Treasury Receipts	Change in CCL	-2,288	-2,287	-1,657	-1,763	-2,484
	Change in VAT	401	408	21	-32	520
	Change in Treasury Receipts	-1,887	-1,879	-1,636	-1,795	-1,965
Ancillary metrics, 2020						
Carbon	Annual change in carbon dioxide (MtCO ₂)	-20	-20	-18	-18	-21
	Cost per tonne CO ₂ avoided (£/tCO ₂)	180	181	-3,320	111	190
Fuel use	Annual change in use of gas (mtoe)	-6.28	-6.27	-5.58	-3.81	-7.01
	Annual change in use of coal (mtoe)	-1.56	-1.55	-1.59	-4.11	-1.51
	Annual change in use of oil (mtoe)	0.00	0.00	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	0	-8	0	0
Renewables	Qualifying renewables generation in 2020	28.1%	28.1%	22.4%	28.1%	29.0%

J Appendix: Results summary

Table 46 presents a summary table of effectiveness, efficiency, generation cost index and consumer cost index for all runs.

Table 46 Results Summary

Policy Option & Case	Effectiveness	Efficiency	Consumer Cost Index	Generation Cost Index
Fix. T. Price Shocks	28.1%	72%	1.87	1.34
Fix. T. Base	28.1%	75%	1.95	1.46
Fix. T. Low	22.9%	83%	2.59	2.16
Min. Ch. Price Shocks	28.1%	72%	1.87	1.34
Min. Ch. Base	28.1%	75%	1.95	1.46
Min Ch. Low	22.4%	85%	2.49	2.12
BO C-C Price Shocks	30.0%	75%	1.79	1.33
BO C-C Base	30.0%	75%	1.94	1.46
BO C-C Low	25.2%	79%	2.79	2.20
Band C-C Price Shocks	30.0%	73%	1.82	1.34
Band C-C Base	30.0%	75%	1.95	1.46
Band C-C Low	24.9%	82%	2.67	2.20
Band Index Price Shocks	29.8%	74%	1.78	1.32
Band Index Base	29.9%	76%	1.90	1.44
Band Index Low	27.1%	80%	2.82	2.25
CfD Price Shocks	29.8%	74%	1.78	1.32
CfD Base	29.9%	76%	1.90	1.44
CfD Low	27.2%	80%	2.83	2.25
Min. Ch. Base Low Build	17.2%	68%	1.88	1.27
Band Index Base Low Build	17.3%	68%	1.84	1.25
Band Index Base Hiatus	28.9%	75%	1.89	1.42
Min. Ch. Base 32	32.1%	73%	2.15	1.57
Min. Ch. Base 24	24.1%	77%	1.78	1.36
Min. Ch. Low 28	28.1%	83%	2.97	2.46
Min. Ch. High High 28	28.1%	65%	1.41	0.92
Min. Ch. Base 29	29.0%	75%	1.98	1.48
CfD Base 29	29.1%	76%	1.88	1.42
Min. Ch. EUA update 29	29.0%	73%	1.94	1.41
Status Quo Price Shocks	15.9%	64%	1.65	1.05
Status Quo Base	15.9%	67%	1.70	1.14
Status Quo Low	11.8%	75%	2.22	1.68
Status Quo High High	16.9%	58%	1.40	0.82
Status Quo EUA update	15.7%	65%	1.69	1.10