Electricity Market Reform
Analysis of policy options

A report by Redpoint Energy in association with Trilemma UK

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1 Executive summary

The need for market reform

There is a growing consensus across political parties and within the industry that reforms to the Great Britain (GB) electricity market are required in order to deliver the investment needed to replace an aging generation fleet and achieve ambitious targets for reducing the UK's carbon dioxide emissions, while maintaining secure and affordable supplies for consumers.

Baseline analysis

To demonstrate this, we modelled a 'business as usual' evolution of the GB generation market under current policies, with a carbon price rising to £70/t by 2030. This Baseline scenario, based on the Central assumptions of the Department of Energy and Climate Change (DECC), resulted in a carbon intensity of around 200 g/kWh in 2030, compared to 452 g/kWh in 2009[1]. Despite a 35% generation market share for renewables, assumed to be achievable under existing policies[2], this is still double the 100 g/kWh previously recommended by the Committee on Climate Change[3] (CCC). Although nuclear stations and plant fitted with carbon capture and storage (CCS) should be competitive with unabated fossil technologies without subsidy under Baseline assumptions, the key issue is investors' lack of confidence that future carbon prices will rise to the levels assumed by Government, resulting in a significant lag in development of low-carbon generation other than renewables.

Analysis of the Baseline scenario also highlighted potential future risks to security of supply towards the end of this decade and into the next. De-rated capacity margins, while expected to be high in the near term, could fall below 10% towards the end of the decade, lower than they have been over the last ten years. There is also the added uncertainty surrounding how the system will operate with much more renewable plant in the mix. The risks stem from a combination of closures of existing plant (25 GW by 2020 or around 30% of existing capacity), uncertain returns for investors in thermal plant, and the intermittent nature of wind plant and other types of renewables.

Policy response

The policy response to these challenges should be to strengthen incentives to accelerate investment in low-carbon generation, to counter uncertainty over the long-term evolution of the current carbon market. There are three broad approaches for achieving this:

- evolution of existing policy, for example extending the premium support which renewables currently receive under the Renewables Obligation (RO) to all low-carbon generators,

[1] Carbon intensity figures are based on direct emissions from generation rather than total life-cycle emissions.

[2] With adjustments to support levels through re-banding under the Renewables Obligation as needed.

[3] See letter to the Secretary of State for Energy and Climate Change dated 17 June 2010 from Lord Adair Turner, Chair of the Committee on Climate Change. In its Fourth Carbon Budget report, published on 7 December 2010, the Committee has revised its 2030 generation sector target to 50 g/kWh.

- introduction of policies that influence investment behaviour by increasing the anticipated costs of carbon dioxide emissions, either explicitly through a carbon price floor, or implicitly through constraining emissions such as through an emissions performance standard, and
- introduction of policies that more directly target particular volume objectives, such as targets for low-carbon generation and/or particular technologies, through the provision of long-term contracts for low-carbon plant.

In addition, mechanisms should be considered to reduce future risks to security of supply by strengthening the incentives to provide flexible and back-up capacity on both the supply and demand sides.

DECC asked Redpoint Energy and Trilemma UK to analyse a range of policy options and policy packages designed to address the challenges identified by the Baseline modelling. We initially analysed five different options to accelerate investment in low-carbon generation, before considering mechanisms for enhancing security of supply. Finally, we assessed a range of packages that combined the different options.

Policy options to accelerate decarbonisation

The five different options to accelerate decarbonisation span the range of possible approaches identified above:

- Evolution of existing policy
  - Premium Payments for all low-carbon generators
- Policies that influence investment behaviour
  - Carbon Price Support
  - Emissions Performance Standards
- Policies that target particular volume/technology objectives
  - Fixed Payments for low-carbon generators
  - Contracts for Difference for low-carbon generators

The analysis suggests that all five of these options could be designed to achieve an illustrative target carbon intensity of 100 g/kWh by 2030 under DECC's Central assumptions by promoting low-carbon generation through a combination of lowering investment risk and explicit support for low-carbon technologies.

Generation capital expenditure between 2010 and 2030, which is approximately £75bn on a net present value basis (2009 real terms)[4] under the Baseline, would increase by a further £16 to £24bn under the policy options assessed. There would be increased costs associated with bringing forward nuclear and CCS investment, but possible savings in delivering the renewables targets with lower cost finance, and significant reductions in fuel and carbon costs. Should carbon and gas prices rise strongly in the future, as the current DECC projections assume, the incremental costs of these policies relative to the Baseline could be relatively modest, in the range £3.6 to £7.8bn to 2030. The analysis suggests that costs to consumers could actually be lower than the Baseline under some policy options. For example, under the Contracts for Difference option, the wholesale cost of electricity (including low-carbon support), which currently accounts for approximately 40%[5] of an average domestic customer's bill, could be lower on average over the period 2010-2030 than under the Baseline. However, this result depends on the ability of Government

[4] Capital costs are annuitised based on hurdle rates of investment, and then discounted over the period 2010-2030 using a Government Green Book discount rate of 3.5% real. All assumptions and results are in 2009 real terms.

[5] Source: Ofgem Electricity and Gas Supply Market Report, December 2010

to establish effective mechanisms for setting contract price levels that accurately reflect the costs of the different low-carbon technologies. In the longer run customers would be better protected from further rises to carbon and fuel prices.

Although each of the options can be shown to deliver the desired outcome under a certain set of assumptions, external uncertainties such as fuel and carbon allowance prices will be key factors influencing the decarbonisation pathway. The level of confidence in a policy delivering the 2030 objectives will be dependent on its robustness to these external drivers. In addition, credibility that the policy will remain intact in the long-term will be essential for investor confidence.

The different policies also have different implications in terms of the implementation overhead for Government and industry players, compatibility with existing arrangements and interconnected markets, and the speed with which they could be implemented. By extension, each of the policy options therefore could carry a greater or lesser risk of a near term investment hiatus depending on how the transition is managed.

Premium Payments

Premium Payments, sometimes referred to as 'capacity payments for low-carbon generation', could be implemented either through administered tariffs, or through some form of volume-based auction. By providing additional support for all low-carbon generators, not just renewables, greater levels of investment in nuclear and CCS might be expected. However, investors would still be exposed to electricity price risk in general (driven primarily by fuel and carbon price volatility) and uncertainties surrounding future erosion in the wholesale electricity price as more generation with low variable costs is added to the system, bringing down the average short-run marginal price. Hence, investors may be seeking premia sufficient to meet a higher investment hurdle rate.

A possible variant on the Premium Payments option would be to introduce a low-carbon obligation on suppliers, either alongside the existing RO or as an extension of it. We have not explored this option explicitly but conceptually it could be similar to the Premium Payments option since it would provide those low-carbon technologies to which the obligations relate with an additional revenue stream in addition to selling their electricity.

Therefore, a possible benefit of this option is that it could be implemented as an extension of current arrangements, reducing the chance of a hiatus in renewables investment compared to some other options. The key challenge with it is in setting the correct payment levels given the large uncertainty in technology costs, and uncertainty in future electricity prices. If premia are set too low there is a risk that decarbonisation objectives are not met, but if set too high there is a risk of excessive economic rents for generators and higher costs for consumers.

Carbon Price Support (£50/t)

Carbon Price Support would place a floor under the carbon price for electricity generators and should reduce investment risk in low-carbon technologies by underpinning the electricity price. Our analysis suggests that a Carbon Price Support level of £22/t[6] implemented in 2013 rising to £50/t in 2020 and £70/t in 2030 should be sufficient to achieve the illustrative 100 g/kWh decarbonisation target for 2030 under DECC's Central fuel price assumptions, by bringing forward new nuclear investment[7]. It may also reduce the level of support required under the RO for new renewables investment, saving consumers money in

[6] The minimum cost of emissions for generators, including the underlying EU ETS price where this is lower.

[7] Note that under Carbon Price Support (£50/t), RO banding is reduced relative to the Baseline in order to meet the illustrative target of 35% of generation from renewables by 2030. If the RO banding had been left unchanged from the Baseline, Carbon Price Support would also have encouraged more investment in renewables than there is under the Baseline.

the longer run if carbon prices rise as Government expects. Furthermore, Carbon Price Support would likely reduce domestic emissions in the near term by encouraging coal to gas switching[8].

However, our analysis suggests that the effectiveness of Carbon Price Support in driving low-carbon investment is dependent on the confidence that investors have that this policy will not be subject to future change. It may also be less effective if investors are forecasting low future gas prices since low-carbon generation would be less competitive with gas-fired generation. A further consideration is that as the system decarbonises, the impact of the Carbon Price Support on the electricity price is likely to diminish, weakening it as an investment signal. As is the case under Premium Payments, investors are exposed to the risk of this price erosion.

Given our assumption of a constant increase in Carbon Price Support from 2013 to 2020, this is likely to increase costs to consumers in the near term by increasing the cost of electricity. High carbon emitting generators will lose, whereas existing low-carbon generators, such as nuclear and renewables, are likely to gain. There is also the possibility that it leads to the unintended consequence of greater imports from connected markets where the carbon price is lower (though the extent of interconnection is currently relatively small).

A key advantage of Carbon Price Support is that it is compatible with current GB electricity market arrangements and could be implemented relatively quickly, thus reducing the risk of an investment hiatus. It also maintains a role for the market in determining the generation mix (although the mix of renewables investment would still be influenced by the different levels of support available under the RO and sub-5MW Feed-in Tariff mechanisms).

Emissions Performance Standard

An Emissions Performance Standard (EPS) provides a mechanism for limiting the carbon dioxide emissions from individual plant or across a generation portfolio. In our analysis, we assume a base 'Targeted' EPS is in place as a minimum under all policy packages. This Targeted EPS would be structured as an annual emissions limit, to be applied to all new coal plant at the station level, to ensure that they are at least partially fitted with CCS and that there are the necessary incentives to run the CCS units even when carbon prices are low.

In addition, we have also modelled a Strong EPS applied to all fossil plant from 2018, to assess its effectiveness in driving deeper decarbonisation without additional policies (other than the RO). To address security of supply concerns, we have assumed that the Strong EPS is implemented as an annual limit rather than a rate based limit, allowing plant to remain open but limiting operation to progressively lower load factors. The Strong EPS would lead to early reductions in emissions, and could drive investment in low-carbon generation. However, the analysis suggests that this investment may come at the cost of high electricity prices due to the tight restrictions on the operation of fossil plant.

Sensitivity analysis on the Strong EPS policy demonstrates the difficulty in setting the correct level. There is also a risk for investors in low-carbon generation that an EPS could be softened in the light of future security of supply concerns.

Based on the analysis, it appears that a Strong EPS is unlikely to be the most effective mechanism to drive low-carbon investment as a stand-alone policy, but a Targeted EPS designed as an insurance policy against low-carbon prices could be effectively combined with other policy options.

[8] Under the EU ETS, it would be expected that lower emissions from the GB electricity sector in a given year would be offset by higher emissions elsewhere within the trading scheme.

Fixed Payments

Under a policy of Fixed Payments, low-carbon generators would be offered long-term fixed price contracts for the output from their plant, with some form of central agent acting as the counterparty. Contract prices could be set directly by Government or through an auction process. Fixed Payments could help to de-risk investments (we estimate that reductions in hurdle rates of up to 1-2% may be possible in some cases) and hence could both accelerate investment in low-carbon generation and reduce overall costs. Depending on how the policy is implemented, it would require the Government to take a role in determining future volume targets for low-carbon generation, possibly with a specific technology mix including targets for decentralised generation.

Since low-carbon generators are insulated from the electricity market, the policy is more robust to uncertain fuel and carbon prices and risks to future erosion of the electricity price. This increases confidence in achieving decarbonisation objectives and offers more stable prices for consumers. Consumers are exposed however, to any poor decisions surrounding the choice of volume targets (and technology mix), a risk that investors would normally carry.

A challenge with this option is in establishing the correct price level for payments, with the associated risk of excessive rents to new low-carbon generators. An administered price approach requires Government to have a good understanding of the costs of different technologies, where information is not always transparent. A volume-based auction could address this, but introduces other challenges – making the auction specific enough that bids can be effectively compared, while ensuring that sufficient players can participate in order to make it competitive. Careful consideration is also required to ensure that contracted investments are delivered in a timely and efficient manner.

There would be significant implementation issues associated with this policy, including the establishment of long-term volume targets, the creation of the necessary contracting agent and the urgent requirement to implement effective grandfathering arrangements for the RO. Investors would also need time to understand the commercial implications of the new arrangements. An important function of the purchasing agent would be to re-sell electricity contracts back into the competitive wholesale market in a manner that preserves, or possibly promotes, market liquidity, for example through day-ahead auctions. However, as low-carbon generation increases in the longer run, this has the potential to change significantly the nature of electricity trading with profound implications for the role and strategies of market participants. For example, by 2030 around 70% of electricity generated could be administered under Fixed Payments, by which stage the role of electricity suppliers may have changed fundamentally. With so much electricity being bought and sold at fixed prices, the key strategic differentiator in terms of cost of supply will be largely gone, and suppliers may then only be competing on cost to serve and quality of service.

Contracts for Difference

Offering low-carbon generators Contracts for Difference (CfDs) against the electricity price, together with technology specific premia, could also achieve a high degree of earnings stabilisation. Unlike Fixed Payments, however, generators would still participate directly in the physical market, with the central agent purchasing wholesale price 'risk' rather than power, and as a result they would face some residual level of market exposure (and hence earnings uncertainty). Depending on the design, this could in turn provide incentives for forecasting plant availability, scheduling output and (for renewables) siting plant efficiently. The implementation overhead may be somewhat lower compared to Fixed Payments, although there would be a number of challenges, in particular determining the correct price levels, establishing robust indices against which the CfDs can be settled, and managing the credit arrangements. While physical positions would still be traded bilaterally, the change to the long-term financial exposures of generators would be similar to Fixed Payments, and could have a similar effect on market dynamics in the longer term.

Capacity mechanisms

The Baseline modelling demonstrated possible future risks to security of supply. The analysis suggests that policies that promote further decarbonisation could exacerbate the risks, since although they should stimulate new low-carbon investment, it is likely that this will undercut fossil generators, leading to less investment in these technologies and/or earlier plant closures. The speed of deployment of low-carbon generation then becomes critical. Delays would exacerbate any security of supply risk.

The security of supply risk should be reduced where it is possible to stimulate an expansion of demand side response, enabled by smart meters, other demand side technologies and new pricing propositions encouraging customers to shift demand.

We have analysed two policies designed to mitigate the risk to security of supply further – a universal capacity payment mechanism (Capacity Payments for All) and a Targeted Capacity Tender. Either could increase capacity margins and reduce risks to security of supply but could lead to very different outcomes in terms of capacity mix and costs to consumers.

The analysis suggests that the main effect of a universal Capacity Payments for All could be to extend the lifetimes of existing plant, rather than necessarily stimulating investment in new plant. This may leave the system short of sufficient flexibility to manage the intermittency of renewables and could result in the unintended consequence of keeping high emitting plant on the system for longer. From an implementation perspective it is difficult to envisage how a universal capacity mechanism would run alongside the existing bilateral market and not risk the possibility of windfall gains for generators. It seems more likely that such a mechanism would be associated with a more radical reform of the current arrangements including the introduction of a pool-based system or organised electricity exchange requiring some level of mandatory participation. An additional problem with a global capacity mechanism is that it may create obstacles for the future integration of the GB market with those elsewhere in Europe unless similar mechanisms are the norm in other markets.

A Targeted Capacity Tender would be more compatible with existing arrangements and could be implemented as an insurance policy if required. It would place responsibility on a central body, probably the System Operator, for delivering a defined security standard, by contracting for a mix of back-up generation capacity (that would not otherwise have been available) and demand side response that meet specific requirements for flexibility. The costs to consumers of the Targeted Capacity Tender could be relatively low. In addition, such a mechanism could be used actively to stimulate investment in new sources of system flexibility, such as demand response. There is, however, a risk that it displaces private investment or encourages the planning of earlier closures in order to qualify for the tender, thus increasing the requirement for tendered capacity, leading to an increasing role for the central body/System Operator. The way that the tendered capacity is deployed and how it influences imbalance prices would therefore be a very important design consideration.

Combination packages

We have explored combining Carbon Price Support rising more slowly (reaching £30/t rather than £50/t by 2020) with other decarbonisation options, alongside a Targeted Capacity Tender. Adding Carbon Price Support (£30/t) to Fixed Payments or Contracts for Difference makes little difference in terms of the amount of low-carbon investment projected by the model. However, it could have a benefit of enhancing investor confidence prior to the establishment of the new low-carbon support arrangements, thus reducing the risk of an investment hiatus. In addition, emissions are reduced in the shorter term by encouraging coal to gas switching. However, by increasing electricity prices it would lead to higher costs to consumers.

Since investors remain exposed to wholesale prices under the Premium Payments option, introducing Carbon Price Support (£30/t) has a more direct effect on low-carbon investment in this case. It would allow the level of premia to be reduced, saving consumers money if carbon prices subsequently rise, and makes the Premium Payments option more robust to lower outturn carbon prices. It may also support investments in lower cost low-carbon technologies, such as nuclear, without the need for a premium payment at all.

Conclusions

The analysis suggests that the societal costs of delivering the required levels of decarbonisation differ between the options due to the impact on financing, and the extent to which the Government may target different technology mixes. However, these differences are relatively small, equivalent to about 1% of the total wholesale cost of electricity between 2010 and 2030. Where the options differ more markedly is in their impact on customers, their robustness to key uncertainties, the complexity of implementation and consequences for the electricity market as a whole.

Fixed Payments or Contracts for Difference (in conjunction with a Targeted EPS) could deliver the best value for customers and be the most robust to long-term uncertainties around fuel and EUA prices. The key risks with these approaches are that they depend on Government being able to set prices and target volumes appropriately, and that they represent a significant departure from current arrangements, with longer term consequences for the operation of the market. They would be more costly and time consuming to implement, and the transition would have to be effectively managed to minimise a potentially significant hiatus in near term investments. The inclusion of Carbon Price Support (£30/t) within the package may mitigate this latter risk to some extent.

The Premium Payments option would involve less implementation complexity but would be less robust to long-term uncertainties. If this route is adopted, there appear to be advantages in combining it with Carbon Price Support (£30/t) since this would make it more robust and potentially cheaper for consumers than either option by itself. Establishing the appropriate level to set premia remains a challenge however, given the uncertainty in future gas prices.

The Fixed Payment/Contracts for Difference approaches clearly place more reliance on Government intervention and central management (with a corresponding transfer of risks from investors), relative to the Premium Payments approaches, which have less impact on the market overall. This choice is likely to be strongly influenced by the trade off between longer term certainty in the generation mix versus risks associated with Government decision-making under uncertainty and information asymmetry, disruption to current market arrangements and near-term investment.

Finally, the risks to security of supply appear material but uncertain and an insurance policy may be needed. Retaining the option to include a Targeted Capacity Tender within the policy package appears to offer a cost effective mechanism for achieving this and has the potential to stimulate new sources of flexibility. However, there are many detailed design challenges that will need to be addressed.

2 Introduction

2.1 Background

2.1.1 History of investment in GB electricity market

Thermal generation

Liberalisation of the GB electricity market was initiated with the passage of the Electricity Act 1989. In the 20 years since, there has been significant investment in new thermal generation capacity. During the 1990s and early 2000s, this investment primarily took the form of Combined Cycle Gas Turbine (CCGT) plant, which benefited from relatively low capital costs and an abundant, low-cost source of fuel from the North Sea as the gas market was opened up to competition. This so-called 'dash for gas' marked a significant change from previous decades where investment in thermal plant had been predominantly focused on coal generation.

Nuclear generation

Under the Central Electricity Generating Board (CEGB) and the South of Scotland Electricity Board (SSEB), nuclear capacity was commissioned in several phases, starting with Magnox reactors in the 1960s and then Advanced Gas-Cooled Reactors (AGRs) during the 1970s and 1980s. A further reactor, the Sizewell B Pressurised Water Reactor (PWR) plant, was completed in 1995. Nuclear output increased during the 1990s due to improved plant performance and the commissioning of Sizewell B, but has since declined with the retirement of the older Magnox reactors and several of the AGR plant suffering from prolonged outages.

Nuclear assets were not privatised in the initial round of market liberalisation in GB, but rather remained in state ownership via Nuclear Electric (the former nuclear division of National Power) and Scottish Nuclear. In 1996, subsequent to the completion of Sizewell B, the AGR and PWR assets of Nuclear Electric and Scottish Nuclear were combined and privatised as British Energy, with the Magnox assets remaining in state ownership as Magnox Electric. No new nuclear plant have been commissioned since that time, although EDF, which now owns British Energy, has indicated an intention to invest in up to four new plants with the first operational by 2018. RWE and E.ON have formed a joint venture, Horizon Nuclear Power, with similar plans. Also, a consortium of Iberdrola, GDF SUEZ and Scottish and Southern Energy has announced that their joint venture company, NuGeneration, is aiming to develop up to 3.6 GW of new nuclear capacity.

Renewable generation

At the time of the Electricity Act 1989 a Non-Fossil Fuel Obligation (NFFO) was introduced, and this remained the primary 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 (PES) 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.

Prior to 1990 the only renewable technology of any scale in GB was hydro power, predominantly in Scotland. The UK's first onshore wind farm was opened in Delabole, Cornwall, in 1991, and consisted of 10 turbines with a capacity of 4 MW. Further wind farm developments followed during the 1990s, along with the development of landfill gas and other biomass-fired generation. By 2002, total renewable output stood at around 11 TWh – double the 1990 level, but still a small proportion (just over 3%) of total electricity supply.

The NFFO was considered to suffer from a number of issues, in particular the problem that a high proportion of winning bids were not ultimately developed. In April 2002, the NFFO was replaced by the RO. Eligible renewable generation facilities receive Renewable Obligation Certificates (ROCs) for each MWh of generation. Electricity suppliers are obliged to buy ROCs corresponding to their share of total electricity sales. This obligation was set at 3% of sales in 2002/03, 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)[9].

The original RO provided the same support level irrespective of technology (1 ROC for 1 MWh), 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 document[10] 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 provided the necessary powers to introduce banding and the changes to the RO were implemented from April 2009.

Since the introduction of the RO there has been a steady increase in the development of renewable capacity, notably wind, with a number of large onshore and offshore wind farms being commissioned in recent years. The percentage of output supplied by renewable sources in 2009 was 6.7% – more than double the 2002 total, but still well short of the level that will be required to meet European Union (EU) 2020 targets on the use of renewable energy[11].

2.1.2 Current generation mix

Current installed generation capacity by plant type for GB is shown in Figure 1. CCGTs now represent the largest share of generation type in capacity terms, at around 37% of the total, with the majority of this having been brought on stream since 1990. Coal plant retain an approximate 32% share, although a significant proportion of this is scheduled to close over the next one to two decades in response to EU Directives on emissions. Renewable generation (including hydro, wind, waste and biomass) accounts for around 10% of total installed capacity, with over half of that comprising onshore or offshore wind.

[9] We have assumed in our modelling that headroom of 10% applies under the RO.

[10] Reform of the Renewables Obligation, BERR, May 2007, http://www.berr.gov.uk/files/file39497.pdf

[11] The UK's target is for 15% of overall energy use to be met from renewable sources. In order to achieve this it is expected that around 30% of electricity generation will need to be from renewable sources by 2020.

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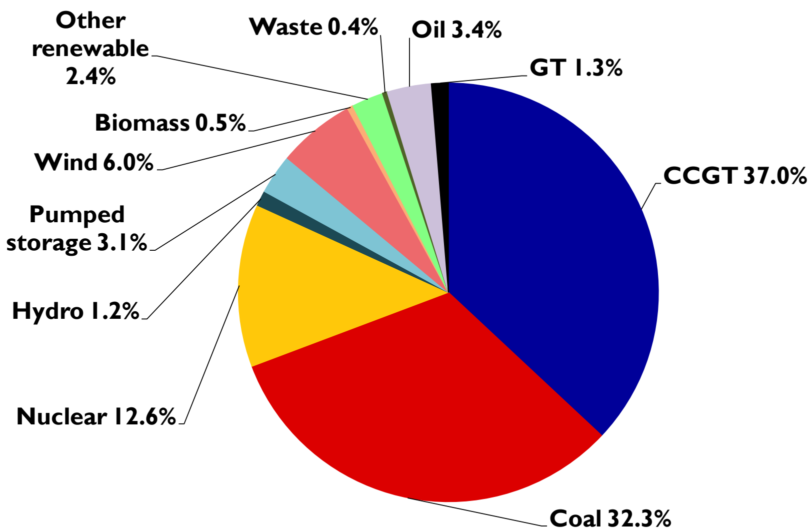
Figure 1 GB generation capacity by type – 2010[12]



2.1.3 Carbon dioxide (CO_2) emissions from the generation sector

Based on provisional data, total annual CO_2 emissions from the generation sector in 2009 were 186 million tonnes (Mt). On a unit output basis, emissions averaged 452 g/kWh of electricity generated, down from 496 g /kWh in 2008[13].

Fossil fuel plant are responsible for the majority of these emissions. On a unit output basis, these plant emitted 573 g CO_2 /kWh generated in 2009. However, there is a significant difference between the average CO_2 emissions intensity of coal-fired generation plant (882 g/kWh) and gas-fired generation plant (376 g/kWh). This means that total emissions are very sensitive to the relative balance of coal versus gas in the generation mix, which in turn is driven by the relative prices of the two fuels along with the carbon price.

To give an idea of the potential impact of gas versus coal switching on overall emissions, if all of the electricity output produced by CCGT plant in 2009 had been generated from coal instead, there would have been an increase of around 75 Mt in total CO_2 emissions (40% above the 2009 level). Conversely, if all of the output produced by coal plant in 2009 had instead been generated from CCGTs, there would have been a reduction in CO_2 of around 55 Mt (30% below the 2009 level).

2.1.4 Security of supply

Since market liberalisation margins of available generation capacity over peak demand have generally been maintained at a stable level. Figure 2 shows three measures of the historic capacity margin between 2002 and 2010:

- **outturn peak capacity margin**, which shows how much excess capacity was actually declared available during the half-hour period with the highest demand for a given year, calculated on a backward-looking basis,

[12] Source: Redpoint estimates

[13] Source: DECC Statistical Release on Provisional 2009 Greenhouse Gas Emissions, March 2010.

- **historic forecast de-rated capacity margin**, which is based on National Grid's Seven Year Statement (NG SYS) forecasts of peak demand and generation capacity (de-rated based on expected availability) under an Average Cold Spell (ACS) at the year-ahead stage[14], to provide a historic forward-looking measure of security of supply, and

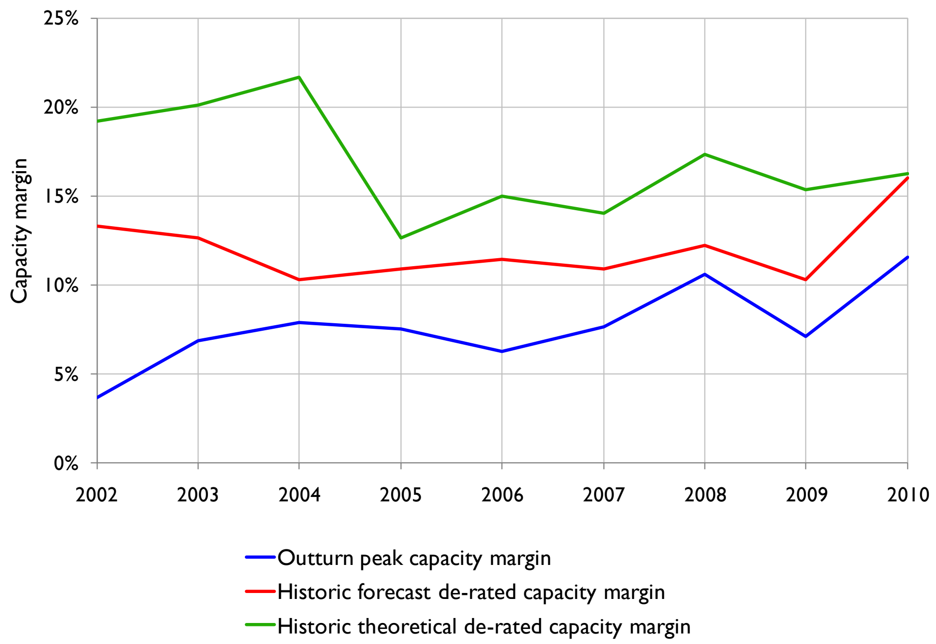
- **historic theoretical de-rated capacity margin**, which is calculated in a similar fashion to the previous measure but with NG's forecast of ACS demand replaced with the actual outturn peak demand. It is thus forward-looking with respect to the likely available capacity at the system peak in a given year, but backward looking with respect to peak demand.

As can be seen from the chart, while there are fluctuations between years there is no obvious trend in any of the measures of capacity margin, suggesting a broadly stable supply-demand balance. The historic forecast de-rated capacity margin, which is the most relevant measure for comparison with the forward projections of de-rated capacity margin in this study, has typically been in the range of 10-15%. This measure has consistently been below the historic theoretical margin suggesting that outturn peak demand has been lower on average than National Grid's forecast of ACS demand, with the exception of the cold winter of 2009/10.

The outturn peak capacity margin has been lower than both of these measures. However, this result is not unexpected since the outturn margin is calculated based on plant declared available on the day. Since plant can be declared unavailable for both technical and commercial reasons, it is possible that more capacity could have been made available had it been needed. The biggest difference between the outturn peak capacity margin and the historic forecast de-rated capacity margin occurred in 2002, due to unexpectedly low available capacity during the period of highest demand.

[14] To construct the data series, we have taken NG's forecasts at the year-ahead stage in each year and applied the same capacity de-rating factors as used in this study. It should be noted that the NG ACS forecast is prepared on the basis of a 31 March year end under the assumption that the ACS peak demand occurs in January. The actual system peak is calculated on the basis of normal calendar years.

Figure 2 Measures of GB electricity capacity margin[15] – 2002 to 2010



2.2 Decarbonisation agenda

The extent of the challenge of climate change is now widely accepted across political parties in the UK. A Climate Change Bill was introduced by the UK Government in 2008 to respond to this challenge and create a legally binding, long-term framework to cut greenhouse gas emissions. This requires the UK to cut overall greenhouse gas emissions by at least 80% by 2050 relative to 1990 levels and sets out a process for establishing shorter term emissions limits through five-year 'carbon budgets' (now fixed out to 2022, with the CCC due to advise on the 2023-2027 period by the end of 2010)[16]. Meeting these targets will mean a radical change in the way the UK produces and consumes energy over the coming decades.

This UK-based legislation is in addition to that introduced at EU level where a package of measures (the 'climate and energy package') has been implemented to reduce greenhouse gas emissions, improve energy efficiency and increase energy produced from renewable sources by 2020. In particular, the requirement for the UK to produce 15% of energy from renewable sources by 2020 will require a significant change from the current energy mix.

These new legal requirements have led policy makers to review the existing policy, regulatory and market framework and to consider where changes might be necessary to deliver the required outcomes. This has involved a combination of scenario analysis, which seeks to identify what investments might be required, along with a review of the market and regulatory arrangements, which considers whether the correct incentives are in place to attract and deliver the necessary investments.

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[15] Note that prior to 2005 the capacity margins shown in the chart have been calculated using data for the electricity system in England and Wales only. From 2005 onwards, margins have been calculated based on available data for the entire GB electricity system.

[16] Note that the timing of publication of this report was such that it could not be updated for the publication of the CCC 4th Carbon Budget report.

A range of scenario studies have been undertaken by various organisations, including DECC's 2050 pathway analysis[17], intended to provide the background for overall policy development. These studies have highlighted the range of possible future pathways. However, there exists a degree of consensus across these studies that electrification presents an important option in decarbonising the heat and transport sectors. This conclusion is based upon the assumption that it will be possible to decarbonise the power sector using existing technologies and over timescales of a few decades. Indeed, studies undertaken by the CCC have suggested that power sector CO_2 emissions of less than 100g/kWh by 2030 are necessary to put the UK on the pathway to reach 2050 emissions targets for the economy as a whole.

In parallel with these scenario studies, both DECC and Ofgem have undertaken reviews of the market arrangements. DECC's Energy Market Assessment[18] and Ofgem's Project Discovery[19] both concluded that significant reform of the electricity market would be necessary to attract the levels of investment necessary to deliver sufficient reductions in emissions over the next two decades. In addition, these reviews proposed a range of potential reforms to be considered for implementation.

Following the general election in May 2010, the Conservative and Liberal Democrat parties entered into a coalition government and produced an agreement[20] which set out the policies that they would seek to implement. This agreement included the intention to introduce a floor to the carbon price, feed-in tariffs for renewable generators, a security of supply guarantee and an emissions performance standard. This package of proposals has therefore set the power market reform agenda for the new Government.

2.3 Carbon Price Support

Carbon pricing has been at the centre of the UK and EU policy agenda to tackle climate change since 2005 when the EU Emissions Trading Scheme (EU ETS) was initially implemented. The EU ETS establishes a cap on overall emissions from a defined group of sectors and the corresponding number of emission permits are allocated or sold into the market. The market price for these permits therefore sets a cost for carbon emissions and this carbon price has proved increasingly influential in affecting the way that power stations generate in addition to creating an important new variable that investors in new power plants must consider.

However, the future price for carbon arising from the EU ETS is highly uncertain and will not only be driven by market fundamentals, such as gas price and electricity demand, but will also depend on future policy decisions by the EU and its Member State Governments. Some investors in new power stations may therefore consider it necessary to ensure that their investments are robust to a potential collapse in the carbon price while others might look for a higher return in light of this risk. This has led many observers to suggest that future carbon price uncertainty is slowing the rate of power sector decarbonisation and increasing the costs of the transition. The new Government therefore included a proposal to introduce a carbon price floor as part of the Coalition Agreement.

A carbon price floor can be implemented in various ways. However, so long as it directly affects the costs of power station emissions, it will constitute an important element of the market arrangements and will

[17] Downloaded from http://www.decc.gov.uk/assets/decc/What%20we%20do/A%20low%20carbon%20UK/2050/216-2050-pathways-analysis-report.pdf

[18] Downloaded from http://www.decc.gov.uk/assets/decc/1_20100324143202_e_@@_budget2010energymarket.pdf

[19] See http://www.ofgem.gov.uk/Markets/WhlMkts/Discovery/Pages/ProjectDiscovery.aspx

[20] 'The Coalition: our programme for government', http://www.cabinetoffice.gov.uk/media/409088/pfg_coalition.pdf

influence both operational decisions for existing plant and the investment case for new projects. It has therefore been an important element of the analysis which is described in this report.

Proposals for supporting the carbon price are the subject of a separate stand-alone consultation by HM Treasury. However, it is important to recognise the interactions between this proposal and the other elements of market reform.

2.4 Electricity Market Reform Project

The Government initiated the Electricity Market Reform (EMR) project to consider the best way to implement the proposals contained within the Coalition Agreement. In particular, it was recognised that the individual elements could be designed a wide variety of ways and that they would interact such that the outcome would be driven by the overall package rather than the individual elements.

The Electricity Market Reform project has therefore concentrated on identifying the key design options for implementing feed-in tariffs for renewables, a security of supply guarantee and an emissions performance standard and assessing how they operate as a package along with a floor to the carbon price.

Redpoint and Trilemma UK were commissioned to undertake a quantitative assessment of the proposed packages of reform through modelling investor behaviour in the power generation sector out to 2030. Given the extent of the potential reform options, it has been necessary to supplement the quantitative work with a qualitative assessment of the proposed reform packages. However, it is important to note that many detailed design and implementation issues lie outside the scope of this study and remain to be considered at a later date.

2.5 Approach to the analysis

The focus of the study is a detailed quantitative assessment of the different options for Electricity Market Reform. We have grouped the analysis into three areas:

- **options to promote decarbonisation**, including Carbon Price Support, Emissions Performance Standards, and targeted low-carbon support
- **options to enhance security of supply**, including universal capacity mechanisms and targeted capacity tenders, and
- **combination packages**, which combine some of the above options.

It should be recognised that the analysis requires a large number of assumptions, which are subject to considerable uncertainty. Hence, the quantitative analysis should be used to inform comparisons between options but not regarded as a prediction of the future. Given the complexities involved, it has not been possible to capture every aspect of each policy option within the analytical framework, and we have therefore supplemented the quantitative analysis of the options with some qualitative assessment.

As a starting point for the analysis we have established a 'Baseline' for the period 2010 to 2030, which is intended to represent a Business As Usual case. This is based on current policy, and incorporates DECC's Central assumptions on fuel prices, carbon prices, demand, maximum build rates and capital costs within Redpoint's investment modelling framework. This Baseline is then used as a comparison, or counterfactual, for the different EMR options.

The objective of the quantitative analysis is to understand better the possible impact of the different EMR options relative to the Baseline in the following areas:

- the pace and extent of decarbonisation
- future generation mix
- levels of security of supply
- overall resource costs, and
- costs to consumers.

The analysis is focused on the different financial incentives under each of the EMR options and does not consider other factors that may affect the rate of new generation investment, such as resource potential, planning, connections and supply chain constraints. One key assumption, for example, is that these issues will be sufficiently addressed such that the 2020 renewables target could be met with the right level of financial support, whether under the Baseline or any of the proposed reform packages.

The EMR policy options to analyse were provided to us by DECC. Our approach to modelling these was broadly as follows:

- identify which of the possible variants of each option to model
- qualitatively assess the possible effect of the option on investment risk, and estimate the impact on cost of capital (hurdle rates)
- define policy specific assumptions such as implementation timing and price levels (using iteration as necessary)
- model each option using Redpoint's investment modelling framework and compare results with the Baseline, and
- test the sensitivity of the results to key uncertainties.

Within the investment modelling framework is an agent simulation engine which aims to mimic investors' decision-making in response to expectations of future revenues relative to the project costs, taking into account investment risk. Future expectations of electricity prices are formed based on prevailing fuel and carbon price levels, and forward-looking views of demand and capacity on the system. The supply/demand balance evolves as investors commit to new build and other plant retire. The model does not assume perfect foresight, but produces internally consistent results which may reflect cyclicality in returns and investment patterns.

The model also captures investors' forward expectations of revenues under the RO, and new low-carbon support options required for this study such as Fixed and Premium Payments for low-carbon generators. We also have enhanced the model to capture the effect of Carbon Price Support and different forms of emissions performance standard.

The investment decision framework incorporates a simplified dispatch engine to calculate plant output, fuel usage, carbon dioxide emissions, and to derive electricity prices, at a level of detail appropriate for the evaluation of multiple policy options. Further details of the modelling framework are provided in Appendix E.

REDPOINT

2.6 Conventions

The main focus of this study has been the Great Britain (GB) electricity market, and our results are presented on this basis. The generation sector in Northern Ireland is subject to different market arrangements as a part of the Irish all-island Single Electricity Market (SEM), and separate consideration will need to be given as to how the policy options considered in this report would be implemented in that context.

All assumptions and results are in 2009 real monetary terms.

Commodity prices are shown in High Heating Value (HHV) terms.

Unless specifically stated otherwise, the proportion of total generation coming from renewable sources includes an assumption on the level of renewable microgeneration in each year between 2010 and 2030.

2.7 Structure of report

The remainder of this report is structured as follows:

- in Section 3, we present the assumptions and results for the Baseline analysis
- in Section 4, we present the analysis of the options to promote decarbonisation
- in Section 5, we cover the options to enhance security of supply
- in Section 6, we describe and present the results for the combination packages, and
- finally, in Section 7, we draw out a summary of the key messages from the study.

In addition we include a number of appendices as follows:

- Appendix A contains a glossary of abbreviations of scenario names
- Appendix B covers the High Demand Sensitivity
- Appendix C sets out additional assumptions and results for the Baseline
- Appendix D sets out the methodology for estimating hurdle rates for investment
- Appendix E gives a description of our modelling methodology
- Appendix F describes our results metrics, and
- Appendix G sets out cost benefit analysis results for all packages relative to the Baseline.

3 Baseline

3.1 Overview

The Baseline scenario models the development of the GB generation sector from 2010 to 2030 under current policy, incorporating DECC's Central assumptions on fuel prices, carbon prices, demand, build rates and capital costs. In this section we summarise the key assumptions behind the Baseline and present key outputs in terms of generation mix, carbon dioxide emissions and security of supply. These provide the basis against which we evaluate the EMR policy options, using the Baseline as the counterfactual in our results analysis. This baseline is consistent with the baseline used in HM Treasury's separate consultation on Carbon Price Support proposals.

3.2 Baseline assumptions

Fuel and carbon prices

For the Baseline, we use fuel price assumptions based on DECC's Updated Energy Projections (UEP) June 2010 Central price case. EU Allowance (EUA) carbon price assumptions are taken from DECC's Central assumptions. Further details are provided in Appendix C. All prices are in 2009 real terms.

Taken together, these projections represent a relatively coal favouring environment in the near term[21] with a significant fall in the coal price between 2010 and 2015 before carbon prices start to increase rapidly after 2020.

Demand

The annual demand assumptions for the Baseline correspond to the UEP June 2010 Central scenario for total electricity supply. In this context, electricity supply is defined as gross generation less the amount of electricity used on station sites. It therefore corresponds to the term 'Supplied (gross)' used in the Digest of United Kingdom Energy Statistics (DUKES) Table 5.6.

Interconnection

We assume a further 1.5 GW of interconnection to the Netherlands and Ireland in 2012, in addition to the existing French (2 GW) and Northern Irish interconnections (450 MW). Further interconnection is possible during this period including the possibility of a European Supergrid, but we have not included this within our Baseline assumptions.

[21] As at the time of writing, these assumptions differ from current forward curves. As of 1 Dec 2010, the UK NBP mid-market gas forward price was 55.0 p/th for Summer 2013 and 61.6 p/th for Winter 2013 (Source: Platts). This compares to an average gas price of 63.3 p/th in 2013 under DECC's Central assumptions. The ARA Coal Year Futures Price for delivery in 2013 as of 1 Dec 2010 was 115 $/t. This compares to an average coal price of 94.1 $/t in 2013 under DECC's Central assumptions.

REDPOINT

Capital costs

Capital cost assumptions for new build generation have been taken from the Mott MacDonald UK Electricity Generation Costs Update report, June 2010[22]. These are shown by technology in Appendix C.

Costs are quoted for First Of A Kind (FOAK) and Nth Of A Kind (NOAK) plant, with an assumed switch date related to expected levels of deployment in GB[23]. More mature technologies such as CCGTs and onshore wind are assumed to be NOAK from the start of the modelling time horizon.

Additional learning is assumed to take place on a continuous basis for most technologies leading to further reductions in capital costs over time. This takes the form of scalar adjustments to capital costs[24].

To reflect the fact that there is a spread in project costs, with the best opportunities likely to be exploited first, a supply curve is modelled which increases capital costs once certain volume thresholds are met by technology. In addition, there are limits on both annual build rates and total cumulative new build to 2030 by technology[25].

Planning and construction

Assumptions on construction and planning times are mostly taken from the Mott MacDonald report. Two exceptions to this are Offshore Round 1/Round 2 (R1/R2) and Offshore Round 3 (R3) wind plant, for which the planning times for the purposes of this study are assumed to be two years in both cases. Further details can be found in Appendix C.

Hurdle rates

Hurdle rates are based on Redpoint assumptions, informed by market data points where possible. We assume hurdle rates are higher for less mature technologies. Our approach for deriving hurdle rate assumptions is described in Appendix D.

RO

Under the Baseline, we assume that the RO continues to be the primary mechanism for providing financial support for large scale renewables (above 5 MW). We assume that it continues until 2037/38, with all plant guaranteed support until 2027/28 or a maximum of 20 years, whichever is later, subject to the RO end date. We have adjusted future ROC bands upwards in order to deliver 29% generation from all renewables by 2020, a figure consistent with DECC's Renewable Energy Strategy[26] to meet the total 2020

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[22] Downloaded from http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf and adjusted for DECC exchange rate assumptions where appropriate.

[23] Although change from FOAK to NOAK relates to deployment of a given technology in GB, significant deployment of a technology outside of GB would reduce the difference between FOAK and NOAK costs.

[24] Details can be found in Table 1 of Appendix C.

[25] Assumptions taken from SKM, Quantification of Constraints on the Growth of UK Renewable Generation Capacity, June 2008

[26] See http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/Renewable%20Energy%20Strategy/1_20090717120647_e_@@_TheUKRenewableEnergyStrategy2009.pdf

renewables target from domestic production. This outcome assumes that constraints in planning, connections and the supply chain can be overcome, and that there are sufficient good quality project development opportunities. ROC bands are subsequently reduced to target an illustrative level provided by DECC of 35% of generation from renewable sources by 2030. Detailed assumptions on ROC banding are set out in Appendix C. These changes in to ROC banding are modelling assumptions rather than any indication of future government banding decisions.

Within the total renewables figures we assume that generation from small scale renewables (sub 5 MW) under the Feed-in Tariff scheme reaches 2.8 TWh by 2020 before levelling off.

LCPD / IED

The Large Combustion Plant Directive (LCPD) is currently applied to the power sector to limit SO_x, NO_x and particulate emissions. This affects the coal and oil fleet in GB. Operators had the option to 'opt in', which required them to fit Flue Gas Desulphurisation (FGD) equipment to meet environmental standards, or 'opt out', with plant operation limited to a total of 20,000 hours between 2008 and 2015, at which point they must close. In GB, there are 9 GW of coal plant and 3 GW of oil fired plant that are 'opted out' and must close by the end of 2015.

The Industrial Emissions Directive (IED) recasts seven existing Directives, including the Large Combustion Plant Directive and the Integrated Pollution Prevention and Control (IPPC) Directive, with tighter limits in particular for NO_x emissions, coming into force in 2016. The details of the IED were approved by the European Parliament during Summer 2010 and have also recently gained European Council approval. Unlike the LCPD, some older gas plant will also be affected. CCGTs built after 2002, however, are already compliant. There are four options available to plant which do not meet the NO_x limits:

- Comply by fitting Selective Catalytic Reduction (SCR) equipment. For gas plant, SCR is not usually an economic upgrade.
- Enter a Limited Lifetime Obligation (LLO). This is analogous to opting out of the LCPD. Plant can operate up to 17,500 hours over an 8 year period to 2023 and then must close.
- Operate under the Transitional National Plan (TNP) as set out by individual Member States. During the period 2016 – mid-2020 plant will be able to operate as a function of historic generation levels and have the option of fitting SCR before June 2020 to comply fully.
- Enter a Derogation. Under this option, plant will be permitted to run for a maximum of 1,500 hours per year, but with no date for closure. Plant operating under the TNP can opt to enter a derogation at the end of the TNP in June 2020, but plant operating under the LLO cannot.

The economics of these choices for individual plant are evaluated within the modelling framework.

Nuclear lifetime extensions

Closure dates for existing nuclear plant are based on recommendations by the Nuclear Installations Inspectorate (NII), which is part of the Health and Safety Executive (HSE). We assume a five year extension from published closure dates for the three Advanced Gas Reactor (AGR) plant which have not already been extended. Details of the closure date assumptions for existing nuclear plant are set out in Appendix C.

It has recently been announced that the Wylfa Magnox nuclear plant will be allowed to operate until 2012 and there is also a possibility that the life of the Oldbury Magnox nuclear plant will be extended beyond the summer of 2011. Our assumptions for this study were agreed with DECC prior to these announcements, and the model assumes that both plant are closed by the end of 2010.

CCS demonstration projects

The Baseline assumes that four coal[27] carbon capture and storage (CCS) demonstration projects go ahead, and that sufficient support is provided to enable this. The assumptions for the four projects are shown in Table 1 below[28].

Table 1 Assumptions for CCS demonstration projects

	Demo 1	Demo 2	Demo 3	Demo 4
CCS type	Post combustion	Pre combustion	Post combustion	Oxyfuel
CCS capacity (MW)	300	360	300	300
Unabated capacity (MW)	1,140	468	1,140	0
Year completed	2014	2015	2018	2018

Under the Baseline (and in all EMR policy runs), CCS is assumed to be a proven technology by 2025. However, under the Baseline assumptions, none of the unabated units of the demonstration plant would be retrofitted before 2030 without additional support to cover the costs of the retrofits since investors are not anticipating the steep increase in carbon prices assumed under the Central assumptions.

3.3 Key Features of the Baseline

Figure 3 shows the cumulative new generation capacity between 2011 and 2030 as projected by the model under the Baseline assumptions. As explained in Appendix E, the model builds new capacity by simulating the investment decisions of different agents in the market. Capacity is built where future expected returns exceed the long-run marginal costs (LRMCs) of different technologies. In forming expectations of future returns, we assume that investors take a ten year forward view of the expected supply/demand balance, but use prevailing fuel and carbon prices in their projections of future electricity prices. Hence, the model assumes that investors do not anticipate future increases in carbon prices, a key factor in determining the generation mix produced by the model.

Renewables dominate new build with an additional 29 GW added by 2030, of which 17 GW is onshore wind and 12 GW is offshore wind. New nuclear only comes on-line from 2027 (by which point the carbon price has reached £54/t), with 6.4 GW added by 2030. There is 11.2 GW of new CCGT coming online between 2020 and 2025 in anticipation of IED-related retirements.

[27] It has recently been announced that the CCS demonstration programme would also be open to gas plant. Our assumptions for the CCS demonstration plant pre-date this announcement.

[28] It is likely that the first demonstration plant will be a retrofit to Scottish Power's Longannet plant.

Figure 3 New build – Baseline

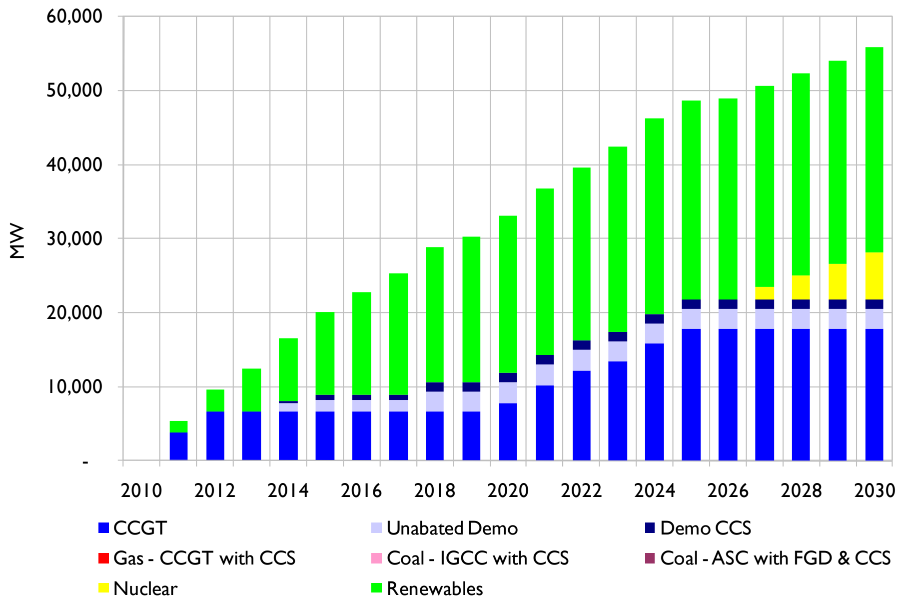


Figure 4 shows cumulative retirements between 2010 and 2030 under the Baseline assumptions, broken down by plant type. During the period between 2010 and 2030, all existing nuclear plant close with the exception of Sizewell B. Around 12 GW of coal and oil plant retire at the end of the LCPD and a further 11 GW of coal and gas plant by 2023 under the terms of the IED. Further retirements of gas and coal plant occur on economic grounds throughout the period. By 2030, most existing coal capacity has closed and that remaining open is co-firing with biomass.

Figure 4 Cumulative plant retirements – Baseline

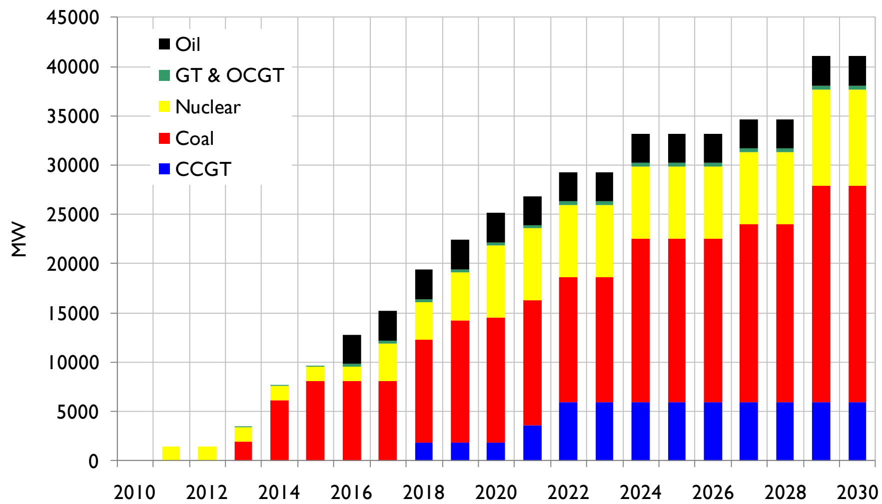


Figure 5 shows total generation capacity broken down by plant type. Gas represents the largest component of the overall capacity mix throughout the period between 2010 and 2030. Coal capacity steadily decreases, being replaced largely by renewables, mainly wind. Nuclear capacity contracts with plant closures and then expands again as new nuclear plant come on-line from 2027. No new CCS capacity is developed before 2030 beyond the CCS demonstration plant.

Figure 5 Capacity mix – Baseline

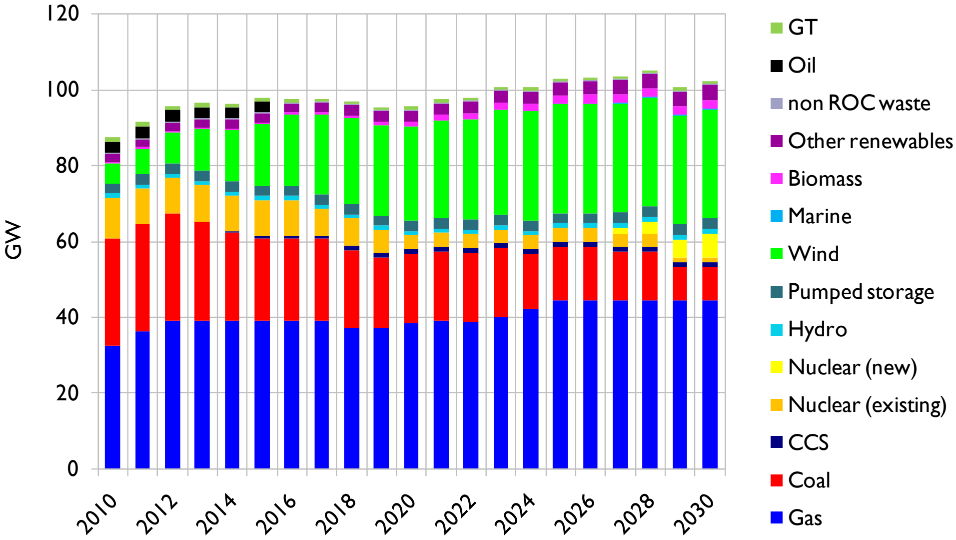


Figure 6 shows total generation broken down by plant type. With gas prices high relative to coal, output from gas plant declines in the near term but then rises again from 2016 as other plant close under the LCPD and IED. Likewise, output from coal plant is initially high, but falls off rapidly in the 2020s in response to a sharply rising carbon price and as a result of plant closures. The output gap left by falling coal plant output is filled by a mixture of output from renewables and new gas generation.

Output from renewables increases steadily, reaching 29% of electricity generated by 2020, and 35% by 2030, achieved by adjusting ROC bands as described above. Wind accounts for the majority of this output. The share of biomass in the total generation mix by 2030 is higher than its share of total capacity as it achieves high load factors relative to wind. This is also the case for nuclear generation, which accounts for a higher proportion of total generation than of total capacity.

Figure 6 Generation mix – Baseline[29]

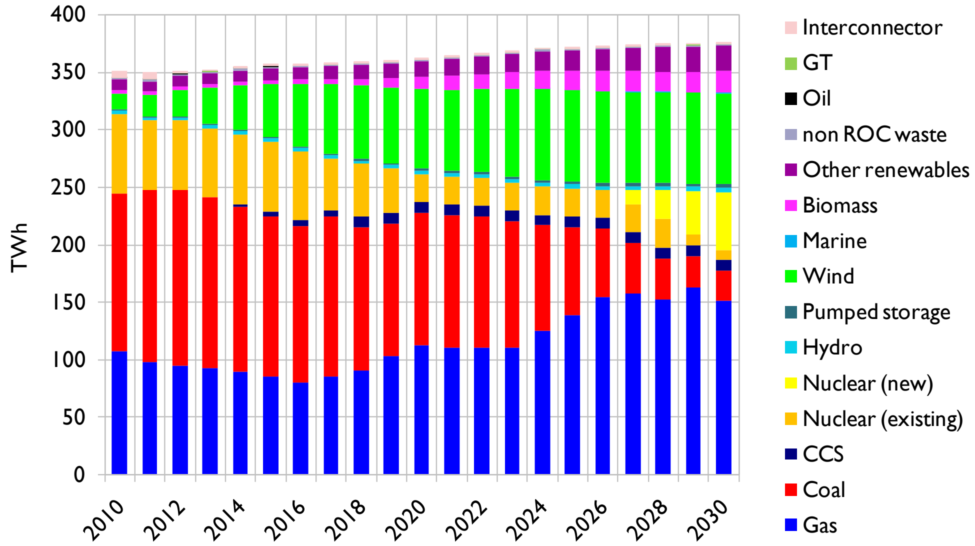
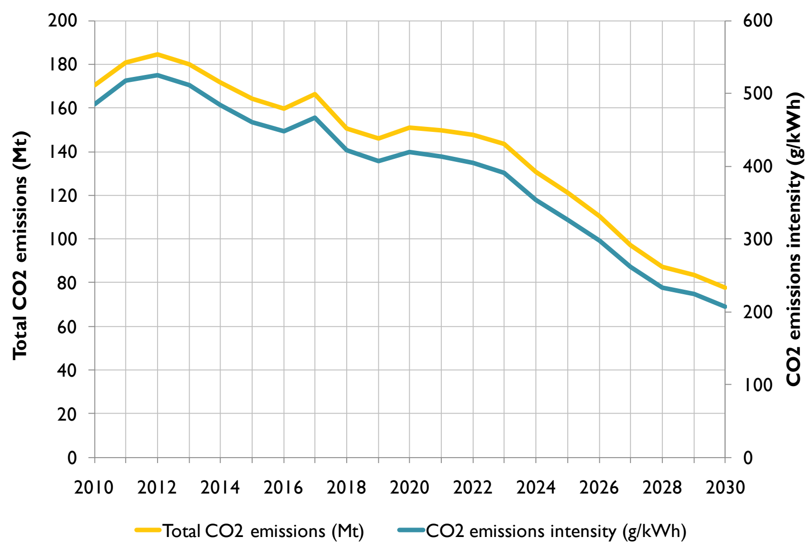


Figure 7 shows total annual carbon dioxide emissions and emissions intensity from the power sector between 2010 and 2030 for the Baseline. Up until 2023, there is a gradual decline in emissions driven by the expansion of renewables and the closures of more highly emitting plant (but offset to a degree by nuclear closures).

After 2024 decarbonisation is more rapid, driven by steeply increasing EUA prices, IED-related closures of coal plant and the continued expansion of renewable generation. By 2030 the emissions intensity under the Base Case is around 200 g/kWh, approximately double our assumed decarbonisation target of 100 g/kWh.

Figure 7 Carbon dioxide emissions intensity – Baseline



[29] Figures for interconnector represent expected net flows.

Figure 8 shows the time-weighted average wholesale price of electricity under the Baseline. It remains relatively steady until 2015 and then rises on the back of tightening capacity margins in the near term and rising fuel and carbon prices thereafter. By 2030, the baseload price is approximately double that in 2010 under DECC's Central assumptions.

Figure 8 Time-weighted average wholesale price of electricity[30] – Baseline

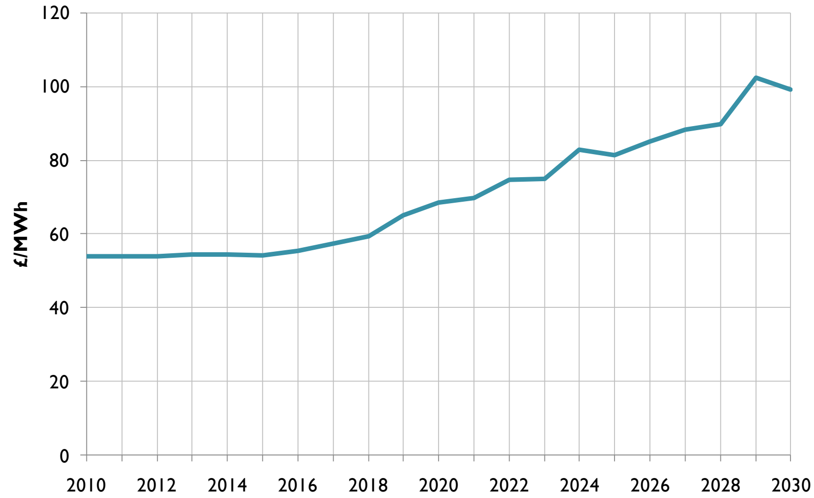


Figure 9 shows the de-rated capacity margins produced by the model under the Baseline assumptions, compared to historical levels. We also show the non-de-rated margin for comparison, which is simply the excess of total capacity on the system as a percentage of peak demand. However, with an increasing proportion of intermittent renewables on the system this becomes an increasingly less reliable indicator of security of supply.

While recognising the large uncertainty associated with trying to predict future de-rated capacity margins, these results provide a useful insight into future risks. The years immediately after 2009 are characterised by a dramatically increasing de-rated capacity margin. This is due to a combination of falling demand as a consequence of the economic downturn, new CCGT plant coming online and continued renewable new build supported by the RO. After 2012, capacity margins fall due to the retirement of plant impacted by the LCPD and IED, together with decommissioning of nuclear plant. After 2018 the de-rated capacity margin falls below 10%, which is lower than the historical average seen between 2002 and 2010.

These lower capacity margins reflect a changing investment climate. Traditionally, investment in CCGTs has been on the back of expectations of baseload running, but due to the increasing proportion of intermittent renewables on the system, CCGTs may only be operating at mid-merit levels. The modelling suggests that if peak prices can rise to the value of lost load (which we assume to be £10,000/MWh on average) when the system is very tight, then in theory CCGT investors could earn a reasonable return operating at lower load factors. However, there is significant uncertainty surrounding this, increasing risk, and investment may lag as a result. Furthermore, as identified by Ofgem under Project Discovery[31], there are reasons to suggest that under current arrangements prices may not rise high enough to reflect the value of lost load, thus increasing the security of supply risk further.

[30] The term 'time-weighted' is used to denote a plain average over all hours of a given year.

[31] See section 3.26 of http://www.ofgem.gov.uk/Markets/WhlMkts/Discovery/Documents1/Project_Discovery_FebConDoc_FINAL.pdf

The de-rated capacity margin includes assumptions on the 'capacity credit' for wind plant, which is a statistical measure of the average contribution of wind to security of supply. The capacity credit declines with the increasing proportion of wind on the system as explained in Appendix E. We assume a combined capacity credit for wind of 27.5% in 2010, 17.5% in 2020 and 16.2% in 2030. We also show the more extreme case on Figure 9 of a 'no wind' margin, which represents the scenario where a period of no wind across the entire country coincides with a period of peak demand. On this basis, margins fall close or even below zero under the Baseline from 2019. Hence, the risk of insufficient supply to meet demand increases towards the end of this decade.

Figure 9 Measures of capacity margin – Baseline

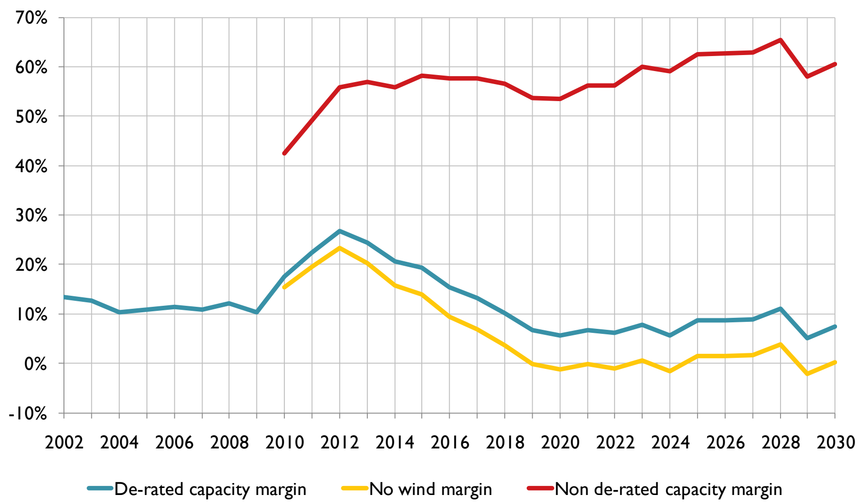


Figure 10 shows the annual expected energy unserved, the average amount of demand that cannot be met under the Baseline, and the probability of at least one 'brown out'[32] within the year. The expected energy unserved is a statistical measure and hence in some years there would be no supply shortfalls, while in other years they could be considerably greater. The risks of unserved energy appear very low over the next few years, but rise after 2016. By 2020, expected energy unserved reaches 5.8 GWh, and the probability of at least one brown out in the year exceeds 20%. This is considerably greater than anything experienced in recent history, and more than that lost annually as a result of outages on the transmission system[33]. However, in the context of outages experienced on the distribution networks, the figure is relatively modest. For example, averaged across the whole system the 5.8 GWh of unserved energy would be equivalent to around 8.7 minutes of lost supply annually for all customers[34]. This compares to an average of approximately 75 customer minutes lost through power distribution failure in the year to April 2009[35].

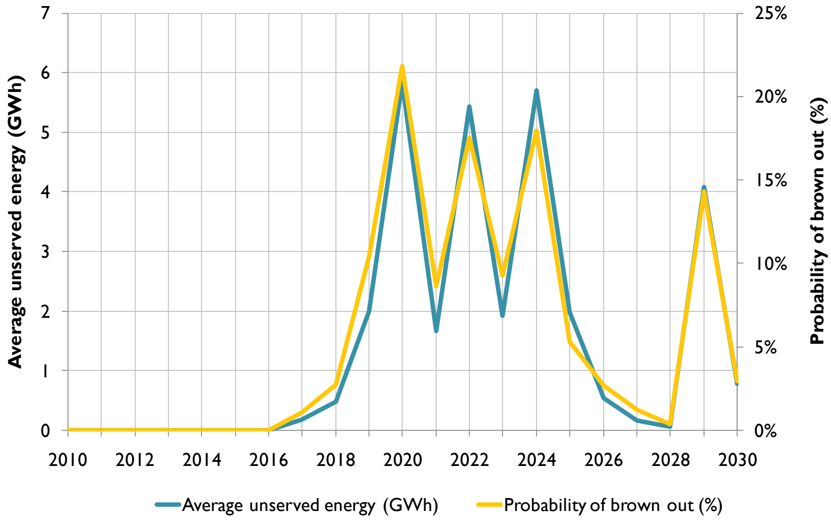
[32] A brown out is defined here as a drop in voltage for some customers but without necessarily a full outage. Short periods (up to 1 hour) of supply shortages can be managed by the System Operator through voltage control.

[33] The average total annual amount of unserved energy due to electricity transmission failure in the five years to 2010 was 613 MWh. The largest single loss of supply in MW terms in 2009-2010 was 154 MW at Kingsnorth 132 kV substation lasting for 11 minutes. (Source: National Grid 2009-2010 National Electricity Transmission System Performance Report).

[34] The minutes lost figure is obtained by multiplying the total number of minutes in a non-leap year by the proportion of total 2010 annual demand under Baseline assumptions accounted for by 5.8 GWh.

[35] Source: Ofgem 2008/09 Electricity Distribution Quality of Service Report (Ref:162/09)

Figure 10 Unserved energy and probability of brown out – Baseline



We have made conservative assumptions under the Baseline with respect to the future expansion of demand side response, only including an estimated 1 GW[36] of existing capacity from large scale industrial and commercial consumers. The roll out of smart and advanced meters to all customers by 2020 could, for example, help mitigate some of these risks by making demand more responsive to price.

[36] Current estimates of demand side response from the I&C sector are taken from Global Insight, May 2005, Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices.

4 Options to promote decarbonisation

4.1 Overview

Analysis of the Baseline suggests that, assuming current constraints in planning, connections and supply chains are resolved, and there are enough good quality project development opportunities available, the RO could provide the financial incentives necessary to deliver a proportion of generation from renewables sources consistent with the 2020 renewables target. However, it also demonstrates that the carbon intensity of the electricity system may be well in excess of what is required to meet overall UK carbon reduction targets, unless greater investment in nuclear and/or CCS occurs. There may also be more cost effective ways of achieving the renewables targets.

While DECC's carbon price assumptions (rising to £70/t by 2030) are 'target consistent', under our modelling, investors make no assumptions about future increases in carbon prices, and low-carbon investment lags as a result. It is also possible that carbon prices turn out lower than DECC's Central assumptions, further jeopardising achievement of the carbon targets.

We have analysed five alternative policy options designed to achieve the following objectives:

- 29% of generation from renewable sources by 2020
- 35% of generation from renewable sources by 2030, and
- carbon intensity from the electricity system of 100 g/kWh by 2030.

These policy options are:

- Carbon Price Support (£50/t)
- Premium Payments for low-carbon generation
- Fixed Payments for low-carbon generation
- Contracts for Difference for low-carbon generation, and
- Strong Emissions Performance Standard.

Each of these policies has been designed through iteration to achieve the objectives outlined above under the commodity prices, carbon prices, demand and technology cost assumptions used in the Baseline. We test the sensitivity of the results to gas and carbon prices.

There are a range of other options that have not been modelled as a part of this study, in particular a Regulated Asset Base (RAB) mechanism for new low-carbon generation. This approach would offer a high degree of certainty to investors, and as such, directionally, could be considered to be similar in impact to the Fixed Payments option modelled here. The main difference would be that under RAB, investors would be allowed a certain level of return on their investment for a fixed period, rather than a certain level of revenue. By lowering the level of risk borne by investors further, this could result in a lower cost of capital. Different designs could nevertheless leave different levels of risk with generators, such as those related to construction costs and timeframe, to ensure that appropriate incentives remained in place.

In Section 5, we assess options to address the risks to security of supply highlighted by the Baseline modelling, and in Section 6 we describe and present the results for a number of combination packages that incorporate one or more of the decarbonisation options described in this section with capacity mechanisms described in the next section.

4.2 Policy options

In this section, we describe each policy option, and in particular the way they have been implemented in our modelling. A key consideration is how each option affects investors' risk and what the impact might be on cost of capital. At this stage it is very difficult to assess what the impact of the EMR policy options could be in this respect. We have made some assumptions, based on simulating earnings risk under the different policy options for different technologies using a methodology set out in Appendix D. We recognise that there is significant uncertainty surrounding these assumptions.

4.2.1 Carbon Price Support (£50/t)

Description

Carbon Price Support places a minimum price on the cost of carbon emitted by generators, thus increasing confidence in low-carbon investment. By underpinning future carbon prices it should better align Government and investor future price expectations.

As set out in HM Treasury's consultation on Carbon Price Support, it would work by requiring generators to pay a tax on the fossil fuels they use for power generation based on the carbon content of each fuel. The levels of tax would be set to target an overall long-term carbon price (EUA price plus carbon price support tax) for generators.

Impact on investment risk

Table 2 summarises the possible impact of Carbon Price Support on the major sources of investment risk for five illustrative technologies – CCGTs, nuclear, CCS, wind and biomass. The different types of risk factors considered, defined as factors posing a potential for downside impact on overall project earnings, are shown in the left-hand column. The main impact is in reducing risk from low electricity prices associated with low-carbon prices. Also there is a reduction in load factor risk for CCS and biomass plant, since there is a lower chance that electricity prices will fall below their short-run generation costs. Technology risks, such as construction and availability risk, are unchanged.

Table 2 Impact of Carbon Price Support on investment risk

	CCGT	Nuclear	CCS	Wind	Biomass
Fuel costs	Risk unchanged	Risk unchanged	Risk unchanged	n/a	Risk unchanged
Carbon costs	Risk unchanged (from high C prices)	n/a	n/a	n/a	n/a
Electricity revenues	Risk reduced (but note spread more important)	Risk reduced	Risk reduced	Risk reduced	Risk reduced
Support levels	n/a	n/a	n/a	Risk unchanged	Risk unchanged
Load factor risk	Risk unchanged	Risk unchanged	Risk reduced	Risk unchanged (but risk only comes with very high penetration)	Risk reduced
Balancing risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Construction costs/times	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Availability/ technology risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
O&M costs	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged

Modelling assumptions

In Appendix D we set out our methodology for estimating the impact of policy options on hurdle rates for different investments. Based on the results of simulating the earnings risk for different types of investment, we make some broad assumptions on the possible increase in gearing that may be achievable for different technologies under Carbon Price Support[37], shown in Table 3 below. In approximate terms we assume that for every percentage reduction in earnings risk, it is possible to increase the debt in the project by one per cent. Such assumptions can only be estimates at this stage, and there are diverging views as to the extent to which Carbon Price Support will be 'bankable', ie whether financial institutions are willing to increase lending to projects on the back of it.

The impact of these gearing changes on the hurdle rates of typical investors, and under the other decarbonisation options, are summarised at the end of this section. Under current arrangements, we typically assume a range of project gearing between 40% and 70% depending on investor type. Hence, for example, a CCS coal plant that might be funded with 40% debt under current arrangements, we assume could be funded with 45% under Carbon Price Support.

[37] It must be recognised, however, that this is yet to be tested in the financial markets since there is no market experience of a Carbon Price Support scheme.

Table 3 Assumptions on possible increase in gearing under Carbon Price Support[38]

	Assumed increased in gearing
CCGT	0%
CCGT + CCS	7.5%
Coal + CCS	5%
Nuclear	5%
Onshore wind	0%
Offshore wind	0%
Biomass	2.5%
OCGT	0%

Overall, the impact of Carbon Price Support on earnings risk appears to be relatively small, but not insignificant. For CCGTs the effect seems to be negligible given the high correlation between electricity prices and gas-fired generation costs. Hence, we assume no impact on possible gearing.

For nuclear and CCS plant there appears to be a small benefit. The benefit may be greater for gas plant fitted with CCS rather than coal since, given their relatively higher fuel costs, which puts them lower than coal CCS plant in the merit order, they benefit more from the reduction in load factor risk. We assume that the benefit for wind (and other non-dispatchable renewables) is small since electricity prices make up a relatively low proportion of overall revenues. However, biomass plant would benefit from reduced load factor risk under Carbon Price Support.

Consistent with HM Treasury's consultation document, we assume that the Carbon Price Support policy would be introduced in 2013 at a level that escalates on an annual basis with visibility to at least 2020. How much certainty investors place on the future Carbon Price Support level is critical to its effectiveness as a policy for driving low-carbon investment. There is a possibility that investors would discount stated future price levels on the basis that these could be changed as a result of future Government decisions. For the purposes of our modelling, we assume that investors have certainty in the Carbon Price Support level for a five year period, but do not assume any increase beyond that. (We have also modelled a sensitivity where investors believe that the Carbon Price Support falls away completely after five years.)

Based on this assumption, and using Baseline fuel and technology cost assumptions, we found through iteration that the Carbon Price Support level would need to rise to £50/t by 2020 and £70/t by 2030 in order to achieve a carbon intensity in our modelling of 100 g/kWh by 2030. (The level of £50/t in 2020 is higher than the range of scenarios presented in HM Treasury's carbon price support consultation). In parallel, we were able to reduce bands under the RO and still maintain the target objectives of 29% and 35% of generation from renewables sources by 2020 and 2030 respectively[39]. In other words, the

[38] Note that figures in Table 3 indicate percentage point changes to gearing.

[39] Note that this modelling assumption differs from that used in HM Treasury's consultation on carbon price support. In the carbon price support consultation, the levels of Renewable Obligation banding are left unchanged from the Baseline for each of the carbon price support scenarios considered in order to isolate the effect of having different levels of carbon price support with all other factors unchanged.

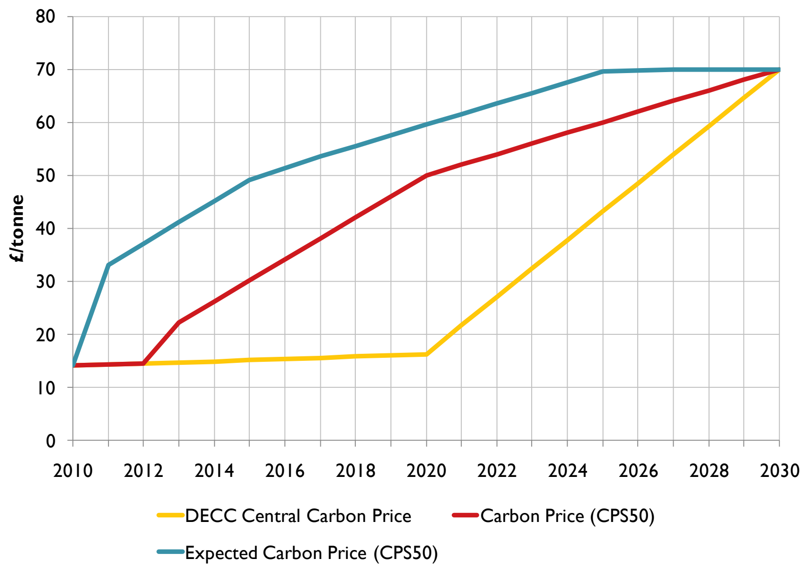
reduction in carbon intensity relative to the Baseline is the result of more nuclear and CCS investment rather than greater renewables investment (as is the case for all the policy options under consideration).

Figure 11 illustrates DECC's Central EUA carbon price assumption (in blue), the assumed Carbon Price Support (£50/t) level (in orange), and investors' expectation in a given year of the average carbon price across the lifetime of their investments (in green). Note that we assume investors start factoring in Carbon Price Support into their decisions from 2011 – the date at which the Government has said it would introduce potential legislation.

In the Baseline, the investors' view of the carbon price over the economic life of the investment is simply the prevailing EUA price in the year they make the investment decision. For example, in 2010 the investors' expectation of the carbon price is £14.1/t throughout the life of the investment, despite the fact that carbon prices reach £70/t by 2030 under DECC's Central assumptions. Under Carbon Price Support (£50/t) we assume that investors have greater confidence in the future carbon price as a result of the floor but that they take a cautious view with respect to how the floor increases in the future. The average expectation of carbon price over the lifetime of an investment is calculated based on these assumptions:

- Because the carbon price support level is rising from 2012 to 2030, investors' expectations of future carbon pries will always be greater than the current carbon price in that year.
- Investors form expectations on the basis of an investment that has a construction period of three years and an economic life of thirty years. A single expected carbon price figure is calculated for every year to be consistent with the levelised cost approach adopted in the model.

Figure 11 Carbon Price Support (£50/t)



Under Carbon Price Support (£50/t), we assume that the four CCS demonstration plant are still funded separately, but that an extension of this support to cover retrofits is not required.

We also include within this policy option a Targeted Emissions Performance Standard to be applied to all new plant as explained below.

4.2.2 Premium Payments

Description

The objective of Premium Payments is to accelerate investment in low-carbon generation by providing additional revenues to low-carbon generators on top of those received by selling electricity into the wholesale market. The Premium Payments are designed to cover the additional costs of low-carbon generation relative to cheaper fossil fuel alternatives, including the higher perceived investment risk.

There are two main approaches by which Premium Payments could be implemented for low-carbon generation:

- administered premium tariffs paid directly to generators, set by government by technology, or
- through competitive tenders, where investors in different technology classes bid for the premia they require above expected future electricity prices.

A possible variant on the Premium Payments option would be to introduce a 'low-carbon obligation', either alongside the existing RO or as an extension of it. A volume-based obligation on suppliers is not strictly a Premium Payments mechanism. However, the design of the RO with an option to pay a buy-out price, a guaranteed headroom that provides a relatively stable price for ROCs, and differentiated bands by technology means that from a generator's perspective it closely resembles a Premium Payments scheme.

The premia could be paid based on output, as is the case under the RO, or could be paid based on availability. As discussed below, the choice here has implications for how low-carbon generation is dispatched and the potential impact on the electricity market.

The costs of Premium Payments would be paid for by consumers through some form of consumer levy (or through an obligation on suppliers).

Impact on investment risk

Table 4 summarises the possible impact of Premium Payments on the major sources of investment risk for low-carbon generation. For wind and biomass, we show investment risks as unchanged on the basis that these technologies already receive support via the RO. Depending on the design of the Premium Payments, risks surrounding support levels may reduce, for example if the uncertainty surrounding ROC prices was removed by implementing fixed premia.

Nuclear and CCS[40] would benefit from receiving new support, reducing the overall investment risk. Load factor risk, particularly for CCS plant, would also be reduced.

[40] Aside from the demonstration plant which may already be receiving other forms of support.

Table 4 Impact of Premium Payments on investment risk

	CCGT	Nuclear	CCS	Wind	Biomass
Fuel costs	Risk unchanged	Risk unchanged	Risk unchanged	n/a	Risk unchanged
Carbon costs	Risk unchanged	n/a	n/a	n/a	n/a
Electricity revenues	Risk unchanged (but note reduction in expected price)	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Support levels	n/a	New support	New support	Risk unchanged	Risk unchanged
Load factor risk	Risk unchanged	Risk reduced	Risk reduced	Risk unchanged	Risk unchanged
Balancing risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Construction costs/times	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Availability/ technology risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
O&M costs	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged

Modelling assumptions

Based on the results of simulating the earnings risk for different types of investment, we make some assumptions on the possible increase in gearing that may be achievable for different technologies under Premium Payments.

These assumptions are shown in Table 5 below.

Table 5 Assumptions on the possible increase in gearing under Premium Payments

	Assumed increased in gearing
CCGT	0%
CCGT + CCS	10%
Coal + CCS	15%
Nuclear	10%
Onshore wind	0%
Offshore wind	0%
Biomass	0%
OCGT	0%

CCGTs and OCGTs would not qualify for Premium Payments and hence we assume no change in the investment hurdle rate, although it should be noted that investment in CCGTs could become riskier where other technologies are receiving premium support. We also assume no impact on renewables since they are already receiving an equivalent to premium payments through the RO.

For nuclear and CCS plant, the modelling suggests that earnings risk would be reduced under Premium Payments (depending on level) and we assume that an increase in gearing / reduction in hurdle rate is possible as a result[41].

For the purposes of modelling we assume that the Premium Payments policy is based on administered tariffs set by Government, and that the objective is to promote a diverse range of low-carbon generation by setting premia at different levels that bridge the 'funding gap' for different technologies. Tariffs would typically be set every three years[42] and plant would receive the greater of the tariff when construction of the plant begins or when it first becomes operational. This would be held constant in real terms over the economic life[43] of the plant.

Based on DECC guidance we assume that the Premium Payments policy is implemented in 2014 with two years' notice. Renewables plant commissioned on or after 2014 would fall under the new Premium Payments scheme. Plant that are commissioned before 2014 would fall under the RO. From 2014 onwards, plant falling under the RO would receive grandfathered payments set at the prevailing buy-out price plus 10% to cover headroom, multiplied by the respective ROC band level. Given that an investment hiatus is a significant risk with any major change in policy, it may be beneficial to offer plant that enter construction before 2014 but become operational on or after 2014, the choice of whether to take the grandfathered RO or new Premium Payments.

We assume that the support associated with the four CCS demonstration plant is incorporated within the Premium Payments mechanism, and that premia are available to support retrofits.

We initially estimated the required premia for different technologies by subtracting their LRMCs from the LRMCs of a CCGT and rounding to the nearest £5/MWh. We then iterated the premia until we achieved modelled build levels consistent with the objectives of hitting 29% and 35% generation from renewables in 2020 and 2030 respectively and a carbon intensity of 100 g/kWh by 2030 under DECC's Central price assumptions. The mix of low-carbon generation that results is strongly influenced by the premia assumed for each technology. The methodology adopted, which sets premia at a level necessary to cover the LRMCs of each technology, leads to a diverse mix of low-carbon investment. However, in practice, investment patterns will clearly be dependent on the levels at which premia are set relative to the (uncertain) costs of different technologies.

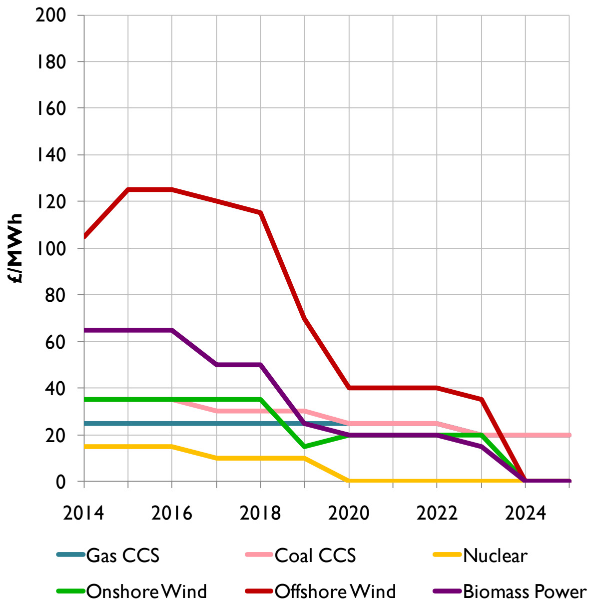
Figure 12 shows the level of Premium Payments assumed for different technologies (in 2009 real terms). These are available to plant that begin construction by these dates. In general, the premia fall over time as learning rates cause costs to fall, and because the rate of renewables deployment could potentially be slowed after 2020 assuming that the 2020 target has been met. Offshore wind is an exception, as premia increase in the near term to incentivise Round 3 development, which we assume to be more expensive than Rounds 1 and 2. Under DECC's Central assumptions, nuclear plant not already under construction would require no Premium Payments from 2020 onwards in order to make it economic to invest.

[41] The benefit appears to be greater for coal plant fitted with CCS rather than gas plant fitted with CCS which is because the premia have a greater effect in diversifying earnings risk given the high correlation between gas and electricity prices assumed.

[42] In order to achieve the target levels of renewables generation in 2020 and 2030 in the model we have had to relax this rule in some instances.

[43] See Appendix C for assumptions on economic lives of different technologies.

Figure 12 Assumed levels of Premium Payments by technology – Options to promote decarbonisation



For the sensitivity modelling, we hold the levels of Premium Payments constant under different gas and carbon prices, in order to illustrate the risks to deployment, or conversely the risk of higher economic rents for low-carbon generators associated with the need to set payment levels against uncertain future outcomes. (In practice, there would be some scope for Government to adjust Premium Payments if gas and carbon prices evolved differently.)

For the purposes of the modelling, we have assumed that Premium Payments are paid based on availability rather than output (unlike the current RO). We have made this assumption since under the high levels of low-carbon generation assumed by 2030, there is a significant risk of distortions to electricity prices from generators making dispatch decisions based on subtracting their Premium Payments from their underlying short-run marginal costs (SRMCs) (ie, treating the Premium Payments as a negative opportunity cost) in order to keep generating. The resulting suppression of electricity prices could undermine investment in both low-carbon and other forms of generation, with risks to security of supply.

We also include within this policy option a Targeted Emissions Performance Standard to be applied to all new plant as explained below.

4.2.3 Fixed Payments

Description

Fixed Payments, or feed-in tariffs, are payments made to low-carbon generators for their output. These payments are an alternative to selling electricity in the market and would involve a long-term contract between the generator and a central buying agency. This agency would be responsible for selling the aggregated physical output into the market.

Broadly there are two alternative methods for setting the levels of Fixed Payments:

- administered tariffs set by government according to technology, or

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- competitive tenders organised by technology class where investors bid for the level of payment they require.

For low-carbon plant with low (and stable) short-run generation costs, such as most types of renewables and nuclear, the Fixed Payments are simply a price paid for the output of the plant and would be expected to be close to the LRMC of the plant. Because of their low short-run costs, these plant would expect to run when they are available. However, there may be occasions when it is necessary to reduce the output from these plant due to an excess of generation relative to demand at a national level (which could occur with high levels of low-carbon generation on the system) or because of locational transmission constraints. On these occasions, the plant may be compensated for lost revenues. This would effectively mean that plant receive Fixed Payments based on their availability rather than output.

For plant with higher and varying short-run costs such as CCS plant and biomass, the Fixed Payments would need to take a different form, incorporating a utilisation element and an availability element. The utilisation element would be designed to cover the SRMC of the plant and would be paid when the plant operates (ie, when the electricity price is higher than the SRMC of the plant). This could be achieved through a contract price indexed to a basket of fuel and carbon prices[44], taking into account plant efficiency and operating costs. (This component of the payment would clearly then vary with fuel prices, and the term Fixed Payments would be something of a misnomer in this respect.) The availability element would be designed to cover the fixed and capital costs of the plant, and paid regardless of whether the plant operates, as long as it is technically available to do so. The combination of utilisation and availability elements would yield a stable earnings stream for the generator.

There are a number of detailed implementation issues in setting administered tariffs or organising competitive tenders which are discussed in further detail below.

The costs of the Fixed Payments less the revenues earned by the central buying agency from selling electricity would be paid for by (or rebated to) consumers.

Impact on investment risk

Table 6 summarises the possible impact of Fixed Payments on the major sources of investment risk for low-carbon generation. By removing low-carbon generation from the market, electricity revenue risk is removed, and by providing long-term contracts, the political and regulatory risk to future changes to the support level is also very low. Fuel cost risk should also be reduced for CCS and biomass generators where utilisation fees closely match their underlying costs. The other benefit to generators from Fixed Payments is the removal of balancing risk, which is dealt with by the central buying agency[45].

[44] The exact indexation terms will determine how the generator chooses to hedge its fuel risk. If the index is against spot fuel and carbon prices then the generator is incentivised to buy fuel and carbon in the spot markets or sign physical agreements indexed against spot prices. Alternatively, if the indexation terms relate to forward prices then the generator can manage its risk best by buying fuel in the same forward markets.

[45] Note the terms of the Fixed Payments contracts may include incentives on the generator around availability and forecasting accuracy.

Table 6 Impact of Fixed Payments on investment risk

	CCGT	Nuclear	CCS	Wind	Biomass
Fuel costs	Risk unchanged	Risk unchanged	Risk reduced	n/a	Risk reduced
Carbon costs	Risk unchanged	n/a	n/a	n/a	n/a
Electricity revenues	Risk unchanged	Risk removed	Risk removed	Risk removed	Risk removed
Support levels	n/a	New support (no risk)	New support (no risk)	Risk removed	Risk removed
Load factor risk	Risk unchanged	Risk removed	Risk removed	Risk unchanged	Risk unchanged
Balancing risk	Risk unchanged	Risk removed	Risk removed	Risk removed	Risk removed
Construction costs/times	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Availability/ technology risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
O&M costs	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged

Modelling assumptions

Based on the results of simulating the earnings risk for different types of investment, we make some assumptions on the possible increase in gearing that may be achievable for different technologies under Fixed Payments.

These assumptions are shown in Table 7 below.

Table 7 Assumptions on the possible increase in gearing under Fixed Payments

	Assumed increased in gearing
CCGT	0%
CCGT + CCS	15%
Coal + CCS	25%
Nuclear	25%
Onshore wind	25%
Offshore wind	25%
Biomass	25%
OCGT	0%

Based on a large reduction in earnings risk, we assume that it may be possible to increase typical project gearing quite significantly under Fixed Payments (reducing hurdle rates by up to 2% in some cases), although we recognise that the benefits may be less for integrated players who are able to offset wholesale electricity market risk against their retail businesses. The relative benefits of Fixed Payments may be somewhat lower for CCGT plant fitted with CCS than other low-carbon plant, since these already benefit from high correlations between gas and electricity prices.

As with Premium Payments, we have modelled the Fixed Payments policy based on administered tariffs set by Government rather than through tenders[46]. We also assume that tariffs are set at a technology specific level such that a diverse range of low-carbon investment is incentivised. Tariffs would typically be set every three years[47] and plant would receive the greater of the tariff when construction of the plant begins or when it first becomes operational. This would be held constant in real terms over the economic life of the plant[48].

As with the Premium Payments policy, we assume that Fixed Payments are implemented in 2014 with two years' notice. The same rules for renewables plant with respect to eligibility for the RO and Fixed Payments, and the associated grandfathering arrangements, would apply. We also assume that the support for the CCS demonstration plant is incorporated within the Fixed Payments regime.

We initially estimated the required level of payment for different technologies from the LRMC of each technology (recognising the possible impact of the policy on hurdle rates) and rounding to the nearest £5/MWh. For technologies with non-zero fuel costs, payments were split between utilisation payments to cover the SRMC of the plant and availability payments to cover fixed and capital costs. As with Premium Payments, we then iterated the payment levels to be consistent with the objectives of hitting 29% and 35% generation from renewables in 2020 and 2030 respectively and a carbon intensity of 100 g/kWh by 2030 under DECC's Central price assumptions. Again, the methodology yields a diverse range of low-carbon generation by 2030. The resulting mix is less susceptible to incorrect assumptions regarding future fuel and carbon prices, but the same caveats apply as for Premium Payments with respect to incorrectly forecasting technology costs.

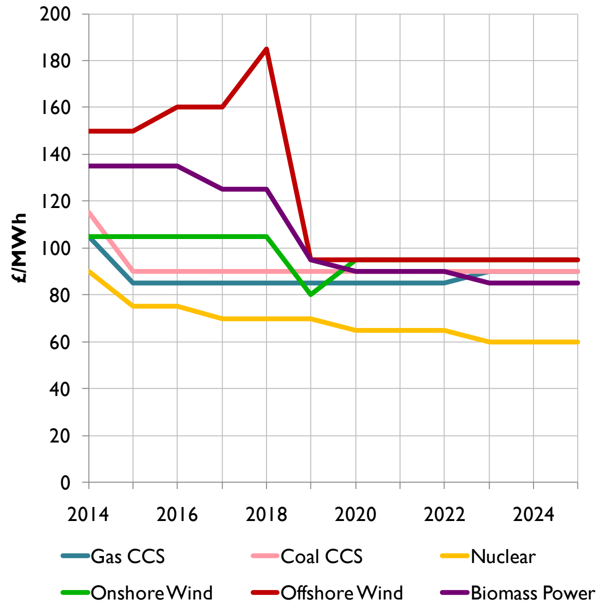
Figure 13 shows the level of Fixed Payments assumed for different technologies. As with Premium Payments, the levels tend to fall over time. The large drop in the offshore wind payment level follows the achievement of the 29% renewables generation target in 2020, after which the rate of renewables deployment can slow in order to achieve 35% renewables generation by 2030.

[46] Assuming that tariffs are set to deliver a specific volume of different technologies, the economic modelling of these two options would look similar. Where they differ is in how price levels are set and how the new capacity is delivered.

[47] In order to achieve the target levels of renewables generation in 2020 and 2030 in the model we have had to relax this rule in some instances.

[48] See Appendix C for assumptions on economic lives of different technologies.

Figure 13 Assumed levels of Fixed Payments – Options to promote decarbonisation



As for Premium Payments, we assume that Fixed Payments are paid based on availability rather than output. In other words, Fixed Payments provide a firm offtake agreement with compensation for being constrained off. Hence the central buying agency (in tandem with the System Operator where these are different entities) has the option to reduce output from certain plant if the system becomes long overall or there are local transmission constraints.

We also include within this policy option a Targeted Emissions Performance Standard to be applied to all new plant as explained below.

4.2.4 Contracts for Difference

Description

The principle behind Contracts for Difference is similar to Fixed Payments, in that it is a scheme for providing a stable earnings stream for low-carbon generation. The key difference is that generators retain responsibility for selling their physical output into the market.

Under Contracts for Difference, the generator swaps an electricity index price for a fixed strike price and receives an additional Premium Payments depending on the technology type. The combination of the two would be designed to cover the LRMCs of the plant, and provided the generator is able to sell its output close to the electricity index price in the market it should receive a stable earnings stream. Rather than trading in the short-term markets, one possible strategy would be to align indexation terms in physical power offtake agreements with the terms of the Contract for Difference[49].

[49] Output from renewables plant is currently typically sold under long-term power purchase agreements with prices linked to various power price indices, subject to a floor.

As with Fixed Payments, the design of the Contracts for Difference would be different for technologies with low and stable short-run costs (such as most renewables and nuclear), compared to technologies with fuel input costs such as CCS and biomass.

For the former, the Contracts for Difference would be 'two-way'. If the electricity index price were to be above the strike price, the generator would pay the difference to a central agency, and if it were below it would receive the difference. For many types of low-carbon generation, for example wind, output levels vary considerably and hence the CfD would need to be structured to recognise this volume variability. How this is done has implications for the level of risk retained by the generator. If the CfD was settled at a half-hourly level based on a within-day price index against the actual output from the generator, its risk would be low provided it could trade its output close to the within-day index. It would, however, retain some short-term balancing risk. The downside with this approach (also a risk with Fixed Payments) is that it provides little differential incentive for the generator to ensure that its plant is available when prices are higher, to forecast accurately (other than to minimise short-term balancing risk), or to site plant away from locations where there is already a high concentration of similar plant[50]. In order to maintain these incentives, an alternative approach would be to settle the CfD based (for example) on a monthly averaged price and monthly averaged output.

The indexation terms and strike for the two-way CfD would most likely be set directly by Government. The additional premia by technology could either be set:

- via administered premium tariffs set by Government according to technology, or
- by holding a competitive tender where investors in different technology classes bid for the premia they require above the CfD strike price.

Conceptually this is the same as setting Fixed Payments, since the sum of the CfD strike and premia would also yield an essentially fixed revenue stream. However, it does require Government implicitly to take a long-term view of the electricity price when setting the CfD strike which may present some challenges.

The Contracts for Difference concept is more complex for plant that have significant fuel input costs such as CCS and biomass. Because the input costs vary (based on fuel and carbon prices), a two-way CfD against the electricity price does not stabilise earnings in the same way as for nuclear and most renewables. Also it is possible that electricity prices may fall below short-run costs on occasions and the plant would choose not to run.

In this case the CfD concept becomes more like a tolling agreement – the central agency pays the generator a tolling fee for use of the plant. Effectively the generator is swapping the infra-marginal spread (the difference between the electricity price and its SRMC) for a fixed tolling fee. In terms of financial instruments this is equivalent to the generator selling a one-way CfD on the spread between the electricity price and its short-run costs (defined by some form of indexation formula) and receiving a premium in return. If the spread is positive (and the plant runs) the generator pays out the difference between the electricity price and the fuel indexation formula. Hence, to minimise its risk the generator is incentivised to sell its power and buy its fuel / carbon close to the respective indices. The premium that it receives would be designed to cover the fixed and capital costs of the plant, and is equivalent to the concept of the availability fee under Fixed Payments.

As under the two-way CfD, these premia would differ by technology and could be set by Government or established via a competitive tender.

[50] Due to the correlated nature of wind output there is likely to be an increasing relationship between windy periods and low prices. There is a benefit to the system of having a more geographically dispersed generation mix to smooth the variability in wind output. There should also be a benefit to the generator since it should be able to 'capture' a better price for its output under the current market arrangements.

The net difference payments on the CfDs and the costs of the premia would be collected by the central agency and levied (or rebated) to consumers via suppliers.

Impact on investment risk

Table 8 summarises the possible impact of Contracts for Difference on the major sources of investment risk for low-carbon generation. Electricity revenue risk is significantly reduced, but not completely eliminated unlike under Fixed Payments, since generators are still exposed to 'basis' risk, the difference between the index price against which the contract is settled and the price at which they sell their electricity. Support level risk is very low since the Contracts for Difference approach is based around long-term contracts.

Fuel price risk is significantly reduced for CCS and biomass generators since their CfDs are settled on the spread between an electricity price and fuel price index. Load factor risk for nuclear, and particularly CCS plant, would also be reduced if these plant receive their premia based on availability.

Table 8 Impact of Contracts for Difference on investment risk

	CCGT	Nuclear	CCS	Wind	Biomass
Fuel costs	Risk unchanged	Risk unchanged	Risk reduced	n/a	Risk reduced
Carbon costs	Risk unchanged	n/a	n/a	n/a	n/a
Electricity revenues	Risk unchanged (but note reduction in expected price)	Risk reduced	Risk reduced	Risk reduced	Risk reduced
Support levels	n/a	New support (no risk)	New support (no risk)	Risk removed	Risk removed
Load factor risk	Risk unchanged	Risk reduced	Risk reduced	Risk unchanged	Risk unchanged
Balancing risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Construction costs/times	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Availability/ technology risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
O&M costs	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged

Modelling assumptions

Based on the results of simulating the earnings risk for different types of investment, we make some assumptions on the possible increase in gearing that may be achievable for different technologies under Fixed Payments.

These assumptions are shown in Table 9 below.

Table 9 Assumptions on the possible increase in gearing under Contracts for Difference

	Assumed increased in gearing
CCGT	0%
CCGT + CCS	10%
Coal + CCS	20%
Nuclear	25%
Onshore wind	15%
Offshore wind	15%
Biomass	20%
OCGT	0%

In general, we assume that the increase in gearing possible is somewhat less than under Fixed Payments since generators are still exposed to certain risks from selling their output. Intermittent renewables such as wind also retain balancing risk which is not the case under Fixed Payments.

We have made a similar set of assumptions for Contracts for Difference as for Fixed Payments, namely:

- contract strike prices and technology premia are set by Government and contracts cover the economic lifetime of the plant,
- a diverse range of technologies is incentivised by providing technology-differentiated premia that bridge the different funding gaps,
- the policy is implemented in 2014 with two years' notice, and
- the combined contract strike prices and technology premia are set based on the LRMCs of the different technologies rounded to the nearest £5/MWh.

We have also assumed the same arrangements for grandfathering the RO, and that the support for CCS demonstration plant would be incorporated within the Contracts for Difference regime.

Figure 14 shows the level of Contracts for Difference assumed for different technologies. We have not separated explicitly the CfD strike price from the technology premia in this illustration since for the purposes of investment modelling it is the combined level that is important. The combined payments follow similar paths as under Fixed Payments.

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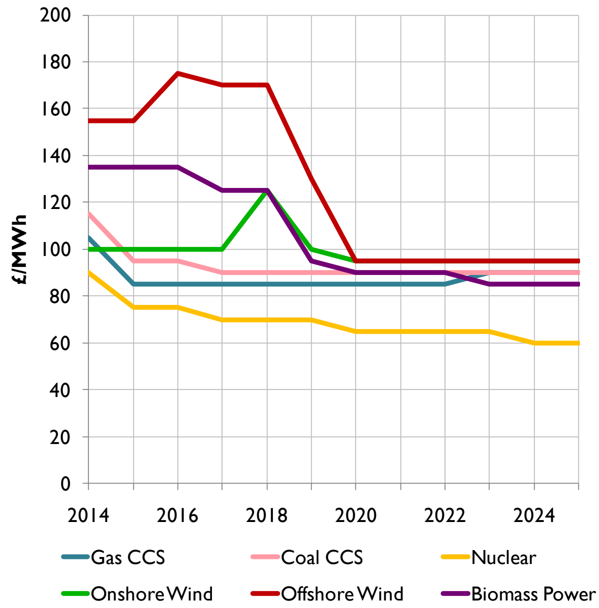
Figure 14 **Assumed levels of Contracts for Difference including technology premia – Options to promote decarbonisation**



For the one-way CfDs for generators with non-zero SRMCs such as CCS and biomass, we have modelled them such that generators only receive the low-carbon premia when the spread between fuel costs and electricity prices is positive, although it could equally well be paid on availability. The way we have modelled it leaves load factor risk with the generator requiring slightly higher premia to attract investment, but the payments are made less often. From the modelling perspective there would be little difference between the options, although this is an important design consideration.

We also include within this policy option a Targeted Emissions Performance Standard to be applied to all new plant as explained below.

4.2.5 Strong Emissions Performance Standard

Description

An Emissions Performance Standard (EPS) would place limits on the amounts of carbon dioxide that could be emitted from generating plant. Its objective would be to discourage investment in high carbon generating plant, and thus incentivise investment in low-carbon technologies.

There are a number of different ways that an EPS could be implemented:

- on a rate basis (a limit of emissions per MWh generated), or as an annual ‘bubble’ (a limit on emissions within a year),
- on new plant only, or on all plant,
- on specific plant types, eg coal, or on all plant types, and
- at the individual plant level or on a generator’s portfolio.

These design choices have important implications for the types of investment that are possible, the timing of CCS retrofit decisions, how plant on the system operate, and the speed with which existing plant on the system retire. For example, a rate-based limit on new plant may prevent investment in unabated coal plant but allow investment in CCGTs. A rate-based limit applied to existing plant may force closures of coal plant, whereas, under an annual 'bubble' limit these plant may be able to stay open longer but operate at progressively lower load factors.

Impact on investment risk

The introduction of an EPS does not directly impact the investment risk for low-carbon technologies since these plant are still exposed to uncertain future electricity prices. However, by restricting output from highly emitting generators this is likely to push up the expectation of future electricity prices, hence improving expected returns for low-carbon plant.

Conversely, for highly emitting plant, the EPS may make investment untenable. For CCGTs[51], the impact on investment risk is complex. On the one hand, these plant may benefit where coal plant are squeezed out of the merit order, while on the other hand, they themselves may become affected by a progressively tightening limit.

Modelling assumptions

Under all policy options we assume that there is a Targeted Emissions Performance standard on new plant as a minimum. This would be an annual limit equivalent to 600 g/kWh operating at baseload. At this level it would prevent new unabated coal investment, and require demonstration plant to have at least 25% of their capacity fitted with CCS. CCS units would have to run in order for the plant to be able to operate at baseload.

Set at this level, the EPS would not be sufficient alone to drive the low-carbon investment required to achieve a carbon intensity of 100 g/kWh by 2030. The Strong EPS policy option would therefore need to consider capturing all plant (new and existing) and be set at a much tighter level. Our assumptions were derived through iteration in the model.

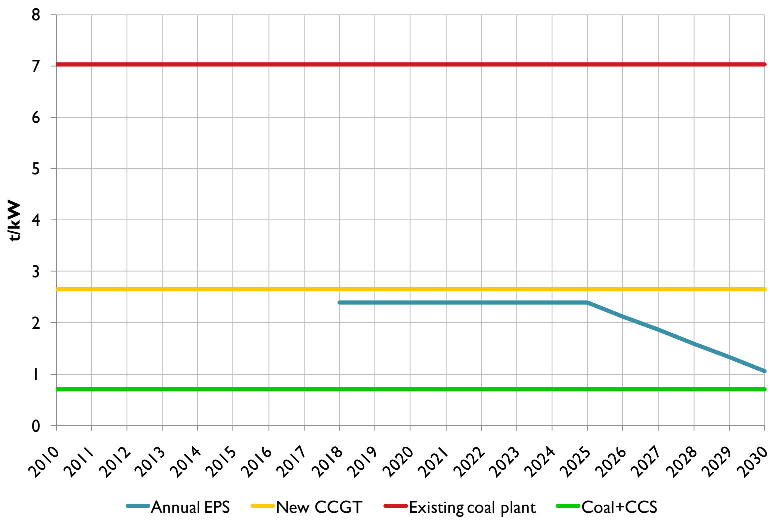
We assume that the annual EPS limit for all plant is first introduced in 2018 at 2.39 t/kW. This is equivalent to 275 g/kWh operating at baseload, ie significantly tighter than the Targeted EPS included in the other policy options. At this level it would restrict the annual load factors of CCGTs to around 75% and existing coal plant to around 30%[52].

The limit is progressively tightened after 2025 such that by 2030 only fossil plant fully fitted with CCS could operate at baseload. This is illustrated in Figure 15 below.

[51] The typical emissions from a new CCGT are approximately 350 g/kWh.

[52] Note that it may be necessary to exempt the unabated portions of the CCS demo projects from the EPS in order to attract the participation required.

Figure 15 Modelling annual EPS relative to emissions intensity of different plant types – Options to promote decarbonisation



As the modelling results below show, the impact of this Strong EPS is to drive up electricity prices, improving the economics of low-carbon investment, while deterring investment in fossil fuel plant. Due to the higher electricity prices, we assume that bands under the RO can be reduced while still achieving the targets of 29% and 35% of generation from renewable sources in 2020 and 2030. We assume that the CCS demonstration projects would still be funded separately, but that the tighter EPS would be sufficient to incentivise these plant fully to retrofit with CCS after 2025.

For the purposes of the modelling, we assume that there is no change in gearing / hurdle rates for low-carbon investment associated with the Strong EPS policy.

4.3 Summary of policy impact on hurdle rates

We described above our assumptions for the increase in gearing that might be possible under each of the decarbonisation options. Table 10 summarises the resultant hurdle rates (post-tax nominal) for typical investors in different technologies relative to the Baseline. Further details of how hurdle rates are calculated in the analysis are provided in Appendix D.

The table shows assumed typical rates for a utility, independent developer and a developer of nuclear plant. The hurdle rates illustrated are based on the maturity of each technology in 2010. These maturities are assumed to evolve over time, with corresponding changes in hurdle rates, as shown in Appendix D.

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Table 10 Summary of hurdle rate assumptions under different decarbonisation options

	Tech maturity (2010)	Baseline	CPS50	EPS	PP	FP	CfD
Carbon Price Support (£50/t)		No	Yes	No	No	No	No
Emissions Performance Standard		No	Targeted	Strong	Targeted	Targeted	Targeted
Capacity payments		No	No	No	No	No	No
Low-carbon support		RO	RO	RO	Prem	Fixed	CfD
Hurdle rates (typical utility)							
CCGT	Mature	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
CCGT+CCS	Emerging	12.1%	11.7%	12.1%	11.6%	11.5%	11.6%
Coal+CCS	Emerging	12.1%	11.8%	12.1%	11.5%	11.4%	11.4%
Onshore wind	Mature	8.1%	8.1%	8.1%	8.1%	7.8%	7.8%
Offshore wind (R1/R2)	Established	10.1%	10.1%	10.1%	10.1%	9.6%	9.6%
Offshore (R3)	Emerging	12.1%	12.1%	12.1%	12.1%	11.4%	11.5%
Biomass	Emerging	12.1%	11.9%	12.1%	12.1%	11.4%	11.4%
OCGT	Mature	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
Hurdle rates (independent developer)							
CCGT	Mature	9.1%	9.1%	9.1%	9.1%	9.1%	9.1%
CCGT+CCS	Emerging	13.3%	12.5%	13.3%	12.5%	12.5%	12.5%
Coal+CCS	Emerging	13.3%	12.5%	13.3%	12.5%	12.5%	12.5%
Onshore wind	Mature	9.1%	9.1%	9.1%	9.1%	7.8%	8.1%
Offshore wind (R1/R2)	Established	11.2%	11.2%	11.2%	11.2%	10.0%	10.0%
Offshore (R3)	Emerging	13.3%	13.3%	13.3%	13.3%	12.5%	12.5%
Biomass	Emerging	13.3%	12.9%	13.3%	13.3%	12.5%	12.5%
OCGT	Mature	9.1%	9.1%	9.1%	9.1%	9.1%	9.1%
Hurdle rates (nuclear developer)							
Nuclear	Emerging	13.2%	12.7%	13.2%	12.2%	11.2%	11.2%

The greatest reductions in hurdle rates occur under Fixed Payments since this policy option has the greatest impact in reducing risk for low-carbon generators, with a reduction of up to 1.3% for onshore wind and up to 2% for nuclear. Independent developers are generally assumed to benefit more than vertically integrated utilities from policy options that reduce earnings risk since they are less able to diversify their risk against a wider portfolio.

4.4 Results of modelling

In this section, we present some of the key results from the modelling of the five decarbonisation options – Carbon Price Support (£50/t), Premium Payments, Fixed Payments, Contracts for Difference and Strong Emissions Performance Standard – in relation to the following:

- carbon dioxide emissions
- plant mix
- electricity prices

- low-carbon support payments
- wholesale energy costs
- plant profitability
- resource costs
- security of supply, and
- overall cost benefit analysis.

4.4.1 Carbon dioxide emissions

Figure 16 shows the annual average carbon emissions intensity under the decarbonisation options and the Baseline. All options meet an emissions intensity of 100 g/kWh in 2030, as designed. Carbon Price Support (£50/t) has the lowest level of emissions throughout, as it encourages coal to gas fuel switching as well as stimulating low-carbon investment. Strong EPS also has low emissions throughout as the annual bubble limits restrict coal operation. Premium Payments has the slowest decarbonisation as investment in nuclear and CCS occurs later under this option.

Figure 16 Annual average carbon emissions intensity – Options to promote decarbonisation

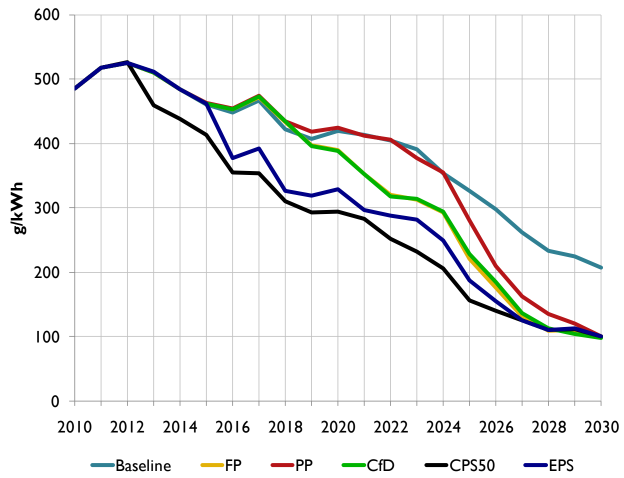
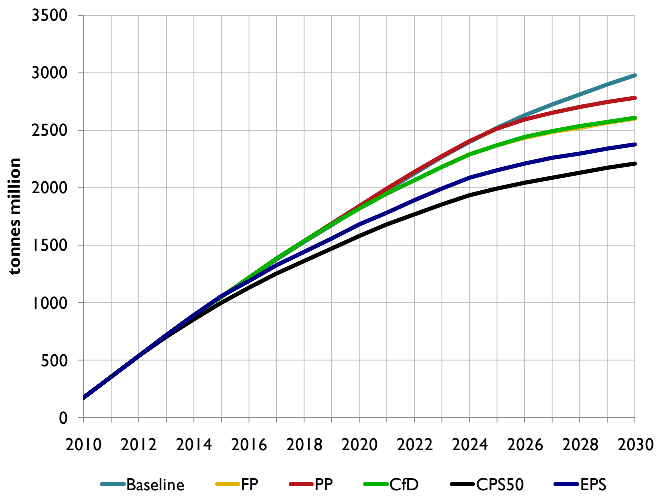


Figure 17 shows cumulative carbon emissions from the generation sector under the decarbonisation options and the Baseline. Cumulative emissions reflect the patterns in annual emissions intensity seen in Figure 16 above. By 2030, cumulative emissions under Carbon Price Support (£50/t) are 770 Mt or 26% lower than under the Baseline.

Figure 17 Cumulative carbon emissions from 2010 – Options to promote decarbonisation



4.4.2 Plant mix

Although the level of renewables generation is similar to that under the Baseline, each of the policy options has more new nuclear and CCS, although the proportions of these technologies differ between the options. The options also vary in the amount of new CCGT that is built as a consequence of the speed with which low-carbon investment occurs.

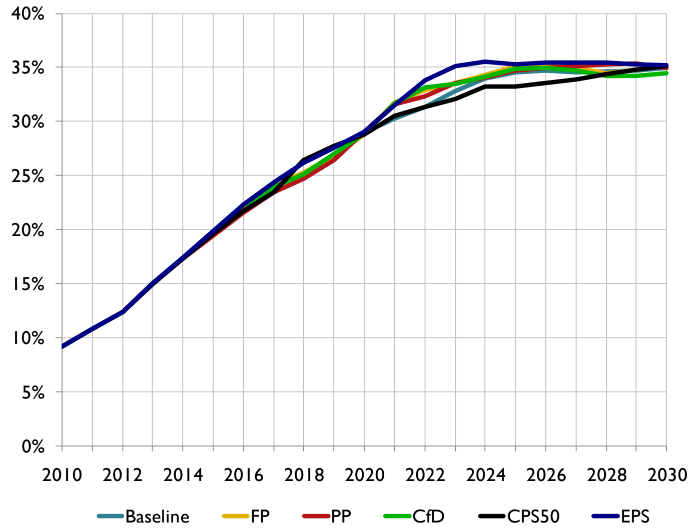
Renewables

By adjusting renewables support levels, all decarbonisation options have been designed to achieve approximately 29% and 35% generation from renewables by 2020 and 2030 respectively under Central assumptions.

Figure 18 shows similar trajectories for renewables output under each of the decarbonisation options and the Baseline. The proportions of different renewable technologies are broadly similar across the options, although there are some variations depending on the exact level at which support has been set.

In the period 2010 to 2013, renewables are built under the RO under all options, which is then grandfathered under the options where the RO is replaced (Premium Payments, Fixed Payments and Contracts for Difference). We have not assumed any investment hiatus as the result of the change in policy but this is a material risk. From 2014 onwards, renewables are built under the new policy option although under Carbon Price Support (£50/t) and Strong EPS the RO is retained.

Figure 18 Proportion of generation from large scale renewables – Options to promote decarbonisation



Nuclear and CCS

The timing and amount of investment in nuclear and CCS plant differs depending on the policy option. Under the assumptions modelled, the first new nuclear plant becomes operational earliest under Fixed Payments and Contracts for Difference (2019[53]) on the back of securing long-term fixed price contracts. Under Carbon Price Support (£50/t), Premium Payments and Strong EPS, as modelled, the first new nuclear becomes operational in the period 2022-2024. (This result is very dependent on the assumptions made around price levels.) By contrast the first new nuclear under the Baseline becomes operational in 2027.

The modelling suggests that nuclear is favoured over CCS when the investment incentive is purely based on a market-wide price signal, as is the case under Carbon Price Support (£50/t). This is because it is assumed to be lower cost and to mature earlier. Under Premium Payments, Fixed Payments and Contracts for Difference there is a greater proportion of CCS since we assume that it would receive targeted support at a level that bridges the different funding gaps. As a result these options tend to promote a more diversified, but (initially) more expensive generation mix. Note that under all the policy options we assume that CCS becomes technically proven and that it is economic to retrofit the unabated units of the demonstration plant by 2025.

[53]According to EDF, the first new reactor, which is likely to be Hinkley Point C, could become operational a year earlier than this in 2018.

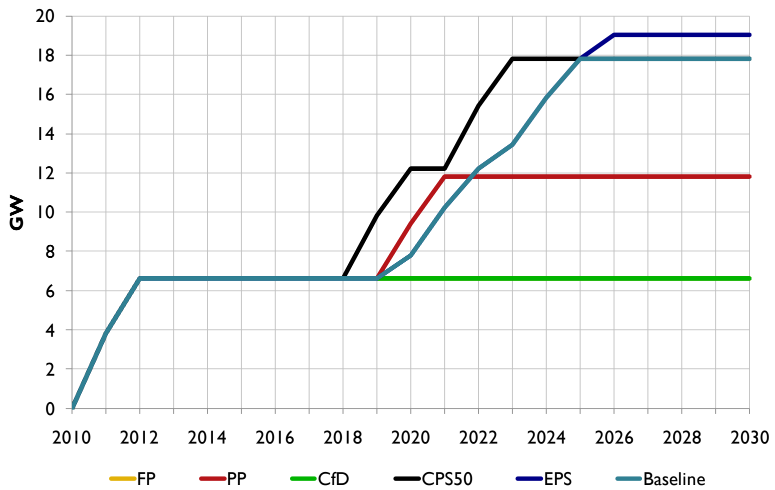
Table 11 Timing and capacity of Nuclear and CCS investment

	Baseline	CPS50	EPS	PP	FP	CfD
Year of first new nuclear	2027	2022	2024	2023	2019	2019
Year of CCS demo plant retrofit	After 2030	2025	2025	2025	2025	2025
New nuclear capacity (2030)	6.4 GW	14.4 GW	11.2 GW	9.6 GW	9.6 GW	11.2 GW
New CCS capacity (excl Demos) (2030)	0.0 GW	0.0 GW	3.5 GW	7.0 GW	7.0 GW	5.5 GW

CCGT

The amount of investment in new CCGTs varies across the options (Figure 19). Earlier investment in nuclear under Fixed Payments and Contracts for Difference, coupled with the assumption that the 2020 renewables target can be met, results in no further CCGT investment after 2012. Under Carbon Price Support (£50/t), Premium Payments and Strong EPS, where nuclear investment comes later, there is additional CCGT investment in the period 2019 to 2026 although this plant is built with lower expectations of future load factors.

Figure 19 Cumulative new CCGT build[54] – Options to promote decarbonisation

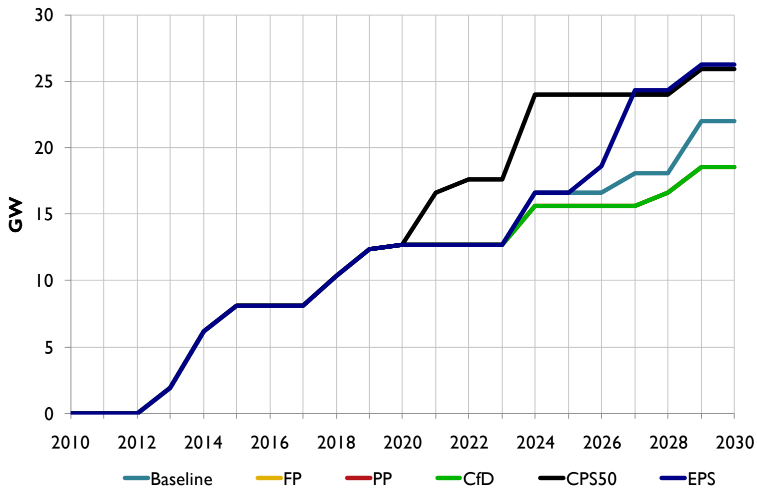


[54] Note that where sections of some lines are not visible, they are hidden behind the Baseline except in the case of Fixed Payments, where new CCGT build is identical to that under CfDs.

Coal plant retirements

Under Fixed Payments, Premium Payments and Contracts for Difference, the pattern of plant retirements is similar to the Baseline, driven by economics and restrictions under the IED. Under Carbon Price Support (£50/t), the higher carbon price faced by generators makes coal plant less profitable and brings about earlier closures. The Strong EPS also accelerates coal plant closures. Retirements of gas plant under the different decarbonisation options are generally similar to the Baseline.

Figure 20 Coal plant retirements – Options to promote decarbonisation



Capacity and generation mix

Figure 21 and Figure 22 show the total capacity and generation mix respectively from the modelling for the decarbonisation options compared to the Baseline.

Figure 21 Capacity mix – Options to promote decarbonisation

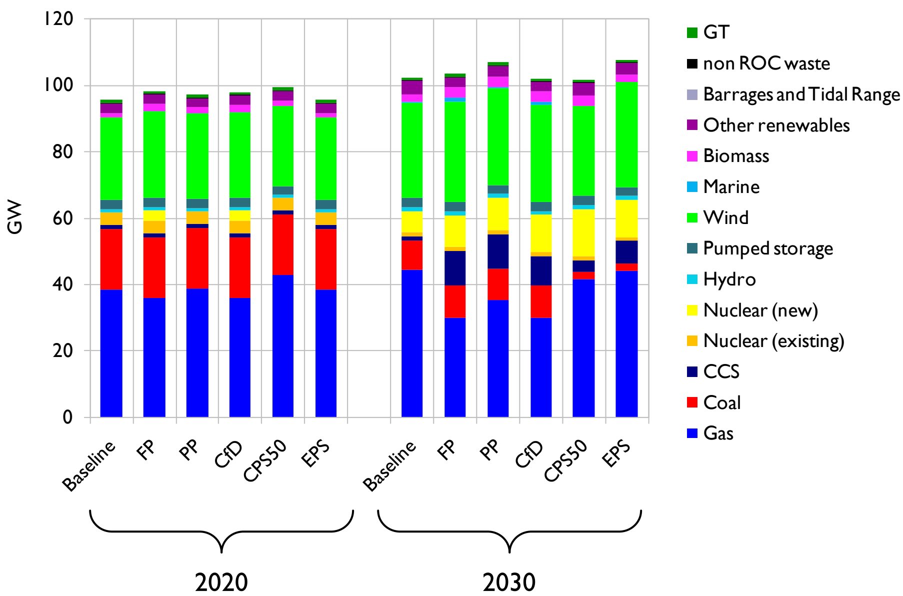
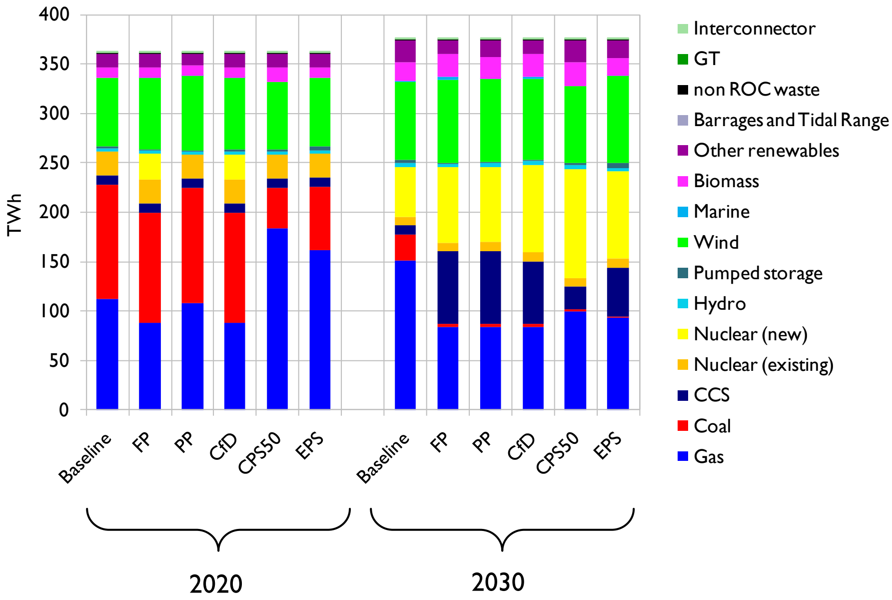


Figure 22 Generation mix – Options to promote decarbonisation



4.4.3 Electricity prices

Figure 23 shows the annual average baseload electricity prices from the modelling under the five decarbonisation options compared to the Baseline. The impact is different depending on whether the policy option provides targeted support to low-carbon generation or is designed to influence the electricity price signal.

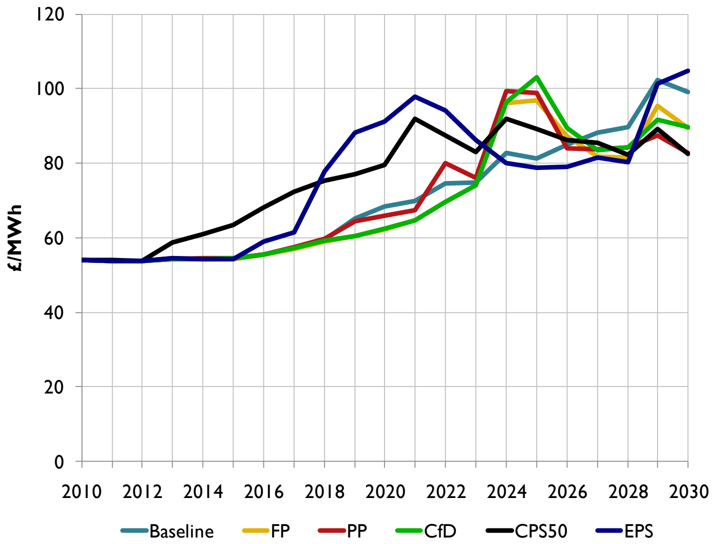
Increased fossil generation costs put upward pressure on electricity prices under Carbon Price Support (£50/t) but over time the effect 'wears off' as the average carbon intensity of the system diminishes with increasing low-carbon generation. This change in the pass-through of the carbon costs into the electricity price has implications for the effectiveness of Carbon Price Support as a continued signal for low-carbon investment in the longer term.

The Strong EPS also leads to significantly higher prices in the period 2015 to 2025 since the restriction on coal plant operation requires more generation from higher cost sources (gas plant), and because plant with restricted operation are expected to reflect the opportunity cost of output under the annual bubble limit in the prices they offer in the market.

In all cases the greater proportion of low-carbon generation on the system, with low SRMCs, reduces prices relative to the Baseline in the latter part of the 2020s, although tighter capacity margins in some years counter this effect. This is discussed further in Section 4.4.8 below.

As explained above, we have assumed that plant receive Fixed Payments or Premium Payments based on availability rather than output. There is an increasing risk that under an output-based mechanism prices could become negative at times when output from low-carbon generation exceeds demand as low-carbon generators compete to keep running to receive their support payments. This would lead to significantly lower electricity prices with possible negative implications for security of supply.

Figure 23 Annual average baseload electricity prices – Options to promote decarbonisation



4.4.4 Low-carbon support payments

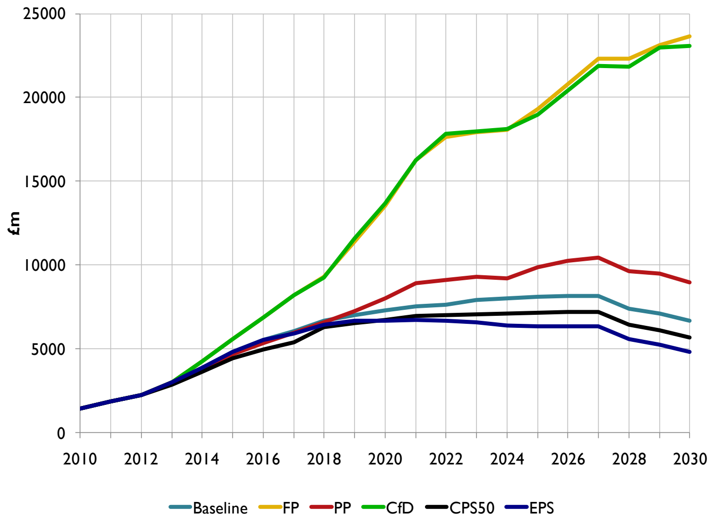
The amount of low-carbon support payments differs between the different policy options. Low-carbon support payments include the total of RO costs (including any grandfathering costs), Levy Exemption Certificates (LECs) and any payments from Premium Payments, Fixed Payments or Contracts for Difference.

Figure 24 compares the total annual low-carbon support payments across the decarbonisation policy options compared to the Baseline. Payments are highest under Fixed Payments and Contracts for Difference[55], and lowest under Carbon Price Support (£50/t) and Strong EPS where low-carbon support is limited to the RO and Levy Exemption Certificates[56].

[55] For CfDs we show the total payments as the combination of the CfD strike price and technology premia.

[56] We have assumed that the Climate Change Levy is retained, although it may be replaced as part of the introduction of Carbon Price Support or other policy options.

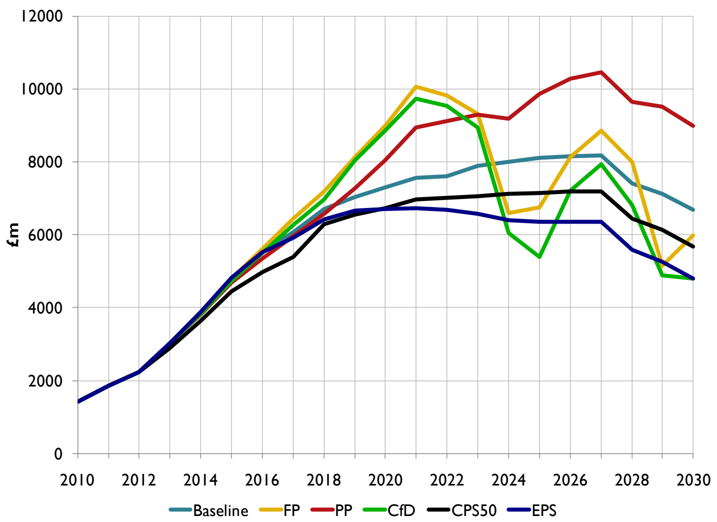
Figure 24 **Gross annual low-carbon payments to generators – Options to promote decarbonisation**



To make comparison between the options easier, Figure 25 shows the 'net' low-carbon payments, which subtract the forsaken wholesale electricity market revenues for generators operating under Fixed Payments, and the electricity revenues for plant operating under Contracts for Difference. On a net basis, the analysis suggests that low-carbon support is greater on average under Premium Payments than under Fixed Payments or Contracts for Difference. This is because if electricity prices rise, as is the case in this analysis, support for plant operating under Contracts for Difference reduces since generators pay out more in difference payments. Similarly, the implied net support for plant operating under Fixed Payments also reduces in this case. However, the level of support received under Premium Payments does not adjust in response to increasing electricity prices. The opposite result would be observed if electricity prices were to fall.

Although net payments to low-carbon generators are lower under Strong EPS and Carbon Price Support (£50/t), consumers are exposed to higher wholesale electricity prices under these options.

Figure 25 **Net annual payments to low-carbon generators – Options to promote decarbonisation**



4.4.5 Wholesale energy costs

Figure 26 shows the wholesale energy costs under each of the decarbonisation options compared to the Baseline. Wholesale energy costs include the price of wholesale electricity on a demand-weighted basis, balancing system use of system charges, and the cost of low-carbon support. Currently wholesale energy costs represent about 40% of an average domestic consumers' bill, the other components being network charges, supplier costs and margins and VAT. Under the Baseline assumptions, wholesale energy costs would approximately double between 2010 and 2030.

Wholesale energy costs are initially higher under the decarbonisation options than the Baseline in all cases but then fall lower after 2025. In general, consumers pay more for the low-carbon support in the early years but then benefit from lower (and more stable) electricity prices in the long-run as the short-run generation costs of the system decrease. Wholesale energy costs are greatest in the near term under Carbon Price Support (£50/t) and Strong EPS due to the higher electricity prices, but in the long-run are lower given the lower levels of low-carbon support under these policy options.

The longer-term benefits to consumers of lower wholesale electricity prices would be greater but for a reduction in capacity margins (as discussed below) which tends to push prices up in certain years.

Figure 26 Annual average wholesale energy costs – Options to promote decarbonisation

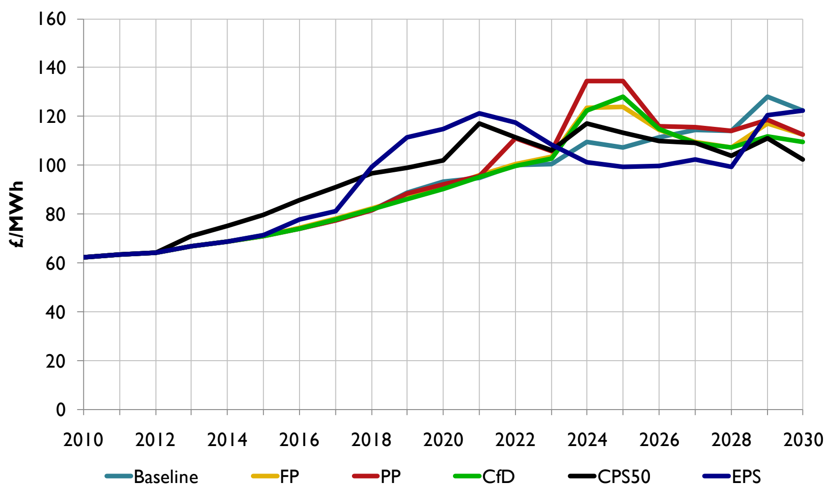


Figure 27 shows the average wholesale energy costs over the period 2010 to 2030 under each of the options. Prices are higher on average under Carbon Price Support (£50/t), Strong EPS and Premium Payments, compared to the Baseline. Average wholesale energy costs for Fixed Payments and Contracts for Difference are very similar to the Baseline. Under Fixed Payments wholesale costs are £0.13/MWh higher and under Contracts for Difference £0.33/MWh lower than the Baseline on average.

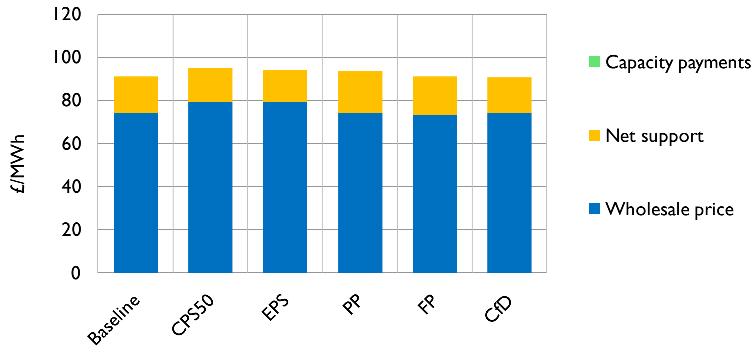
In terms of the average domestic consumer bill, the impacts of the different options range from a £1 per year average saving under Contracts for Difference, to a £12 per year average increase under Carbon Price Support (£50/t)[57]. By way of context, the cost of low-carbon support already included in the Baseline,

[57] The calculation of impact on the average domestic consumer bill is based on an annual electricity consumption level of 3.3 MWh. This assumption is made throughout this document where the impact of a given change on the average domestic consumer bill is stated.

excluding the EUA carbon price which is factored into the electricity price, is approximately £56 per year for an average domestic consumer over the period 2010-2030.

However, it should be noted that these results are dependent on Government being able to establish appropriate mechanisms for setting payment levels accurately. For example, for every £5/MWh that payments under Fixed Payments or Contracts for Difference are higher than necessary to bring forward low-carbon investment, an average domestic consumer would pay an additional £5 per year. Effective design is therefore key to the conclusion that Fixed Payments or Contracts for Difference could represent the best value for consumers.

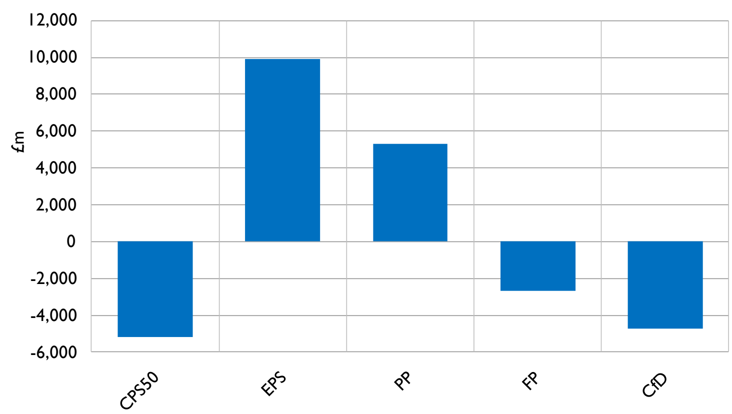
Figure 27 Average wholesale energy costs (2010-2030)[58] – Options to promote decarbonisation



4.4.6 Plant profitability

The different policy options could have significantly different impacts on the profitability of generators. Figure 28 below shows the net present value of generation sector profitability relative to the Baseline between 2010 and 2030 from the modelling.

Figure 28 NPV of change in generation sector profitability relative to the Baseline (2010-2030) – Options to promote decarbonisation



[58] Net support is defined as the total revenue received above the wholesale electricity price.

The higher electricity prices are the key driver of the large increase in profitability of the generation sector under Strong EPS. By contrast, generation sector profitability is lower under Carbon Price Support (£50/t) than the Baseline. This is due mainly to the costs to fossil generators of the carbon price floor. At the same time some generation plant, in particular existing nuclear and renewables, could be significantly more profitable under Carbon Price Support (£50/t).

Under Premium Payments, generation sector profitability is higher than the Baseline between 2010 and 2030. This is partly a function of the assumptions used with increasing electricity prices to 2030. Premia are set based on lower expectations of electricity prices, and then when they subsequently rise low-carbon generators are able to earn economic rents. (This is also a feature of the Baseline for renewables generators.) However, these generators are also exposed to longer-term price erosion as increasing proportions of low SRMC generation on the system could start to push prices down, although this effect only starts to manifest itself towards the end of the modelling period in 2030.

Low-carbon generators are not able to benefit from increasing electricity prices under Fixed Payments and Contracts for Difference and hence generation sector profitability is lower under these options than the Baseline. However, this result does assume that Government is able to implement mechanisms that can set payment levels close to the long-run costs of different technologies.

Economic rents for new renewables generators

One key driver of the differences in generation sector profitability under the different policy options relative to the Baseline is the risk of economic rents for renewables generators. Under the Baseline assumptions of rising gas and carbon prices, there is a significant risk of large rents accruing for renewables generators whose support levels (ROC band) may have been set (and subsequently grandfathered) when prevailing prices were lower. Figure 29 compares the annual total economic rent for new renewable generators (ie, excluding plant already operating under the RO) in each option relative to the Baseline. To the extent that rents can be minimised while renewables targets are still met, the cost to consumers should be reduced.

In general over the long-run, the analysis suggests that rents for new renewables should be lower under the decarbonisation options being considered, although in some cases they may be higher in the near term.

The additional low-carbon generation on the system under the decarbonisation options reduces prices in the long-term relative to the Baseline (the 'price erosion' effect). Hence, where renewables receive premium support (CPS50, EPS and PP) rents are lower. Carbon Price Support (£50/t) allows for lower ROC bands and hence rents are much lower than the Baseline when carbon prices subsequently rise.

Rents are also lower in the long-term under Fixed Payments and Contracts for Difference since revenues are largely fixed for renewables whereas they are rising under the Baseline. Under Fixed Payments, rents could be higher in the near term depending on how close prices can be set to the long-run costs of different types of plant. This is a material risk with this policy.

Rents appear generally lower under Contracts for Difference relative to Fixed Payments since plant remain exposed to balancing risk, and for wind plant in particular there is deteriorating price capture over time given the increased concentration of wind on the system[59]. If payment levels need to be increased to compensate for these risks, then this apparent benefit of Contracts for Difference over Fixed Payments in terms of consumer impacts may be lower.

[59] We have assumed that the CfDs settle against monthly average volumes and monthly averaged day-ahead electricity prices. As the proportion of wind on the system increases there will be a growing negative correlation between wind output levels and price. Hence, the price that wind plant actually achieve and the price that the CfDs settle will diverge over time.

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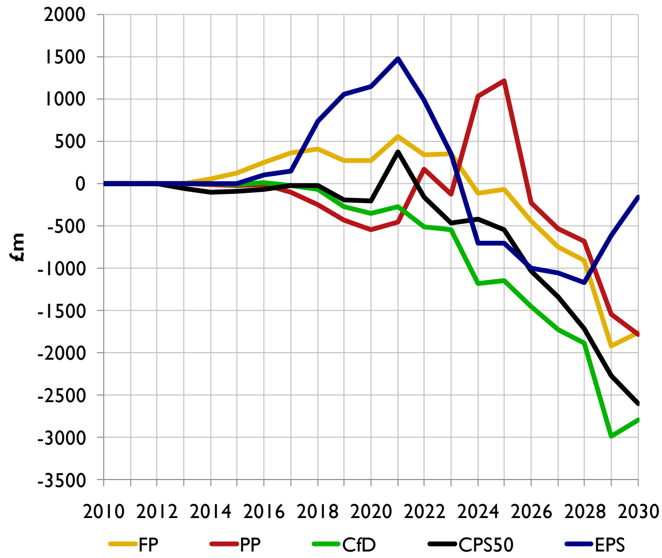
Under Premium Payments, rents increase when wholesale prices rise due to tighter capacity margins (for example in 2024 and 2025 in this illustration), unlike the situation for Fixed Payments and Contracts for Difference.

Figure 29 Change in annual rents for new renewables relative to the Baseline – Options to promote decarbonisation



4.4.7 Resource costs

Figure 30 shows the change in different elements of resource costs relative to the Baseline. These include carbon costs, generation costs (which include fuel and operating costs) and new plant capital costs[60].

Under all the decarbonisation options the total resource costs are higher than the Baseline, although the breakdown in the change of resource costs is quite different under the different decarbonisation options.

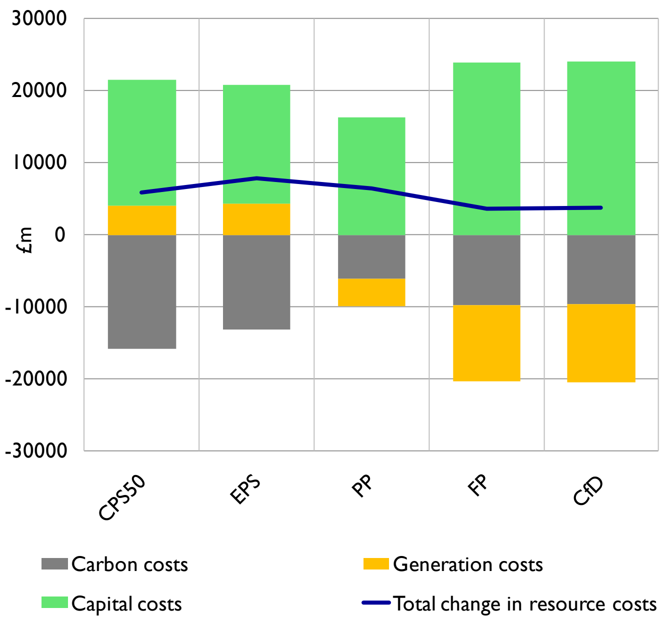
Under Fixed Payments and Contracts for Difference, new plant capital expenditure is greatest, adding approximately £24bn on a net present value basis to the £75bn incurred under the Baseline. This is a consequence of accelerated investment and a relatively expensive generation mix, featuring more CCS and less nuclear than other options. However, this increase in capital expenditure is offset by the lower hurdle rate assumptions, which saves around £4bn over the period 2010-2030 relative to the Baseline. The result of accelerated low-carbon investment is that the combined carbon and generation costs savings are greatest under these options. This means that despite the higher capital expenditure, overall increases in resource costs are lowest under these two options.

Later low-carbon investment under Premium Payments leads to lower levels of new plant capital expenditure but also lower savings in generation and carbon costs. Carbon Price Support (£50/t) and Strong EPS have the greatest increase in resource costs relative to the Baseline due in part to the higher generation costs caused by greater use of gas which is more expensive than coal generation under the Central assumptions.

[60] Capital costs are annuitised based on hurdle rates of investment, and then discounted over the period 2010-2030 using a Government Green Book discount rate of 3.5% real. All assumptions and results are in 2009 real terms.

Changes in resource costs relative to the total wholesale energy cost of electricity are small in percentage terms, ranging from a 0.8% increase under Fixed Payments and Contracts for Difference to a 1.7% increase under Strong EPS. The results are sensitive to the exact generation mix and the timing of investment which can be affected by the design of each policy option.

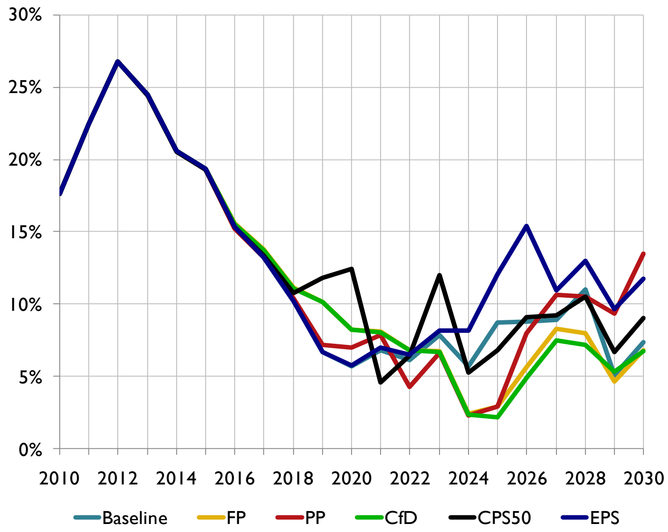
Figure 30 Change in resource costs relative to the Baseline – Options to promote decarbonisation



4.4.8 Security of supply

Figure 31 shows the annual de-rated capacity margins produced by the modelling under the decarbonisation options relative to the Baseline.

Figure 31 Annual de-rated capacity margin – Options to promote decarbonisation

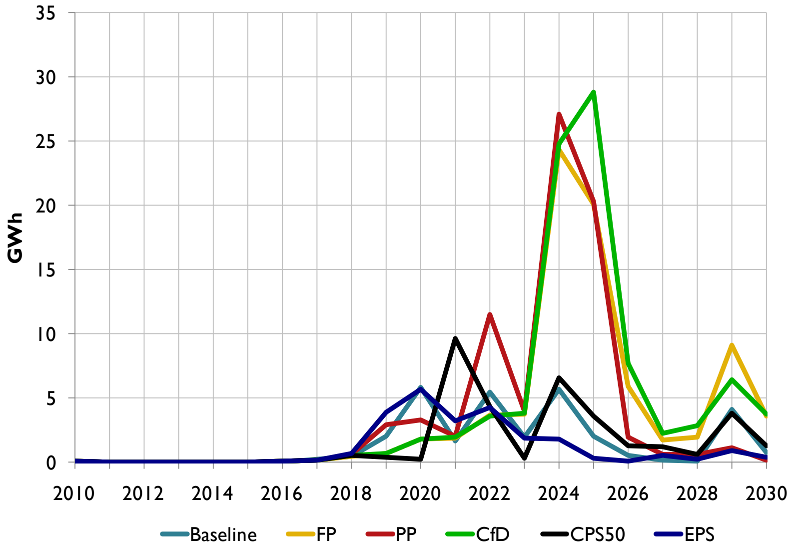


Analysis of the Baseline suggested that there may be material risks to security of supply by the end of the decade. The effect of increasing proportions of low-carbon generation on the system is likely further to depress electricity prices, and deter investment in conventional generation. The risk appears to be greatest under the targeted low-carbon support options (Premium Payments, Fixed Payments, Contracts for Difference) in the period to 2025, before the bulk of the new low-carbon investment comes on line.

Under Carbon Price Support (£50/t), there is more investment in new CCGTs which are able to earn a reasonable return with the higher wholesale prices, although some coal plant closes earlier. Under Strong EPS, coal plant do not necessarily close earlier since they are able to benefit from the higher peak prices associated with the tighter capacity margins. It is profitable for them to remain open operating under the TNP until 2020 and then under a derogation under the IED. However, if the Strong EPS, affecting all plant, was implemented as a rate limit rather than a bubble limit it is more likely that coal plant would close earlier.

Figure 32 shows the levels of expected energy unserved for the decarbonisation options. The risk of unserved energy is significantly greater than under the Baseline and appears highest under Fixed Payments, Premium Payments and Contracts for Difference, in the mid-2020s. Carbon Price Support (£50/t) and Strong EPS have a similar level of expected energy unserved to the Baseline.

Figure 32 Expected Energy Unserved – Options to promote decarbonisation



4.4.9 Cost benefit analysis of decarbonisation options

Table 12 summarises the cost benefit analysis for the period 2010 to 2030, in net present value terms[61]. Further explanations of the cost benefit calculation are provided in Appendix G. All five decarbonisation options show a small reduction in net welfare to 2030, largely because the costs of new low-carbon investment are somewhat higher than the cost of carbon saved to this point. The decrease in net welfare as a proportion of the total wholesale costs of electricity over the period is between 0.8 and 1.7%. As shown in Figure 33 below, by 2030, Carbon Price Support (£50/t), Fixed Payments and Contracts for Difference are showing a net welfare gain on an annual basis.

[61] Note that the cost benefit analysis does not include any assessment of the impact on air quality of the different packages.

Table 12 Decarbonisation options relative to Baseline, NPV 2010-2030[62]

Change in welfare NPV 2010-2030, (£m 2009 real)		Carbon Price Support (£50/t)	Strong Emissions Performance Standard	Premium Payments	Fixed Payments	Contracts for Difference
Net Welfare	Carbon costs	15,758	13,081	6,037	9,806	9,637
	Generation costs	-4,098	-4,400	3,828	10,492	10,790
	Capital costs	-17,496	-16,496	-16,337	-23,920	-24,105
	Unserved energy	44	93	-212	-207	-265
	Demand side response	12	16	-15	-18	-23
	Change in Net Welfare	**-5,780**	**-7,706**	**-6,698**	**-3,846**	**-3,965**
Distributional analysis						
Consumer Surplus	Wholesale price	-30,545	-27,420	-1,257	3,316	611
	Low carbon payments	7,474	9,811	-10,533	-4,237	437
	Capacity payments	0	0	0	0	0
	Unserved energy	44	93	-212	-207	-265
	Demand side response	12	16	-15	-18	-23
	Change in Consumer Surplus	**-23,015**	**-17,499**	**-12,017**	**-1,146**	**760**
Producer Surplus	Wholesale price	30,545	27,420	1,257	-3,316	-611
	Low carbon support	-7,535	-9,691	10,532	4,266	-434
	Capacity payments	0	0	0	0	0
	Producer costs	-28,190	-7,815	-6,471	-3,621	-3,678
	Change in Producer Surplus	**-5,180**	**9,914**	**5,318**	**-2,671**	**-4,722**

Differences in net welfare are predominantly driven by changes in resource costs (carbon, generation and capital costs) and hence Fixed Payments and Contracts for Difference appear the most favourable on this basis. There are small variations between the options with respect to welfare gains and losses associated with short-term demand elasticity[63], both involuntary (unserved energy) and voluntary (demand side response). Welfare losses here suggest a lower level of security of supply relative to the Baseline.

Larger changes are apparent in welfare distribution. Consumer surplus is lower under Carbon Price Support (£50/t), Strong EPS, and Premium Payments relative to the Baseline. Under Carbon Price Support (£50/t) and Strong EPS the reduction in consumer surplus results from the higher wholesale electricity prices (offset to a degree by lower low-carbon payments). Under Premium Payments, the loss of consumer surplus is largely the result of higher low-carbon payments. The additional costs under Fixed Payments are low, and under Contracts for Difference there may be a small benefit to consumers.

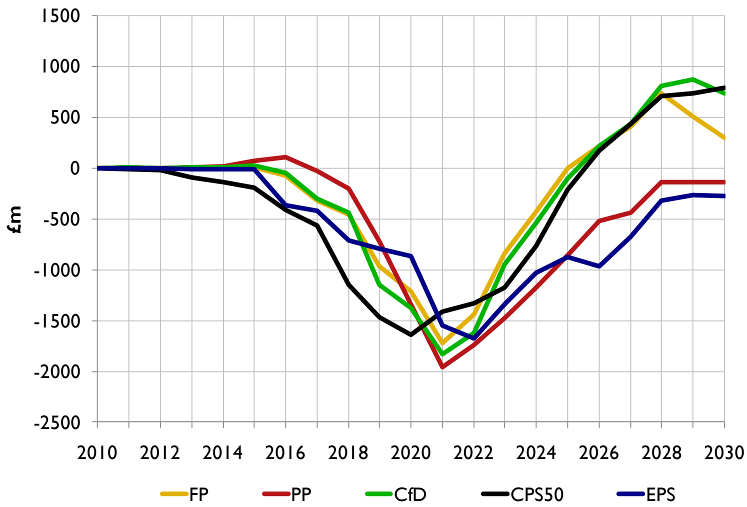
Producer surplus declines under Carbon Price Support (£50/t), Fixed Payments and Contracts for Difference, but increases under Strong EPS and Premium Payments for the reasons outlined above in the discussion of generation sector profitability above. With Carbon Price Support (£50/t) there would be additional Treasury receipts (not shown) associated with the carbon price floor.

Figure 33 shows the net welfare in each year, from 2010 to 2030 (in 2009 real terms). This shows a similar pattern under all the decarbonisation options, namely that the costs of accelerating low-carbon investment outweigh the benefits in terms of net welfare in the near term. However, once the carbon price starts to rise sharply, the trend reverses and by the end of the 2020s there is a net welfare benefit under most options. With an increasing carbon price after 2030, we may expect all policies to deliver enduring net welfare benefits.

[62] Excluded from this table are changes in tax revenues associated the Climate Change Levy and Carbon Price Support.

[63] For simplicity we have not included long-term demand elasticity within the analysis.

Figure 33 Annual Net welfare change relative to Baseline – Options to promote decarbonisation



4.5 Sensitivity analysis

4.5.1 Overview

In order to test the outcomes of the analysis to key uncertainties, we have modelled a number of sensitivities on commodity prices, and investor confidence in Carbon Price Support.

4.5.2 Commodity price sensitivities

All five decarbonisation options have been designed to achieve 29% and 35% generation from renewables in 2020 and 2030 respectively, and a carbon intensity of 100 g/kWh by 2030, under Central assumptions. Under different sets of assumptions the levels of decarbonisation achieved may be higher or lower under each option. We have explored the following sensitivities on commodity prices:

- **High Gas** - higher gas prices, reaching almost 100 p/th by 2020 and continuing at this level until 2030,
- **Low Gas** - lower gas prices, gradually rising to 35p/th in 2030, and
- **Low-carbon** - lower EUA prices**,** below £9/tCO2 until 2020 and reaching £35/tCO2 in 2030.

These assumptions are shown in Figure 34 and Figure 35.

Figure 34 Gas price sensitivity assumptions

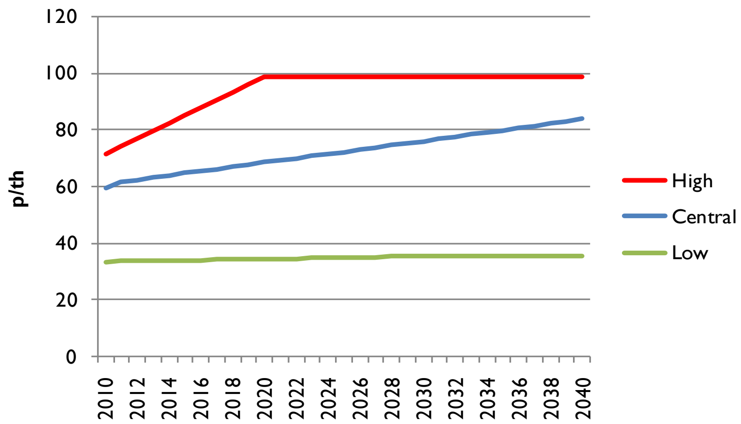
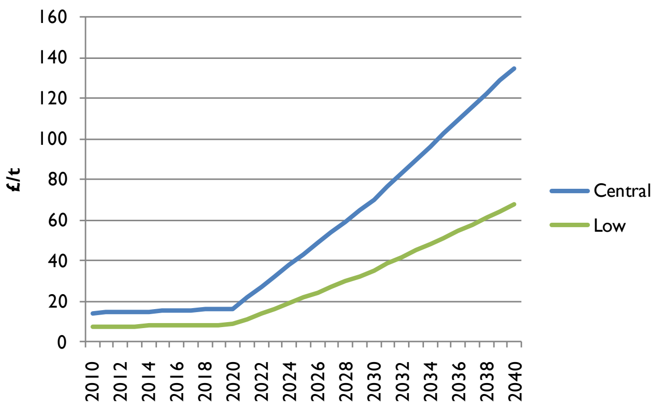


Figure 35 Carbon price sensitivity assumptions



We have run each sensitivity for the Baseline and the five decarbonisation options. We show the sensitivity under each option compared to the corresponding sensitivity in the Baseline. The key results are the robustness of each option under the sensitivities, both in term of decarbonisation and security of supply, and also the risk of higher costs for consumers.

We have held the price levels for Premium Payments, Fixed Payments and Contracts for Difference constant under the sensitivities, at the same level as under the Central assumptions[64], and the levels of Carbon Price Support and assumptions on the Strong EPS are unchanged. In reality, it is likely that some adjustments to policy would be made in response to different outturn commodity prices, and hence the results for the sensitivities could be regarded as extreme outcomes. However, they provide useful illustrations of the risk under each policy.

[64] We assume that the utilisation payments under Fixed Payments and the strike prices under Contracts for Difference are indexed to fuel prices and so these will adjust automatically. However, the availability payments remain constant.

4.5.3 Low Gas Sensitivity

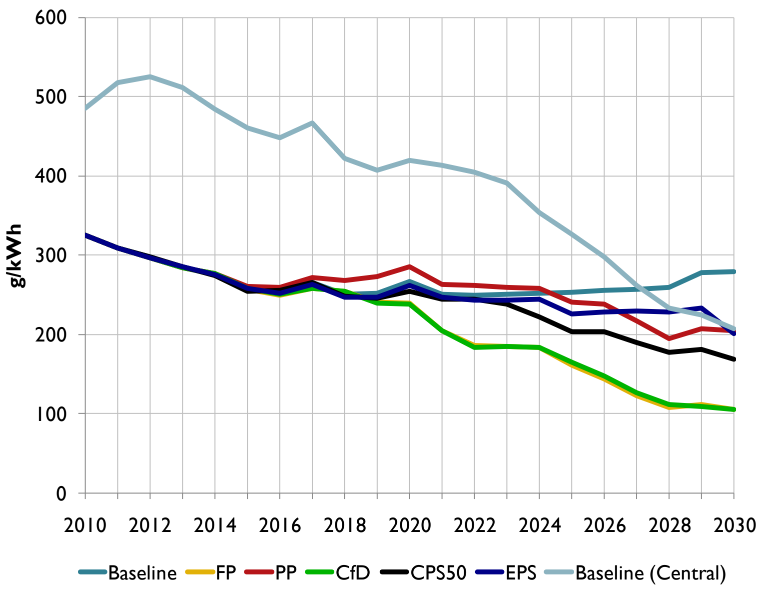
Carbon dioxide emissions

Since gas prices are a strong driver of electricity prices, lower gas prices have a significant impact on the trajectory of carbon dioxide emissions. In the near term there is coal to gas switching, leading to lower emissions under all policy options, but in the longer term the lower gas prices may result in less low-carbon investment under some policy options due to lower wholesale electricity prices.

Figure 36 shows the carbon dioxide emissions intensity under the Low Gas sensitivity for the Baseline and each of the five decarbonisation options. Emissions intensity for the Baseline under Central assumptions is also shown for comparison. The emissions intensity is much lower over the next decade under the Low Gas price sensitivity as a result of the increased competitiveness of gas-fired generation, compared to the Central assumptions which are more coal favouring. However, the pace of decarbonisation slows under some policy options.

Only under Fixed Payments and Contracts for Difference is a carbon intensity of 100 g/kWh achieved by 2030. Under these options, low-carbon generation is not exposed to the electricity price and so investment is broadly unaffected. Carbon Price Support (£50/t), Strong EPS and Premium Payments are less effective in stimulating low-carbon investment when gas prices are lower, as a result of lower electricity prices.

Figure 36 Annual average carbon dioxide emissions intensity – Options to promote decarbonisation (Low Gas Sensitivity)

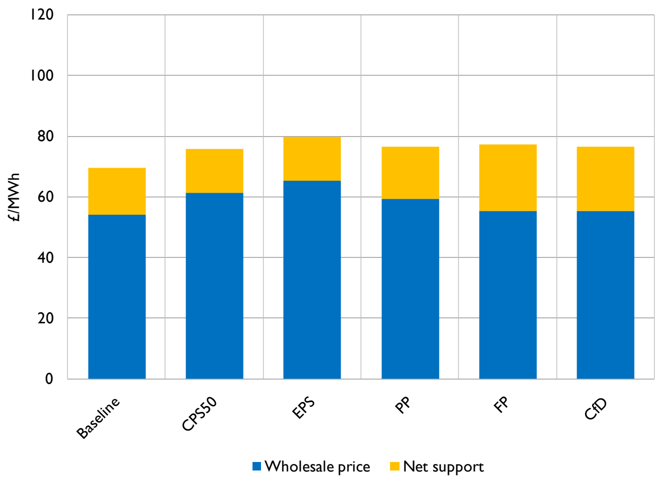


Wholesale energy costs

Figure 37 shows wholesale energy costs for the Low Gas sensitivity. Wholesale energy cost levels are lower than under Central assumptions as a result of lower gas prices driving lower electricity prices. Fixed Payments and Contracts for Difference are generally more expensive under the Low Gas price sensitivity but still deliver the decarbonisation objectives, which are not achieved under the options with premium support – Carbon Price Support (£50/t), Strong EPS and Premium Payments.

The net support element of wholesale energy costs under Fixed Payments and Contracts for Difference implicitly adjusts to the changing underlying electricity prices, whereas under the premium support options this is largely fixed.

Figure 37 Average wholesale energy cost – Options to promote decarbonisation (Low Gas Sensitivity)

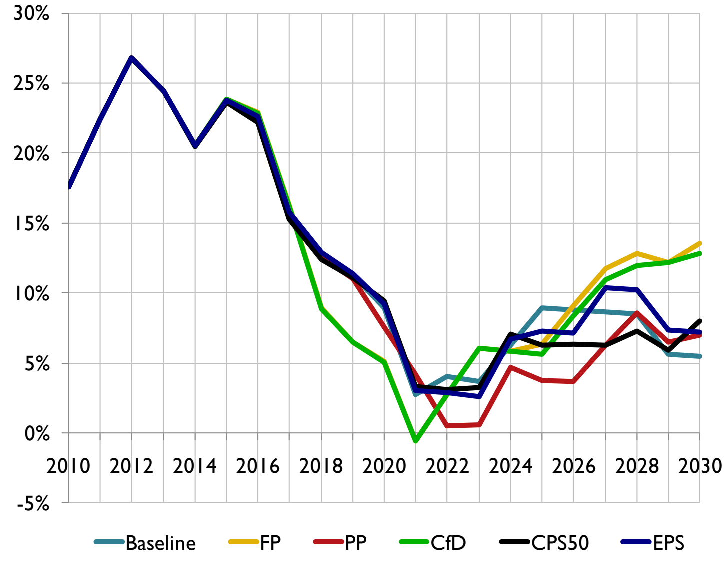


Security of supply

Figure 38 shows the de-rated peak capacity margins under the Low Gas sensitivity. The risks to security of supply appear to increase materially under lower gas prices as a result of earlier closures of coal plant in the period 2016 to 2020 due to these plant no longer being profitable.

The risk appears greatest under Fixed Payments and Contracts for Difference where investment in CCGTs is deterred by the early deployment of nuclear and CCS. In the longer run, the de-rated capacity margins in the model recover as investors react to the tight capacity margins and more low-carbon generation is commissioned.

Figure 38 **Annual de-rated capacity margin – Options to promote decarbonisation (Low Gas Sensitivity)**



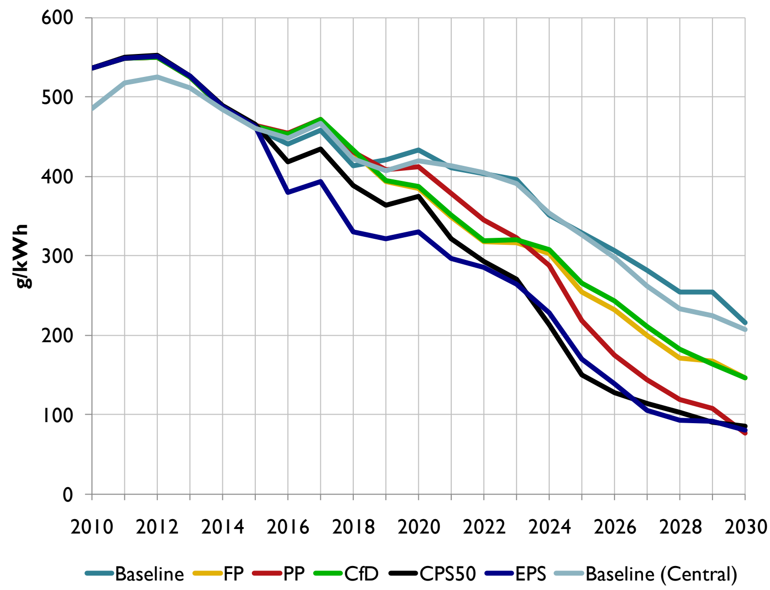
4.5.4 High Gas Sensitivity

Carbon dioxide emissions

Figure 39 shows annual carbon intensity for the Baseline and each of the decarbonisation options under the High Gas sensitivity. Higher gas prices lead to increased carbon intensity of the electricity system in the near term but result in greater decarbonisation by 2030 under Carbon Price Support (£50/t), Strong EPS and Premium Payments.

The higher gas price increases the amount of coal generation in the short-run (although note that Central assumptions are already coal favouring). Thereafter, the higher gas prices and resulting higher electricity prices lead to accelerated investment in low-carbon generation under options with premium support - Carbon Price Support (£50/t), Strong EPS and Premium Payments. For example, nuclear investment is accelerated by one to two years. Low-carbon investment is largely unaffected by the higher gas prices under Fixed Payments and Contracts for Difference. However, emissions intensity is somewhat higher than 100 g/kWh by 2030 due to greater coal burn, although this result depends on the extent to which there is any unabated coal plant on the system by 2030.

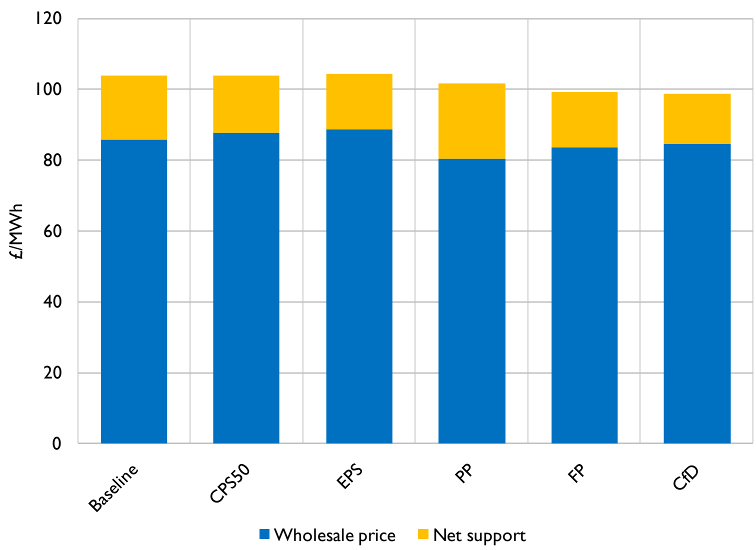
Figure 39 **Annual average carbon dioxide emissions intensity – Options to promote decarbonisation (High Gas Sensitivity)**



Wholesale energy costs

Figure 40 shows consumer energy costs for the High Gas sensitivity. Consumer energy price levels are higher than under Central assumptions as a result of higher gas prices driving higher electricity prices. The effect of the higher gas prices is reduced under Fixed Payments and Contracts for Difference since payments to generators are essentially fixed, and the average cost to consumers is less than the Baseline as a result. In general, these options reduce the variability of costs to consumers, by lessening the impact of fuel price volatility. Under Premium Payments, wholesale energy costs are also lower, due to a reduction in baseload electricity price as a result of the higher penetration of low-carbon generation.

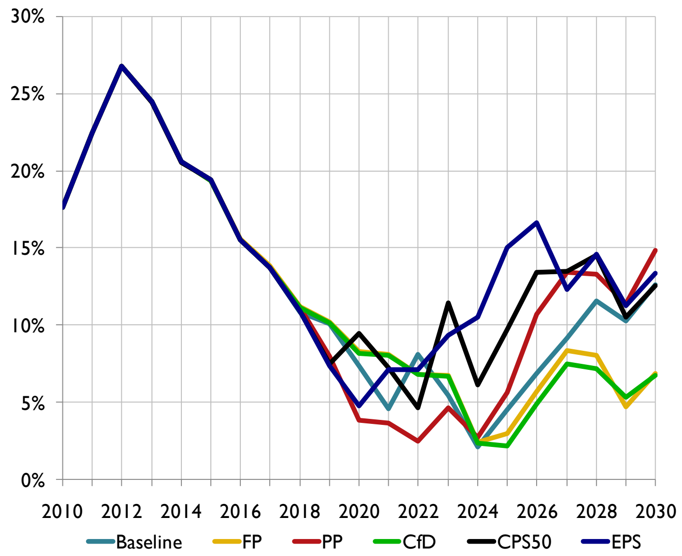
Figure 40 **Average wholesale energy cost – Options to promote decarbonisation (High Gas Sensitivity)**



Security of supply

Figure 41 shows the de-rated peak capacity margins for each of the decarbonisation options and the Baseline under the High Gas sensitivity. The risks to security of supply are less than under the Low Gas price sensitivity and are similar to those under the Central assumptions.

Figure 41 Annual de-rated capacity margin – Options to promote decarbonisation (High Gas Sensitivity)



4.5.5 Low Carbon Sensitivity

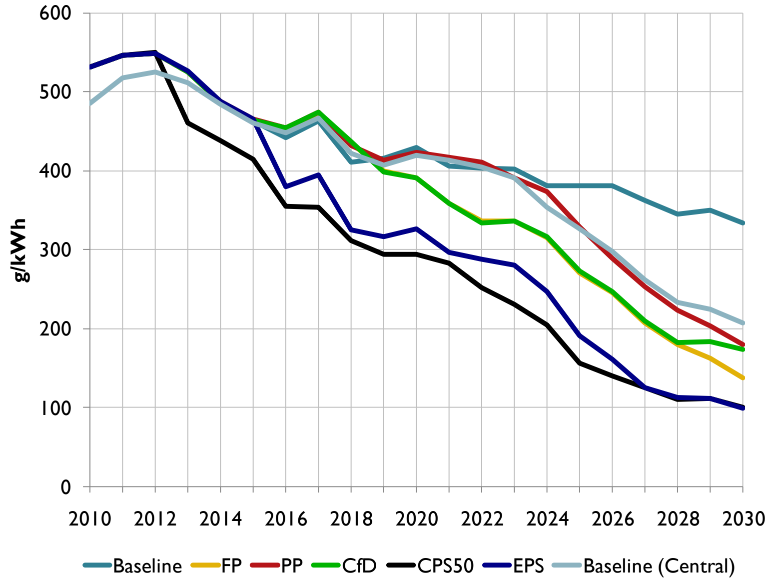
Carbon dioxide emissions

Figure 42 shows emissions intensity for the decarbonisation options and the Baseline under the Low Carbon sensitivity. Carbon Price Support (£50/t) and Strong EPS counter the effect of a lower EUA price but the 100 g/kWh carbon intensity is not achieved under the other policy options.

Carbon emissions are largely unaffected by the lower EUA price under Carbon Price Support (£50/t) – although this result assumes that investors have full confidence in the CPS. We explore a sensitivity to this below. Under Strong EPS, emissions are capped and hence the lower carbon price also has little impact on the speed of decarbonisation.

Under Premium Payments there is less low-carbon investment as a result of the lower EUA price. Although low-carbon investment is similar to the Central assumptions for Fixed Payments and Contracts for Difference, there is more unabated coal and gas burn and lower load factors for CCS plant. Hence, under these policy options the 100 g/kWh carbon intensity is also not achieved by 2030.

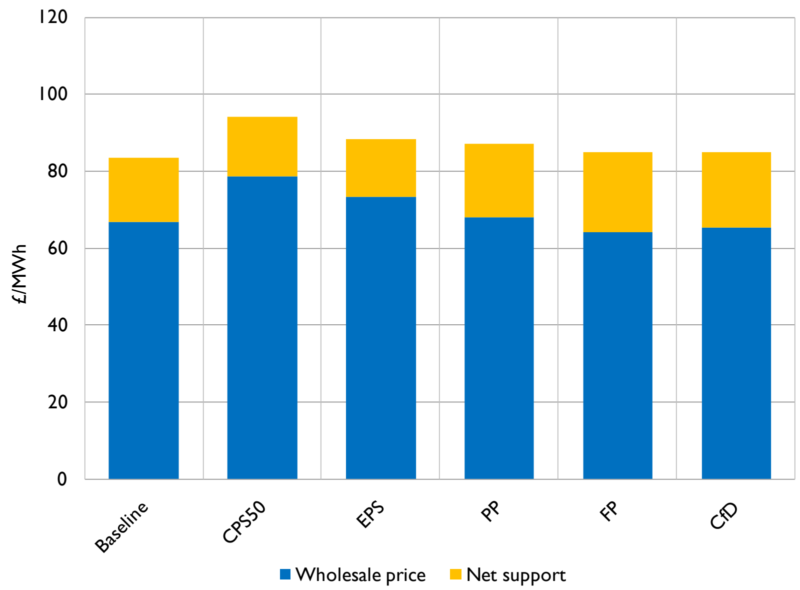
Figure 42 Annual average carbon dioxide emissions intensity – Options to promote decarbonisation (Low Carbon Sensitivity)



Wholesale energy costs

Figure 43 shows consumer energy prices for the Low Carbon sensitivity. Wholesale energy costs are highest under Carbon Price Support (£50/t) – the carbon prices faced by generators, and therefore passed through to consumers, are unchanged from the Central assumptions given the price floor. Fixed Payments and Contracts for Difference have the lowest cost to consumers. However, under this sensitivity they do not deliver the decarbonisation targets whereas Strong EPS and Carbon Price Support (£50/t) do.

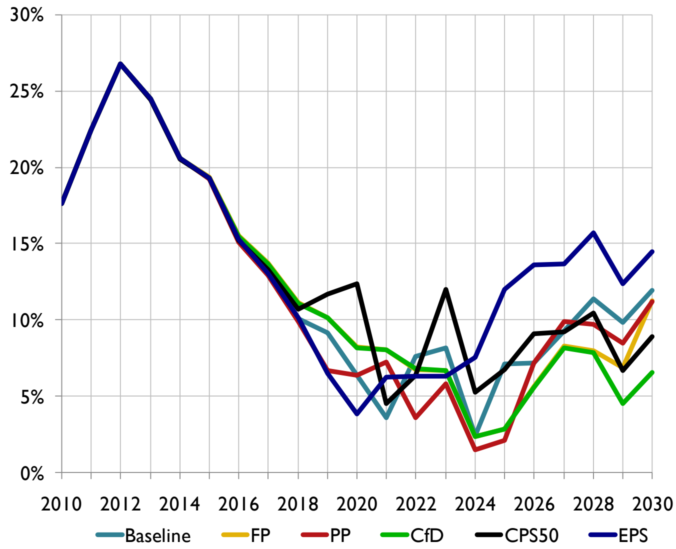
Figure 43 Annual average wholesale energy costs – Options to promote decarbonisation (Low Carbon Sensitivity)



Security of supply

Figure 44 shows the de-rated peak capacity margins under the Low Carbon sensitivity. The risks to security of supply are similar to those under the Central assumptions.

Figure 44 De-rated peak capacity margin – Options to promote decarbonisation (Low Carbon Sensitivity)



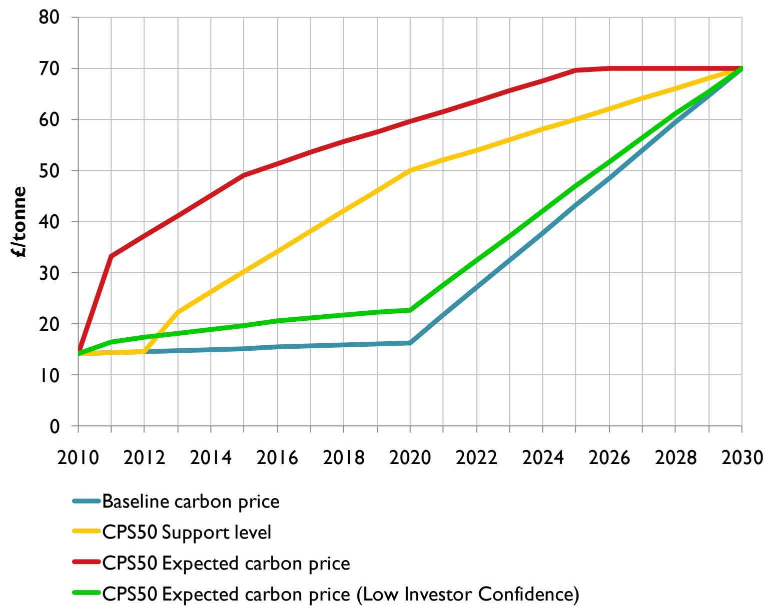
4.5.6 Low Investor Confidence in Carbon Price Support Sensitivity

Assumptions

The effectiveness of Carbon Price Support as a mechanism for driving low-carbon investment is dependent on investors' confidence that it will endure through the lifetime of an investment. Under the Central assumptions, we assumed that this was the case, although investors discounted any increase in the level beyond five years out.

The Low Investor Confidence sensitivity is designed to test this assumption. We assume that investors' future view of carbon prices reverts to the prevailing EUA carbon price beyond a 5 year horizon. The differences in investor expectations of carbon prices through the investment lifetime are illustrated in Figure 45. Under the Low Investor Confidence sensitivity, carbon price expectations are close to those under the Baseline.

Figure 45 Carbon price expectations – Low Investor Confidence in Carbon Price Support Sensitivity

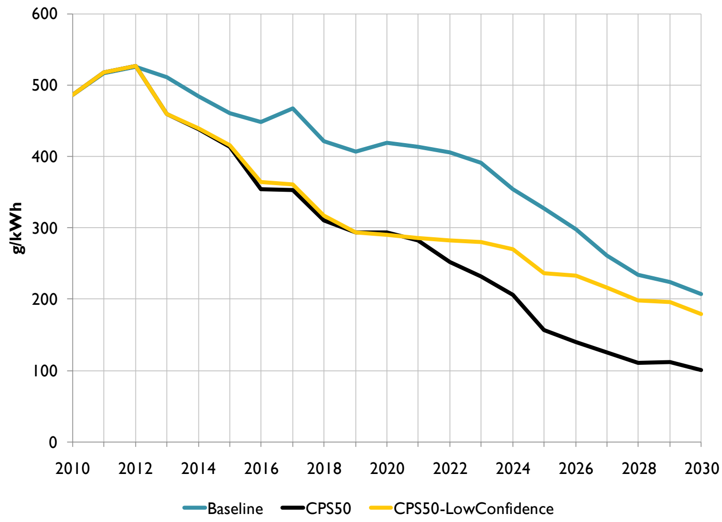


We also assume that lower investor confidence means that investors perceive no reduction in investment risk under Carbon Price Support. Therefore we assume no increase in gearing and that hurdle rates are the same as in the Baseline.

Carbon dioxide emissions

Figure 46 shows the annual average carbon emission intensity for the Low Investor Confidence sensitivity. Emissions intensity is the same as under Carbon Price Support (£50/t) until 2020. The main reason for this is that the outturn Carbon Price Support level is the same and so coal to gas switching occurs to the same extent. After 2020, carbon intensity is higher in the Low Investor Confidence sensitivity because there is less investment in nuclear, due to lower carbon price expectations.

Figure 46 Annual average carbon emissions intensity – Low Investor Confidence in Carbon Price Support Sensitivity



Impact on plant mix

Figure 47 shows new capacity in 2020 and 2030. A key impact of low investor confidence in Carbon Price Support is that it leads to lower investment in nuclear and renewables and greater investment in CCGTs. Investment in nuclear is similar to the Baseline, suggesting that Carbon Price Support has little effect if investors have no confidence in it.

Figure 47 New build 2020 and 2030 – Low Investor Confidence in Carbon Price Support Sensitivity

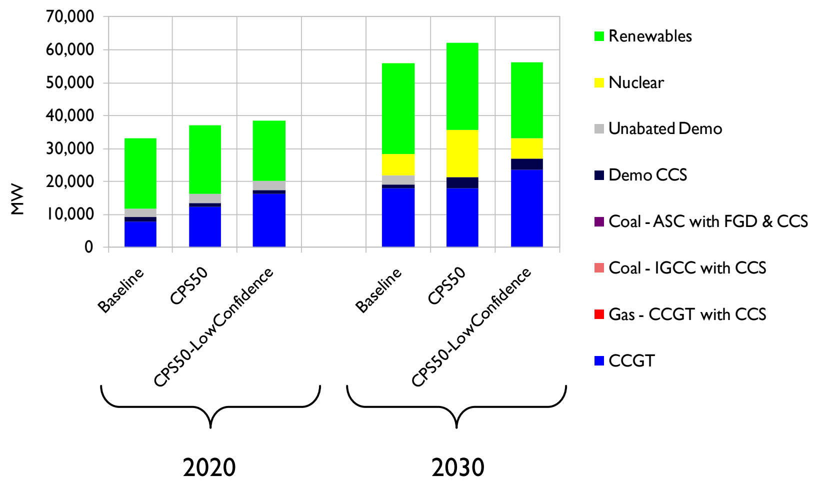
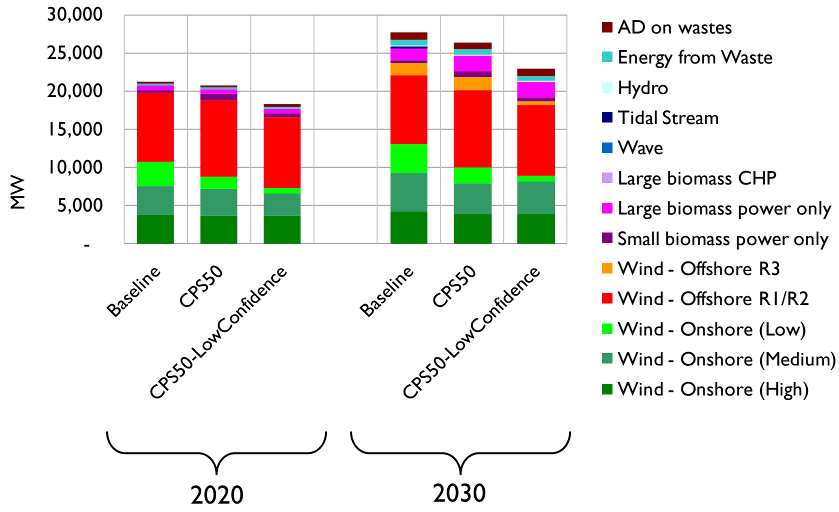


Figure 48 shows new renewables capacity in 2020 and 2030. Investment in renewables is actually lower than in the Baseline. This is because we assume that Government sets ROC bands based on full confidence in Carbon Price Support, which are therefore lower than the ROC bands in the Baseline. Investors do not share this confidence in Carbon Price Support, resulting in lower levels of investment.

The greatest negative effect in terms of renewables investment is on the higher cost technologies, namely Round 3 offshore wind, and also on lower yield onshore wind plant.

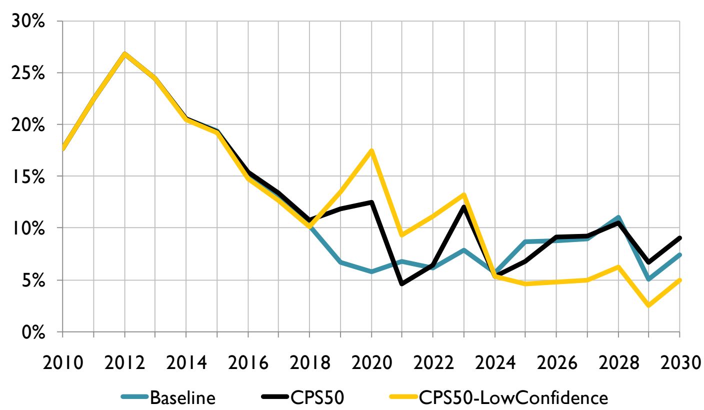
Figure 48 Renewables new build in 2020 and 2030 – Low Investor Confidence in Carbon Price Support Sensitivity



Impact on security of supply

The lower levels of renewables investment and replacement with CCGT could improve security of supply in the near to medium term, but in the long-term less investment in low-carbon generation could lead to lower margins. Figure 49 compares the de-rated peak capacity margins from the model for Carbon Price Support (£50/t) with the Low Investor Confidence sensitivity.

Figure 49 De-rated peak capacity margin – Low Investor Confidence in Carbon Price Support Sensitivity



4.6 Key messages

Below we summarise the main impact of the five decarbonisation options, and highlight key risks and implementation issues. In Section 5, we assess the costs and benefits of including capacity mechanisms to address security of supply concerns. In Section 6 we explore options that combine Carbon Price Support with other decarbonisation options and capacity mechanisms.

4.6.1 Impact of options

The analysis suggests that, assuming constraints in planning, connections and supply chains are resolved, and there are enough good quality project development opportunities available, each of the five decarbonisation options could be designed under Central assumptions to achieve the 2020 renewables target and hit a carbon intensity for the generation system of 100 g/kWh by 2030.

However, there are significant differences between the options in regard to the pace of decarbonisation, the diversity of the generation mix, security of supply, resource costs, distributional effects on generators and consumers, and robustness to fuel and carbon prices. This is illustrated in Table 13, which presents summary metrics from the modelling for each option under the Central assumptions and the sensitivities.

Table 13 Decarbonisation: summary metrics

		Decarbonisation		Generation mix				Security of supply		Resource costs	Costs to consumers	CBA
		Carbon intensity	Cum. CO2	2030 % generation				Capacity margin		NPV rel. to baseline	Average wholesale energy costs	Net welfare relative to Baseline
Package	Sensitivity	2030	2010-2030	Unabated fossil	CCS	Nuclear	Renewables	Ave 2018-2030	Min 2018-2030	2010-2030	2010-2030	2010-2030
Baseline	**Central**	**207**	**2,973**	**47%**	**2%**	**16%**	**34%**	**7.6%**	**5.1%**	**N/a**	**91**	**N/a**
	High Gas	216	3,050	33%	2%	26%	38%	8.0%	2.1%	N/a	104	N/a
	Low Gas	280	2,033	67%	2%	2%	26%	7.4%	2.7%	N/a	70	N/a
	Low Carbon	333	3,248	50%	2%	16%	31%	8.0%	2.5%	N/a	83	N/a
Strong EPS	**Central**	**100**	**2,377**	**25%**	**13%**	**26%**	**34%**	**9.6%**	**5.7%**	**7,815**	**94**	**-7,706**
	High Gas	81	2,369	21%	12%	28%	38%	10.8%	4.8%	17,817	104	-17,508
	Low Gas	201	1,929	49%	7%	2%	27%	7.6%	2.6%	5,622	80	-5,668
	Low Carbon	99	2,421	24%	13%	26%	35%	9.9%	3.9%	21,085	88	-20,945
Carbon Price Support	**Central**	**100**	**2,207**	**27%**	**6%**	**32%**	**34%**	**8.8%**	**4.6%**	**5,836**	**95**	**-5,780**
	High Gas	85	2,456	20%	10%	33%	36%	10.1%	4.7%	9,894	104	-9,597
	Low Gas	168	1,833	43%	7%	19%	29%	6.9%	3.1%	2,068	76	-2,126
	Low Carbon	100	2,241	27%	6%	32%	34%	8.8%	4.5%	18,969	94	-18,796
Premium Payments	**Central**	**101**	**2,782**	**23%**	**19%**	**23%**	**34%**	**7.7%**	**2.3%**	**6,471**	**94**	**-6,698**
	High Gas	77	2,674	14%	14%	35%	36%	8.1%	2.5%	7,079	102	-7,272
	Low Gas	204	1,967	48%	13%	9%	29%	5.9%	0.5%	8,214	77	-8,985
	Low Carbon	180	3,010	27%	18%	23%	32%	6.9%	1.5%	12,475	87	-12,817
Fixed Payments	**Central**	**101**	**2,599**	**23%**	**19%**	**23%**	**34%**	**6.9%**	**2.4%**	**3,621**	**91**	**-3,846**
	High Gas	147	2,763	23%	19%	23%	34%	7.0%	2.5%	-1,001	99	964
	Low Gas	105	1,617	25%	19%	23%	33%	7.7%	-0.6%	19,487	77	-19,916
	Low Carbon	137	2,802	20%	17%	29%	32%	7.4%	2.4%	12,642	85	-12,704
Contracts for Difference	**Central**	**98**	**2,606**	**23%**	**17%**	**26%**	**33%**	**6.7%**	**2.2%**	**3,678**	**91**	**-3,965**
	High Gas	146	2,786	24%	17%	26%	33%	6.7%	2.2%	-1,828	99	1,711
	Low Gas	105	1,621	25%	15%	26%	32%	7.4%	-0.6%	19,581	77	-20,025
	Low Carbon	173	2,827	25%	19%	23%	33%	6.8%	2.4%	13,285	85	-13,408

Note that where 2030 generation shown above does not add up to 100%, the remainder is accounted for by a balance of interconnector flows, pump storage and other generation. Note also that % of total 2030 generation from renewables does not include output from renewable microgeneration.

Decarbonisation: While all options meet the illustrative 100 g/kWh target in 2030 under Central assumptions, Carbon Price Support (£50/t) and Strong EPS reduce carbon emissions in the shorter term through coal-to-gas switching. Premium Payments produces the slowest pathway with investments in nuclear and CCS occurring later.

Generation mix: Renewables build is, by design, similar across all options. Nuclear, as a lower cost option compared to CCS, is favoured under mechanisms which are less technology-specific (Carbon Price

Support (£50/t) and Strong EPS), whereas a more diversified mix is achieved with technology-differentiated Premium Payments, Fixed Payments and Contracts for Difference.

Security of supply: Security of supply is similar to the Baseline under Strong EPS (where annual limits allow coal plant to remain open and benefit from high peak prices) and Carbon Price Support (£50/t) (where CCGT investments are still attractive due to higher spark spreads). The targeted low-carbon options show a higher risk around 2022-2025 created as a result of the hiatus in CCGT deployment prior to additional low-carbon generation being connected to the system.

Resource costs: Capital costs are higher than the Baseline in all options. This is particularly the case under Fixed Payments and Contracts for Difference where low-carbon investment is accelerated and includes a diversified mix with more expensive technologies, despite a lower cost of capital. However, these higher capital costs are significantly offset by reduced carbon and fuel costs.

Costs to consumers: Fixed Payments and Contracts for Difference show very little change in average wholesale energy costs over the period 2010 to 2030. The greatest increase in wholesale energy costs occurs under Carbon Price Support (£50/t), adding an average of £12 to this component of the average domestic consumer's annual bill over the period. However, by 2030, all options result in a lower wholesale energy cost component of bills compared to Baseline.

Generator rents: Most generators benefit from the higher wholesale electricity prices under Strong EPS. Under Carbon Price Support (£50/t), there is a mixture of winners and losers with high carbon generators worse off by having to pay higher carbon costs, but existing low-carbon generators gaining from the higher electricity prices. Under Premium Payments, low-carbon generators could benefit from economic rents should prices subsequently rise as a result of higher gas and carbon prices, although in the long-run they could be exposed to falling margins as a result of the price erosion effect. This risk of rents accruing where gas and carbon prices increase also occurs under the Baseline, and hence options with stable earnings such as Fixed Payments and Contracts for Difference, assuming they can be set at appropriate levels, should be beneficial in this respect.

Robustness to fuel and carbon prices: By isolating low-carbon generation more completely from the market, Fixed Payments and Contracts for Difference are the most robust options with respect to gas and carbon prices, both in terms of decarbonisation and rents. Both Carbon Price Support (£50/t) and Strong EPS protect the decarbonisation target against a lower carbon price outcome, while these and Premium Payments are at risk where investors' expectation of gas prices are low.

4.6.2 Risks of options

There are a range of important risks associated with each option that are not all captured in the quantitative analysis.

Incorrect levels: For each option, a significant challenge will be setting the right level – whether it be the carbon price floor, the emissions limits under EPS, or the specific premia or payments to low-carbon generators. For Fixed Payments and Contracts for Difference, the Government will be aiming to evaluate the long-run cost of the respective technologies, and doing so against a background of uncertain capital costs while facing a significant information asymmetry with respect to developers, as well as inherent uncertainty particularly in regard to less mature technologies. Getting the levels too low leaves the risk of under-delivery and missed decarbonisation targets, while if prices are too high, consumers will be paying for higher (low risk) economic rents for generators. While Premium Payments represent only a portion of generator revenues, the ongoing risks left with the generators may make these even harder to judge. Experience of setting and adjusting ROC bands provides evidence of this challenge. An auction-based approach could clearly play a role in price discovery, but it will be difficult to achieve the desired degree of technology-specificity while retaining a competitive process. This is especially true for the large scale technologies where there are relatively few prospective bidders and some may already have key advantages, for example in securing nuclear sites. Another challenge here is to define how much delivery risk to place on successful bidders. If the penalties for non-delivery are too high there is a risk that few bidders will come forward or the tender will clear at a very high price.

Longevity of signal: Investors are making long-term decisions – over timeframes as great as 40 years in the case of nuclear – and as such, mechanisms will be more effective to the extent that investors envisage that the impact will remain over the long-term. In this respect, Fixed Payments and Contracts for Difference clearly have an advantage, both in regard to the continued existence of the mechanism once investment decisions are made (through long-term contracts), and because there is no reliance on market-based signals that may change over time. The credibility of Premium Payments can be assured through clear grandfathering rights (and potentially also through contracts if direct payments are made), whereas Carbon Price Support, as a tax, could in principle be changed or removed at any point. Similarly, EPS terms could be changed, and in particular could be under pressure if security of supply became a concern. In addition, in the longer term, as low-carbon generation increases its share, the electricity price will be driven less by the carbon price, and hence it will gradually lose its effectiveness as a decarbonisation driver – something that will impact all mechanisms except Fixed Payments and Contracts for Difference.

Potential hiatus: Where significant changes are made to market arrangements, there is always the risk of some delay in the investment cycle as developers wait for the details of the new framework to be agreed, and as they absorb the impact on projects. This is probably less of an issue for nuclear, where plans are in any case at early stages, while for CCS the consideration will be around the impact on the attractiveness of participation in the demonstration projects (especially for projects with significant unabated coal capacity). For renewables, the introduction of Fixed Payments and Contracts for Difference would represent a major change, and careful thought would need to be given to grandfathering, and potentially the option for new plant to choose the RO or the new regime for a transition period. It is also possible that CfDs could be made optional for certain technologies, which could help in managing the transition. Arguably it is CCGT investment that is most at risk of a hiatus given the very large uncertainty introduced for unabated new plant as a consequence of major intervention directly affecting the amount and mix of new capacity, and the corresponding effect on electricity prices and spreads. This is likely to be minimised under Carbon Price Support (£50/t) or Strong EPS, both of which would directly benefit CCGTs at the expense of coal.

Incentives on generators: If intermittent renewable plant are exposed to electricity prices and balancing risks, they are incentivised to make plant available at times of highest price and forecast their output accurately. There is also an incentive for investors in wind plant to seek geographically diverse locations, thus reducing correlation between their output and the wind fleet as a whole, which should ensure a better 'capture price' as the penetration of wind on the system increases and the relationship between prices and aggregate wind output levels becomes stronger. Under Fixed Payments, these incentives could be lost unless explicitly incorporated within the terms offered within the contracts.

Incentives on suppliers: Suppliers currently compete on the basis of the costs to supply their customers through their electricity purchasing strategies, the costs to serve these customers and through the quality of services and products that they offer. Under Fixed Payments and Contracts for Difference an increasing proportion of electricity will be bought on the basis of fixed price, therefore reducing the role of the supplier in hedging price risk. This has fundamental implications for the vertically integrated supplier business model.

4.6.3 Implementation issues

While the detailed design of the decarbonisation policies has not been within the scope of this study, we identify a number of key issues which are important in comparing the relative benefits and risks of the different options.

Central purchasing: Fixed Payments to generators would require a central agency to buy the physical output from these generators and re-sell it in the market. Given that this could be a very significant proportion of generation (possibly up to 70% by 2030), this would be a profound change to existing arrangements. It would be challenging to develop principles for the entity involved to operate in a transparent manner, while managing price and volume risk (associated with outages, intermittent renewable output and load factor uncertainty). It seems likely that an approach involving regular auctions of forward power for different maturities and terms, combined with residual activity on day-ahead and within-day exchanges, may be the most appropriate. This would also have to tie appropriately to nominations for plant with significant fuel exposures (CCS in particular) to limit the fuel price risk associated with timing differences between power sales and fuel purchases.

Dispatch: We have already noted above the issue with regard to dispatch economics for subsidy payments made on output – and the potential for generators to subtract the payment from their SRMC in forming their offers. It is for this reason that we have modelled availability-based Premium Payments. The introduction of Carbon Price Support, while leaving dispatch internally consistent at a GB level, would change the economics of dispatch relative to neighbouring markets (assuming carbon is priced based on the EU ETS only), potentially distorting import/export decisions. There is the added complexity that Northern Ireland is part of the Irish SEM raising the possibility that the input costs for plant in the North could be higher than those in the South. Under Fixed Payments, the short-run economic decision no longer sits with the generator, and hence a central agency will be required to determine dispatch. This could be the same entity that physically purchases the power, the System Operator, or a separate body. It could be very challenging to define appropriate and transparent rules to enable dispatch decisions to be made fairly both for plant with significant fuel costs (CCS and biomass) as well as in situations of 'spill' for low marginal cost plant (nuclear and other renewables). Attempting in addition to account for the technical constraints of plant points to a Pool-type central optimisation process but it is difficult to see how this would interact with the residual bilaterally traded, self-dispatched market.

Indexation: Carbon Price Support would be implemented through a tax on fuel use such that, when EUAs are taken into account, there would be a minimum cost of carbon emissions to generators. To determine the actual level of the tax over a given period, a determination of the associated EUA prices will be required. Likewise, difference payments for the Contracts for Difference option would be determined as the difference between the strike price and electricity prices (or spreads) over a period. In both cases, care will be needed in defining the appropriate index to use. It must clearly be transparent and robust, and derived from a credible reference, itself based on a sufficiently liquid underlying market. (This is likely to be especially difficult for CfDs for biomass plant.) However, it must also be recognised that participants' exposures will be determined by the form of the index. In the case of Contracts for Difference, recipients will face risks to the extent that their sales of physical power do not align with the way in which the index is derived. For example, if the index is calculated as the average of day-ahead power prices across a month, then a 'risk-minimising' strategy would be for CfD counterparties to aim to sell power in the day-ahead market to match this, or to sign a physical power offtake agreement with a supplier with matching indexation terms. Similarly, for Carbon Price Support, again exposures will result if the pattern of EUA purchases made by generators does not match that against which the index is defined. The choice of the index may thus be a major driver in the way liquidity evolves in the market. Key choices include the extent to which the index is based on forward prices or spot prices, whether it is 'laddered' by more extended averaging, and the extent to which it is shaped (potentially down to the half-hourly level) or not.

Impact on traded market: As noted above, Fixed Payments would fundamentally change the GB power market. An increasingly large proportion of the market would be managed centrally, most likely through an auction process. This will also dramatically change the typical exposures of generating companies and vertically integrated utilities with significant low-carbon portfolios, potentially changing the long-term strategic rationale of organisations. 'Natural longs' (generators) will no longer match 'natural shorts' (suppliers). The ability for participants to manage hedging strategies for retail portfolios and for the 'residual' (non-low-carbon) generation portfolios may be affected by the inflexibilities of the central purchasing agency operations, and the ramifications for traded market liquidity. A Contracts for Difference mechanism, while leaving the physical sales of power under the current arrangements, would likewise profoundly change the exposures of participants, and could dramatically affect the dynamics and liquidity of traded markets. On the other hand, Carbon Price Support (£50/t), Strong EPS and Premium Payments should all be implementable without dramatically changing current arrangements. However, while providing greater long-term certainty, Carbon Price Support could complicate shorter term carbon price risk management for participants – as the exposure they face will depend on the relative levels of the EUA price and the floor price, as well as the 'basis risk' associated with the difference between the EUA price assumed in calculating the tax, and the direct cost of EUAs traded by the generator. This could be particularly tricky if EUA prices were close to the floor price – when participants would be fully exposed if EUA prices rose above the floor price, but at risk against the index basis if they fell below.

Demand side: The various instruments considered in this section have the potential to reduce risks and increase revenues for supply side investments in low-carbon generation. The importance of demand side investments in energy efficiency, demand management and distributed energy in reducing overall system emissions should also be recognised. Carbon Price Support (£50/t) and Strong EPS would stimulate such investments through increasing electricity price, and a Feed-in Tariff mechanism is already in place for small scale (< 5MW) renewable generation. Further thought is needed as to whether analogous mechanisms to Premium Payments, Fixed Payments and CfD approaches could be applied to demand side investment.

Monitoring: All of the options will have monitoring requirements, but these may not extend beyond those already in place. For Strong EPS, carbon emissions must be tracked. To the extent that these are annual (which would be the case for an annual plant limit), then this would coincide with existing monitoring for the EU ETS and hence impose little new burden on the industry. However, a rate limit implementation of the EPS would correspondingly need auditable carbon emissions on matching time periods. For availability-based payments (which could be a part of the implementation of Premium Payments, Fixed Payments and Contracts for Difference), monitoring would again be required. In principle this is already a part of the operating regime under the current arrangements, but may need to be enhanced in line with the much higher financial consequences.

Cashflow and credit: Under each of the options there are important design considerations surrounding how cashflows and credit would be managed. These include the timing of payments to low-carbon generators and recovery of costs from suppliers, the schedule of tax payments under Carbon Price Support, the working capital requirements of any central buyer, and the settlement schedule and credit arrangements for CfDs.

4.6.4 Summary

Carbon Price Support (£50/t)

The analysis suggests that Carbon Price Support, set at the appropriate level, could deliver the required low-carbon investment (in conjunction with the RO) to deliver 100g/KWh by 2030, but only as long as investors have confidence in it. It is compatible with existing GB arrangements and would drive coal-to-gas switching in the near term, although there is a risk of distortion to import / export decisions. However, it is less likely to encourage a diverse energy mix, with new nuclear being the likely main addition in the period to 2030. Its effectiveness could be undermined by lower than expected gas prices, but it reduces the risk if EUA prices are low. It does not remove the risk to investors of the reducing pass-through of carbon price to electricity price over time as the generation mix decarbonises.

By generally increasing rather than suppressing electricity prices (as may occur with some of the other decarbonisation options), Carbon Price Support may be better for security of supply, notwithstanding the risk of earlier coal plant closures. This could however lead to higher consumer costs (albeit associated with higher Treasury receipts) and higher rents for existing low-carbon generators in the first part of the period. On the other hand, by aligning investor and government expectations of future carbon prices, it should reduce the other forms of support required to stimulate low-carbon investment, for example through lower ROC bands. This in turn should benefit consumers in the longer term where carbon prices subsequently rise.

Premium Payments

Decarbonisation under the Premium Payments approach is at risk from both lower gas prices and carbon prices, and conversely consumers are at risk if gas and carbon prices turn out higher than those assumed when premia are set. However, it could be implemented as an extension of existing policy (for example by converting the RO into a broader 'low-carbon obligation' on suppliers) and hence may be less disruptive to current arrangements than other options.

The Premium Payments approach does not de-risk projects to the same extent as Fixed Payments or Contracts for Difference, leading to higher costs to achieve the same outcome in terms of low-carbon investment.

The analysis suggests that risks to security of supply could be greatest under Premium Payments since investment in other forms of generation may be deterred and yet low-carbon investment may come later than under Fixed Payments and Contracts for Difference where investment risk is assumed to be lower.

Fixed Payments

Fixed Payments appears to be the lowest cost mechanism for delivering a specific volume of low-carbon investment due to lower cost of capital, albeit by transferring risk to consumers. The long-term contractual arrangements should increase investor certainty, may attract new sources of finance and new entrants, and build confidence in supply chains. They are also more robust to commodity price uncertainty in terms of delivering decarbonisation objectives and protecting consumers from price variability. A specific low-carbon generation mix can be targeted if this was an objective, but security of supply concerns could be exacerbated if CCGT investments are deterred as a result.

This option represents the biggest disruption to current market arrangements, taking low-carbon generation out of the market and creating a two-tier electricity system, and has a corresponding risk of hiatus in renewables build. It requires the establishment of a new central buyer agency with significant overhead, and the challenge of implementing a transparent set of principles in selling power into the market and managing dispatch, in place of incentives directly on generators. There would be a major impact on the balance of exposures between participants, and this could profoundly influence the long-term strategies of different types of player.

The onus for setting the appropriate levels for the payments or designing effective tenders sits with Government. For maturing or emerging technologies this could be extremely difficult, due to an information asymmetry with developers. Tenders could yield useful price information but with challenges in ensuring competition while being technology-specific, and judging the right balance for delivery risk for successful bidders.

Contracts for Difference

The potential benefits of the Contracts for Difference option in terms of bringing forward low-carbon investment, possibly reducing the cost of capital and robustness to uncertain fuel and carbon prices, are similar to Fixed Payments.

However, unlike Fixed Payments, this option keeps low-carbon generation in the physical market. With an appropriate design, this should maintain incentives on generators to forecast accurately, schedule maintenance at appropriate times, and to pursue geographic diversification of intermittent renewables build. By removing the need for a central agency to buy and sell power physically there could be lower implementation overheads. Nevertheless, the exposures of low-carbon generators would be fundamentally changed under these arrangements, with potential consequences for market liquidity and long-term strategies for participants.

As for Fixed Payments, identifying the appropriate strike prices and premia to deliver the required volumes and types of low-carbon investment will be challenging. A further risk with Contracts for Difference is in identifying an index with sufficient underlying liquidity that it can be reliably used to settle financial contracts with low risk of manipulation. However, the choice of index may itself act to stimulate liquidity since those with CfDs may seek to sell their output in the same underlying market in order to minimise their own basis risk.

The Contracts for Difference option could be implemented as an optional scheme for certain technologies. It could, for example, run alongside the RO for renewables plant, with investors having the choice of whether to enter into a CfD as well as receive premium payments via the RO. This could reduce the risk of an investment hiatus.

Strong Emissions Performance Standard

A Targeted EPS on new plant is assumed under all policy options. The analysis suggests that in order for an EPS alone to drive the level of low-carbon investment required, it would need to be set at a level that could result in significant increases in prices, with consequent windfall gains for some generators and additional costs for consumers. Furthermore, it is not clear whether investors in low-carbon generation would be sufficiently confident to invest given the high regulatory risk that the standard could be softened in response to high prices or risks to security of supply. It would be difficult to set at an appropriate level given uncertainty surrounding fuel prices and security of supply. However, it would be robust to uncertain carbon prices (although less so to uncertain fuel prices).

Like Carbon Price Support (£50/t), a Strong EPS could lead to earlier decarbonisation since it forces coal to gas switching. It would be compatible with the current market arrangements, and would require significantly less overhead to implement than Fixed Payments or Contracts for Difference.

5 Options to enhance security of supply

5.1 Overview

The modelling of the Baseline and the decarbonisation options suggested that there are potential risks to security of supply towards the end of this decade and into the next. These risks result from uncertain returns for investors in fossil generation as a consequence of support for low-carbon generation, and the fact that some of this low-carbon generation is intermittent in nature.

We have analysed two generic capacity mechanisms designed to reduce the risks to security of supply:

- **Capacity Payments for All** whereby all generation plant and qualifying demand-side response receive an additional revenue stream based on their availability, and
- **Targeted Capacity Tenders** whereby the System Operator, or other body, tenders for specific generation and demand-side capacity to address a forecast capacity gap against a pre-defined security standard.

We have analysed these capacity mechanisms in conjunction with the decarbonisation options outlined in Section 4 above.

5.2 Capacity Payments for All

5.2.1 Description

A number of different capacity mechanisms have been implemented internationally. These broadly break down into quantity-based mechanisms and price-based mechanisms.

Quantity-based mechanisms may involve obligations on suppliers to secure sufficient capacity to meet the peak load of their customers, or may require the system operator to purchase capacity on behalf of the market sufficient to meet expected demand, usually via some type of auction, the cost of which is recovered from suppliers. Examples of quantity-based capacity mechanisms include the New England and PJM markets in the United States.

Price-based mechanisms involve setting an administered price for capacity at a level designed to deliver a certain security standard. The price mechanism may be based on the value to consumers of maintaining continuous supply (which was the approach adopted in the former England and Wales Pool) or on the cost of providing peaking capacity, as is the case in the SEM in Ireland.

Detailed assessment of alternative designs of capacity mechanisms was beyond the scope of this study. Instead we focus on the economic impact of a generic price-based capacity mechanism on the electricity market in terms of new investment and plant retirement decisions, and the implications for security of supply.

5.2.2 Impact on investment risk

Table 14 below summarises the impact of capacity payments on investment risk for different types of technology. The main effect is to reduce electricity revenue risk since some of the electricity price variability is replaced by a more stable capacity payment stream. Capacity payments also reduce load factor risk for those technologies that have significant fuel input costs, such as CCGTs, CCS plant and biomass, since they will receive some revenues even when not running.

Table 14 Impact of capacity payments on investment risk

	CCGT	Nuclear	CCS	Wind	Biomass
Fuel costs	Risk unchanged	Risk unchanged	Risk unchanged	n/a	Risk unchanged
Carbon costs	Risk unchanged	n/a	n/a	n/a	n/a
Electricity revenues	Risk reduced	Risk reduced	Risk reduced	Risk reduced	Risk reduced
Subsidy levels	n/a	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Load factor risk	Risk reduced	Risk unchanged	Risk reduced	Risk unchanged	Risk reduced
Balancing risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Construction costs/times	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
Availability/ technology risk	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged
O&M costs	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged	Risk unchanged

5.2.3 Modelling assumptions

We have modelled a simple price-based capacity payment scheme for the Capacity Payments for All option. We have assumed that the scheme is implemented in 2018 (the year in which the analysis suggests that the risks to security of supply become material) and that generators and investors have two years' forward knowledge of its introduction.

The scheme would work on the principle that a new entrant open cycle gas turbine (OCGT) peaking plant should just be able to cover its fixed and capital costs when the desired de-rated capacity margin is achieved. This would be implemented by creating an annual capacity payment pot calculated as:

- Capacity payment pot size = Forecast peak demand * (1 + targeted de-rated capacity margin) * fixed and capital costs of a new entrant OCGT.

This capacity pot is then distributed to generators based on their availability through the year, or, in the case of intermittent renewables, according to a deemed capacity credit[65].

On the basis of a targeted de-rated capacity margin of 10% and combined fixed and annuitised capital costs for an OCGT of £60/kW/yr this would yield capacity payments of approximately £7/MWh of availability for an outturn de-rated capacity margin of 10%. The pot size is independent of the amount of capacity on the system, so if the de-rated capacity margin is below the 10% target the capacity pot is spread across a smaller amount of capacity and the average capacity payment scales up, and vice versa. This yields a fairly

[65] In practice, demand side response may also qualify for capacity payments but for modelling simplicity we have focused the analysis on the supply side.

stable capacity payment revenue stream with payments only varying by a few percentage points depending on the outturn de-rated capacity margin[66].

For the purposes of the investment modelling, we have assumed a flat profile of capacity payments through the year, although it is possible that the scheme could be implemented with capacity payments that scale depending on the relative tightness of the system. This would sharpen the incentives on generators (and demand-side response) to be available when capacity is most needed.

Once Capacity Payments for All are implemented we have assumed that the electricity market trades based on the short-run costs of the marginal plant since generators no longer require an 'uplift' in electricity prices to cover their fixed and capital costs. To achieve this in practice may require price regulation and it is not clear in a bilaterally traded market how this could be implemented[67].

We assume that low-carbon generators receive capacity payments under all decarbonisation options (with low-carbon support payments adjusted accordingly) with the exception of Fixed Payments. Under this policy option it is assumed that the central buying agency receives the capacity payments associated with the low-carbon generation it is purchasing, and these payments are deducted from the costs of Fixed Payments recovered from consumers.

Based on the results of simulating the earnings risk for different types of investment, we make some assumptions on the possible increase in gearing that may be achievable for different technologies under Capacity Payments for All.

These assumptions are shown in Table 15 below. A 5% increase in gearing for new CCGT investment would, for example, translate to a reduction in hurdle rate of about 0.3%. For low-carbon generation these adjustments to hurdle rates do not apply under Fixed Payments or Contracts for Difference since investors are not exposed to wholesale electricity prices.

Table 15 Assumptions on the possible increase in gearing achievable with Capacity Payments for All

	Assumed increased in gearing
CCGT	5%
CCGT + CCS	5%
Coal + CCS	5%
Nuclear	5%
Onshore wind	2.5%
Offshore wind	2.5%
Biomass	2.5%
OCGT	25%

[66] Under a capacity auction approach there would likely be greater variability, with the auction clearing at a low price if the forecast de-rated capacity margin was in excess of the targeted level.

[67] Where wholesale price regulation has been implemented in markets internationally this has normally been associated with pool based systems.

The simulation results suggest that capacity payments could reduce earnings risk somewhat for generators, although fuel and carbon price uncertainty remains a key driver of price risk. Intermittent renewables benefit less than other plant since they would be likely to receive lower levels of capacity payment revenues. The greatest benefit occurs for OCGT plant which are very exposed to load factor uncertainty under current market arrangements (in the absence of reserve contracts with the System Operator).

5.2.4 Modelling results

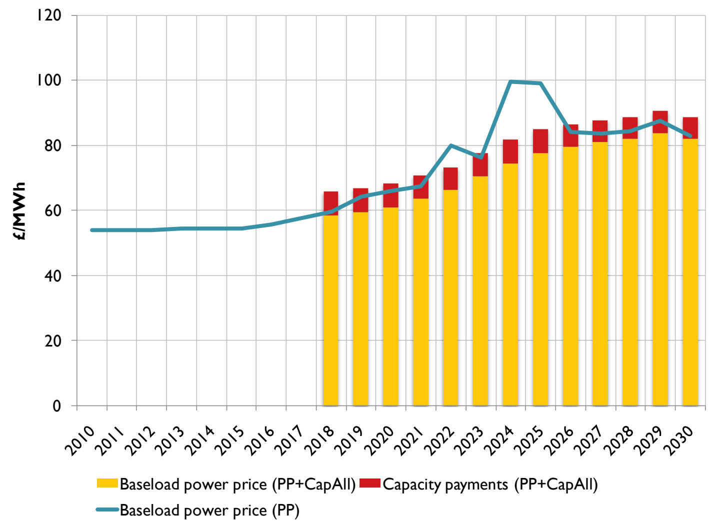
The impact of introducing Capacity Payments for All is similar across all five decarbonisation options. In this section we focus on the impact of Capacity Payments for All when combined with Premium Payments for low-carbon generation. We present results for the other four decarbonisation options in summary format.

Reduction in price volatility

The introduction of Capacity Payments for All, along with SRMC pricing in the energy market, would likely reduce year-on-year electricity price variability as well as within year electricity price volatility.

Figure 50 shows the impact of Capacity Payments for All on baseload prices under the Premium Payments option. The blue line shows the modelled baseload electricity price in the absence of a capacity payment mechanism. In years where capacity margins are tight, for example in 2024 and 2025, prices spike well above the average short-run generation costs. Under Capacity Payments for All (introduced in 2018) this variable 'uplift' in prices is replaced by a steady stream of capacity payments. The combination of the average electricity price based on SRMC pricing (yellow bars), and the capacity payment revenues (red area), yield a more stable combined revenue stream for generators.

Figure 50 Comparison of baseload prices under Premium Payments with and without Capacity Payments for All



For a generator that operates at baseload, capacity payments represent only a relatively small portion of total revenue, around 10% under the assumptions modelled. Figure 50 suggests that in some years baseload generators would be better off under Capacity Payments for All and in others worse off. On average, under the Premium Payments option, total revenues for baseload generators are slightly lower over the modelling period when Capacity Payments for All are included.

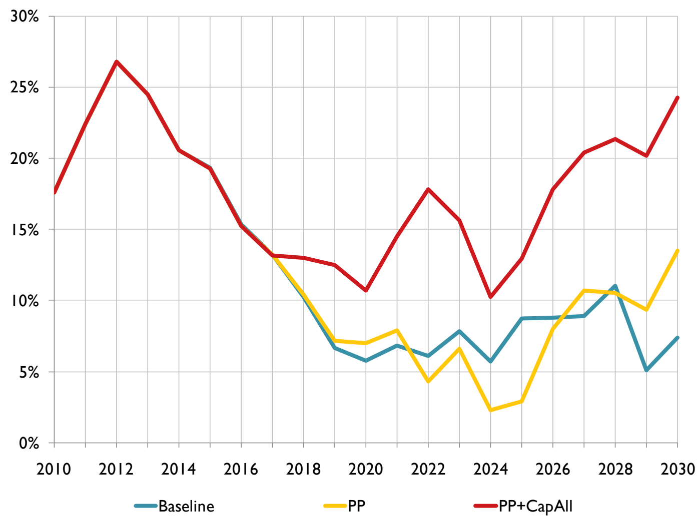
For mid-merit and peaking plant, however, the capacity payments would represent a much larger component of the overall revenue stream. For example, an older CCGT, which is available for 90% of the year, would receive capacity payments equivalent to around £55-60/kW/yr. This should be sufficient to cover annual fixed operating costs providing an incentive for the plant to remain open even when operating with very low load factors. Hence, for the scheme modelled, average revenues for mid-merit and peaking plant are likely to be higher, and more certain, when a capacity mechanism is in place.

Impact on security of supply

The main objective of a capacity mechanism is to ensure that there is sufficient generating capacity (and demand-side response) available to the system to meet an acceptable level of security of supply (which we have assumed in the modelling is a de-rated capacity margin of 10%). Capacity Payments for All, at the levels modelled, would likely significantly increase de-rated capacity margins and reduce the risk of unserved energy.

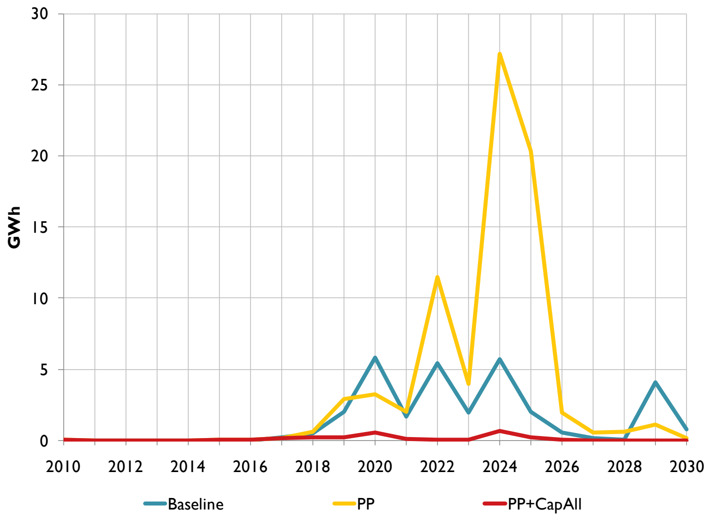
Figure 51 and Figure 52 show the impact of Capacity Payments for All on de-rated capacity margins and expected energy unserved for the Premium Payments option. De-rated capacity margins are significantly higher after 2020 with Capacity Payments for All, and are at or higher than historical levels. As we discuss below, one of the main contributing factors to the increase in de-rated capacity margins is the extension in lifetimes of existing coal and gas plant.

Figure 51 De-rated capacity margins under Premium Payments with / without Capacity Payments for All



The increase in capacity has the impact of reducing the risk that there is not enough supply available to meet demand, and therefore the risk of energy unserved is apparently very low with Capacity Payments for All. However, this result does assume that the plant on the system is able to provide the flexibility required to manage intermittency associated with renewables.

Figure 52 Expected Energy Unserved under Premium Payments with / without Capacity Payments for All



In all policy options modelled, the introduction of Capacity Payments for All leads to increases in de-rated capacity margins. The impact varies across options and the target objective of keeping de-rated capacity margins above 10% is not achieved in all cases, as shown in Table 16 below. For example, the de-rated capacity margin still falls as low as 6.8% under Contracts for Difference. This demonstrates the risk with priced-based capacity mechanisms – there is no guarantee that a certain security standard will be met, while in other years they could lead to over-capacity.

Table 16 Minimum de-rated capacity margins 2010-2030

	Minimum de-rated capacity margin	
	Without capacity payments	With Capacity Payments
Baseline	5.1%	5.7%
FP	2.4%	9.2%
PP	2.3%	10.2%
CfD	2.2%	6.8%
CPS50	4.6%	10.5%
EPS	5.7%	6.5%

Impact on retirements

Capacity Payments for All would likely lead to the deferral of retirements, particularly of older CCGTs.

Figure 53 and Figure 54 show cumulative plant retirements with and without Capacity Payments for All under the Premium Payments policy. Capacity payments change the economics for existing plant and encourage them to stay open longer since annual fixed costs can be covered by the payments. Existing generators with declining load factors receive higher, more stable revenues under Capacity Payments for All. In total 8 GW of CCGT and 2 GW of coal is extended by between two and ten years.

Capacity payments may lead to generators changing their decisions surrounding the IED. Within the modelling, a number of older CCGTs change from LLO to TNP in order to stay open after 2023. The timing of the announcement surrounding a capacity payment mechanism is therefore important with respect to decisions generators make surrounding the IED.

Figure 53 Cumulative plant retirements – Premium Payments

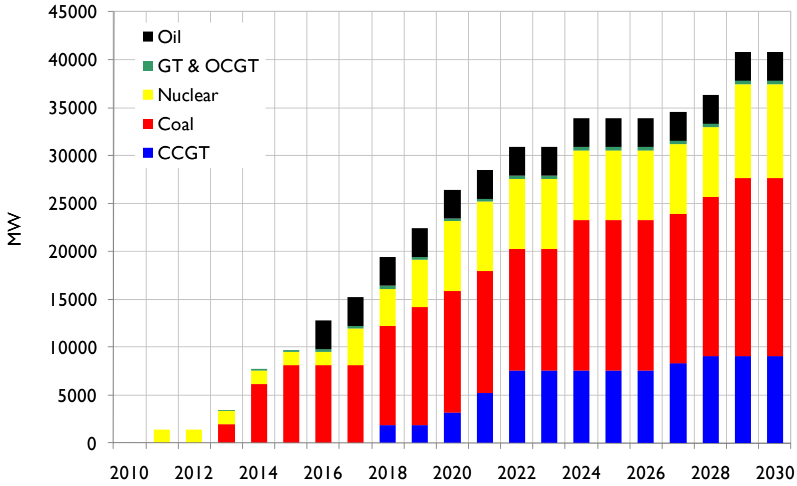
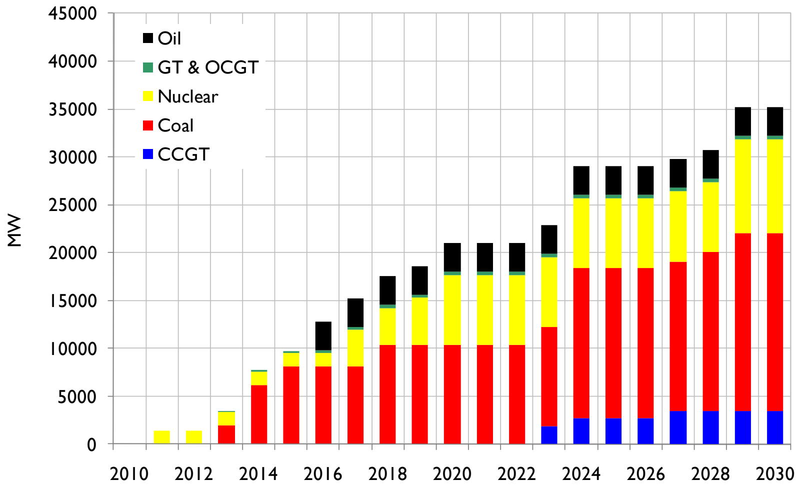


Figure 54 Cumulative plant retirements – Premium Payments + Capacity Payments for All



Impact on new build

The modelling suggests that the introduction of Capacity Payments for All does not necessarily lead to significantly greater investment in new plant. Premium Payments have been adjusted to reflect lower wholesale energy market revenues but greater income from capacity payments. Investment in low-carbon generation is broadly unchanged as a result.

If low-carbon investment is forthcoming, the targeted de-rated capacity margin can be achieved largely through lifetime extensions of existing plant[68]. Figure 55 and Figure 56 show cumulative new build by technology with and without Capacity Payments for All under the Premium Payments option. The cumulative amount of new CCGT capacity is only slightly higher by 2025 when capacity payments are introduced. There is also no investment in new OCGTs. This is because capacity payments turn out just below the level required to support new OCGT build due to the surplus of existing plant. The modelled capacity mechanism treats all thermal capacity equally and therefore does not incentivise plant with any particular technical capabilities. There is therefore a risk with a universal capacity payment mechanism that the wrong type of capacity is incentivised.

Figure 55 Cumulative new plant build – Premium Payments

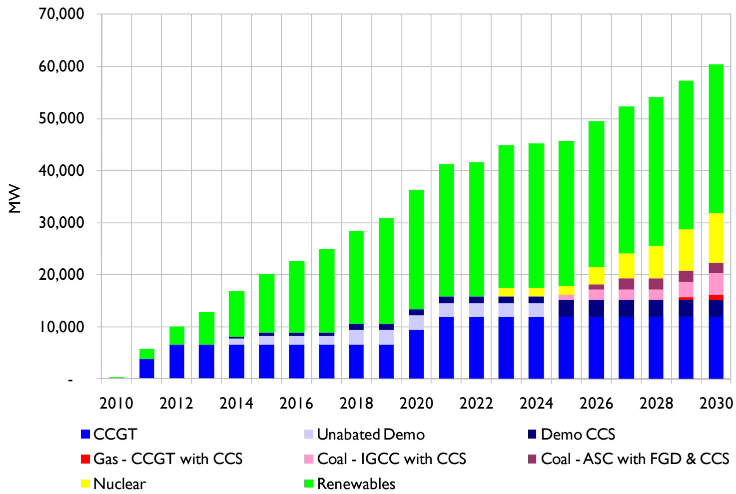
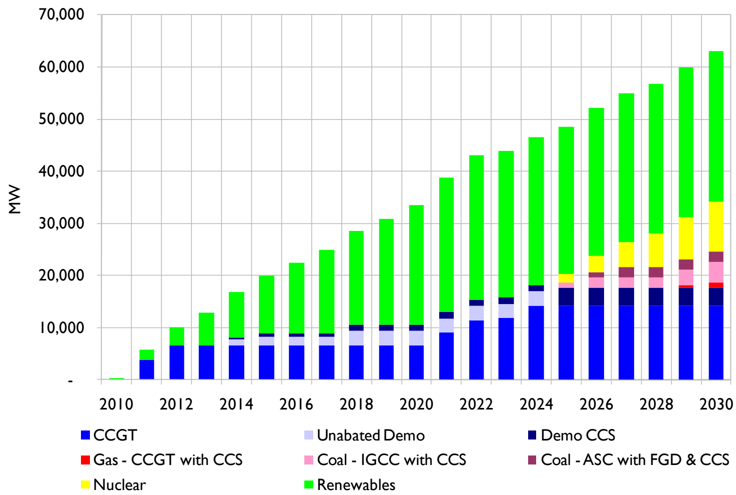


Figure 56 Cumulative new plant build – Premium Payments + Capacity Payments for All

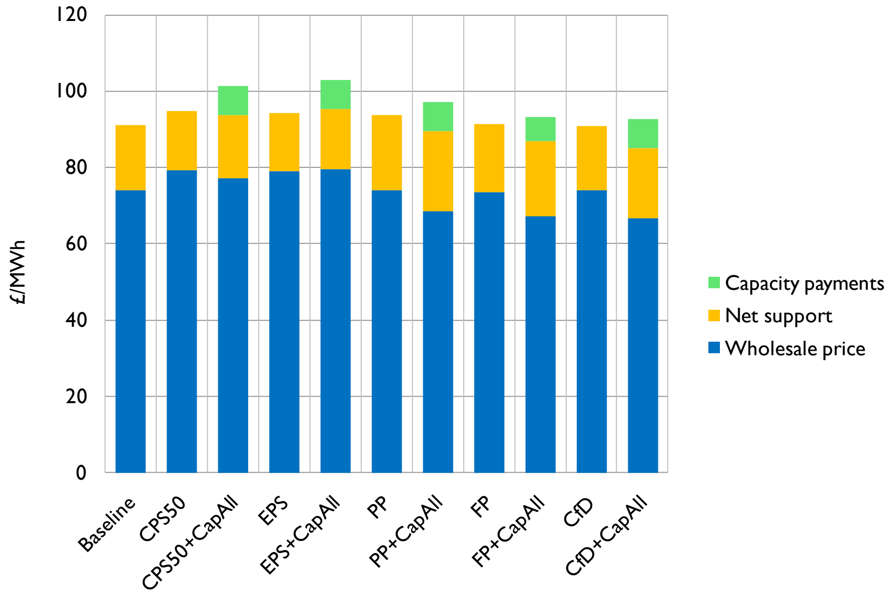


[68] Although not modelled, there may also be increased demand-side response.

Impact on wholesale energy costs

Figure 57 shows the average consumer energy prices under Capacity Payments for All compared to the corresponding decarbonisation option with no capacity payments. The cost of capacity payments is similar for all options, but the overall impact on the wholesale energy cost differs depending on the extent to which electricity prices come down. Under Premium Payments, Fixed Payments and Contracts for Difference there is a large reduction in electricity prices, if SRMC pricing was implemented alongside capacity payments, but not sufficient to compensate fully for the additional costs of capacity payments at the levels set. Under Carbon Price Support (£50/t) and Strong EPS where de-rated capacity margins are generally higher without capacity payments and there is less price 'uplift', the corresponding reduction in electricity prices is much less and consumers are considerably worse off. The modelling suggests that wholesale energy costs would be on average £2/MWh higher (£6 on an average domestic customer's bill) under Fixed Payments and Contracts for Difference and up to £9/MWh higher (£28 on an average domestic customer's bill) under Strong EPS.

Figure 57 Wholesale energy costs – Capacity Payments for All



Impact on decarbonisation

Capacity Payments for All may encourage less efficient fossil plant to stay on the system (albeit running at low load factors) and so unless support for low-carbon generation is adjusted accordingly carbon dioxide emissions may be higher. Figure 58 shows that the carbon intensity falls short of the illustrative target of 100 g/kWh by 2030 when Capacity Payments for All are introduced with Carbon Price Support (£50/t), which reaches112 g/kWh, and with Strong EPS, at 132 g/kWh. While ROC bands under these policies can be adjusted there are no easy levers to increase investment in nuclear and CCS to compensate, whereas it is easier to adjust price levels under Premium Payments, Fixed Payments or Contracts for Difference if necessary.

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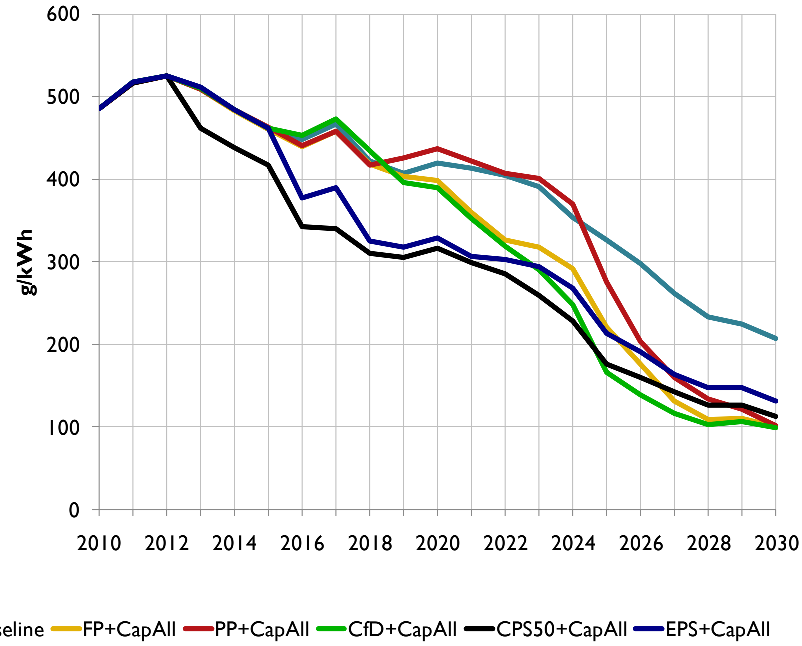
Figure 58 Annual average carbon dioxide emissions intensity – Capacity Payments for All



Cost benefit analysis

Table 17 shows the cost benefit analysis for the Capacity Payment for All options relative to the respective decarbonisation options alone. The cost benefit analysis results relative to the Baseline are shown in Appendix G[69].

[69] Please note that though Capacity Payments for All are assumed to be introduced in 2018 in the model, the associated benefits and costs are discounted back to 2010.

Table 17 Cost benefit analysis relative to decarbonisation option

Change in welfare NPV 2010-2030, (£m 2009 real)		Carbon Price Support (£50/t) & Capacity Payments For All	Strong Emissions Performance Standard + Capacity Payments For All	Premium Payments + Capacity Payments For All	Fixed Payments + Capacity Payments For All	Contracts for Difference + Capacity Payments For All
Net Welfare	Carbon costs	-1,828	-2,654	-84	18	1,883
	Generation costs	-2,754	-3,495	-2,347	-1,287	2,006
	Capital costs	7,403	10,257	-2,040	0	-4,446
	Unserved energy	192	104	444	434	426
	Demand side response	33	20	59	61	49
	Change in Net Welfare	**3,047**	**4,232**	**-3,968**	**-774**	**-83**
Distributional analysis						
Consumer Surplus	Wholesale price	9,369	732	25,990	27,599	33,199
	Low carbon payments	-5,346	-4,201	-6,303	-7,915	-7,550
	Capacity payments	-35,136	-35,120	-35,136	-29,196	-35,099
	Unserved energy	192	104	444	434	426
	Demand side response	33	20	59	61	49
	Change in Consumer Surplus	**-30,888**	**-38,465**	**-14,946**	**-9,016**	**-8,976**
Producer Surplus	Wholesale price	-9,369	-732	-25,990	-27,599	-33,199
	Low carbon support	5,335	4,100	6,341	7,913	7,517
	Capacity payments	35,136	35,120	35,136	29,196	35,099
	Producer costs	1,900	4,108	-4,471	-1,269	-558
	Change in Producer Surplus	**33,002**	**42,596**	**11,015**	**8,240**	**8,859**

Introducing Capacity Payments for All generally leads to a reduction in net welfare (relative to the decarbonisation option without capacity payments) since the additional resource costs associated with having more capacity on the system are greater than the savings in expected energy unserved. However, this result is critically dependent on assumptions regarding the cost of unserved energy. We have assumed an average value of lost load (VoLL) of £10,000/MWh.

Under Carbon Price Support (£50/t) and Strong EPS, the inclusion of Capacity Payments for All appears to lead to an increase in net welfare. However, this is due to the lower investment in low-carbon generation which results from the lifetime extensions of existing plant and comes at the cost of not achieving the decarbonisation objectives.

The distributional effects of Capacity Payments for All are much greater than the overall net welfare impact. Under our modelling assumptions, consumers are worse off with Capacity Payments for All for the reasons described above. Correspondingly, producers are significantly better off particularly under Carbon Price Support (£50/t) and Strong EPS.

These results suggest that price based capacity mechanisms could be expensive for consumers. By varying the level of capacity payments, we have identified that under some decarbonisation options it may be possible to reduce the level of payment with no loss in security of supply. Under the Fixed Payments option it is possible to maintain a de-rated capacity margin close to 10% through the combination of early investment in low-carbon generation and lifetime extensions of existing plant. There is also potential for greater demand-side response, although this has not been modelled. In this case, a reduction in capacity payments of 30%, to around £5/MWh of availability, is still sufficient to keep older plant on the system, and yields the same levels of de-rated capacity margin (although there is an increased risk that new CCGT investment might not be forthcoming). At this level, the additional cost to consumers from the capacity payment mechanism would be very small (on the assumption that the electricity prices are based on SRMCs).

However, under other options where low-carbon investment comes later, and new thermal capacity is needed to fill the capacity gap, this lower level of capacity payment would not be sufficient to stimulate investment. This illustrates the difficulty in setting the correct level for a priced-based universal capacity mechanism. Volume-based mechanisms, such as capacity auctions, may offer a more cost effective solution in this respect by helping to reveal the value of different types of capacity.

5.3 Targeted Capacity Tender

5.3.1 Description

The Targeted Capacity Tender differs from Capacity Payments for All in that it would only cover a small subset of generating plant or demand-side response. Under the Targeted Capacity Tender, a central body, probably the System Operator, would be responsible for procuring a volume of back-up capacity to meet a defined security standard. This would in effect be an extension of the System Operator's current role in procuring reserve and other balancing services. The costs of the tendered capacity could be recovered through Use of System charges.

To fulfil this role the central body would forecast expectations of de-rated capacity margins for a defined number of years forward. To the extent that the de-rated capacity margin is expected to fall below the defined security standard it would tender for additional capacity, which could include new generation capacity, demand-side response or extensions to existing plant that would otherwise be closing on economic grounds[70]. Tenders could be run on a rolling annual basis.

Since the de-rated capacity margin includes a capacity credit for wind that is non-zero, a more conservative approach would be to procure back-up assuming no output from wind plant. This would be an important consideration when designing the security standard.

The mix of capacity that the central body procures will depend on the System Operator's requirements for flexibility and responsiveness. For example, in order to manage variability in wind output a certain proportion of the capacity will need to be able to ramp very quickly. Not all existing generating plant will necessarily be able to meet this requirement.

A very important consideration is the impact of the tendered capacity on electricity prices. If as a result of the procurement of additional back-up, investors' expectations of future electricity prices are dampened, the policy could become self-defeating with progressively less private investment and a progressively increasing requirement for back-up. There are broadly two alternatives to mitigate this risk:

- to use the back-up capacity only as a 'strategic reserve' to be deployed as a last resort before firm load curtailment would occur, which should mean that prices still spike to high levels when margins become very tight, or
- to use the back-up capacity when the electricity price exceeds its utilisation (short-run operating) cost but to price in the availability fees of the capacity into imbalance charges thus maintaining signals on parties to cover their peak positions.

[70] The tender would need to be designed carefully so as not to create the unintended consequence that plant that would have been available announce an intention to close in order to be able to participate in the tender.

The latter approach is similar to how the costs of reserve are currently factored into imbalance charging[71]. Exactly how this would be done with respect to back-up capacity would be an important design consideration.

5.3.2 Modelling assumptions

We assume that Targeted Capacity Tenders are introduced when the de-rated capacity margin is forecast to drop below a required security standard, which we assume to be a 10% de-rated capacity margin. For simplicity, we assume that the SO has perfect foresight in tendering for the correct amount of capacity required, and that all tendered capacity is delivered. In reality, there will clearly be uncertainty on both the supply- and demand-side forecasts in determining the requirement.

Under our approach, the SO tenders for capacity which fulfils certain flexibility and responsiveness requirements, some of which can be provided by existing plant and some of which would be from new OCGT plant. We have not modelled the potential role of demand-side response in the tender, although we recognise that this could fulfil some of the requirement and would have the potential to lower the costs to consumers.

The tender would be broken down into longer duration and shorter duration contracts. The longer duration tenders would be necessary to secure investment in new flexible OCGT plant, and we have assumed 20 year contracts. There is a balance here between providing longer-term certainty for investors in OCGTs and the risk of stranded assets should de-rated capacity margins subsequently recover. Shorter contracts could be offered but bidders would likely increase their price so that they could earn their required return over a shorter period. The shorter duration tenders would be run more frequently and cover existing plant. We have assumed that both the long and short duration tenders are paid as bid, although again this is design question.

We have assumed initially that the tendered capacity is used as a strategic reserve, and hence in theory would not influence price. Hence, consumers would benefit from improved security of supply but not necessarily from the avoidance of large price spikes associated with very tight capacity margins. We also consider a variant where the tendered capacity can be used by the System Operator when prices exceed the utilisation fee for the capacity, with the availability fees priced into the imbalance prices. This approach would prevent prices peaking to extreme levels but should in theory maintain incentives on parties to cover their peak positions since the cost of providing peaking capacity should still be reflected in the market price of electricity.

5.3.3 Modelling results

We have modelled the impact of a Targeted Capacity Tender on one of the decarbonisation options, Fixed Payments. In this option the de-rated capacity margin falls below 10% in the 2020s. Figure 59 shows the de-rated margin excluding the tendered capacity, the tendered capacity in each year, and the final de-rated margin including the tendered capacity.

We assume that part of the forecast capacity shortfall, which peaks at 5.4 GW in 2024, is filled through long-term tenders for new OCGT capacity, which is also capable of providing a high degree of responsiveness. Thereafter, more general capacity requirements are met through shorter term tenders,

[71] As laid out in the Balancing Services Adjustment Data Methodology (http://www.nationalgrid.com/NR/rdonlyres/C6941419-3742-43A5-B4EE-3AFB03C324A4/38313/BSADv5_Review1.pdf)

which are filled by extensions of older gas and coal plant that would otherwise have closed. The mix of long-term and short-term tenders, and the technical specifications for these, would be based on the System Operator's assessment of future system requirements. If the security standard assumed a zero de-rating factor for wind, the peak requirement for tendered capacity would double to around 10.7 GW.

We assume that in the long-term capacity tenders, the cleared bids cover annual fixed costs as well as annuitised capital costs (financed over the economic life of the plant), and equate to around £60/kW/yr. The price received by existing capacity in the short-term tenders is assumed to cover annual fixed costs as well as a margin over these costs, which equates to around £43/kW/yr.

Figure 59 Impact on capacity margins – Fixed Payments + Targeted Capacity Tender

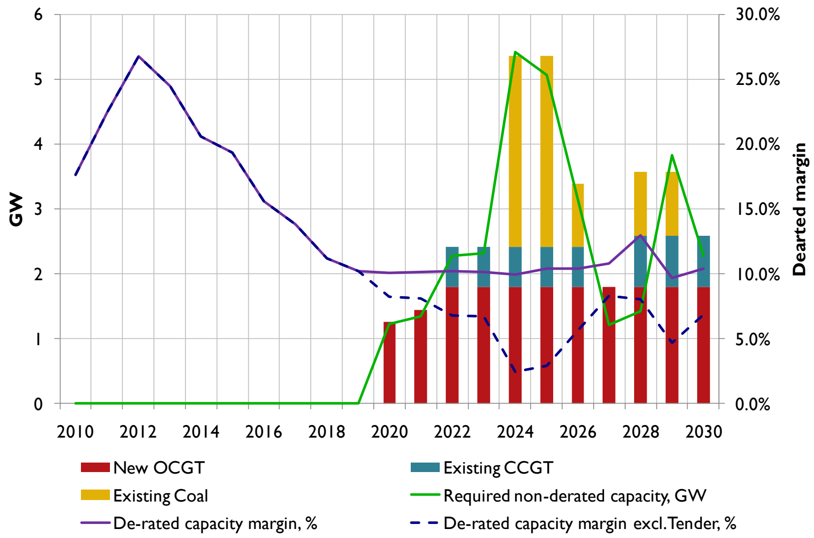


Figure 60 shows the impact on annual expected energy unserved of the Targeted Capacity Tender on the Fixed Payments option. The risk to security of supply is significantly reduced, and lower than the Baseline which is also shown in the graph.

Figure 60 Impact on expected energy unserved – Fixed Payments + Targeted Capacity Tender

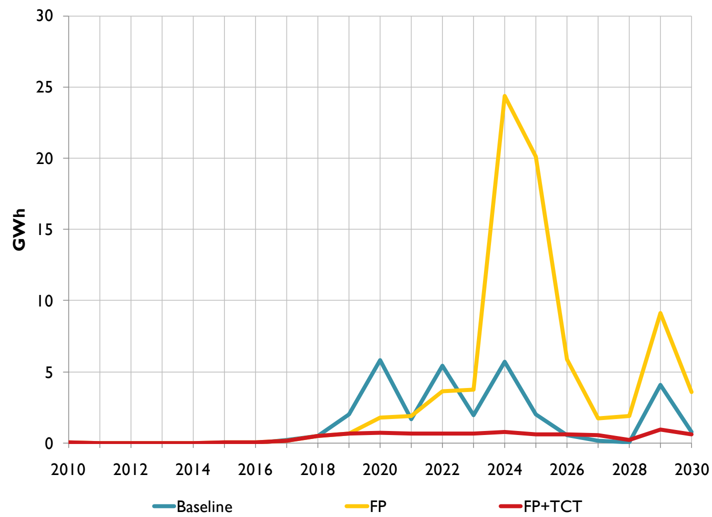
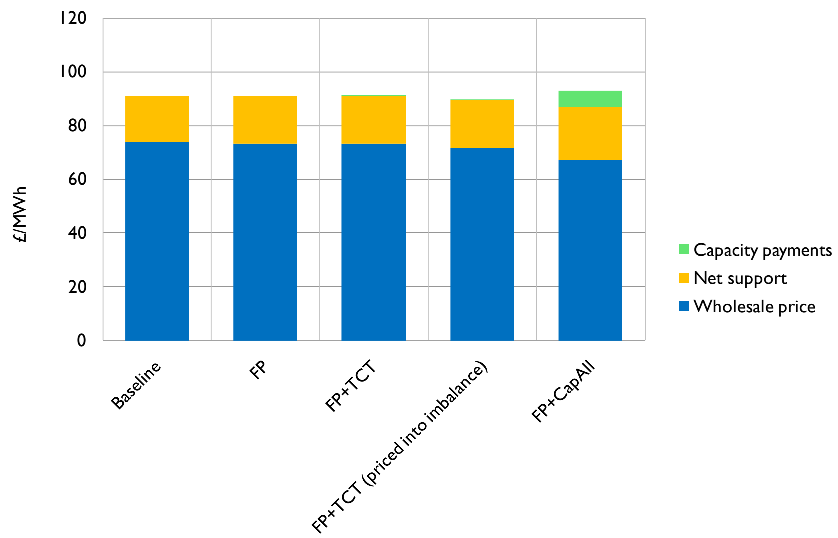


Figure 61 compares the average wholesale energy costs for the Fixed Payments option with and without a Targeted Capacity Tender. The Targeted Capacity Tender adds about £0.3/MWh which equates to around £1 on the average annual domestic consumer bill. This compares to between £2/MWh and £9/MWh under Capacity Payments for All.

Figure 61 Average consumer electricity price



There is no corresponding benefit in terms of lower wholesale electricity prices if the tendered capacity is held as a strategic reserve. In the alternative case, where tendered capacity is used by the SO when it is economic to do so[72], and not as a last resort, there could be lower wholesale prices as they would no longer spike up to £10,000/MWh which we have assumed in the modelling is possible if there is insufficient supply to meet demand[73]. If, for example, the tendered capacity was priced into imbalance charges at £500/MWh, effectively putting a cap on prices at this level, then costs to consumers under Fixed Payments could on average be lower by about £1.3/MWh with a Targeted Capacity Tender[74]. However, it is difficult to draw strong conclusions as to whether a Targeted Capacity Tender could result in savings to customers without a better understanding of how prices behave under times of system stress, and how the tendered capacity would be deployed and priced into the market.

Table 18 shows the cost benefit analysis for Fixed Payments + Targeted Capacity Tender, relative to Fixed Payments. There is a slight reduction in net welfare under the Targeted Capacity Tender since the additional costs of the tender capacity exceed the savings in unserved energy (given assumptions on value of lost load).

Consumers are slightly worse off than under Fixed Payments without Targeted Capacity Tender primarily because the benefit in terms of reduction in total unserved energy is outweighed by the cost of the tender.

[72] The term 'economic' in this context pertains to periods when the SRMC of tendered capacity is lower than the SRMC of the system marginal plant.

[73] As explained in Section 3 there may be reasons why under the current arrangements this may not happen.

[74] This figure represents an average over the period 2010-2030 and is derived by calculating the reduction in consumer electricity cost resulting from imposing a £500/MWh price cap on the wholesale price of electricity. This calculation assumes that there is no change to dispatch or to the distribution of prices below £500/MWh as a result of imposing the price cap.

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Table 18 Cost benefit analysis – Targeted Capacity Tender

Change in welfare NPV 2010-2030, (£m 2009 real)		Fixed Payments + Targeted Capacity Tender
Net Welfare	Carbon costs	82
	Generation costs	-709
	Capital costs	-470
	Unserved energy	404
	Demand side response	0
	Change in Net Welfare	**-694**
Distributional analysis		
Consumer Surplus	Wholesale price	-279
	Low carbon payments	39
	Capacity payments	-1,133
	Unserved energy	404
	Demand side response	0
	Change in Consumer Surplus	**-969**
Producer Surplus	Wholesale price	279
	Low carbon support	-37
	Capacity payments	1,133
	Producer costs	-1,098
	Change in Producer Surplus	**277**

5.4 Key messages

The modelling of the Baseline and the decarbonisation options suggested that there are potential risks to security of supply towards the end of this decade and into the next. These risks result from the possible suppression of electricity market prices as a consequence of support for low-carbon generation, and the fact that some of this low-carbon generation is intermittent in nature.

One potential mitigating factor for the security of supply risk is the possible expansion of demand-side response, enabled by smart meters, other demand side technologies and new customer pricing propositions encouraging them to shift demand away from peaks. However, some form of capacity mechanism could be introduced to mitigate this risk further. The analysis suggests that if appropriately designed, Capacity Payments for All or Targeted Capacity Tenders could result in higher de-rated capacity margins and lower risks to security of supply, although the outcomes in terms of generation mix could be quite different under these two different schemes. Many other scheme designs are possible.

The cost benefit analysis suggests that the introduction of a capacity payment mechanism could lead to a small reduction in net welfare since the additional resource costs are generally higher than the savings from reduced expected energy unserved. However, this result is highly dependent on the assumptions surrounding the value of lost load, assumed to be an average £10,000/MWh.

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5.4.1 Impact of options

The analysis suggests that, if appropriately designed, Capacity Payments for All or Targeted Capacity Tenders could result in higher de-rated capacity margins and lower risks to security of supply. However, the outcomes in terms of generation mix could be quite different under these two different schemes. Table 19 summarises the impact of each relative to the underlying decarbonisation option.

Table 19 Decarbonisation + Capacity Mechanism: Summary metrics

Decarbonisation option	Capacity mechanism	Decarbonisation		Security of supply		Resource costs	Costs to consumers	CBA
		Carbon intensity	Cum. CO2	Capacity margin		NPV rel. to baseline	Average wholesale energy cost	Net welfare relative to Baseline
		2030	2010-2030	Ave 2018-2030	Min 2018-2030	2010-2030	2010-2030	2010-2030
Baseline	No capacity mechanism	207	2973	7.6%	5.1%	N/a	91	N/a
Strong EPS	**Central**	**100**	**2377**	**9.6%**	**5.7%**	**7,815**	**94**	**-7,706**
	Capacity Payments for All	132	2472	13.6%	6.5%	3,707	103	-3,474
Carbon Price Support	**Central**	**100**	**2207**	**8.8%**	**4.6%**	**5,836**	**95**	**-5,780**
	Capacity Payments for All	113	2285	16.0%	10.5%	3,015	101	-2,733
Premium Payments	**Central**	**101**	**2782**	**7.7%**	**2.3%**	**6,471**	**94**	**-6,698**
	Capacity Payments for All	102	2784	16.3%	10.2%	10,942	97	-10,666
Fixed Payments	**Central**	**101**	**2599**	**6.9%**	**2.4%**	**3,621**	**91**	**-3,846**
	Capacity Payments for All	101	2596	14.8%	9.2%	4,890	93	-4,620
	Targeted Tender Capacity	101	2591	6.9%	2.4%	4,719	92	-4,540
Contracts for Difference	**Central**	**98**	**2606**	**6.7%**	**2.2%**	**3,678**	**91**	**-3,965**
	Capacity Payments for All	99	2531	10.1%	6.8%	4,236	93	-4,049

Decarbonisation: As older, higher-emitting plant will tend to stay on the system longer under Capacity Payments for All, emissions can be somewhat higher as a result, particularly under Carbon Price Support (£50/t) and Strong EPS where it is more difficult to adjust incentives for low-carbon investment in order to compensate. The Targeted Capacity Tender, by design, has minimal effect since the back-up capacity would only be run when required to meet peak system requirements.

Generation mix: Older plant stay on the system longer under Capacity Payments for All, and no new OCGTs are built. In contrast, new OCGTs are specifically brought on-line, together with some extensions, under the Targeted Capacity Tender. It may also be possible to target particularly forms of demand-side response.

Security of supply: The de-rated capacity margin increases significantly under both options. Under a price-based version of Capacity Payments for All, it can still fluctuate around the target security standard, although it averages higher due to the stronger incentives to keep existing plant open for longer.

Resource costs: There is some increase in resource costs in most cases, except for Carbon Price Support (£50/t) and Strong EPS, under which low-carbon investment is somewhat reduced (meaning that decarbonisation targets are not met).

Costs to consumers: Under Capacity Payments for All, costs to consumers increase (by between 6 and £28 per year on average over the period 2010-2030 for a domestic customer) as the reduction in electricity prices is less than the capacity payments to generators. However, assuming the 'uplift' in prices is subsequently avoided, consumers should benefit from reduced volatility in prices associated with system tightness. The cost increase is much smaller under the Targeted Capacity Tender, on average around £1 per year for a domestic consumer. If the tendered capacity is utilised when economic to do so (ie, not held as a strategic reserve) and appropriately priced into the market, extreme price spikes could be avoided, and it is possible that there could be cost savings for consumers.

Generator rents: There is a risk of rents for generators under Capacity Payments for All depending on the level set, and whether prices in the bilateral market subsequently SRMC pricing. The risk is lower under the Targeted Capacity Tender.

5.4.2 Risks of options

Incorrect levels: In both cases, it will be difficult to evaluate the appropriate security standard, particularly as the penetration of intermittent renewables increases. For the price-based approach, an appropriate benchmark 'cost of capacity' will also be required. Getting these levels wrong could lead either to higher costs for consumers, or result in a lower level of security of supply than intended.

Forecast uncertainty: The volume-based approach requires the tendering body to forecast both demand and the supply position (including demand-side response) over a number of years forward. Both of these are uncertain, meaning that the resulting tendered volumes may correspondingly be too high or too low. In practice it is likely that the central entity tasked with ensuring the security standard will err on the side of higher volumes (to ensure a defined target is met) as it will be challenging to create incentives that reflect the risk of higher costs to consumers in this case.

Displacement of investment: There is a risk, despite the intended design of the mechanism, that tendering for peak capacity may displace investment that would otherwise have taken place, due to an anticipated effect on prices. This may be particularly true for demand-side response, and other smaller scale innovative technologies, as although in theory this could be eligible for payments, in practice monitoring and administrative requirements may be relatively much more onerous. There is a further risk that existing plant may announce an intention to close earlier in order to increase the requirement for tendered capacity, and make themselves eligible to participate. The combination of this and displaced investment could result in an unintended consequence of a progressively expanding role for a central buyer of capacity.

Flexibility requirements: The price-based Capacity Payments for All may lead to a mix of plant that, while nominally providing a required level of total capacity, does not provide the flexibility required to manage the fluctuation in demand and intermittent renewable output. This can be addressed with the Targeted Capacity Tender option by tendering for different tranches of capacity with specific technical requirements.

Wholesale price uplift: The principle of Capacity Payments for All is that this new revenue stream will cover the capital and fixed costs of low load factor plant, such that these plant are economic without the need for significant price 'uplift' above the system SRMC. With this in place, any remaining 'uplift' creates rents to generators with no benefit to consumers. However, it is difficult to see how this could be monitored and controlled in a bilateral market.

Interconnected markets: Other than the Irish SEM, none of GB's neighbouring markets have capacity payments. The design of the scheme would need to consider carefully the impact of greater future interconnection (for example the 1 GW BritNed cable in 2012) and plans for market coupling. Greater market integration and regional harmonisation may become more difficult.

5.4.3 Implementation issues

Timing: As discussed above, the introduction of capacity payments could change the economics around plant retirement. For older CCGTs, this could lead to different decisions with regard to their choices under the IED. As a result, the timing of the announcement and implementation of a capacity payment scheme should take this into account.

Administration: A Targeted Capacity Tender would be a natural extension of the System Operator's current reserve procurement function. Capacity Payments for All would represent a separate revenue stream for generators, and an entity will need to manage the associated settlements, cashflows and credit, as well as the recovery of the costs. It may be noted that the processes would be equivalent to availability payments for low-carbon generation, and hence there would be efficiency in combining these processes.

Demand side: There is significant potential for the demand side of the market to provide response that would help the dynamic balancing of the system and reduce overall capacity requirements. It is likely that provision of this response will involve up front capital investments in instrumentation and communications technology to ensure an appropriate level of control for the System Operator. It is therefore important that careful consideration is given in the design of any capacity payment mechanism (either Capacity Payments for All or Targeted Capacity Tender) to ensure that demand side investments can compete on an equitable basis with both new generation investments and the life-extension of existing generation assets. In particular, the timescales and granularity of the capacity 'service' requirements must be consistent with making investments in demand response capability.

Monitoring: As noted above, introducing Capacity Payments for All could require monitoring of market prices to mitigate against the risk of continuing price 'uplift'. While a market-level indication of this could be generated by comparing outturn spot prices to those theoretically predicted from modelling, it is extremely difficult to envisage a method which could be used to connect this to the behaviour of specific market participants without drastically changing the market arrangements, or imposing very burdensome regulation on trading activities.

5.4.4 Summary

Capacity Payments for All

Capacity Payments for All would be likely to lead to improved capacity margins and reduce the risks to security of supply. It could reduce price volatility and increase investor confidence in developing new plant, particularly in CCGTs, that may no longer be able to guarantee baseload operation with high levels of low-carbon generation deployment.

However, it would be difficult to establish the correct level to set capacity payments at, and a universal scheme may not deliver an appropriate generation mix to provide the flexibility needed in a system with increasing proportions of intermittent renewables. With additional support for low-carbon investment, the required de-rated capacity margins could be achieved predominantly through extensions of existing coal and gas plant on the system. This would require capacity payments to be set at a relatively low level, sufficient to cover the annual fixed costs of these assets and any capital expenditure required in order to extend their lifetime. However, this older plant may not be sufficiently flexible. To attract more flexible back-up plant, such as new OCGTs, capacity payments would need to be set at a higher level. However, this could lead to windfalls for existing plant. In addition, there is a significant risk that generators are over-remunerated should electricity prices not fall on the introduction of the scheme, and any form of price regulation would be difficult with current trading arrangements. Similarly, compatibility with interconnected markets could be an issue, especially with increasing regional harmonisation.

For these reasons, designing an appropriate administered scheme becomes very difficult. Implementing a quantity-based capacity auction could address some of these issues and would aid price discovery, and the specification for the auctions could be more tightly defined to deliver the requisite flexibility.

Targeted Capacity Tender

The main benefit of the Targeted Capacity Tender relative to the Capacity Payments for All is that it allows for specific tranches of back-up to meet different technical requirements, particularly around flexibility. Through direct tendering, it removes the risk of windfalls for generators. It can act as an insurance policy and be implemented when it is needed, and therefore would be less disruptive to current market arrangements.

Nevertheless, forecast uncertainty will still represent a challenge, as will the risk that the tendered capacity could undermine private investment, and encourage existing plant to announce earlier closure, thus exacerbating a forecast capacity shortage.

6 Combination Packages

6.1 Packages considered

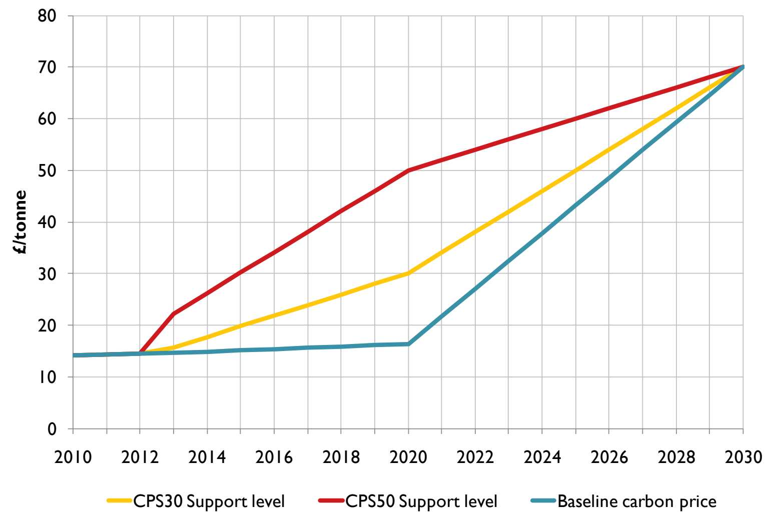
In this section we explore packages of options that combine Carbon Price Support set at a lower level with other policy options. The packages that we consider are:

- Premium Payments with Carbon Price Support (£30/t)
- Premium Payments, Carbon Price Support (£30/t) and Targeted Capacity Tenders
- Fixed Payments, Carbon Price Support (£30/t) and Targeted Capacity Tenders, and
- Contracts for Difference, Carbon Price Support (£30/t) and Targeted Capacity Tenders.

We also include a High Demand sensitivity on two of the combination packages in Appendix B.

The level of Carbon Price Support assumed in these combination packages rises less rapidly than that considered for the stand-alone Carbon Price Support (£50/t) option. It reaches £30/t by 2020 (compared to £50/t), before hitting the same level of £70/t by 2030, as shown in Figure 62 below. This scenario is consistent with the mid-range of illustrative scenarios presented in HM Treasury's Carbon Price Support consultation.

Figure 62 Carbon Price Support (£30/t)



When Carbon Price Support (£30/t) is combined with Fixed Payments we assume that the utilisation fee (for CCS plant) is automatically adjusted for a higher carbon cost[75] through the input cost indexation term, but that the availability fees remain unchanged. Likewise, there would be no change to the premia under Contracts for Difference. Hence, under these two combinations, adding Carbon Price Support (£30/t) has no impact on the amount of low-carbon investment that is projected in the modelling.

Investors are exposed to electricity prices under Premium Payments, and hence we assume that premia can be adjusted downwards to reflect higher expectations of electricity prices when Carbon Price Support (£30/t) is combined with this option.

[75] We assume a 90% capture rate for CCS.

We assume that a Targeted EPS as described in Section 4.2.5 is also included in these combination packages.

6.2 Modelling results

We compare the results of modelling the combination packages with each underlying decarbonisation option (Fixed Payments, Premium Payments, or Contracts for Difference). We separate the effects of the two additional policies (Carbon Price Support (£30/t) and Targeted Capacity Tender) in order to answer the following questions:

- What is the impact of combining Carbon Price Support (£30/t) with other decarbonisation options?
- What is the impact of a Targeted Capacity Tender on these combinations?

6.2.1 Plant mix

The impact of Carbon Price Support (£30/t) on low-carbon investment varies depending on the option it is combined with. Under Fixed Payments and Contracts for Difference, investors in low-carbon generation have limited exposure to electricity prices and hence the modelled impact of Carbon Price Support (£30/t) on investment is minimal. As shown in Table 20, the timing and volumes of new nuclear and CCS capacity are similar to the underlying decarbonisation option[76].

The pattern of low-carbon build does, however, change when Carbon Price Support (£30/t) is combined with Premium Payments. With Carbon Price Support (£30/t), premia can be reduced while still achieving the targeted emissions intensity by 2030. As costs come down, Carbon Price Support (£30/t) is sufficient alone to stimulate new nuclear and the premium can be reduced to zero. With more nuclear investment, less CCS is required to meet the same decarbonisation level and we have reduced premia for CCS so that the 2030 carbon intensity of 100 g/kWh is maintained. This is consistent with the analysis of the Carbon Price Support (£50/t) option which suggested that Carbon Price Support (a technology neutral instrument) may tend to favour cheaper and more mature technologies, relative to more targeted support options such as Premium Payments.

Table 20 Timing and capacity of Nuclear and CCS investment[77]

	PP	FP	CfD	PP+ CPS30	PP+ CPS30+ TCT	FP+ CPS30+ TCT	CfD+ CPS30+ TCT
Year of first new nuclear	2023	2019	2019	2023	2023	2019	2019
New nuclear capacity (2030)	9.6 GW	9.6 GW	11.2 GW	12.8 GW	12.8 GW	9.6 GW	9.6 GW
New CCS capacity (2030)[1]	7.0 GW	7.0 GW	5.5 GW	2.0 GW	2.0 GW	7.0 GW	7.0 GW

[76] Note that under Contracts for Difference, adding Carbon Price Support (£30/t) and Targeted Capacity Tender results in a fall in nuclear capacity by 2030 with a corresponding increase in CCS capacity. This results from lumpiness in the setting of CfD strike prices in the model and we do not believe this result to be significant.

[77] Note that new CCS capacity excludes retrofitted capacity.

The inclusion of Carbon Price Support (£30/t) within the combination packages has little impact on investment in CCGT. The inclusion of Carbon Price Support (£30/t) does, however, accelerate the closure of some coal plant under the combination packages.

The inclusion of a Targeted Capacity Tender within the packages results in additional OCGT capacity on the system and lifetime extensions for some coal and gas plant, as shown below.

6.2.2 Carbon dioxide emissions

Figure 63 shows annual carbon intensity with and without Carbon Price Support (£30/t) under the Premium Payments combinations. The difference in emissions intensity is small before 2020, suggesting this trajectory of Carbon Price Support would not lead to significant coal to gas switching under DECC's Central assumptions before 2020. As the support level rises above £30/t after 2020, coal to gas switching starts to occur, and with more rapid deployment of nuclear, carbon emissions intensity falls more rapidly than under the Premium Payments alone. A further effect is that CCS plant operate at higher load factors given their greater competitiveness with unabated fossil plant.

The inclusion of Targeted Capacity Tender has little additional impact on carbon dioxide emissions. The capacity operates rarely and therefore has little impact on overall emissions intensity.

Figure 63 Emissions intensity – Premium Payments combination packages

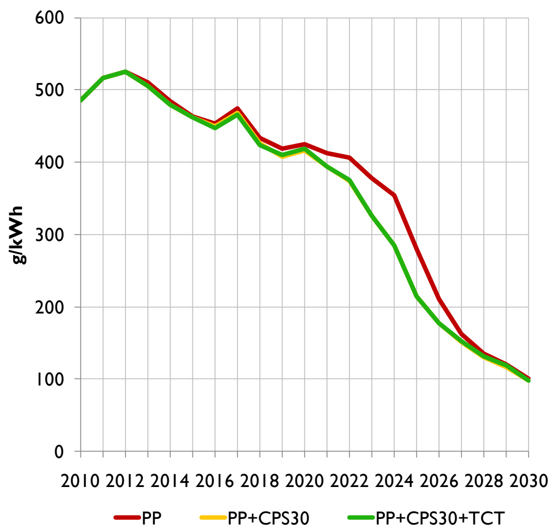


Figure 64 show the cumulative emissions over the period 2010-2030 for the Premium Payments combination packages. The inclusion of Carbon Price Support (£30/t) results in a reduction in carbon dioxide emissions over the period of 125 Mt or 4%. This result is sensitive to assumptions on coal and gas prices.

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Figure 64 Cumulative carbon dioxide emissions – Premium Payments combination packages

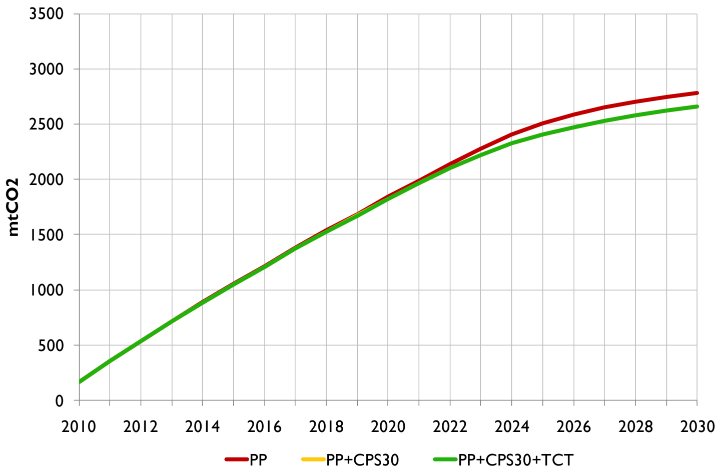


Figure 65 shows carbon intensity when Carbon Price Support (£30/t) is combined with Fixed Payments or Contracts for Difference. As for Premium Payments (above) there is little impact until after 2020 when the carbon price reaches a level high enough to incentivise significant coal to gas switching. The additional impact of CCS plant operating at higher load factors also reduces emissions in the mid 2020s. However, unlike under the Premium Payments combinations, there is no impact in terms of accelerated low-carbon investment.

Again, the inclusion of Targeted Capacity Tender has little additional impact on carbon dioxide emissions.

Figure 65 Emissions intensity – Fixed Payments and Contracts for Difference combination packages

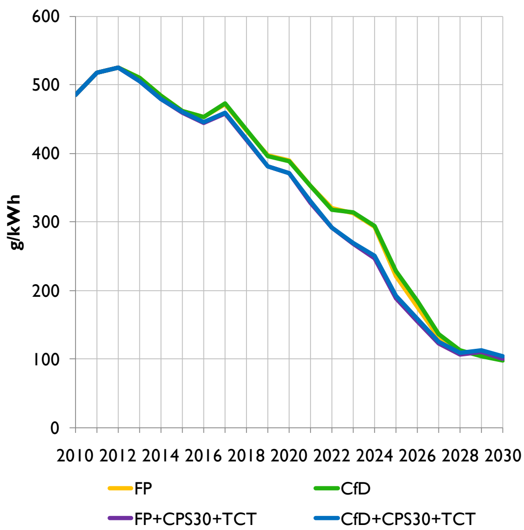
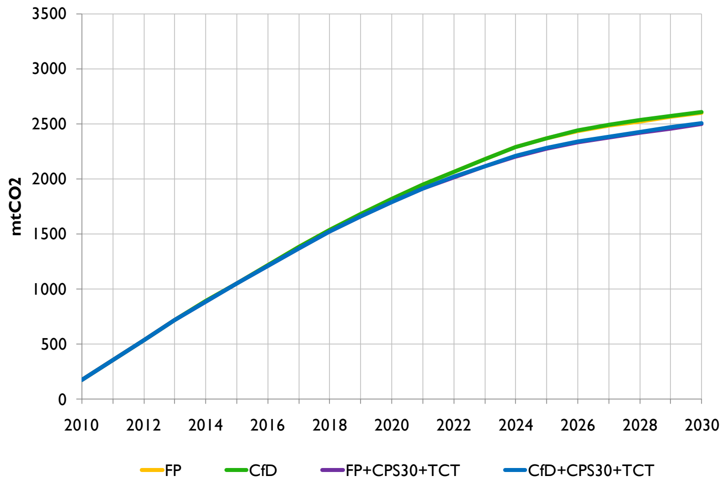


Figure 66 shows the cumulative emissions over the period 2010-2030 for the Fixed Payments and Contract for Difference combination packages. The inclusion of Carbon Price Support (£30/t) results in a reduction in carbon dioxide emissions over the period of 100 to 105 Mt or 4%.

Figure 66 Cumulative carbon dioxide emissions – Premium Payments combination packages



6.2.3 Security of supply

Figure 67 shows the de-rated capacity margins under each of the combination packages prior to the inclusion of a Targeted Capacity Tender. As in the stand-alone options there appears to be a material risk to security of supply after 2018. The lower trajectory of the Carbon Price Support (£30/t) does not result in earlier retirements of coal plant to the same extent as Carbon Price Support (£50/t), but there is also less new CCGT investment as a consequence.

Figure 67 De-rated capacity margins – Combination packages without Targeted Capacity Tender

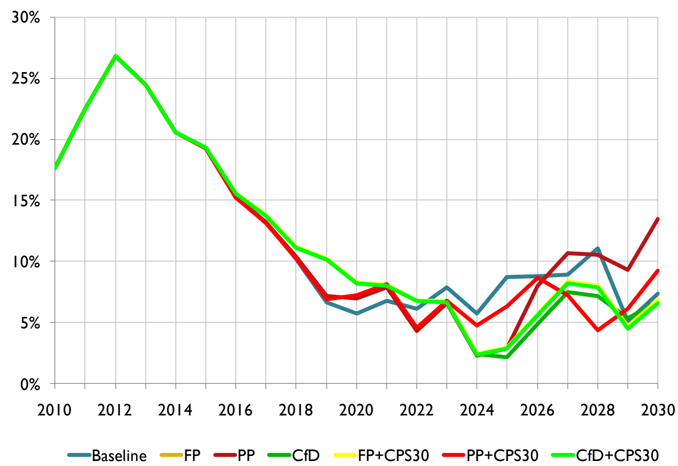


Figure 68 shows the required volumes of tendered capacity to meet at least a 10% de-rated capacity margin under each of the combination packages. The requirement peaks at 5.5 GW under the Fixed Payments + Carbon Price Support (£30/t) combination. (A further 5 GW would be required if the security standard was based on a zero capacity credit for wind.)

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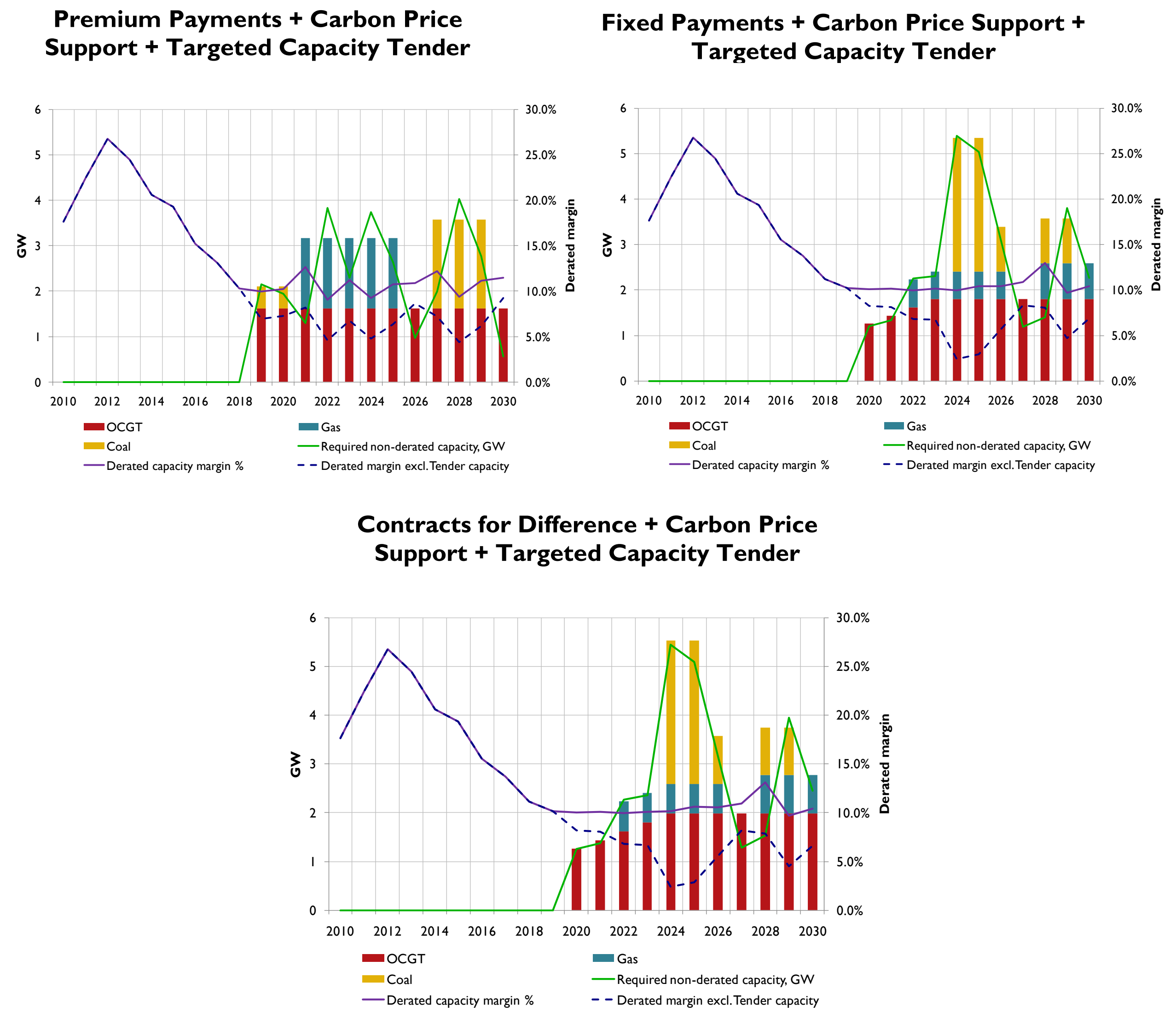
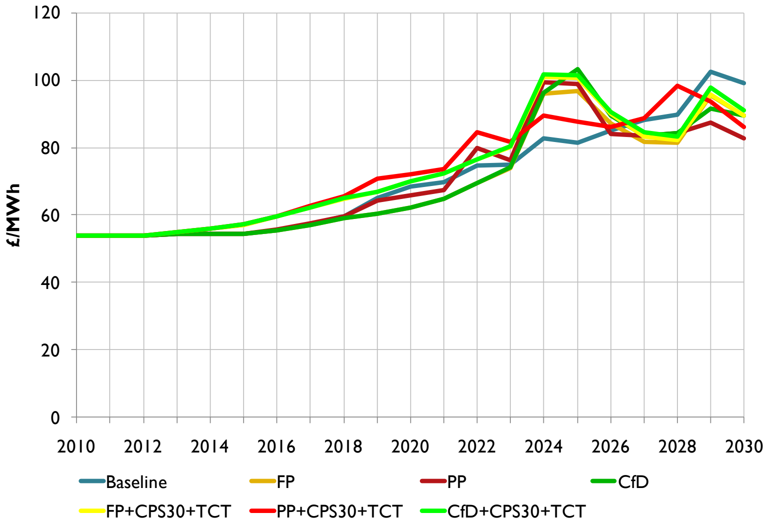
Figure 68 Tendered capacity and impact on de-rated capacity margins margins – Combination packages with Targeted Capacity Tender



6.2.4 Electricity prices

Figure 69 shows the annual average baseload electricity prices from the modelling under the combination packages and the corresponding decarbonisation options. Prices are generally higher in the near to medium term under the combination packages compared to the corresponding decarbonisation options due to the effect of Carbon Price Support. The Premium Payments + Carbon Price Support (£30/t) package shows a different pattern of electricity prices through the 2020s as compared to Premium Payments, due to differences in de-rated capacity margins over this period.

Figure 69 Annual average baseload electricity prices – Combination packages

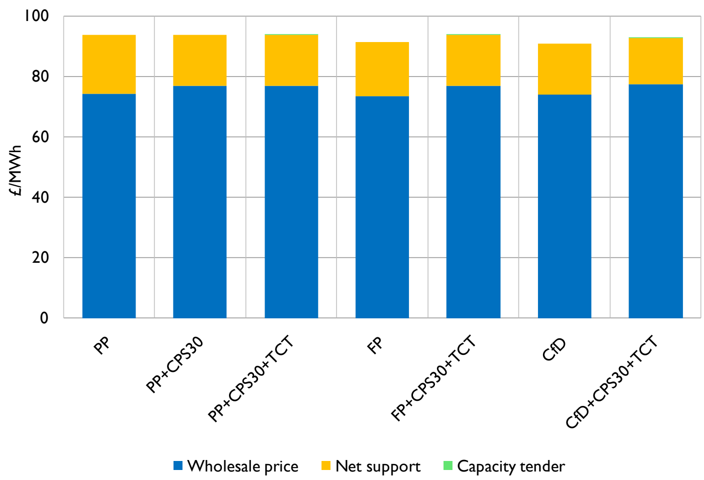


6.2.5 Wholesale energy costs

Figure 70 shows a comparison of wholesale energy costs for the combination packages relative to the underlying decarbonisation options. The combination packages are generally more expensive for consumers, mainly as a result of the higher electricity prices resulting from Carbon Price Support. Under Fixed Payments and Contracts for Difference, the consumer energy price is on average £2.40/MWh higher over the period 2010 to 2030, corresponding to an extra £8 per year on the average domestic consumer bill. Under Premium Payments + Carbon Price Support (£30/t) the higher electricity prices are offset by the lower premium payments that are required to reach the same level of decarbonisation.

The Targeted Capacity Tender has a very small impact on consumer energy prices because of the relatively small volumes of capacity involved. The cost impact is an average of £0.26/MWh.

Figure 70 Wholesale energy costs – Combination packages



6.2.6 Cost benefit analysis

Table 21 shows the cost benefit analysis for the combination packages, relative to their respective decarbonisation option.

Table 21 Cost benefit analysis – combination packages (relative to decarbonisation option)

Change in welfare NPV 2010-2030, (£m 2009 real)		Premium Payments + Carbon Price Support (£30/t)	Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	Fixed Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender
Net Welfare	Carbon costs	2,650	2,599	1,970	1,879
	Generation costs	-21	-523	-2,784	-3,135
	Capital costs	1,574	1,077	-315	132
	Unserved energy	128	406	404	463
	Demand side response	6	7	2	5
	Change in Net Welfare	**4,336**	**3,565**	**-724**	**-657**
Distributional analysis					
Consumer Surplus	Wholesale price	-13,457	-13,470	-17,484	-16,763
	Low carbon payments	11,867	11,866	4,399	6,976
	Capacity payments	0	-1,176	-1,125	-1,169
	Unserved energy	128	406	404	463
	Demand side response	6	7	2	5
	Change in Consumer Surplus	**-1,456**	**-2,367**	**-13,804**	**-10,488**
Producer Surplus	Wholesale price	13,457	13,470	17,484	16,763
	Low carbon support	-11,900	-11,900	-4,336	-6,940
	Capacity payments	0	1,176	1,125	1,169
	Producer costs	-6,678	-7,736	-11,026	-11,059
	Change in Producer Surplus	**-5,121**	**-4,990**	**3,247**	**-68**

The combination packages lead to slightly lower net welfare when associated with Fixed Payments and Contracts for Difference. This is the due to the distortion of dispatch economics towards more expensive fuels as a result of Carbon Price Support and the fact that the cost of the tendered capacity is greater than the assumed savings in the cost of unserved energy. The improvement in net welfare when Carbon Price Support (£30/t) is combined with Premium Payments results from the replacement of more expensive CCS with cheaper nuclear plant.

Consumer surplus falls under the combination packages because Carbon Price Support increases wholesale prices, which feed through to higher bills for consumers. In the case of Premium Payments this is largely offset by a reduction in low-carbon payment levels, but less so under Fixed Payments and Contracts for Difference. There are additional costs for consumers associated with the Targeted Capacity Tender, however these are relatively small.

Under the Premium Payments combinations, producer surplus is lower. Producers benefit from higher wholesale prices. However, fossil generators are exposed to the costs of Carbon Price Support, and low-carbon generators receive lower payments. Under Fixed Payments, producers appear collectively better off since the increase in wholesale prices is not offset by a reduction in low-carbon support to the same extent.

6.3 Key messages

6.3.1 Impact of options

Adding Carbon Price Support (£30/t) to Fixed Payments and Contracts for Difference makes little difference in terms of low-carbon investment, but does reduce emissions by encouraging coal to gas switching and helps to ensure that CCS plant runs ahead of unabated plant. By increasing electricity prices it could, however, lead to higher costs to consumers.

The rationale for combining Carbon Price Support (£30/t) and Premium Payments is perhaps stronger. It allows the level of premia to be reduced, saving consumers money if carbon prices subsequently rise, and makes the Premium Payments option more robust to lower outturn carbon prices. It also allows the market to play a greater role in determining the future generation mix which could lead to a lower cost outcome.

Decarbonisation: Combining Carbon Price Support (£30/t) with other decarbonisation options is likely to lead to lower cumulative emissions to 2030 by encouraging coal to gas switching, and making CCS plant more competitive with unabated fossil plant. Low-carbon investment would be directly affected in combination with Premium Payments, and the impact would depend on how premia are adjusted to account for higher anticipated electricity prices. Adding Carbon Price Support (£30/t) to Premium Payments would also make the package more robust to uncertain carbon prices. However, the effectiveness of the Premium Payments package in driving low-carbon investment would still be at risk from lower gas prices. This risk does not occur under the Fixed Payments and Contracts for Difference combinations. The impact of Targeted Capacity Tenders within these packages on carbon dioxide emissions would be minimal given the plant would be run relatively infrequently.

Generation mix: Carbon Price Support (£30/t) is likely to have little direct impact on low-carbon investment when combined with Fixed Payments and Contracts for Difference, but may change the pattern of investment under Premium Payments. It may be that the Carbon Price Support (£30/t) alone is sufficient to promote investment in cheaper technologies, and this may favour nuclear, reducing the requirement to support CCS to meet the same emissions intensity in 2030. The Targeted Capacity Tender would result in more flexible back-up capacity being held on the system.

Security of supply: The inclusion of the option for Targeted Capacity Tenders should reduce the risk to security of supply.

Resource costs: There are additional costs associated with the Targeted Capacity Tender. The inclusion of Carbon Price Support (£30/t) would also increase generation costs by more than the savings in carbon dioxide emissions (valued at the EUA price). However, in combination with Premium Payments, Carbon Price Support (£30/t) may lead to a cheaper generation mix which could result in savings in resource costs.

Costs to consumers: In general the inclusion of Carbon Price Support (£30/t) and Targeted Capacity Tenders within the combination packages increases the costs to consumers. Under Fixed Payments and Contracts for Difference, these increases average around £2.4/MWh or £8 per year for an average domestic consumer mainly as the result of higher electricity prices. With Premium Payments the increases in wholesale prices are largely offset by reductions in support payments, and the additional costs to consumers are relatively small.

Generator rents: Generators benefit from higher electricity prices when Carbon Price Support (£30/t) is included in the combination packages, but for fossil generators there are greater carbon costs. Hence, there are winners and losers. The scaling back of payments to low-carbon generators under Premium Payments means that generators are collectively worse off under the combination package. However, under Fixed Payments levels remain unchanged, and hence collectively generators appear better off under the combination package. In the case of the combination package under Contracts for Difference, welfare of generators is almost completely unchanged when Carbon Price Support (£30/t) and Targeted Capacity Tender are included.

6.3.2 Risk of options

The risks associated with the combination packages are similar to those outlined for the individual options in Sections 4 and 5.

Adopting a lower level of Carbon Price Support (£30/t) does, however, reduce some of the risks related to rents for existing low-carbon generators and higher costs to consumers in the near term when compared to Carbon Price Support (£50/t).

Combining Carbon Price Support (£30/t) with Premium Payments helps to reduce the risk that lower than expected EUA prices result in decarbonisation objectives being missed. Hence, payment levels can be set with more confidence. There is little long-term benefit of combining Carbon Price Support (£30/t) with Fixed Payments and Contracts for Difference in terms of greater certainty in low-carbon investment. However, its introduction, which could be relatively quick, may enhance investor confidence prior to the establishment of the new low-carbon support arrangements, thus reducing the risk of an investment hiatus. The benefits in terms of reduced emissions from coal to gas switching under this package need to be weighed up against the risks of higher costs to consumers, and the risks of unintended consequences such as the distortion of electricity prices relative to interconnected markets.

Finally, the combination packages would be inherently more complex with greater implementation risks and risks of further unintended consequences.

6.3.3 Implementation issues

The implementation issues identified for the individual options in Sections 4 and 5 would be similar for the combination packages, although the interactions between options would also need to be carefully considered, a good example being the interaction between the level of Carbon Price Support and Premium Payments levels in that package. Similarly, the levels of strike prices for Contracts for Difference and the levels of premium payments would be rebalanced, most likely reducing the net cashflow from the Government to generators.

7 Conclusions

The analysis suggests that the societal costs of delivering the required levels of decarbonisation differ between the options due to the impact on financing, and the extent to which the Government may target different technology mixes. However, these differences are relatively small, equivalent to about 1% of the total wholesale cost of electricity between 2010 and 2030. Where the options differ more markedly is in their impact on customers, their robustness to key uncertainties, the complexity of implementation and consequences for the electricity market as a whole.

Fixed Payments or Contracts for Difference (in conjunction with a Targeted EPS) could deliver the best value for customers and be the most robust to long-term uncertainties around fuel and EUA prices. The key risks with these approaches are that they depend on Government being able to set prices and target volumes appropriately, and that they represent a significant departure from current arrangements, with longer term consequences for the operation of the market. They would be more costly and time consuming to implement, and the transition would have to be effectively managed to minimise a potentially significant hiatus in near term investments. The inclusion of Carbon Price Support (£30/t) within the package may mitigate this latter risk to some extent.

The Premium Payments option would involve less implementation complexity but would be less robust to long-term uncertainties. If this route is adopted, there appear to be advantages in combining it with Carbon Price Support (£30/t) since this would make it more robust and potentially cheaper for consumers than either option by itself. Establishing the appropriate level to set premia remains a challenge however, given the uncertainty in future gas prices.

The Fixed Payments and Contracts for Difference approaches clearly place more reliance on Government intervention and central management (with a corresponding transfer of risks from investors), relative to the Premium Payments approaches, which have less impact on the market overall. This choice is likely to be strongly influenced by the trade off between longer term certainty in the generation mix versus risks associated with Government decision-making under uncertainty and information asymmetry, disruption to current market arrangements and near-term investment.

Finally, the risks to security of supply appear material but uncertain and an insurance policy may be needed. Retaining the option to include a Targeted Capacity Tender within the policy package appears to offer a cost-effective mechanism for achieving this and has the potential to stimulate new sources of flexibility. However, there are many detailed design challenges that will need to be addressed.

A Scenario and sensitivity name abbreviations

Full name	Abbreviation
Carbon Price Support (£50/t)	CPS50
Strong Emissions Performance Standard	EPS
Premium Payments	PP
Fixed Payments	FP
Contracts for Difference	CfD
Baseline - Low Gas	Baseline-LG
Baseline - High Gas	Baseline-HG
Baseline - Low Carbon	Baseline-LC
Carbon Price Support (£50/t) - Low Gas	CPS50-LG
Carbon Price Support (£50/t) - High Gas	CPS50-HG
Carbon Price Support (£50/t) - Low Carbon	CPS50-LC
Carbon Price Support (£50/t) - Low Investor Confidence	CPS50-LowConf
EPS - Low Gas	EPS-LG
EPS - High Gas	EPS-HG
EPS - Low Carbon	EPS-LC
Premium Payments - Low Gas	PP-LG
Premium Payments - High Gas	PP-HG
Premium Payments - Low Carbon	PP-LC
Fixed Payments - Low Gas	FP-LG
Fixed Payments - High Gas	FP-HG
Fixed Payments - Low Carbon	FP-LC
CfDs - Low Gas	CfD-LG
CfDs - High Gas	CfD-HG
CfDs - Low Carbon	CfD-LC
Carbon Price Support (£50/t) & Capacity Payments For All	CPS50+CapAll
Strong Emissions Performance Standard + Capacity Payments For All	EPS+CapAll
Premium Payments + Capacity Payments For All	PP+CapAll
Fixed Payments + Capacity Payments For All	FP+CapAll
Contracts for Difference + Capacity Payments For All	CfD+CapAll
Premium payments & low capacity payments	PP+CapAll(Low)
Fixed Payments + Targeted Capacity Tender	FP+TCT
Premium Payments + Carbon Price Support (£30/t)	PP+CPS30
Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	PP+CPS30+TCT
Fixed Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	FP+CPS30+TCT
Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender	CfD+CPS30+TCT
Baseline - High Demand	Baseline-HD
Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender - High	PP+CPS30+TCT-HD
Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender - High Demand	CfD+CPS30+TCT-HD

B High Demand Sensitivity

DECC requested that we explore the sensitivity of the results under higher demand assumptions for the following two combination packages:

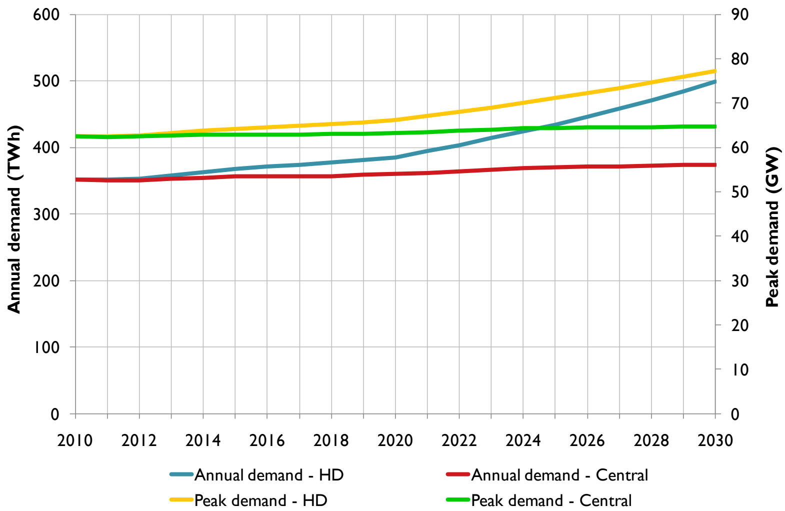
- Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender, and
- Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender.

We also have re-run the Baseline under the High Demand sensitivity to provide a comparison for the policy packages. We present the results in this Appendix.

Assumptions

The assumptions for growth in annual demand for the purposes of these sensitivities are based on a demand scenario provided to us by the CCC, which represents a greater degree of electrification of the heating and transport sectors. Peak demand is assumed to grow at 60% of the rate of growth of annual demand, on the assumption that the additional demand growth would be focused in off-peak periods.

Figure 71 Annual and peak demand – High Demand Sensitivity



For the High Demand sensitivity under the Baseline, RO banding is adjusted to achieve 29% renewable generation by 2020 and 35% by 2030. In capacity terms this is therefore a higher level of renewables deployment than under the Central Demand assumptions. For the combination packages, CfD strike prices and premia levels are adjusted so as to achieve the same renewable generation targets but also to achieve a carbon dioxide emissions intensity of the electricity system of 100 g/kWh by 2030[78]. In general this means

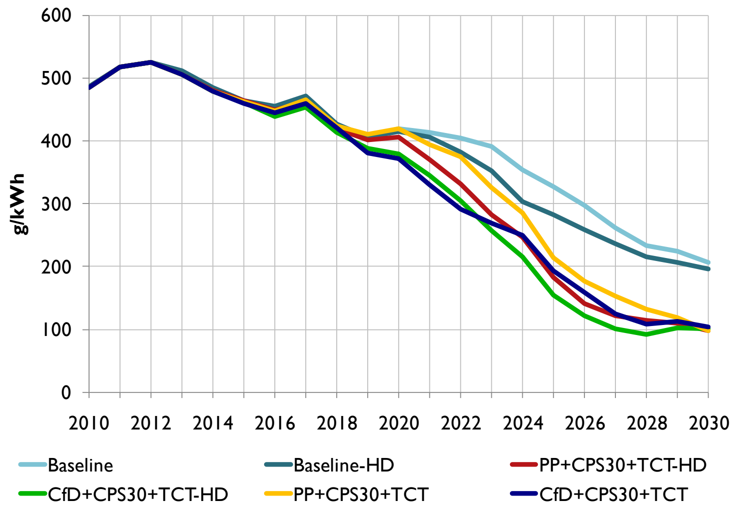
[78] Note that would represent a higher level of decarbonisation for the energy sector as a whole than under Central assumptions since the additional electrification would be displacing consumption of fossil fuels in other sectors.

increasing payment levels in order to stimulate greater low-carbon investment. It is assumed that investors have visibility of future demand growth[79] and are thus able to adjust their investment plans accordingly.

Carbon dioxide emissions

Figure 72 shows the carbon emissions intensity for the generation sector for the Baseline and combination packages under the High Demand sensitivity and corresponding packages under Central Demand assumptions. In general, faster demand growth results in a more rapid reduction in emissions intensity because much of the extra generation comes from low-carbon sources.

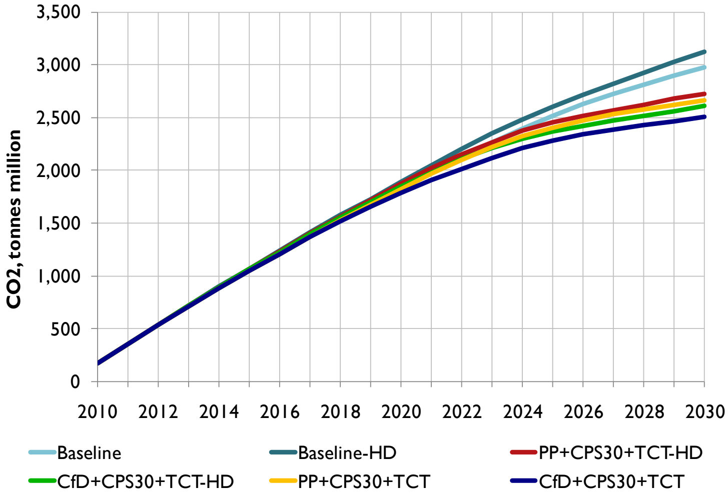
Figure 72 Carbon emissions intensity – High Demand Sensitivity



However, in absolute terms carbon dioxide emissions from the generation sector are higher under the High Demand sensitivity, as more fossil fuel generation is also required to meet the higher demand, as shown in Figure 73. However, it would be expected that this would be offset by savings elsewhere in the energy system from less fossil fuel usage as a result of greater electrification.

[79] There is a risk to the speed of decarbonisation and security of supply if this assumption does not hold.

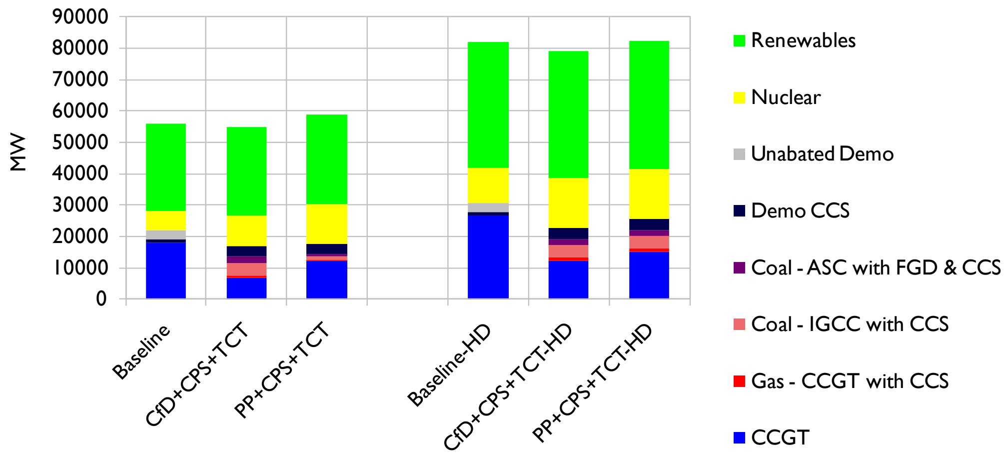
Figure 73 Cumulative carbon emissions – High Demand Sensitivity



Plant mix

Figure 74 shows cumulative new plant build by 2030 under the High Demand sensitivity for the combination packages and Baseline compared to the results for the Central Demand assumptions. The greater demand is met by increased investment in CCGTs and low-carbon technologies. In the Baseline, the higher demand by 2030 leads to an additional 4.6GW of new nuclear without additional support.

Figure 74 Cumulative new plant build by 2030 – High Demand Sensitivity



Security of supply

Figure 75 shows annual de-rated capacity margins under the High Demand sensitivity for the Baseline and combination packages prior to the additional capacity brought on-line through the Targeted Capacity Tender. The results for the Baseline under the Central Demand assumptions are also shown for comparison.

Under the High Demand sensitivity, de-rated capacity margins fall more rapidly from their peak level in 2012. However, since demand growth is anticipated by investors within the model, the average margins in the 2020s are very similar in the Baseline under the Central and High Demand assumptions, since new investment keeps pace with growing demand.

De-rated capacity margins under the Premium Payments combination package are broadly similar to the Baseline under the High Demand sensitivity. However, under the Contracts for Difference combination package de-rated capacity margins fall lower over the period 2019-2023. In the model, this is the result of investors in CCGTs being deterred by greater certainty of forthcoming low-carbon investment receiving Contracts for Difference. This same effect was seen under the Central Demand assumptions, but it is brought forward and exacerbated under the High Demand sensitivity. Under the Premium Payments package, there is less visibility of this investment and more CCGTs are built as a result. This modelling effect highlights a possible risk around CCGT investment.

Figure 75 De-rated peak capacity margins – High Demand Sensitivity

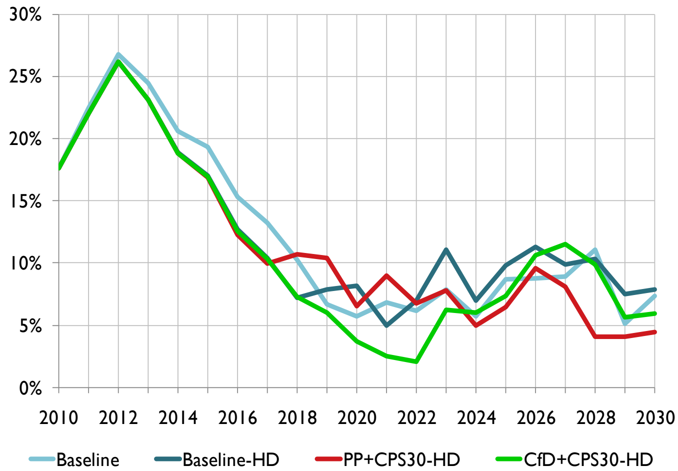
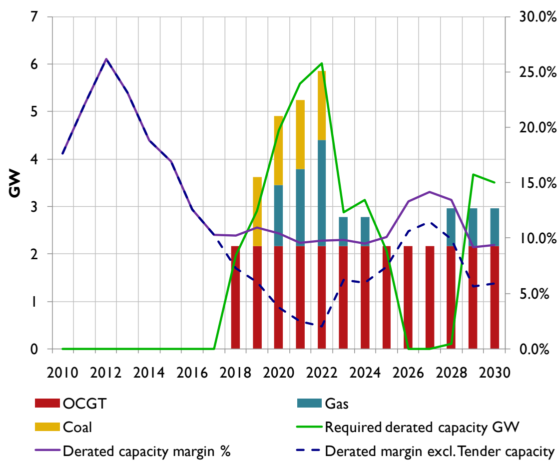


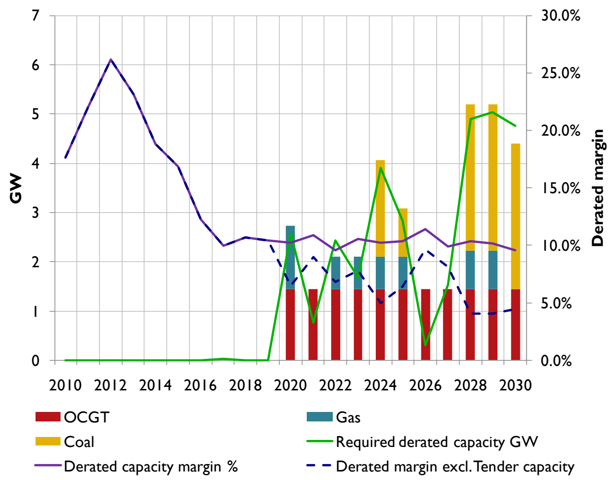
Figure 76 shows the capacity we have modelled as being brought on under Targeted Capacity Tender in the two combination packages under the High Demand sensitivity. Under the Contracts for Difference sensitivity, up to 6 GW of tendered capacity is required to achieve the desired security standard.

Figure 76 Targeted Capacity Tender – High Demand Sensitivity

CfD+CPS30+TCT-HD



PP+CPS30+TCT-HD



Cost benefit analysis

Table 22 shows the cost benefit analysis for the combination packages under Central Demand assumptions and the High Demand sensitivity relative to the Baseline under corresponding demand assumptions.

Table 22 Cost benefit analysis – High Demand sensitivity

Change in welfare NPV 2010-2030, (£m 2009 real)		Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender	Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender - High Demand	Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender - High Demand
Net Welfare	Carbon costs	8,636	11,516	10,519	12,879
	Generation costs	3,305	7,655	2,993	8,135
	Capital costs	-15,260	-23,973	-13,465	-14,476
	Unserved energy	194	198	122	121
	Demand side response	-8	-18	-19	-45
	Change in Net Welfare	**-3,132**	**-4,622**	**150**	**6,615**
Distributional analysis					
Consumer Surplus	Wholesale price	-14,727	-16,152	-24,232	-31,154
	Low carbon payments	1,334	7,413	3,441	557
	Capacity payments	-1,176	-1,169	-1,104	-1,554
	Unserved energy	194	198	122	121
	Demand side response	-8	-18	-19	-45
	Change in Consumer Surplus	**-14,384**	**-9,728**	**-21,793**	**-32,074**
Producer Surplus	Wholesale price	14,727	16,152	24,232	31,154
	Low carbon support	-1,368	-7,374	-3,405	-580
	Capacity payments	1,176	1,169	1,104	1,554
	Producer costs	-14,207	-14,737	-11,100	-4,010
	Change in Producer Surplus	**329**	**-4,790**	**10,832**	**28,118**

Net welfare relative to Baseline over the period 2010-2030 appears higher for the combination packages under the High Demand sensitivity. For example, a net welfare loss of around £4.6bn relative to the Baseline under Central Demand assumptions becomes a net welfare gain of around £6.6bn under the High Demand assumptions for the Contracts for Difference package. This increase in net welfare reflects the fact that under the Baseline, the High Demand sensitivity results in greater use of less efficient existing fossil plant which pushes up costs, and hence the savings from low-carbon investment are greater.

Under the High Demand sensitivity consumer surplus is significantly lower than the Baseline, and producers are correspondingly better off, through a combination of the impacts on price of Carbon Price Support, and in the case of the Contracts for Difference package, low underlying de-rated capacity margins. (As we describe in Section 5.3, we have assumed that the Targeted Capacity Tender would be designed in such a way as to leave wholesale prices unaffected, but in practice the impact on consumers will depend critically on how the tendered capacity is utilised and priced into the market.)

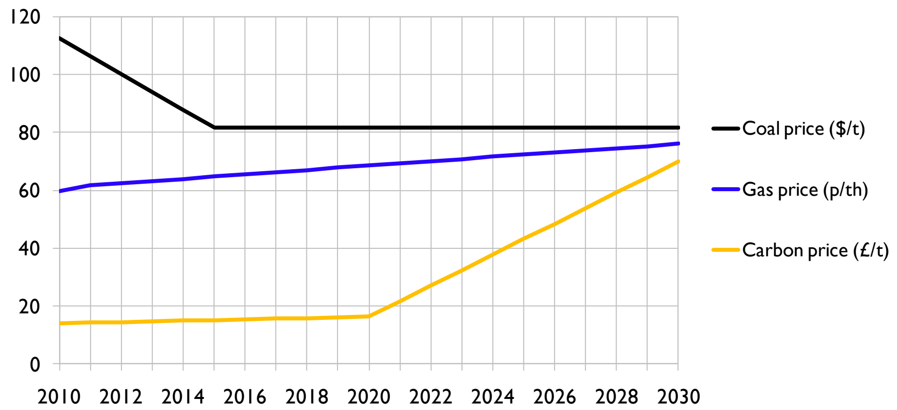
C Baseline assumptions

In this Appendix we outline our Baseline assumptions in more detail.

Fuel and carbon prices

Fuel price assumptions are based on DECC's Updated Energy Projections (UEP) June 2010 Central price case. EU Allowance (EUA) carbon price assumptions are taken from DECC's Central assumptions.

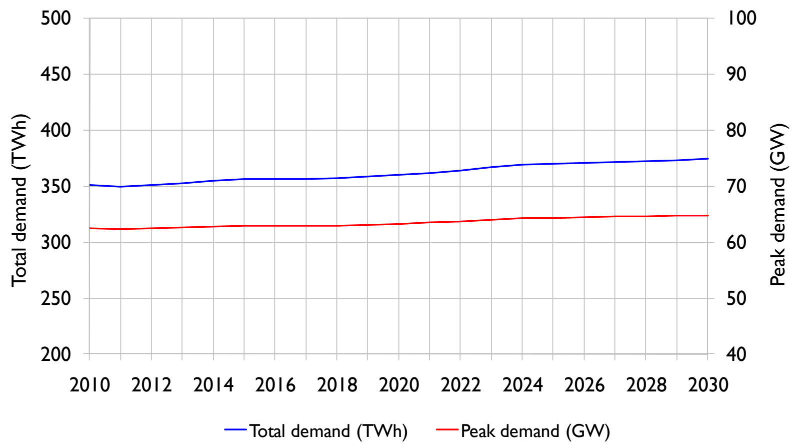
Figure 77 Fuel and carbon prices assumptions



Demand

Growth in baseload demand is subject to mild cyclical variation, as may be seen in Figure 78. Total demand falls in 2011, then grows strongly up to 2015, stalling in 2016 and 2017 and then growing strongly again between 2018 and 2024. After 2024, baseload demand grows at a more modest pace. The relationship between baseload and peak demand is based on historic analysis. The same cyclical pattern as that seen in baseload demand growth may also be seen in peak demand growth.

Figure 78 Total and peak demand assumptions



Capital costs

Capital cost assumptions for new build generation have been taken from the Mott MacDonald UK Electricity Generation Costs Update report, June 2010[80].

Table 23 Capital cost assumptions

Capex, real 2010, £/kW	FOAK	NOAK	FOAK/NOAK switch
Gas - CCGT	823	731	2010
Gas - CCGT with CCS	1,396	1,111	2010
Coal - IGCC with CCS	3,244	2,487	2010
Coal - ASC with FGD and CCS	3,128	2,479	2010
Nuclear - PWR	3,812	2,966	2010
Wind - Onshore	1,731	1,547	2010
Wind - Offshore	3,110	2,840	2010
Wind - Offshore R3	3,625	3,087	2018
Small biomass power only	2,820	2,540	2015
Large biomass power only	2,230	1,950	2020
Large biomass CHP	4,160	3,730	2020
Wave	3,559	3,559	2010
Tidal Stream	3,812	3,812	2010
Hydro	2,070	1,954	2010
Energy from Waste	6,150	5,120	2010
AD on wastes	4,170	3,900	2010
OCGT	474	438	2010

Note: For wave and tidal stream generation the capex figures given in Table 1 above are average values for years 2010 to 2034 inclusive. For the remaining technologies the 2010 figures are given before any learning has taken place.

[80] Downloaded from http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf and adjusted for DECC exchange rate assumptions where appropriate.

Learning

Table 24 Construction cost scalars

	2010	2020	2030
Gas – CCGT	1.00	0.89	0.88
Gas - CCGT with CCS	1.00	0.90	0.89
Coal - IGCC with CCS	1.00	0.88	0.84
Coal - ASC with FGD and CCS	1.00	0.85	0.84
Nuclear – PWR	1.00	0.93	0.91
Wind – Onshore	1.00	0.90	0.89
Wind – Offshore	1.00	0.90	0.89
Wind - Offshore R3	1.00	0.90	0.89
Small biomass power only	1.00	0.88	0.86
Large biomass power only	1.00	0.95	0.87
Large biomass CHP	1.00	0.93	0.89
Wave	1.79	0.90	0.48
Tidal Stream	2.94	0.72	0.46
Hydro	1.00	1.00	1.00
Energy from Waste	1.00	1.00	1.00
AD on wastes	1.00	1.00	1.00
OCGT	1.00	1.00	1.00

Renewable Obligation

Table 25 RO banding assumptions – Baseline

	2010 -2012	2013 -2016	2017 -2021	2022+
Co-firing (regular)	0.50	0.50	0.50	0.00
Co-firing (energy crops)	1.00	1.00	1.00	0.00
Wind – Onshore	1.00	1.30	0.75	0.25
Wind – Offshore	2.00	2.35	1.75	1.00
Small biomass power only	1.50	1.50	1.00	0.25
Large biomass power only	1.50	1.50	1.00	0.25
Large biomass CHP	2.00	2.00	1.00	0.25
Wave	2.00	4.00	4.00	2.00
Tidal Stream	2.00	4.00	4.00	2.00
Hydro	1.00	1.00	1.00	0.25
Energy from Waste	1.00	1.00	1.00	0.25
AD on wastes	2.00	2.00	2.00	0.50

Planning and construction

Table 26 Plant build characteristics

Type	Economic life (years)	Construction (years)	Planning (years)
Gas – CCGT	20	3	2
Gas - CCGT with CCS	25	4	2
Coal - IGCC with CCS	25	4	4
Coal - ASC with FGD and CCS	25	5	4
Nuclear – PWR	30	5	4
Wind – Onshore	20	2	5
Wind – Offshore	20	2	5
Wind - Offshore R3	20	2	5
Small biomass power only	20	2	2
Large biomass power only	20	4	2
Large biomass CHP	20	3	3
Wave	20	2	4
Tidal Stream	20	3	4
Hydro	20	5	5
Energy from Waste	20	3	3
AD on wastes	20	1	2
OCGT	20	2	2

Nuclear lifetime extensions

Table 27 Nuclear capacity, retirements and availability

Plant	Capacity (MW)	Closure date	Annual availability
Dungeness B	1,110	2018	70%
Hartlepool	1,210	2019	70%
Heysham 1	1,150	2019	70%
Heysham 2	1,250	2028	70%
Hinkley Point	820	2016	70%
Torness	1,250	2028	70%
Hunterston	820	2016	70%
Sizewell B	1,190	2045	87%
Oldbury	434	2010	75%
Wylfa	980	2010	75%

Source: Nuclear Industry Association

Capacity credits

Table 28 Capacity credits by technology

	2010	2015	2020	2025	2030
Gas	90.0%	90.0%	90.0%	90.0%	90.0%
Coal	90.0%	90.0%	90.0%	90.0%	90.0%
CCS	90.0%	90.0%	90.0%	90.0%	90.0%
Nuclear (existing)	70.0%	70.0%	70.0%	70.0%	70.0%
Nuclear (new)	90.0%	90.0%	90.0%	90.0%	90.0%
Hydro	70.0%	70.0%	70.0%	70.0%	70.0%
Pumped storage	100.0%	100.0%	100.0%	100.0%	100.0%
Wind	27.5%	20.7%	17.5%	16.2%	16.2%
Marine	30.0%	30.0%	30.0%	30.0%	30.0%
Biomass	92.0%	92.0%	92.0%	92.0%	92.0%
Other renewables	30.0%	30.0%	30.0%	30.0%	30.0%
Tidal Range	12.8%	12.8%	12.8%	12.8%	12.8%
non ROC waste	40.0%	40.0%	40.0%	40.0%	40.0%
Oil	95.0%	95.0%	95.0%	95.0%	95.0%
GT	90.0%	90.0%	90.0%	90.0%	90.0%
Interconnector	95.0%	95.0%	95.0%	95.0%	95.0%

D Estimating hurdle rates

Overview

A key hypothesis behind the analysis is that to the extent that EMR policy options reduce the risk for different types of investment, the hurdle rate (and hence cost of capital) should reduce. Our assumptions are informed by simulating the earnings risk over the lifetime of a project as described below.

Assumptions on hurdle rates are derived by estimating the impact of technology and market risk on the cost of equity and project gearing levels, using benchmarks from recent projects where possible. We assume that the hurdle rate for an investment is a function of both technology and development risk, which is independent of the electricity market arrangements, and market risk, which is directly related to electricity market arrangements.

The relative riskiness of the investment may affect the cost of equity, cost of debt and the gearing of the project which in turn affects the overall hurdle rate.

For simplicity in the modelling, we vary the cost of equity to reflect differences in technology and development risks for projects of different maturity, and vary the amount of gearing possible in the project to reflect differences in market risk.

Our starting assumptions for the cost of capital for vertically integrated utilities and independent developers are shown in Table 29 below. Note that these are long-run assumptions held constant throughout the modelling time horizon.

The hurdle rates are calculated from these starting assumptions by varying the cost of equity and level of gearing for individual projects.

Table 29 Assumptions for cost of capital

	VIU	Independent
Long-term risk free rate	4%	
Equity premium	4%	4%
Debt premium	1.5%	3.0%
Typical equity beta	0.71	1.75
Typical gearing	40%	70%
Corporation tax rate	24%	
Typical WACC	6%	7%

Technology and development risk

We model the technology and development risk by varying the cost of equity which involves scaling the equity premium by an 'investment beta' dependent on the maturity of each technology as follows:

Cost of equity = risk free rate + market premium * equity beta * ***investment beta***

For mature technologies we assume an investment beta of 2, for established technologies an investment beta of 3 and for emerging technologies an investment beta of 4.

Table 30 below shows our assumptions for the maturity of different technologies by year.

Table 30 Technology maturity assumptions

Technology	2010	2015	2020	2025	2030
CCGT	Mature	Mature	Mature	Mature	Mature
Gas - CCGT with CCS	Emerging	Emerging	Emerging	Emerging	Established
Coal - IGCC with CCS	Emerging	Emerging	Emerging	Emerging	Established
Coal - ASC with FGD & CCS	Emerging	Emerging	Emerging	Emerging	Established
Nuclear	Emerging	Emerging	Established	Established	Mature
Wind - Onshore (High)	Mature	Mature	Mature	Mature	Mature
Wind - Onshore (Medium)	Mature	Mature	Mature	Mature	Mature
Wind - Onshore (Low)	Mature	Mature	Mature	Mature	Mature
Wind - Offshore	Established	Established	Mature	Mature	Mature
Wind - Offshore R3	Emerging	Emerging	Established	Established	Mature
Small biomass power only	Emerging	Emerging	Established	Established	Mature
Large biomass power only	Emerging	Emerging	Established	Established	Mature
Large biomass CHP	Emerging	Emerging	Established	Established	Mature
Wave	Emerging	Emerging	Emerging	Emerging	Established
Tidal Stream	Emerging	Emerging	Emerging	Emerging	Established
Hydro	Mature	Mature	Mature	Mature	Mature
Energy from Waste	Established	Established	Established	Mature	Mature
AD on wastes	Emerging	Emerging	Emerging	Established	Mature
OCGT	Mature	Mature	Mature	Mature	Mature

These assumptions yield a range in hurdle rates (post tax nominal) from around 8% for mature technologies to around 12% for emerging technologies for VIUs under current market arrangements. The equivalent range for independent developers is 9-13%.

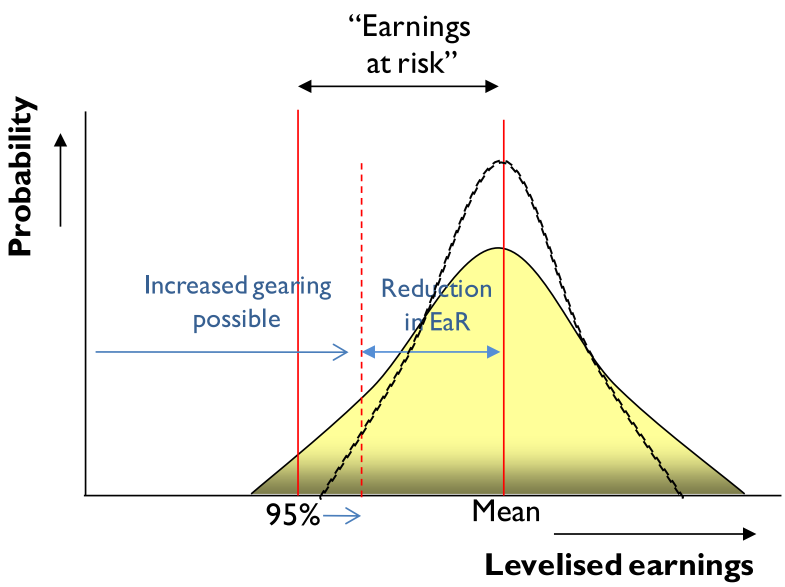
Market and policy risk

For the purposes of the analysis, we assume that where the impact of a different policy is to reduce expected earnings risk, the level of debt in the project can be correspondingly increased.

To do this, we first simulate overall earnings risk over the lifetime of the project, taking account of all key drivers: fuel costs, carbon costs, capital costs, construction times, operating costs, availability, electricity prices, support levels, load factor, and balancing risk. Using this we can then assess the incremental impact of policy options. Where policies reduce earnings risk, for example by reducing revenue uncertainty, it is assumed a greater proportion of the project could be financed with lower cost capital.

We compare the earnings at risk over the lifetime of an investment under each policy option to the Baseline. The simulation of earnings risk is illustrated in Figure 79 below. The 'earnings-at-risk' is calculated as the difference between the mean earnings expectation and a downside case represented by the 95% percentile. This is then expressed as a percentage of the mean. In broad terms a reduction in earnings-at-risk corresponds to a similar increase in the proportion of "safe" earnings, and hence enables an equivalent increase in the proportion of potential debt financing. For example, if the impact of a policy option to is to reduce the earnings at risk by 10 percentage points we assume that it is possible to increase gearing in the project likewise by 10 percentage points. For vertically integrated utilities, this may not literally be the case since projects may be more or less balance sheet financed. However, the ability to raise debt to fund investment across the business will depend on the market's perceived riskiness of a company's investments and hence a similar principle can be considered.

Figure 79 Simulated earnings risk



We assume that the cost of debt increases with the level of gearing, particularly for less mature technologies, but is cheaper than the cost equity.

We also assume that there is a maximum level of gearing possible in projects, regardless of market risk, associated with technology maturity as follows:

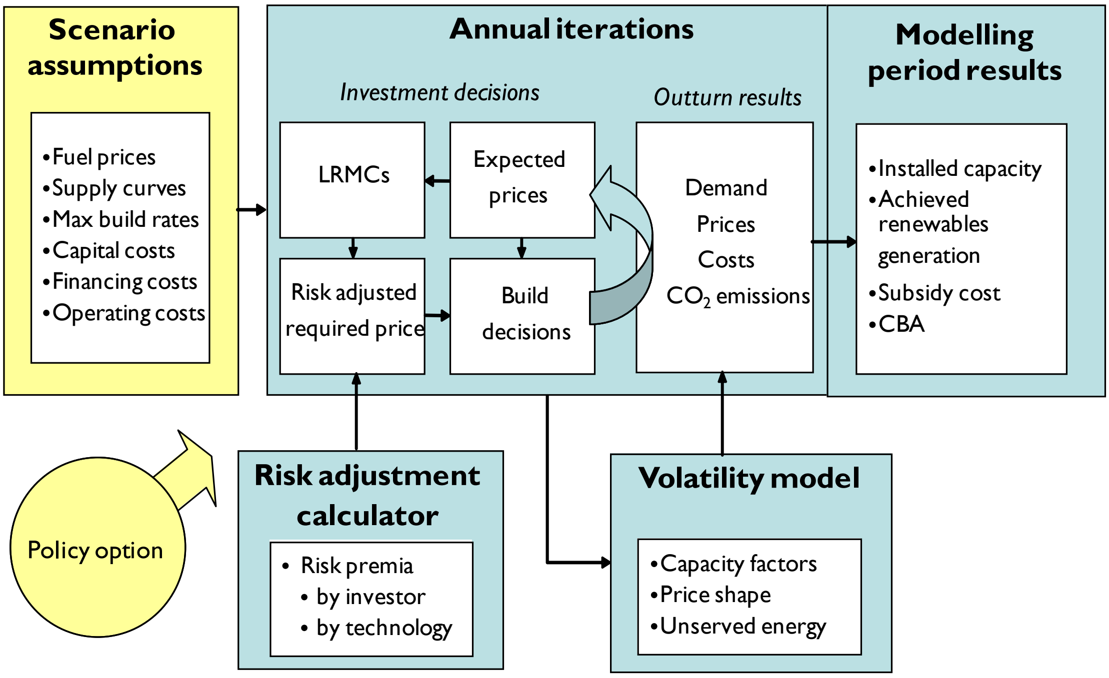
- Mature: 90%
- Established: 80%
- Emerging: 75%

E Modelling approach

In this Appendix, we briefly outline our modelling approach, describing at a high level the modelling framework we have used, and explaining the capacity credit concept in more detail.

Modelling framework

Figure 80 Modelling framework



At the heart of the modelling framework deployed for this study lies an ***investment decisions*** simulator. This computes the risk-adjusted 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 earnings 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[81]. It is used to calibrate the expected price and renewables 'capacity credit' functions within the investment decisions simulator.

[81] A full stochastic simulation is run using the volatility model in order to derive the unserved energy numbers under the Baseline. For all other packages, unserved energy numbers are derived using an estimated relationship between the de-rated peak capacity margin and unserved energy, that relationship itself being derived from a volatility model simulation.

Capacity credit

The capacity credit is the statistical contribution of a particular class of generation to security of supply. The capacity credit for intermittent renewables is often expressed as the amount of conventional thermal generation (taking into account its likelihood of availability) that intermittent generation could effectively "replace", without any reduction in security of supply. It is therefore a useful concept when incorporating different types of generation capacity into a calculation of de-rated capacity margin on an equivalent basis.

Measuring the capacity credit of intermittent generation (wind, wave, tidal) is complex since it is a function of the amount, type and geographical distribution of generation plant on the system. The capacity credit for total installed intermittent capacity will generally be lower than the sum of individual plant capacity factors. In particular, the average capacity credit for a given technology will be affected by:

- the total existing installed capacity of that technology on the system, and
- the geographical distribution of different intermittent technologies and relationships between output levels at different locations.

The first of these factors results from the fact that the output levels of individual units of intermittent capacity of any single technology (such as wind) are generally correlated. As a result, while the first unit of a technology deployed may have a capacity credit close to its capacity factor, the average capacity credit declines as the installed capacity of that technology increases. Each extra unit of installed capacity yields a diminishing marginal contribution to security of supply, because of the high likelihood that its output profile (and especially its zero-output hours) will be correlated with those of the remainder of the installed capacity. For the example of wind, the first MW on the system may have a marginal capacity credit of close to 30%, whereas the 40,000th MW may have a marginal capacity credit below 5%. Thus the difference between each additional unit's capacity factor (constant) and its capacity credit (diminishing) increases with penetration, and the amount of conventional capacity required to back up each additional MWh of output increases as more renewables capacity is built.

F Results metrics

In this Appendix we describe the key metrics summarising the modelling results that are presented in the report.

Decarbonisation

The extent of decarbonisation of the GB electricity sector is measured in terms of the carbon dioxide emissions intensity of the GB electricity generation system as a whole. The unit of measure for emissions intensity is g/kWh. Our modelling only measures the direct emissions from fossil fuel generation and does not take into account emissions relating to the entire life-cycle of generation technologies or fuel production.

Generation mix

For every year between 2010 and 2030, the model outputs the resulting generation mix in every model run, measured in GW of capacity. This is based on the existing generation capacity mix at the start of that year plus any capacity that is built in that year and minus any capacity retired in the model. Total capacity is summarised into categories that may be seen in Figure 5.

The generation mix profile, together with capacity credits and assumptions on peak demand, feeds into security of supply analysis as it is used to derive the de-rated peak capacity margin.

Security of supply

The key indicator we use to assess security of supply between packages 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.

Resource costs

Resource costs, which are calculated in the model as part of the cost benefit analysis, consist of the following elements.

- Carbon costs represent the welfare loss associated with carbon dioxide emissions. They are calculated on the basis of the EUA price in the year in which emissions occur.
- Generation costs include all variable and fixed costs of the GB generation system, including fuel costs, but excluding carbon costs. They represent running costs of generation. These are calculated from DECC assumptions for new capacity built in the model and a mixture of DECC and Redpoint assumptions for existing and committed generation capacity as of 2010 in the model.
- Capital costs represent total debt and equity costs of new generation capacity built in the model. They are based on assumptions on construction costs, debt and equity costs, leverage and gearing levels.

Cost to consumers

This is a measure of the price of the energy component of electricity for a typical consumer, normally quoted in £/MWh. It is the sum of wholesale electricity costs, the cost of low-carbon support, and capacity payments (if applicable). It excludes non-energy items such as transmission and distribution charges, supplier margin and VAT.

Wholesale electricity prices are clearly a key driver of the consumer cost. While the level of wholesale price is dominated by the commodity price levels, there are significant differences between packages. This is a result of the different resulting capacity build profiles, which in turn change both the supply curve through the year, and hence the system marginal price, and the year-to-year system capacity margin, with a resulting impact on price 'uplift'.

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, as the RO effectively provides a premium payment on top of wholesale electricity revenues. However, even under packages we have modelled with fixed payments, there will always be a spread of rents both because of the variation of costs of technologies within a given 'band' or tariff category, and differences in the costs of financing for different player types.

Rent is presented under three different categories through this report. This is measured in £m, and is the total rent achieved by a particular plant type in a given year:

- Rent for existing renewables
- Rent for new renewables

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 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 packages.

G Cost benefit analysis

In this Appendix we describe the cost benefit analysis approach used in the project, and present additional CBA results for sensitivities and combination packages.

Cost benefit analysis: approach

The costs and benefits of each of the options are measured against the Baseline as the counterfactual. They are calculated annually and as a net present value (NPV) for the period 2010-2030 using the Green Book real discount rate of 3.5% and presented in real 2009 terms. It is important to note that the NPV analysis does not capture the costs and benefits of the options after 2030.

A key point that must be understood in the evaluation of any policy in relation to low-carbon investment is that low-carbon generation is generally more expensive than conventional thermal plant under the Baseline assumptions. As there is no explicit penalty for missing the targets. or evaluation of the unquantified impacts of diversifying the generation portfolio, options that meet the decarbonisation targets will typically result in lower net welfare compared to options that fall short. This difference can be considered as the cost to society of meeting the targets, and different options can be compared on this basis.

Each component of the cost benefit analysis is described below.

- **Carbon costs.** 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).
- **Generation Costs.** The change in the costs of generating electricity, including changes in fuel costs, variable and fixed operating costs and system balancing costs. It excludes changes in the costs of carbon which are captured above, and capital costs which are captured below. A negative number represents an increase in generation costs relative to the counterfactual.
- **Capital costs.** The change in capital expenditure in new plant. A negative number represents an increase in capital costs.
- **Unserved energy.** The change in the cost of expected energy unserved, which is valued at an average £10,000/MWh. A negative number implies an increase in the cost of unserved energy and a deterioration in security of supply.
- **Demand side response.** The change in the use of short-term demand side response. A reduction in demand in response to high prices represents a loss of consumer welfare[82].
- **Net welfare.** The change in welfare to society as a whole which is equivalent to the sum of the change in carbon costs, generation costs, capital costs, unserved energy and demand side response. A negative number represents a loss in net welfare to the economy.
- **Consumer surplus**. The change in welfare to consumers, which is a combination of the change in wholesale electricity costs, change in the low-carbon payments, and the change in capacity payments (where these apply). A negative number represents a reduction in consumer surplus or an increase in the costs to consumers.
- **Producer surplus.** The change in the profitability of the generation sector measured as the change in the difference between revenues (electricity sales, low-carbon support and capacity payments) and producer costs. A positive number represents an increase in the producer surplus.

[82] Note we do not consider the long-term price elasticity of demand in the cost benefit analysis.

Cost benefit analysis: Low Gas

Table 31 shows the cost benefit analysis under the Low Gas sensitivities, relative to the Baseline-Low Gas. Net welfare appears much lower under Fixed Payments and Contracts for Difference than the other options since these deliver more low-carbon investment which is relatively more expensive than the alternative (ie, gas) generation under this sensitivity. In Carbon Price Support (£50/t), Strong EPS and Premium Payments, investment in low-carbon generation is reduced and so the net welfare loss is smaller, although the decarbonisation and renewable energy targets are not met.

Consumers are worse off under all the policy options since electricity prices are considerably higher than the Baseline-Low Gas due to some occasions of very low de-rated capacity margins.

Table 31 Cost benefit analysis – Low Gas Sensitivity

Change in welfare NPV 2010-2030, (£m 2009 real)		Carbon Price Support (£50/t) - Low Gas	EPS - Low Gas	Premium Payments - Low Gas	Fixed Payments - Low Gas	CfDs - Low Gas
Net Welfare	Carbon costs	5,735	2,965	2,742	11,283	11,174
	Generation costs	-516	-6,931	115	4,441	4,845
	Capital costs	-7,287	-1,656	-11,071	-35,211	-35,600
	Unserved energy	-54	-44	-717	-409	-421
	Demand side response	-4	-2	-55	-21	-23
	Change in Net Welfare	**-2,126**	**-5,668**	**-8,985**	**-19,916**	**-20,025**
Distributional analysis						
Consumer Surplus	Wholesale price	-37,897	-46,328	-25,559	-8,842	-9,670
	Low carbon payments	5,541	5,747	-5,313	-27,926	-24,440
	Capacity payments	0	0	0	0	0
	Unserved energy	-54	-44	-717	-409	-421
	Demand side response	-4	-2	-55	-21	-23
	Change in Consumer Surplus	**-32,414**	**-40,626**	**-31,643**	**-37,198**	**-34,554**
Producer Surplus	Wholesale price	37,897	46,328	25,559	8,842	9,670
	Low carbon support	-5,442	-5,679	5,127	28,261	24,767
	Capacity payments	0	0	0	0	0
	Producer costs	-20,988	-5,622	-8,214	-19,487	-19,581
	Change in Producer Surplus	**11,467**	**35,027**	**22,472**	**17,616**	**14,856**

Cost benefit analysis: High Gas

Table 32 shows the cost benefit analysis for the High Gas sensitivity. Net welfare is positive under Fixed Payments and Contracts for Difference relative to the Baseline as savings in carbon costs and generation costs relative to the Baseline outweigh the additional capital costs of new generation capacity. Under the options where low-carbon generators are still exposed to wholesale price – Carbon Price Support (£50/t), Strong EPS and Premium Payments – net welfare decreases since they 'over-deliver' low-carbon investment.

Consumers are significantly better off under the High Gas price sensitivity under Fixed Payments and Contracts for Difference. From approximately 2020 onwards, the price paid to low-carbon generators is on average lower than the electricity price under Fixed Payments and Contracts for Difference with a High Gas price.

Table 32 Cost benefit analysis – High Gas Sensitivity

Change in welfare NPV 2010-2030, (£m 2009 real)		Carbon Price Support (£50/t) - High Gas	EPS - High Gas	Premium Payments - High Gas	Fixed Payments - High Gas	CfDs - High Gas
Net Welfare	Carbon costs	14,610	15,595	10,469	7,183	6,649
	Generation costs	-5,663	-19,155	6,562	5,961	6,181
	Capital costs	-18,840	-14,257	-24,111	-12,142	-11,002
	Unserved energy	266	277	-178	-30	-104
	Demand side response	31	32	-15	-7	-14
	Change in Net Welfare	**-9,597**	**-17,508**	**-7,272**	**964**	**1,711**
Distributional analysis						
Consumer Surplus	Wholesale price	-17,970	-19,128	20,568	11,161	6,587
	Low carbon payments	10,034	11,683	-13,104	10,778	17,285
	Capacity payments	0	0	0	0	0
	Unserved energy	266	277	-178	-30	-104
	Demand side response	31	32	-15	-7	-14
	Change in Consumer Surplus	**-7,639**	**-7,137**	**7,272**	**21,902**	**23,754**
Producer Surplus	Wholesale price	17,970	19,128	-20,568	-11,161	-6,587
	Low carbon support	-10,157	-11,587	13,144	-10,949	-17,535
	Capacity payments	0	0	0	0	0
	Producer costs	-36,034	-17,817	-7,079	1,001	1,828
	Change in Producer Surplus	**-28,220**	**-10,275**	**-14,504**	**-21,108**	**-22,293**

Cost benefit analysis: Low Carbon

Table 33 shows the cost benefit analysis for the Low Carbon sensitivity. All options show negative net welfare under the Low Carbon sensitivity since they deliver more low-carbon investment relative to the Baseline, which is more expensive than new build under the Baseline, but the value placed on the resulting decarbonisation is lower as this is based on the lower EUA prices.

Consumers are worse off as a result, particularly under Carbon Price Support (£50/t), where a very large gap between the carbon price support level and the EUA price introduces distortion to economic dispatch on top of distortion to investment incentives.

Table 33 Cost benefit analysis – Low Carbon Sensitivity

Change in welfare NPV 2010-2030, (£m 2009 real)		Carbon Price Support (£50/t) - Low Carbon	EPS - Low Carbon	Premium Payments - Low Carbon	Fixed Payments - Low Carbon	CfDs - Low Carbon
Net Welfare	Carbon costs	11,575	10,112	3,801	6,245	5,837
	Generation costs	-9,860	-8,811	2,265	9,196	8,704
	Capital costs	-20,685	-22,387	-18,541	-28,084	-27,826
	Unserved energy	152	122	-316	-57	-110
	Demand side response	21	17	-26	-5	-12
	Change in Net Welfare	**-18,796**	**-20,945**	**-12,817**	**-12,704**	**-13,408**
Distributional analysis						
Consumer Surplus	Wholesale price	-61,953	-35,272	-6,419	12,199	7,215
	Low carbon payments	6,191	7,762	-10,667	-19,454	-13,997
	Capacity payments	0	0	0	0	0
	Unserved energy	152	122	-316	-57	-110
	Demand side response	21	17	-26	-5	-12
	Change in Consumer Surplus	**-55,589**	**-27,370**	**-17,428**	**-7,316**	**-6,904**
Producer Surplus	Wholesale price	61,953	35,272	6,419	-12,199	-7,215
	Low carbon support	-6,187	-7,483	10,635	19,429	13,964
	Capacity payments	0	0	0	0	0
	Producer costs	-54,575	-21,085	-12,475	-12,642	-13,285
	Change in Producer Surplus	**1,191**	**6,704**	**4,579**	**-5,412**	**-6,536**

Cost benefit analysis: Capacity Payments for All

Table 34 shows the cost benefit analysis under Options to promote decarbonisation with Capacity Payments for All relative to the Baseline. Introducing Capacity Payments for All together with support for low-carbon generation generally leads to a reduction in net welfare relative to the Baseline since the additional resource costs associated with having more capacity on the system are greater than the savings in expected energy unserved, and carbon emission savings are valued at the EUA price, which remains low until after 2020.

The distributional effects of Capacity Payments for All and support for low-carbon generation are much greater than the overall net welfare impact. Consumers appear worse off relative to the Baseline for the reasons described above. Correspondingly, producers are significantly better off, particularly under Carbon Price Support (£50/t) and Strong EPS. In the case of these two packages, consumers lose out due to significantly higher wholesale electricity prices than under the Baseline. This is also the case for these policy packages without capacity payments.

Table 34 Cost benefit analysis – Capacity Payments for All

Change in welfare NPV 2010-2030, (£m 2009 real)		Carbon Price Support (£50/t) & Capacity Payments For All	Strong Emissions Performance Standard + Capacity Payments For All	Premium Payments + Capacity Payments For All	Fixed Payments + Capacity Payments For All	Contracts for Difference + Capacity Payments For All
Net Welfare	Carbon costs	13,930	10,427	5,954	9,825	11,520
	Generation costs	-6,852	-7,895	1,481	9,205	12,796
	Capital costs	-10,093	-6,239	-18,377	-23,920	-28,551
	Unserved energy	236	196	232	228	161
	Demand side response	46	36	44	43	26
	Change in Net Welfare	**-2,733**	**-3,474**	**-10,666**	**-4,620**	**-4,049**
Distributional analysis						
Consumer Surplus	Wholesale price	-21,176	-26,688	24,733	30,915	33,809
	Low carbon payments	2,127	5,611	-16,836	-12,152	-7,113
	Capacity payments	-35,136	-35,120	-35,136	-29,196	-35,099
	Unserved energy	236	196	232	228	161
	Demand side response	46	36	44	43	26
	Change in Consumer Surplus	**-53,903**	**-55,964**	**-26,963**	**-10,162**	**-8,216**
Producer Surplus	Wholesale price	21,176	26,688	-24,733	-30,915	-33,809
	Low carbon support	-2,200	-5,591	16,873	12,179	7,083
	Capacity payments	35,136	35,120	35,136	29,196	35,099
	Producer costs	-26,290	-3,707	-10,942	-4,890	-4,236
	Change in Producer Surplus	**27,822**	**52,510**	**16,334**	**5,569**	**4,137**

Cost benefit analysis: Combination packages

Table 35 shows the cost benefit analysis under Combination packages relative to the Baseline. The Combination packages lead to lower net welfare relative to Baseline. This is the due to the distortion of dispatch economics towards more expensive fuels as a result of Carbon Price Support and the fact that the cost of the tendered capacity is greater than the assumed savings in the cost of unserved energy.

Consumer surplus falls under the combination packages, with the dominant factor being the increase in wholesale prices associated with Carbon Price Support. This is offset to some extent by the reduced need for direct low-carbon support. There are additional costs for consumers associated with the Targeted Capacity Tender, but these are relatively small.

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Table 35 Cost benefit analysis – Combination packages

Change in welfare NPV 2010-2030, (£m 2009 real)		Fixed Payments + Targeted Capacity Tender	Premium Payments + Carbon Price Support (£30/t)	Premium Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	Fixed Payments + Carbon Price Support (£30/t) + Targeted Capacity Tender	Contracts for Difference + Carbon Price Support (£30/t) + Targeted Capacity Tender
Net Welfare	Carbon costs	9,888	8,687	8,636	11,776	11,516
	Generation costs	9,783	3,807	3,305	7,708	7,655
	Capital costs	-24,390	-14,763	-15,260	-24,235	-23,973
	Unserved energy	197	-85	194	197	198
	Demand side response	-18	-8	-8	-16	-18
	Change in Net Welfare	**-4,540**	**-2,361**	**-3,132**	**-4,569**	**-4,622**
Distributional analysis						
Consumer Surplus	Wholesale price	3,037	-14,714	-14,727	-14,168	-16,152
	Low carbon payments	-4,198	1,334	1,334	162	7,413
	Capacity payments	-1,133	0	-1,176	-1,125	-1,169
	Unserved energy	197	-85	194	197	198
	Demand side response	-18	-8	-8	-16	-18
	Change in Consumer Surplus	**-2,115**	**-13,472**	**-14,384**	**-14,950**	**-9,728**
Producer Surplus	Wholesale price	-3,037	14,714	14,727	14,168	16,152
	Low carbon support	4,229	-1,368	-1,368	-70	-7,374
	Capacity payments	1,133	0	1,176	1,125	1,169
	Producer costs	-4,719	-13,149	-14,207	-14,647	-14,737
	Change in Producer Surplus	**-2,394**	**197**	**329**	**576**	**-4,790**