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POTENTIAL IMPACT OF REVISED RENEWABLES OBLIGATION TECHNOLOGY BANDS

A report to the
Department of Energy and Climate Change

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POTENTIAL IMPACT OF REVISED RO TECHNOLOGY BANDS

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EXECUTIVE SUMMARY

When the differentiation of support by technology (banding) was introduced into the Renewables Obligation in April 2009, DECC committed to review support levels every four years[1]. This report presents the results of analysis that Pöyry has undertaken for the review of bands to take effect from April 2013.

When reviewing support levels, DECC is required through the Energy Act 2008, to take account of certain factors. These include the costs and potential generation from each technology, the impacts on the number of ROCs issued, and the associated cost to consumers. DECC commissioned Arup to undertake a study, published in 2011, to understand the costs and deployment potential of each technology[2]. The analysis undertaken by Pöyry uses the results of this study to model the impacts that different bands might have on the deployment of renewable generation, the electricity market and costs to consumers, over the timeframe 2010/11 to 2039/40, with particular emphasis on the next ten years. All of the main input assumptions in the modelling were provided by DECC.

We were asked to model four core banding options:

- Option 1: Do Nothing – retain bands at the existing levels;
- Option 2: Minimum Scope – use the minimum bands DECC suggested for each technology[3] when we undertook the analysis;
- Option 3: Extra Support for Marine – same as the Minimum Scope option, but with 5ROCs/MWh for marine technologies; and
- Option 4: Portfolio Approach – support each technology at its expected (central) cost level.

A comparison of the bands assumed for the main technologies is given in Table 1.

1 In practice, only one of these reviews is now expected to take place: this is for the technology bands to take effect from April 2013. This is because the RO is due to be closed to new projects from April 2017, as a result of the introduction of the Feed-in Tariff with Contracts for Difference.

2 Review of the generation costs and deployment potential of renewable electricity technologies in the UK, Study Report. DECC, June 2011.

3 These 'minimum bands' are higher than in the Do Nothing option for enhanced cofiring and offshore wind.

Table 1 – Technology bands assumed for the main technologies under the four options modelled

	Do Nothing	Minimum Scope	Extra Support for Marine	Portfolio Approach
Biomass (>50MW)	1.5	1.5	1.5	2.4
Biomass (<50MW)	1.5	1.5	1.5	1.9
Biomass Conversion	1.5	1	1	1.3
Enhanced Co-firing	0.5	1	1	1.1
Onshore Wind	1	0.9	0.9	0.8
Offshore Wind	1.5*	2	2	2.5
Tidal (England, Wales & NI)	2	2, (2015/16) 1.9	5**	3.8
Tidal (Scotland)	3	2, (2015/16) 1.9	5**	3.8
Wave (England, Wales & NI)	2	2, (2015/16) 1.9	5**	5.9
Wave (Scotland)	5	2, (2015/16) 1.9	5**	5.9

*The current band for offshore wind is set at 2ROCs/MWh but falls to 1.5ROCs/MWh from April 2014

** The bands for tidal and wave were assumed to drop to 4.85ROCs/MWh after the first 50 MW

Note: Where a year is given in brackets, this is the year in which the new band is assumed to take effect.

Source: DECC

We were also asked to test the sensitivity of our results to some key input assumptions:

- fossil fuel prices;
- deployment potential;
- future costs of offshore wind; and
- the overall target for renewable energy.

Specifically the individual sensitivities run were:

- High Fossil Fuel Prices (Do Nothing);
- Low Fossil Fuel Prices (Do Nothing);
- High Fossil Fuel Prices (Extra Support for Marine);
- Low Fossil Fuel Prices (Extra Support for Marine);
- Lower Deployment Potential;
- High Offshore Learning Rates; and
- Low Ambition (an alternative counterfactual to the Do Nothing option).

Sensitivities were run using the Extra Support for Marine option assumptions with a couple of exceptions. The high and low fossil fuel price sensitivities were conducted on the Do Nothing option, as well as the Extra Support for Marine option. The Low Ambition sensitivity was not run on the Extra Support for Marine option. This sensitivity used the technology band assumptions from the Do Nothing option, but also used different policy assumptions than the other options and sensitivities run. The policy assumptions used for this sensitivity were based on the RO before the introduction of the 2020 Renewable Energy Targets.

The modelling results for the four options

An overview of the results of the modelling is given in Table 2. The capacity, generation and issued ROCs results are shown for capacity installed by March 2016, as all new capacity after this date was assumed to be installed under the FiT CfD. This was because it was assumed projects due to commission after April 2016 would avoid choosing support under the RO to avoid the potential of missing out on support if their project was delayed.

The results shown are based on electricity prices projected using DECC's fossil fuel and carbon price assumptions. The fossil fuel price projections were first published by DECC in 2009, and reviewed by DECC in 2010 but not changed. They are shown in Section 4.2.1.1 of this document and detailed in Annex B of DECC's consultation on the revised RO bands[3]. Since undertaking the modelling DECC's fossil fuel price projections have subsequently been revised.

Under central assumed fossil fuel prices wholesale electricity prices were projected to rise from £58/MWh in 2011/12 to £91/MWh in 2039/40.

Table 2 – Key results for the four options modelled (real 2010 prices)

		Difference		
	Do Nothing	Minimum Scope	Extra Support for Marine	Portfolio Approach
Large-scale renewable capacity in 2015/16 (GW)*	17.8	+0.8	+0.8	+1.8
Large-scale renewable generation in 2015/16 (TWh)*	66.4	+5.0	+5.2	+14.6
ROCs issued in 2015/16 (Millions)*	81.6	-2.7	-1.8	+51.2
Lifetime cost of the RO (£billion)	41.7	-1.1	-0.8	+19.3
Lifetime system costs (£billion)**	650.8	-0.5	+1.1	+22.6

* * DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

** The difference in system costs shown for the Minimum Scope and Extra Support for Marine options should be treated with caution. The relationship we were asked to assume between future marine costs and future deployment means costs fall more steeply in the Minimum Scope option than the Extra Support for Marine option.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results.

Under the Do Nothing scenario, most new capacity build in the banding review period comes from onshore Wind (1.9 GW) and biomass conversion (1.5 GW). For offshore wind only the 500 MW assumed to be under construction is projected to build with 1.5ROCs/MWh, and dedicated biomass has relatively low deployment with only 35 MW built. New wave and tidal capacity reaches 40 MW in total.

3 Consultation on the Renewables Obligation Banding Review. DECC, October 2011.

The results for the Minimum Scope and Extra Support for Marine options are very similar, as the high marine support in the latter option is the only difference between them. Both these options show higher projected generation from renewables than the Do Nothing option.

The most significant increase comes from enhanced cofiring, where it was assumed that the higher band encourages investment in 0.6 GW of enhanced cofiring at the only station assumed to invest in this technology. The remaining increase is made up of 0.4 GW of offshore wind, due to higher support from April 2014 (2ROCs/MWh rather than 1.5ROCs/MWh). This is offset to a small extent by a projected reduction in onshore wind capacity of 0.1 GW as a result of the fall in band from 1ROC/MWh to 0.9ROCs/MWh. No difference is projected in dedicated biomass as the band was not assumed to change.

Notably no change is projected in the level of biomass conversion in the Minimum Scope and Extra Support for Marine options compared to the Do Nothing option. Relatively high load factors and longer assumed technical lifetimes for converted plant mean the conversions still appear economic despite the ROC band being 1ROC/MWh rather than 1.5ROCs/MWh. It should be noted, however, that the decision to convert to biomass is plant-specific. This individual treatment is particularly important in relation to biomass conversion given the small number of plants, and large amount of capacity that each plant represents.

No wave and tidal capacity is assumed to build under the RO in the Minimum Scope option as a result of the 2ROCs/MWh band, which reduces support from the Do Nothing option for new wave and tidal generators located in Scotland. Under the Extra Support for Marine option wave and tidal capacity is projected to increase under the RO by 11 MW over the Do Nothing option.

Relative to the Do Nothing option, lower bands under the Minimum Scope and Extra Support for Marine options – for biomass conversion and onshore wind in particular – reduce the projected number of ROCs issued overall, and the cost of the RO is thereby also reduced. This is despite overall projected renewable generation being higher. These results stem from the assumptions used in the modelling. It is possible that lower bands could lead to a lower capacity deployment if generation costs are not covered.

The difference in system costs is small relative to the overall level of system costs, comprising less than 0.5%. However, the difference in system costs from the Do Nothing option shown for the Minimum Scope and Extra Support for Marine options should be treated with caution. The relationship we were asked to assume between future marine costs and future deployment means costs fall more steeply in the Minimum Scope option than the Extra Support for Marine option.

The Portfolio Approach option shows a greater change from the Do Nothing option than the other options, as in general higher bands are awarded.

Dedicated biomass and offshore wind appear to do particularly well under the higher bands, with a projected additional 1.3 GW and 0.8 GW increase in projected capacity over the Do Nothing option under the RO. Wave and tidal also benefit with 19 MW of additional capacity projected. Projected onshore wind falls by 0.3GW as a result of the fall in band. Biomass conversion and enhanced co-firing show no change as a result of higher assumed bands. The former is due to the fact that all the potential capacity is already converted in the Do Nothing option (within biomass constraints), the latter is due to DECC's assumption that investment in enhanced co-firing would not go ahead if the standard co-firing band provides just 0.1ROC/MWh less support than the enhanced co-firing band.

The combination of the higher level of support offered per MWh, and higher generation as a result of that, means the cost of the RO is projected to be almost 50% higher under the Portfolio Approach option than under the Do Nothing option.

Modelling results for the sensitivities

Table 3 and Table 4 provide an overview of the results for the sensitivities compared to the scenario the sensitivity was tested on. As in Table 2, the capacity, generation and ROCs issued results are shown for capacity installed by March 2016, as all new capacity after this date was assumed to be installed under the FiT CfD.

Of the sensitivities tested, low fossil fuel prices result in the most significant impact on renewables deployment under the RO. The low fossil fuel price sensitivities on the Do Nothing and Extra Support for Marine options show projected renewable generation at 21 TWh and 27 TWh lower respectively under the RO. This results from electricity prices that are projected to be an average of £21/MWh lower than under central fossil fuel prices. After 2015/16 it was assumed that the level of support under the FiT CfD would be sufficient to enable renewables targets to still be met in 2020.

The high fossil fuel price sensitivities result in higher generation under the RO. The effect is not as great as under the low fossil fuel price sensitivities, reflecting a narrower gap between assumed central and high gas prices, causing a smaller difference between projected central and high wholesale electricity prices. The FiT CfD was also adjusted for these sensitivities so that only the level of support required to meet the 2020 targets was provided.

The sensitivity using Arup's central rather than its high deployment potential shows a less dramatic effect than the fossil fuel price sensitivities, with 2 TWh less renewable generation than under the Extra Support for Marine option under the RO. The difference becomes greater from April 2016, meaning renewables targets would not be met unless there was a higher level of support provided under the FiT CfD.

The High Offshore Learning Rates sensitivity has very little impact on renewable generation but means that less support is required to reach a similar level of deployment, particularly beyond 2020.

The Low Ambition sensitivity provides an alternative counterfactual against which the RO policy to meet the 2020 target can be compared. It takes its policy assumptions from the RO before it was altered to take account of the 2020 Renewable Energy Targets. As such it only provides support under the RO to 2027 rather than 2037 in the other Options and Sensitivities. In this sensitivity, the shorter length of support provided, makes investment unattractive, and leads to very little growth in renewables, reaching just 60 TWh in 2020/21.

Table 3 – Key results for sensitivities run against the Extra Support for Marine option (real 2010 prices)

	Extra Support for Marine	Difference			
		High Fossil Fuel Prices	Low Fossil Fuel Prices	Lower Deployment Potential	High Offshore Learning Rates
Large-scale renewable capacity in 2015/16 (GW)*	18.7	+2.7	-5.0	-0.7	+0.1
Large-scale renewable generation in 2015/16 (TWh)*	71.6	+11.7	-26.9	-2.0	+0.2
ROCs issued in 2015/16 (Millions)*	79.8	+17.5	-27.9	-2.2	+0.4
Lifetime cost of the RO (£billion)	40.8	+9.2	-12.2	-0.4	+0.2
Lifetime system costs (£billion)	651.9	+12.1	-42.8	-9.2	+9.4

* * DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

Table 4 – Key results for sensitivities run against the Do Nothing option (real 2010 prices)

	Do Nothing	Difference		
		High Fossil Fuel Prices	Low Fossil Fuel Prices	Low Ambition
Large-scale renewable capacity in 2015/16 (GW)*	17.8	+2.6	-4.0	-1.4
Large-scale renewable generation in 2015/16 (TWh)*	66.4	+13.5	-21.2	-11.6
ROCs issued in 2015/16 (Millions)*	81.6	+17.7	-30.0	-18.0
Lifetime cost of the RO (£billion)	41.7	+9.0	-13.0	-9.9
Lifetime system costs (£billion)	650.8	+9.1	-41.5	-72.3

* * DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

1. INTRODUCTION

The Renewables Obligation (RO) is the main support mechanism currently in place for large scale[4] renewable electricity technologies. It was introduced in April 2002 and is proposed to be open to new plants commissioning before April 2017[5]. In 2009, the RO was adapted to differentiate support between technologies; this is achieved by awarding different multiples of Renewables Obligation Certificates issued per MWh of electricity generated (banding). When banding was introduced, a review of the technology specific ROC bands was scheduled to occur every four years[6]. The ROC bands resulting from the first review are due to be implemented in April 2013. This first review is currently underway and the analysis discussed in this report forms part of that process.

In making a decision on what band to award each technology, the Department for Energy and Climate Change (DECC) is required, under the Energy Act 2008, to take account of the following:

a) the costs (including capital costs) associated with generating electricity from each of the renewable sources or with transmitting or distributing electricity so generated;

b) the income of operators of generating stations in respect of electricity generated from each of those sources or associated with the generation of such electricity;

c) the effect of paragraph 19 of Schedule 6 to the Finance Act 2000 (c. 17) (supplies of electricity from renewable sources exempted from climate change levy) in relation to electricity generated from each of those sources;

d) the desirability of securing the long term growth, and economic viability, of the industries associated with the generation of electricity from renewable sources;

e) the likely effect of the proposed banding provision on the number of renewables obligation certificates issued by the Authority, and the impact this will have on the market for such certificates and on consumers; and

f) the potential contribution of electricity generated from each renewable source to the attainment of any target which relates to the generation of electricity or the production of energy and is imposed by, or results from or arises out of, a Community obligation.

To help decide what ROC bands to award each technology from April 2013, and understand the potential impact, DECC commissioned two studies. The first was an assessment of the technology costs and potential for new renewable generating capacity. It was conducted by Arup and was published in June[7]. This report provides the results of

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4 DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT

5 Limited exceptions will be made for plants unable to meet the 1 April deadline for reasons beyond their control, and for phased offshore wind projects.

6 In practice, only one of these reviews is now expected to take place: this is for the technology bands to take effect from April 2013. This is because the RO is due to be closed to new projects from April 2017, as a result of the introduction of the Feed-in Tariff with Contracts for Difference.

7 Review of the generation costs and deployment potential of renewable electricity technologies in the UK, Study Report. Arup, June 2011.

the second study, which inputted the results of the first study into an electricity despatch model in order to understand the potential impact of different bands on the ROC market and the electricity market. Our contribution has been to undertake the modelling. All the main input assumptions have been provided by DECC, including the information on cost and resource potential from the Arup study.

1.1 Structure of this report

Following this introductory section, the report is structured as follows:

- Chapter 2 explains the modelling methodology and the scenarios modelled;
- Chapter 3 explains the main input assumptions and their sources; and
- Chapter 4 discusses our modelling results.

Annex A to Annex C provide more detailed information on the input assumptions provided by DECC. The remaining Annexes, provide more detail on our modelling results.

1.2 Definitions

To help understand the potential impacts of different banding scenarios a range of indicators are reported, see Section 2.2. These are defined below. All those coloured blue were calculated by DECC using Pöyry's modelled results. The remaining impacts were calculated by Pöyry.

- **System cost** = costs of renewable generation + costs of non-renewable generation + balancing cost + EUA purchase costs.

  Note: this does not include all system costs e.g. transmission, distribution costs and retail costs are not included.

- **Renewable generation costs** = capex (annuitized over 15 years) + opex + fuel costs.

  Renewables capacity commissioned before 2011 is assumed to have the same costs as capacity commissioned in 2011.

- **Non-renewable generation costs** = capex (annuitized over 15 years) + interest during construction+opex + fuel costs.
- **Balancing cost** = assumed balancing cost per unit of intermittent generation x intermittent generation + balancing cost per unit of non-intermittent generation x non-intermittent generation.

  Note: this uses a rough estimate of the level of current balancing costs that are assumed to be attributed to intermittent and non-intermittent generation.

- **Cost of purchasing EUA's** = grid emissions of CO_2 x projected EUA price.
- **Consumer cost** = RO cost + wholesale price cost + balancing cost.

  Note 1: the consumer cost does not include assumed FiT CfD subsidy costs, as the design of the scheme and technology specific 'strike prices' are yet to be determined. This means that whilst wholesale prices might be lower to 2039/40 in scenarios where wind and nuclear generation is higher, reducing the cost to consumers, the increase in consumer costs as a result of the FiT CfD will not be taken into account.

Note 2: the consumer cost does not represent all costs to consumers as other costs which may be assumed to remain constant (e.g. supplier transaction) are not included.

- **RO cost** = buyout price x obligation size.
- **Wholesale price cost** = wholesale price x demand for each period, summed over all periods.
- **Producer surplus for renewable generators** = sum of net present value of total revenues to each generator minus net present value of total generation costs.

1.2.1 Sources

Unless otherwise attributed, the source for all tables, figures and charts is Pöyry Management Consulting.

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2. MODELLING METHODOLOGY AND SCENARIOS

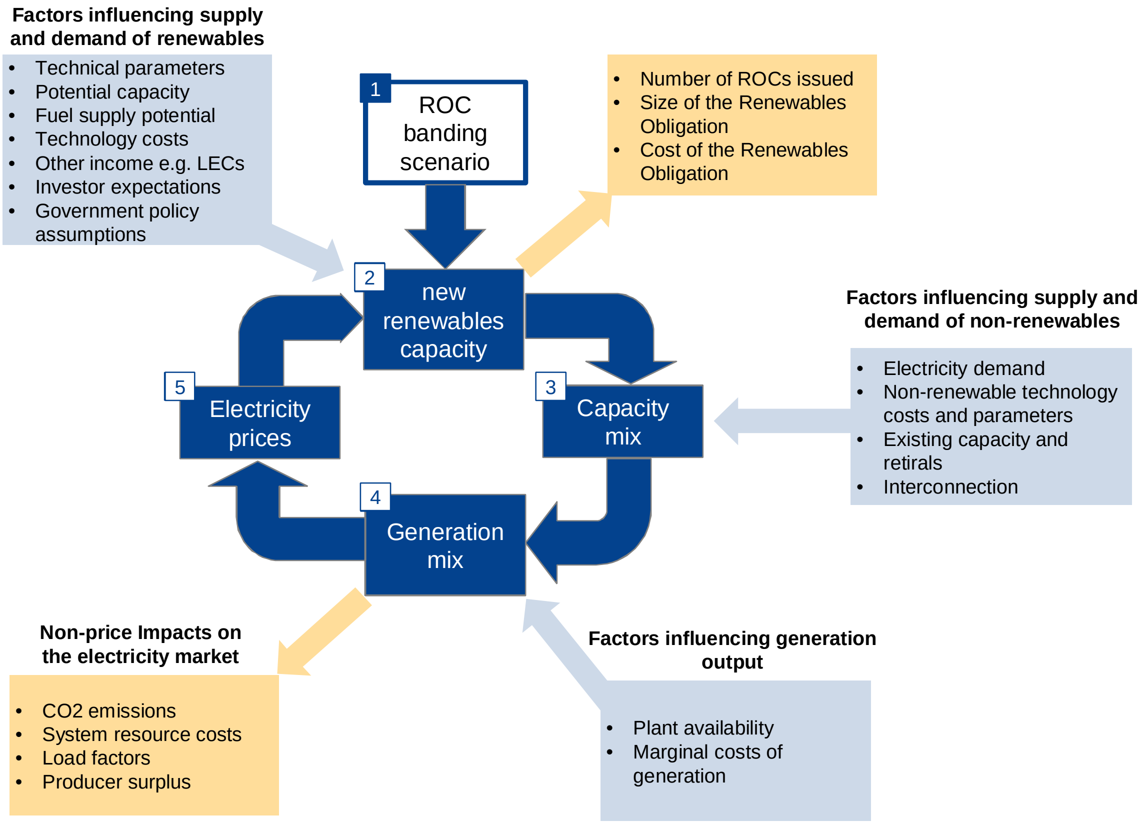
The modelling approach is based on the market fundamentals of demand, supply and long run marginal costs of electricity generating technologies, taking account of support provided by Government to renewable technologies. To consider the effect of different ROC bands on the electricity market, a scenario approach has been used. In this Chapter we first discuss the modelling approach and then discuss the scenarios modelled.

2.1 Modelling approach

Figure 1 provides an overview of the process used to model the potential impact of different bands. The main relationships in the model are shown in blue with numbered stages. Inputs to the model, affecting supply and demand for new electricity capacity and generation, are shown in grey. Outputs from the model, in addition to those that form part of the main relationships, are in orange.

This process begins with entering the technology specific ROC bands; these are then used to determine the amount of new renewables capacity commissioned, new thermal capacity commissioned, generation from available capacity and electricity prices. This process is circular as electricity prices will themselves affect the attractiveness of building new capacity. Our modelling process includes this circularity.

Figure 1 – Overview of the modelling approach



To model the effect of ROC bands on renewable generation and electricity prices a large number of input assumptions are required (shown in grey). These were generally provided by DECC[8] and an overview of the main assumptions used is given in Chapter 3. The main outputs from the modelling process (shown in orange) are discussed in Chapter 4. Below we describe the different stages of the modelling process, as labelled in Figure 1.

- **Stage 1, ROC banding scenarios.** This stage kicks off the modelling process with a set of pre-determined technology specific ROC bands. The bands entered into the model then feed into the amount of new renewables capacity that is projected to be to be developed.

- **Stage 2, new renewables capacity.** To determine what new renewables capacity is built, the model considers whether a project appears economic to investors, taking account of the ROC bands entered in Stage 1, and what can feasibly be built given practical constraints. The higher the ROC bands, the more attractive renewables will be to develop, and the more capacity will get built, subject to non-financial constraints.

  For the economic test, assumed costs include capex, opex and fuel costs. Along with the ROC bands, the assumed income includes the sale of electricity, the sale of LECs and gate fees. Technical characteristics such as load factors and efficiencies are also necessary to understand the return per MWh of generation. In the case of coal fired plants converting to biomass, the test includes whether the plants would be better off remaining a coal fired plant or converting (see Section 3.1.3 for the assumptions on plants tested for conversion).

  The potential for non-financial constraints, e.g. supply chain constraints, is taken into account by constraining the maximum capacity that could be built of each technology in each year. Renewable thermal capacity is also constrained by the available fuel supply. The constraints assumed for capacity and fuel supply are explained in Section 3.1.3.

  Once the build-out of renewables capacity is determined, it is possible to determine the potential impact on the ROC market, including the number of ROCs issued and cost of the RO.

- **Stage 3, capacity mix.** The amount and type of renewables capacity that gets built impacts on the demand for new non-renewable capacity. This means the overall capacity mix will be affected e.g. large amounts of biomass may reduce the amount of new CCGT capacity built. To determine the extent of this effect, assumptions were made on the supply and demand for non-renewable capacity, including non-renewable technology costs and overall electricity demand. Section 3.2 provides more information on the assumptions made.

- **Stage 4, generation mix**. The overall capacity mix will determine the amount of generation that is expected from each technology. This is dependent on both the availability of the technology and its marginal cost of generation. For example, higher levels of renewable generation, with low marginal cost, might reduce the level of non-renewable thermal generation, with a relatively high marginal cost.

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8 With the exception of Power Purchase Agreement discounts of revenue streams which (apart from offshore wind) were suggested by Pöyry and agreed by DECC.

- **Stage 5, electricity prices.** As different technologies have different fixed and marginal costs the change in capacity and generation mix will impact on the overall costs of generation. This in turn will affect electricity prices – the higher the costs, the more revenue generators will require to recover costs. In addition, subsidising renewable generation will mean some of the cost to these generators will be covered outside of the wholesale electricity market. In general, this will mean the more renewable generation through the RO, the more costs are covered outside the electricity market, and the lower projected wholesale prices are.
- **Stage 5 back to Stage 2.** The interaction of the five stages described above is circular. Electricity prices resulting from Stage 5 impact on the level of income available to renewables developers in Stage 2.

  In our modelling the interaction between the electricity market and investment in new renewables capacity is accounted for by iterating between our wholesale electricity market and ROC market models. With Stages 1 and 2 were performed by our ROC market model and Stages 3 to 5 performed by our electricity market model.

  In Stage 3, new renewables capacity determined by our ROC market model is entered into our electricity market model. Moving from Stage 5 to Stage 2 wholesale electricity prices and biomass load factors are passed through from the electricity market model to our ROC model. This included accounting for the generation-weighted average price projected for intermittent technologies e.g. wind, which enables the situation to be accounted for whereby intermittent generators capture lower than average wholesale prices, due to large amounts of installed intermittent capacity generating at similar times.

2.2 Scenarios modelled

DECC provided us with four banding options to model in order to compare the potential impacts of different ROC bands on investment in renewables and the electricity market.

Alongside the four banding options, DECC also asked us to test the sensitivity of some key input assumptions on the modelling results. Table 5 shows a summary of the options modelled and the sensitivities run on each option.

Table 5 – Summary of the scenarios modelled

Option	Name	Description	Sensitivities run
1	Do Nothing	Retain bands at the existing levels	High Fossil Fuel Prices, Low Fossil Fuel Prices, Low Ambition
2	Minimum Scope	Use the minimum bands DECC suggested for each technology* when we undertook the analysis	None
3	Extra Support for Marine	Same as the Minimum Scope option, but with 5ROCs/MWh for marine technologies	High Fossil Fuel Prices, Low Fossil Fuel Prices, Lower Deployment Potential, High Offshore Learning Rate
4	Portfolio Approach	Support each technology at its expected (central) cost	None

* These ‘minimum bands’ are higher than in the Do Nothing option for enhanced cofiring and offshore wind.

Table 6 shows a list of the technologies modelled under each option and sensitivity. On the left hand side are the categories we have used to present our modelling results in charts. On the right hand side is the full list of technologies modelled shown against the category they have been allocated to.

Table 6 – Technologies modelled

Technology category	Technology
Biomass	Bioliquids (Power only), Biomass (>50MW), Biomass (<50MW), Biomass (Energy crops), Biomass (Conversion from existing coal plant), Biomass (CHP)
Cofiring	Co-firing (Standard, <10% biomass), Co-firing (Enhanced, 15% biomass), Co-firing (Energy crops), Co-firing (CHP, 10% biomass)
Energy from waste	Energy from Waste (Power only), Energy from Waste (CHP)
Hydro	Hydro (>5MW), Hydro (<5MW)
Landfill gas	Landfill gas
Offshore Wind	Offshore wind (Round 2), Offshore wind (Round 3)
Onshore Wind	Onshore wind (>5MW), Onshore wind (<5MW)
Other	Advanced Conversion Technology (Power only), Anaerobic Digestion (Power only), Anaerobic Digestion (CHP), Geothermal (Power only), Geothermal (CHP), Sewage gas
Solar PV	PV (>5MW), PV (<5MW)
Tidal	Tidal stream (England, Wales & NI), Tidal stream (Scotland, Shallow), Tidal stream (Scotland, Deep)
Wave	Wave (England, Wales & NI), Wave (Scotland)

The impacts considered for each option included:

- new renewable generating capacity;
- renewable generation;
- ROCs issued;
- wholesale electricity prices (where modelled);
- cost of the RO;
- costs to consumers;
- system costs; and
- producer surplus.

These impacts are defined in Section 1.2 and reported on in Chapter 4 and Annex E.

3. INPUT ASSUMPTIONS

All the main input assumptions were provided to Pöyry by DECC[9]. The renewable technology assumptions used in this modelling were taken from a study undertaken by Arup which was commissioned by DECC for this purpose[10]. The exception is the wave and tidal cost assumptions which were taken from a study by Ernst & Young also commissioned by DECC[11]. The biomass availability and fuel prices were based on a study for DECC by AEA et al[12] and the WRAP gate fees report 2010. The non-renewable cost data was taken from a study by PB Power[13]. All the policy assumptions came directly from DECC.

Below we have summarised the main input assumptions, which are discussed under the following categories:

- renewable technology assumptions;
- electricity market assumptions; and
- renewables revenue assumptions.

3.1 Renewable technology assumptions

The renewable technology assumptions allow DECC to determine how much renewable generation is possible and how much RO support might be required to reach the renewable generation it is looking for. These assumptions consist of:

- technology costs;
- technology technical parameters; and
- potential capacity availability.

3.1.1 Renewable technology costs

Figure 2 shows the capex assumptions for a selection of the renewable technologies modelled. A full description of the capex costs used can be found in the Arup report. Figures are shown for costs in 2010/11 and 2015/16[14], in order to show the extent to which learning is assumed over the RO period for the different technologies.

For offshore wind, wave and tidal, DECC asked us to assume that the costs fell in relation to the amount of capacity commissioned. For offshore wind this was a 12% fall in the capex cost each time capacity doubled; for wave and tidal it was a 15% fall. The resultant

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9 The exception being discounts to wholesale electricity, ROC and LEC revenues assumed to take place under Power Purchase Agreements for technologies other than offshore wind.

10 Review of the generation costs and deployment potential of renewable electricity technologies in the UK, Study Report. Arup, June 2011.

11 Cost of and financial support for wave, tidal stream and tidal range generation in the UK. Ernst & Young, October 2010.

12 UK and Global Bioenergy Resource – Final Report. AEA, Oxford Economics, Biomass Energy Centre, Forest Research, March 2011.

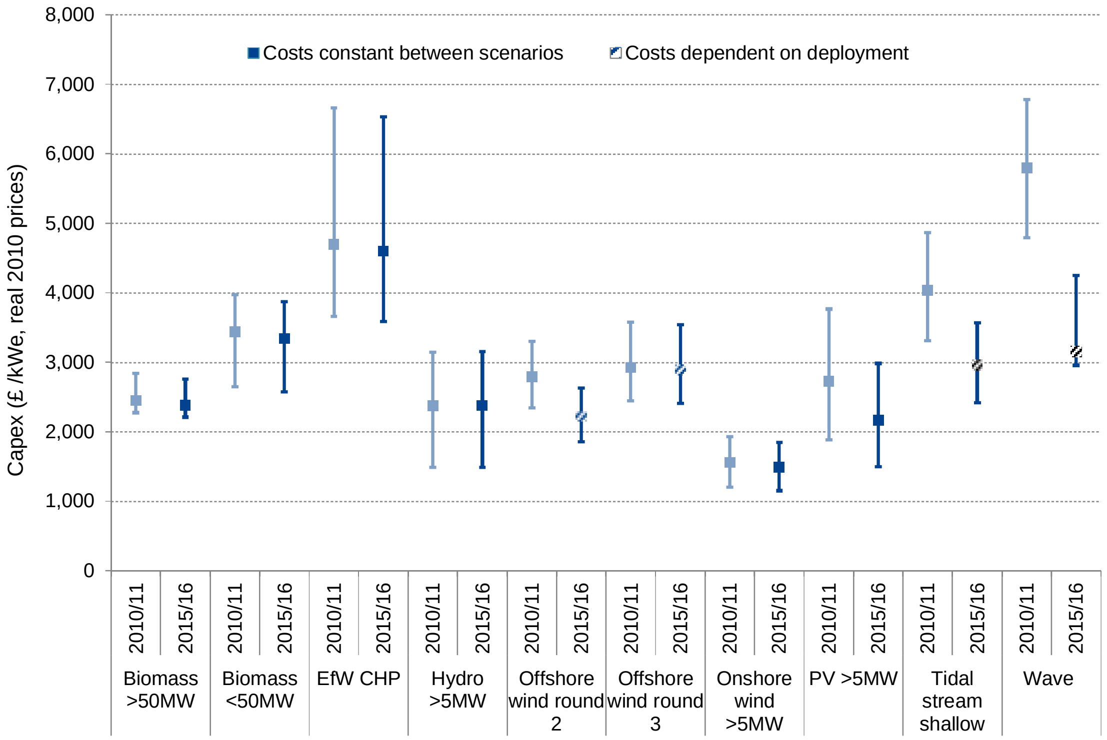
13 Electricity Generation Cost Model – 2011 Update Revision 1. Parsons Brinckerhoff, August 2011.

14 2015/16 is the last year in which new capacity is assumed to be built under the RO.

capex costs for the Extra Support for Marine option (see Table 5) are those presented in Figure 2.

To take account of the range of potential costs, technology supply curves were created by splitting the potential new renewables capacity (see Section 3.1.3) between five cost categories. These were made up of the High, Medium and Low costs determined by Arup and Ernst & Young, along with two intermediate cost categories above and below the Medium cost level. The exception to this was biomass conversion and enhanced co-firing, where only the central cost was assumed.

Figure 2 – Capex assumptions for main renewable technologies (£/KWe, real 2010 prices)



Note: Where costs are dependent on deployment, the cost for the Extra Support for Marine option is shown.

Source: DECC, Arup, Ernst and Young

For plants co-firing using biomass for up to 10% of their fuel input, the assumed technology potential was based on GWh's rather than capacity, see Section 3.1.3. This is because most coal fired power stations are already co-firing and it is how much of the coal fired generation they replace with from biomass that is of interest. The economics of co-firing up to 10% were modelled based on the marginal cost of generating from biomass rather than generating from coal. So it took account of relative assumed biomass, coal and carbon prices. To represent the variance in cost of co-firing annual supply curves were created by splitting the potential generation equally between five different fuel costs. Like the capex for other technologies, these were made up of the High, Medium and Low fuel costs provided by DECC, along with two intermediate cost categories above and below the Medium cost level.

The opex costs, fuel costs and hurdle rates (required internal rates of return for investment to proceed) assumed for the main technologies used are given in Annex A.

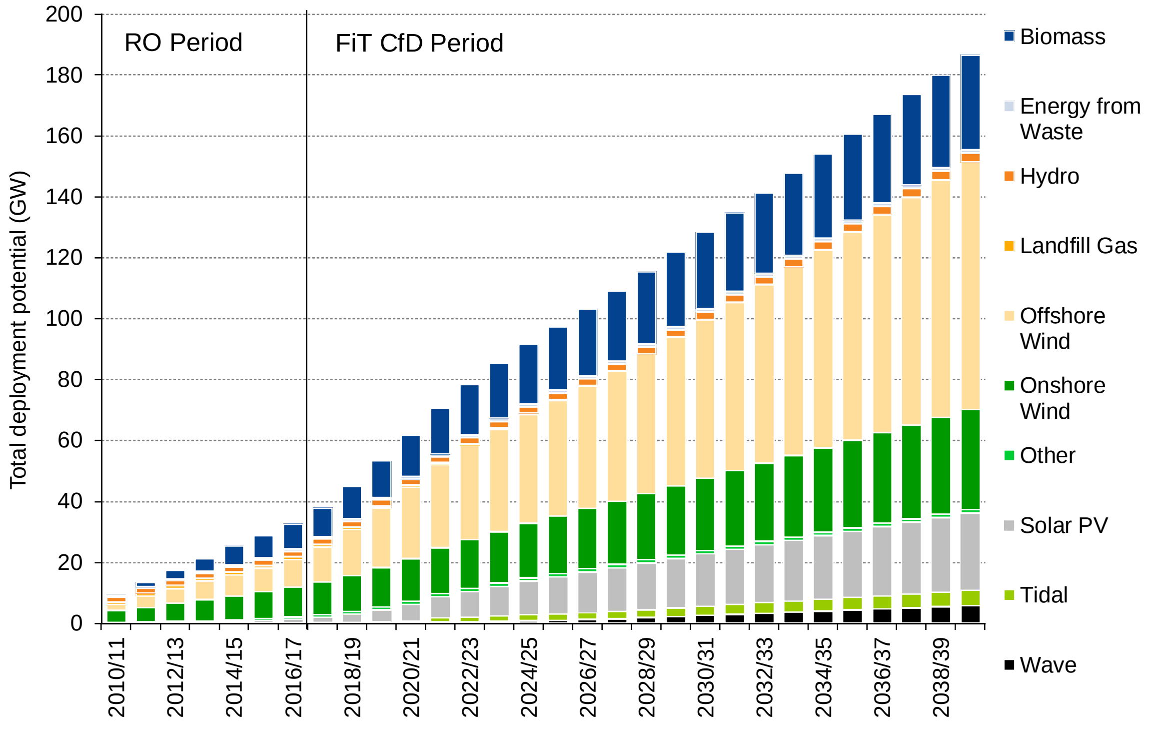
3.1.2 Renewable technical parameters

The technical parameters include the load factors, technical lifetimes and efficiencies, as detailed in Annex A. These were also taken from the Arup study. Load factors for biomass plants were allowed to vary in the electricity despatch model according to their position in the merit order and demand patterns.

3.1.3 Potential capacity assumptions

Aside from the economic constraints, there are a number of constraints on the amount of new renewable capacity that can be built. These include planning, grid connection and supply chain constraints. Figure 3 shows the potential capacity taken from the Arup study that was assumed for each technology, given these constraints. The high potential from that study was assumed for the modelling.

Figure 3 – Assumed cumulative capacity potential by technology (GW)



Note 1: includes operational capacity, capacity currently under construction and potential new capacity.

Note 2: See Table 6 for the definition of aggregated technology categories.

Source: DECC, Arup

Biomass >50MW and biomass energy crops were assumed to have a shared available capacity, with the most economic fuel, taking account of the level of ROC support, being used in that installation.

The potential for cofiring biomass in a coal-fired plant is not included in Figure 3. This is because it has been assumed on a generation rather than capacity basis, as cofiring can vary greatly depending on the load factor of the coal fired plant and the proportion of biomass used.

It was assumed that the amount that of available cofiring was 3 TWh in 2011/12 and 2012/13. After this an increase of 1 TWh a year was assumed to 2015/16. Beyond 2015/16 the cofiring capacity was assumed to remain at the same level for future years, before tailing off in line with the closure of coal-fired power stations. Of this, it was assumed that up to 500 GWh could come from energy crops.

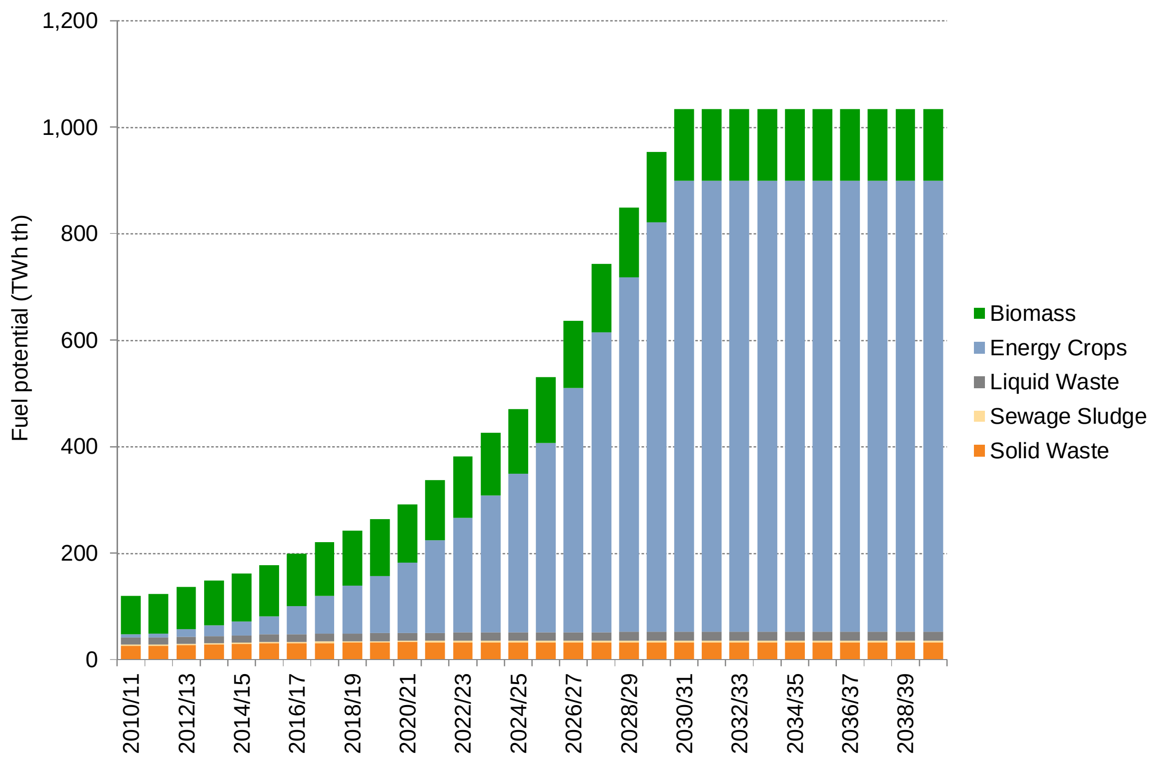
For enhanced cofiring, which requires above 15% biomass to be used in a fossil fuel fired generator, it was assumed that one coal fired power station would invest in enhanced cofiring at the minimum level with a support level of 1ROC/MWh. No other stations were assumed to invest in enhanced cofiring.

We were also provided with assumptions for the potential for existing coal-fired plants to convert to biomass. Five coal stations were assumed to potentially convert to biomass with associated assumed earliest years for the conversion to take place. If a published figure was given for the capacity of the intended conversion, this was used, otherwise, the converted plant was assumed to be 75% of its current capacity.

Assumptions were made by scenario on which biomass plants converted based on the results of an economic test. This used Pöyry's assumptions of the technical parameters of the individual existing coal plant e.g. technical lifetime, relative to the generic technical parameters for biomass conversion from the Arup study. The exception was the load factor, where the new load factor was assumed to be the load factor modelled for large biomass plants in our electricity market model.

The potential for landfill gas was assumed to fall overtime as more biomass waste is diverted from landfill sites. The landfill gas capacity was assumed to fall over time in line with the trajectory from the Arup data and was not modelled.

Figure 4 – Fuel supply potential (TWh_{th})



Source: DECC, AEA

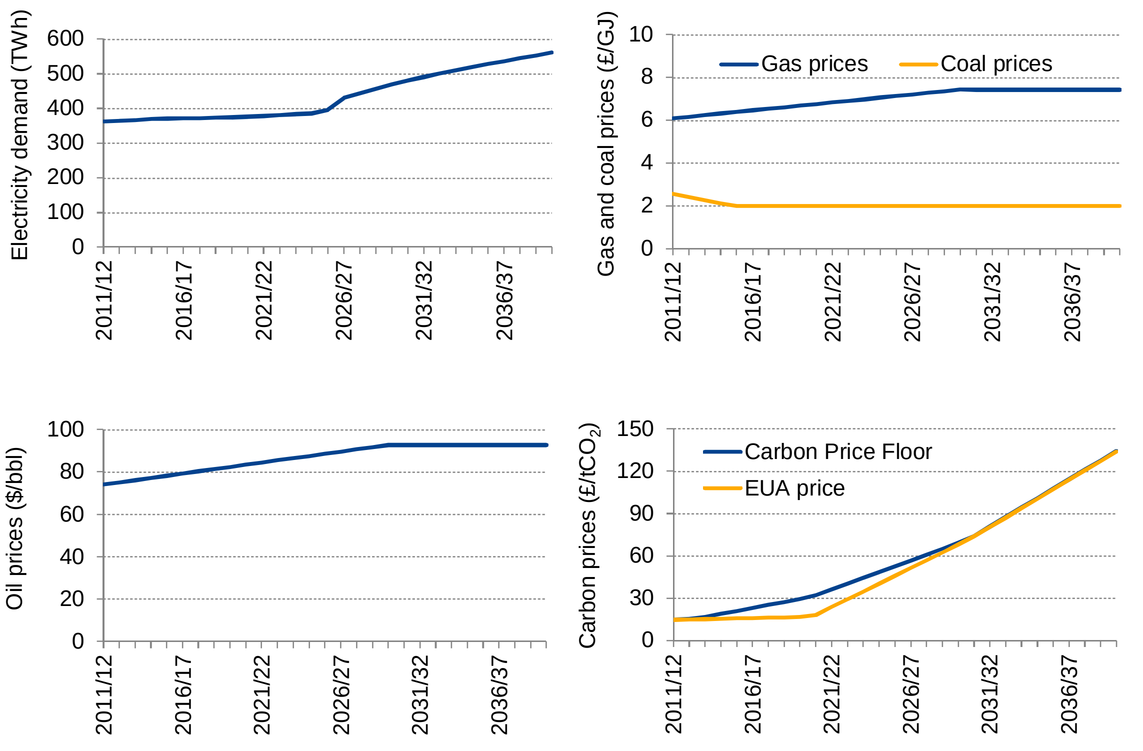
For fuel-burning generators, fuel availability was also taken into account, the assumptions for which were based on the AEA study, but reduced to account for DECC's projected demands for biomass in heating and transport. The assumed fuel availability (on an energy input basis) is shown in Figure 4. Biomass fuel was assumed to be shared between cofiring, biomass >50MW, biomass <50MW and biomass CHP. Energy crops were assumed to be shared between dedicated biomass with energy crops and cofiring with energy crops. Solid waste fuel was assumed to be shared between energy from waste, energy from waste CHP and the Advanced Conversion Technologies. Liquid waste fuel was assumed to be used by anaerobic digestion (AD) and AD CHP, and Sewage Sludge was assumed to only be available to sewage gas.

3.2 Electricity market assumptions

To understand the implications of the change in renewables capacity as a result of different ROC bands we also modelled the impacts on the electricity market.

Figure 5 shows the electricity demand, fuel and carbon price assumptions used. The fossil fuel price projections used were first published by DECC in 2009 and reviewed by DECC in 2010 but not changed. Since undertaking the modelling work, DECC has revised its fossil fuel price projections.

Figure 5 – Electricity market inputs (real 2010 prices)



Source: DECC

The assumptions used for non-renewable technology costs and technical parameters were taken from the PB power report.

3.3 Revenue assumptions

Alongside costs and capacity potential, the revenue assumptions are required to consider the extent of new investment in renewables capacity. A list of technologies and the assumed revenue streams received is provided in Annex C. In relation to the revenue streams, we were asked to make a general assumption that investors have five years' foresight. This means that they expect the projected change in revenue for the next five years, and beyond this their expectation is that the revenue stream will remain at the value it was projected to be in the fifth year. The specific assumptions made for each revenue stream are given below.

3.3.1 Wholesale electricity prices

It was assumed that all generators under the RO are able to sell their electricity in addition to receiving ROC support.

The assumed revenue from the wholesale electricity market took account of generation-weighted average projected wholesale electricity prices by technology, contractual costs and imbalance costs.

The assumed wholesale electricity price achieved is dependent on the technology, as it is possible different technologies will capture different proportions of the average wholesale electricity price. For example, intermittent generators may capture lower prices in later years due to higher levels of intermittent generation pushing down prices in the periods when they are generating.

In our experience, generators generally incur transaction costs in the sale of electricity. This is typically around 10% of the wholesale electricity price. Although this will tend to vary according to the exact terms and the proportions achieved for the other elements of value in a Power Purchase Agreement (PPA).

For the purposes of our modelling, it was assumed, in agreement with DECC, that generators receive 90% of the wholesale value of their electricity under the terms of PPAs with the discount in return for long-run certainty of offtake. Generators in all technologies were assumed to sell their electricity through such PPAs (or equivalent arrangements within vertically-integrated utilities), with the exception of offshore wind. Given the large nature of offshore wind farms combined with the intermittency of their output, it was assumed that offshore wind generators would not generally sign PPAs. DECC asked us to therefore assume offshore wind received 100% of its generation-weighted average wholesale electricity price, and that the higher offtake risk would be reflected through the assumed hurdle rate.

3.3.2 ROCs

It was assumed that all existing generators continue to receive the ROC band already allocated (i.e. support is grandfathered), with the exception of cofiring. It was assumed new generators commissioning before April 2013 receive the current ROC band with the exception of biomass conversion which was assumed to receive the current ROC band to April 2013, and then receive the revised ROC band beyond that. It was assumed all generators commissioning after April 2013 (the date from which the banding review takes effect) receive the ROC band allocated in that scenario. Table 7 in Section 4.1 shows the ROC bands allocated by scenario.

ROC prices are set through the headroom calculation[15], with a proportion of the income from ROCs assumed to meet the cost of financing a ROC and contracting costs. This can be around 11% of the ROC price. Although this will tend to vary according to the exact terms and the proportions achieved for the other elements of value in a PPA.

For the purpose of our modelling, in agreement with DECC, it was assumed that generators receive 89% of the value of their ROCs under the terms of PPA's. Offshore wind generators were assumed to not sign PPAs, and to DECC therefore asked us to assume they receive 100% of the ROC value.

The Electricity Market Reform White Paper states that generators will have a choice between the Feed-in Tariff with Contracts for Difference (FiT CfD) and RO until April 2017 (when the RO is proposed to close to new generators). To account for this, it was assumed that generators expecting to commission prior to April 2016 choose the RO instead of the FiT CfD, due to the FiT CfD being a relatively new scheme. It was also assumed that generators due to commission after April 2016 choose the FiT CfD to avoid the potential of missing out on support if their project is delayed.

3.3.3 LECs

It was assumed that the LEC value remains constant in real terms at £4.70/MWh in 2010 prices, and the CCL remains in place for the length of the modelled period. It was also assumed all currently eligible technologies remain eligible.

In our experience, generators generally incur transaction costs in the sale of LECs. This can be around 7% of the LEC price. Although this will tend to vary according to the exact terms and the proportions achieved for the other elements of value in a PPA.

For the purpose of our modelling, in agreement with DECC, it was assumed that generators receive 93% of the value of their LECs under the terms of PPA's. Offshore wind generators were assumed to not sign PPAs, and to DECC therefore asked us to assume they receive 100% of the LEC value.

3.3.4 FiT CfD

The FiT CfD was set to bring on a proportion of the potential capacity so that the 2020 renewable energy targets are met in DECC's preferred option – Extra Support for Marine. DECC asked us to assume that most RO eligible technologies would be supported by the FiT CfD with the exception of:

- generators eligible for the small scale FiT;
- PV>5MW; and
- Geothermal.

Bioliquids were assumed to be supported, however, unlike other technologies they were not supported at a proportion of their total deployment potential. Instead they were assumed to receive the same level of support as biomass<50MW.

In each technology category, FiT CfD support levels were set to bring on roughly the same proportion of their potential to meet renewable electricity's assumed share of the

[15] Details of how the Renewables Obligation is set are available on the DECC website at: http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/renew_obs/renew_obs.aspx

2020 target (108 TWh), whichever proportion across technologies was sufficient to reach 108 TWh. After 2020, 50% of their potential was incentivised across all technologies. These are simplified modelling assumptions which do not prejudice DECC's future decisions as to the availability and rate of support under the FiT CfD for different technologies.

It was also assumed that 9.6 GW of nuclear, and 3.4 GW of CCS coal and gas combined, would come forward under the FiT CfD by 2040.

3.3.5 Small scale FiT

It was assumed that all generators currently eligible for the small scale FiT are supported under this scheme rather than the RO. Existing plants were assumed to be supported by the scheme they were accredited under at the time the modelling was undertaken. DECC provided weighted average FiT tariff rates to use for each eligible technology (solar PV, hydro, wind and AD in Great Britain) across all size scales <5MW.

3.3.6 RHI

Biomass CHP and Geothermal CHP were assumed to be able to access support under the Renewable Heat Incentive (RHI). The RHI was assumed to be based on the RHI tariffs for biomass[16] and geothermal. It was assumed to be set at £26/MWh_{th} for biomass heat (with a capacity above 200kW) and £30/MWh_{th} for Geothermal. The biomass CHP heat tariff was assumed to reduce to £12.42/MWh_{th} in the scenarios where revised ROC bands were assumed for biomass CHP.

Biomass CHP commissioned prior to April 2015 was assumed to have the option of support under the RHI or the 0.5ROCs/MWh uplift. In the modelling it was assumed that biomass CHP would choose support under the RHI if commissioning prior to April 2013. If commissioning between April 2013 and April 2015 it was assumed to choose the 0.5ROCs/MWh uplift. From April 2015 to March 2016, it was assumed that support would be split between the RO and RHI (i.e. no choice). From April 2016, it was assumed that support would be provided by the FiT CfD alone.

3.3.7 Heat revenue

It was assumed that CHP technologies are able to sell their heat (or equivalently use the heat on-site and avoid the cost of generating it through alternative means), at a value calculated from the cost of gaining heating by alternative means. Annex C shows the heat revenue assumptions provided by DECC.

3.3.8 Capital grants

Wave and tidal technologies under the RO were assumed to have access to a capital grant that would cover up to half of their capital costs. This is a simplified modelling assumption; in reality there are finite public budgets used for capital support for innovation, so not all potential projects would be able to receive capital grants.

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16 The assumed tariff levels for biomass were based on the proposed biomass tariff levels when the modelling was undertaken. These tariff levels have since been revised as a result of European Commission requirements.

4. IMPACTS OF DIFFERENT ROC BANDS

In this chapter, we present the main results of the modelling, based mainly on DECC assumptions which were sourced primarily from the Arup study into the costs and deployment potential for each renewable technology. The assumptions are described in Chapter 3.

It should be noted, the modelling is intended to provide a representation of what the impacts could be under different banding scenarios. In reality decision-making will be more complicated than is possible to model, and there is inherent uncertainty in the parameters assumed when undertaking the modelling which will impact on the outcomes.

In presenting the results we first consider the options provided by DECC for the technology-specific ROC bands for projects commissioning after April 2013. These options are:

- Option 1: Do Nothing – retain bands at the existing levels;
- Option 2: Minimum Scope – use the minimum bands DECC suggested for each technology[17] when we undertook the analysis;
- Option 3: Extra Support for Marine – same as the Minimum Scope option, but with 5ROCs/MWh for marine technologies;
- Option 4: Portfolio Approach – support each technology at its expected (central) cost level.

In Section 4.1, we compare the how differences in the assumed bands impact on renewables deployment under the four options. In Sections 4.1.1 to 4.1.4, each individual option is discussed in more detail.

In addition to the options modelled, the sensitivity of the results to some key input assumptions was also tested. The input assumptions considered were:

- fossil fuel prices;
- deployment potential;
- future costs of offshore wind; and
- the overall target for renewable energy.

Section 4.2 explains the results of the sensitivity analysis.

4.1 Options modelled

Table 7 presents the ROC bands assumed for the options modelled. In the Do Nothing option the current bands were assumed to remain in place for new projects. In the other scenarios DECC provided bands for projects commissioning from April 2013 onwards. For some technologies where bands fall, the fall in band was assumed to take effect in a later year. In these instances we have shown in brackets the year the fall in band was assumed to take effect. Changes in bands effective from April 2016 were not considered

17 These 'minimum bands' are higher than in the Do Nothing option for enhanced cofiring and offshore wind.

as part of the study, as it was assumed all new capacity building from April 2016 would be supported under the FiT CfD.

Under the FiT CfD, DECC requested that support levels were set to bring forward sufficient levels of generation such that renewable electricity's contribution towards the 2020 target would be met in the Extra Support for Marine option. Beyond 2020, half of potential capacity was assumed to be supported. Table 23 in Annex C shows the technologies that were assumed to be eligible for the FiT CfD.

Table 7 – ROC bands assumed in the options modelled (ROCs/MWh)

	Current Bands	Minimum Scope	Extra Support for Marine	Portfolio Approach
ACT (Power only)	2	0.5	0.5	0
Bioliquids (Power only)	1.5	1.4	1.4	6.9
Biomass (>50MW)	1.5	1.5	1.5	2.4
Biomass (<50MW)	1.5	1.5	1.5	1.9
Biomass (Energy crops)	2	(2015/16) 1.9	(2015/16) 1.9	3.3
Biomass (Conversion from existing coal plant)	1.5	1	1	1.3
Biomass (CHP)	2	(2015/16) 1.4 + RHI	(2015/16) 1.4 + RHI	4.8
CoFiring (Standard, <10% biomass)	0.5	0.5	0.5	0.9
CoFiring (Enhanced, 15% biomass)	0.5	1	1	1.1
CoFiring (Energy crops)	1	1	1	0.9
CoFiring (CHP, 10% biomass)	1	1	1	1
EfW (CHP)	1	0.5	0.5	0
Geothermal (Power only)	2	(2015/16) 1.9	(2015/16) 1.9	3
Geothermal (CHP)	2	(2015/16) 1.9	(2015/16) 1.9	4.7
Hydro (>5MW)	1	0.5	0.5	0.1
OffshoreWind (Round 2)	1.5*	(2015/16) 1.9	(2015/16) 1.9	2.5
OffshoreWind (Round 3)	1.5*	1.5	1.5	2.5
OnshoreWind (>5MW)	1	0.9	0.9	0.8
PV (>5MW)	2	(2015/16) 1.9	(2015/16) 1.9	6.6
Sewage Gas	0.5	0.5	0.5	0.4
Tidal Stream (England, Wales & NI, Shallow)	2	2, (2015/16) 1.9	5**	3.8
Tidal Stream (Scotland, Shallow)	3	2, (2015/16) 1.9	5**	3.8
Tidal Stream (Scotland, Deep)	3	2, (2015/16) 1.9	5**	3.8
Wave (England, Wales & NI)	2	2, (2015/16) 1.9	5**	5.9
Wave (Scotland)	5	2, (2015/16) 1.9	5**	5.9

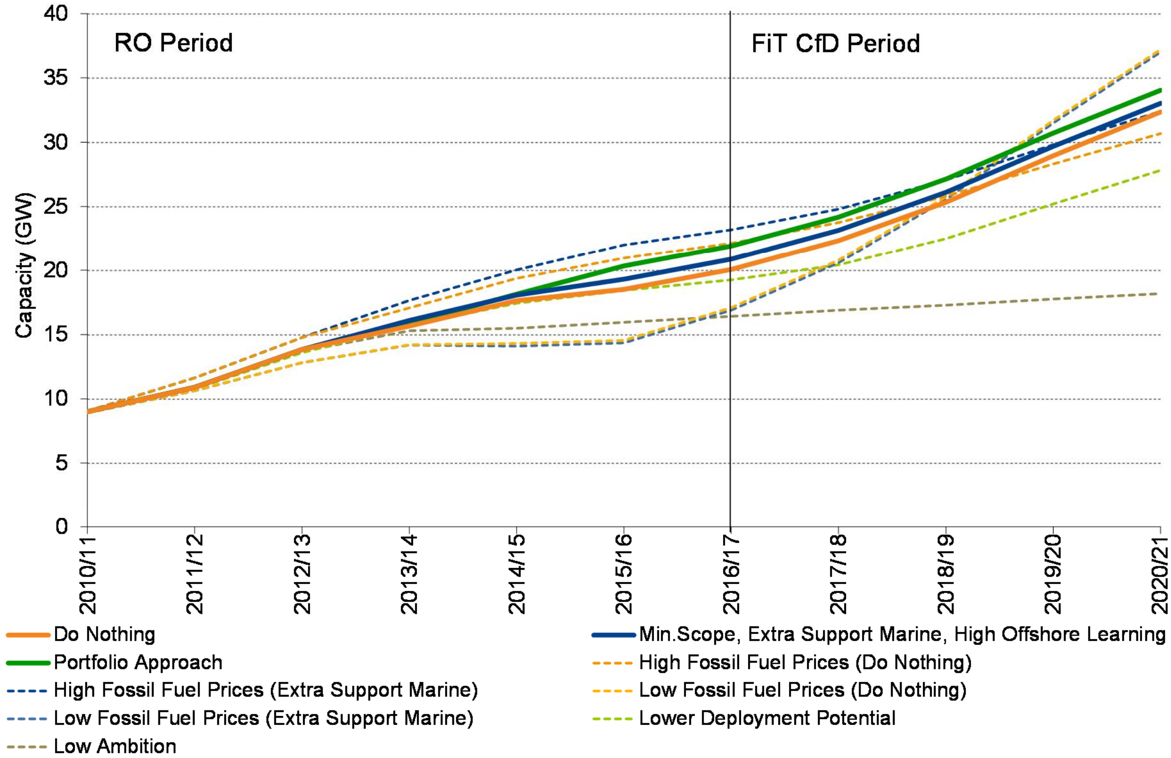
*The band for offshore wind is currently 2ROCs/MWh, but was due to drop to 1.5 ROCs/MWh from April 2014.

**The bands for tidal and wave were assumed to drop to 4.85ROCs/MWh after the first 50 MW of new marine capacity was installed.

Note: Where a year is given in brackets, this is the year in which the new band is assumed to take effect. Otherwise new bands were assumed to take effect from April 2013.

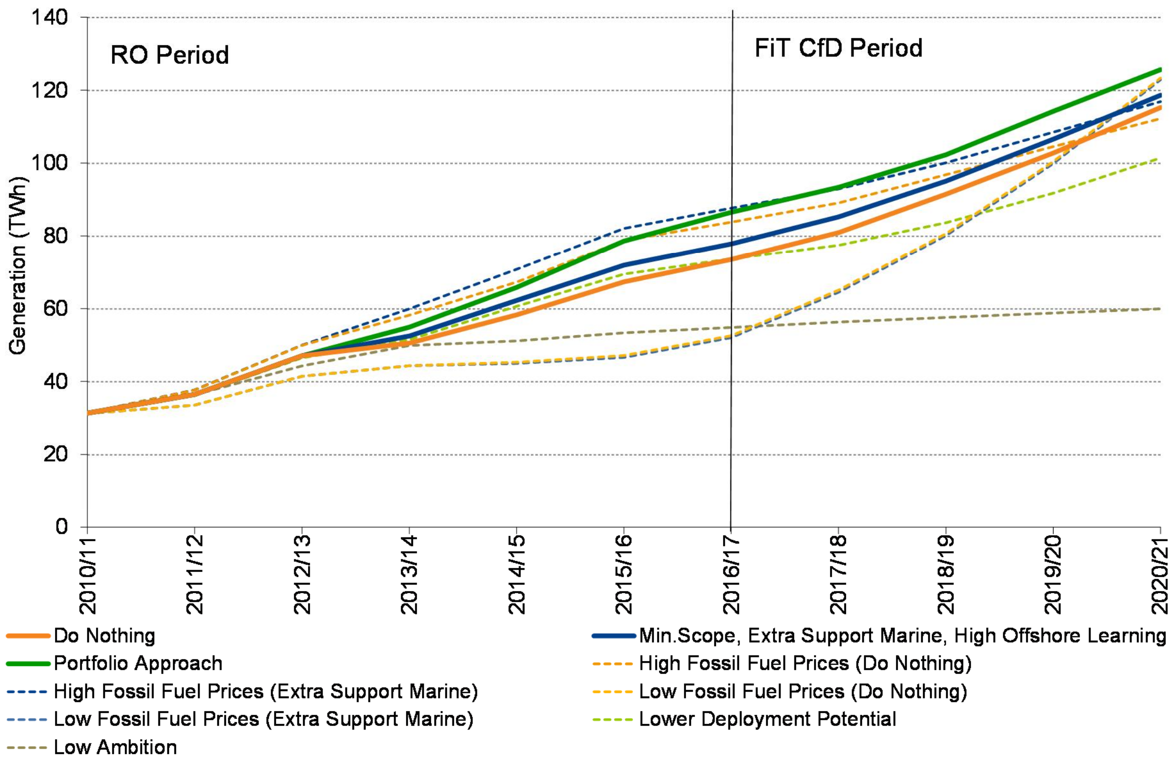
Source: DECC

Figure 6 – Modelled renewables capacity by scenario (GW)



Note: where the results for one or more scenarios are indistinguishable, they have been shown as a single line.

Figure 7 – Modelled renewable generation by scenario (TWh)



Note: where the results for one or more scenarios are indistinguishable, they have been shown as a single line.

Figure 6 and Figure 7 compare the projected renewable capacity and renewable generation across the scenarios modelled until financial year 2020/21.

In these charts, all four options (solid lines) and seven sensitivities (dashed lines) are shown. The Minimum Scope options, Extra Support for Marine option and the Higher Offshore Learning Rates sensitivity results are shown as one line as they are indistinguishable on the chart.

The differences between the options are down to the different bands assumed to be awarded to each technology, as shown in Table 7. The Minimum Scope, Extra Support for Marine and Portfolio Approach options all result in higher levels of projected capacity and generation than the Do Nothing option. Of these the Portfolio Approach results in the highest level of installed renewable capacity, because it assumes the highest bands.

The Minimum Scope and Extra Support for Marine options have very similar levels of projected capacity and generation. The only difference between these options is the higher assumed ROC band for marine technologies, contributing a relatively small difference in the projected capacity installed under the RO. The higher level of installed capacity and generation projected over the Do Nothing option is due to the assumption that the assumed potential investment in enhanced cofiring goes ahead at 1ROC/MWh and more investment in offshore wind as a result of the 2ROCs/MWh band.

After the RO closes to new plants, the FiT CfD is assumed to bring forward sufficient capacity to meet renewable electricity's contribution towards the 2020 renewable energy targets in the Extra Support for Marine option.

The options modelled are discussed in more detail in Sections 4.1.1 to 4.1.4. The sensitivities are discussed in Section 4.2.

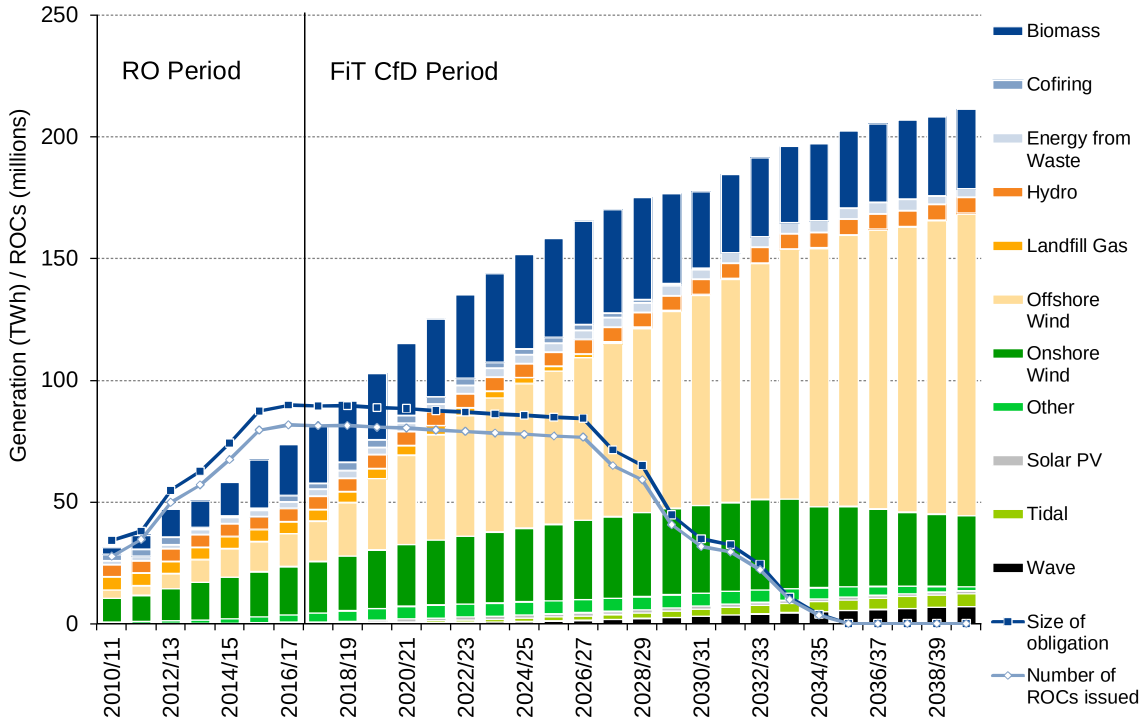
4.1.1 Option 1, Do Nothing

Figure 8 shows the generation of renewable electricity by technology for the Do Nothing option. New capacity commissioned before April 2016 is assumed to choose support under the RO; from April 2016 onwards, it is assumed to be supported by the FiT CfD. As a result the capacity, generation and ROCs issued results in Table 8 are shown for capacity installed by March 2016.

In the banding review period, from April 2013 to April 2017, capacity under the RO is projected to increase by 3.2 GW[18] (see Table 11). The main growth in generation is expected to come from onshore wind and biomass conversion (see Table 9).

Of the five plants assumed capable of converting to biomass four were projected to be converted as a result of longer assumed lifetimes and higher assumed load factors in addition to the 1.5ROCs/MWh support. The fifth was not projected to convert due to the assumed constraint on biomass availability. This means new biomass conversion capacity from April 2013 reaches 1.5 GW by April 2016. The overall difference in capacity shown in Table 9 is 0.7 GW, this is because some capacity assumed to commission prior to April 2013 is assumed to close by April 2015.

Figure 8 – Modelled renewables generation and ROCs for the Do Nothing option



Note 1: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD.

Note 2: See Table 6 for the definition of aggregated technology categories.

18 Excluding small-scale capacity and that assumed to be supported by the FiT CfD.

Other than installations already under construction, no new offshore wind is projected to be built, due to the ROC band falling back to 1.5ROCs/MWh from 2ROCs/MWh from April 2014. New biomass has relatively low deployment under this option with just 35 MW of new capacity projected to be developed between April 2013 and April 2016. At 0.5ROCs/MWh, the cost of investing in enhanced co-firing was not expected to be recovered, and so no enhanced co-firing was assumed.

Under the FiT CfD, offshore wind is projected to become the dominant renewable technology. This reflects its large assumed deployment potential – as, for simplicity, all eligible technologies are assumed to be supported at the same proportion of their deployment potential.

Table 8 – Key results, Do Nothing (real 2010 prices)

Large-scale renewable capacity in 2015/16 (GW)*	17.8
Large-scale renewable generation in 2015/16 (TWh)*	66.4
ROCs issued in 2015/16 (Millions)*	81.6
Lifetime cost of the RO (£billion)	41.7
Lifetime system costs (£billion)	650.8

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

The size of the obligation and the number of ROCs issued rise with generation in the RO period, and then flatten off during the FiT CfD period, before falling away. This is due to closing the RO to new projects, and the subsequent decommissioning of existing projects.

Under this option an average of 1.2 ROCs is projected to be issued per TWh of renewable generation. The total cost of the RO is projected to be £42 billion over its lifetime.

Table 9 – Modelled large-scale renewable capacity before and after the banding review period by technology in the Do Nothing option (MW)

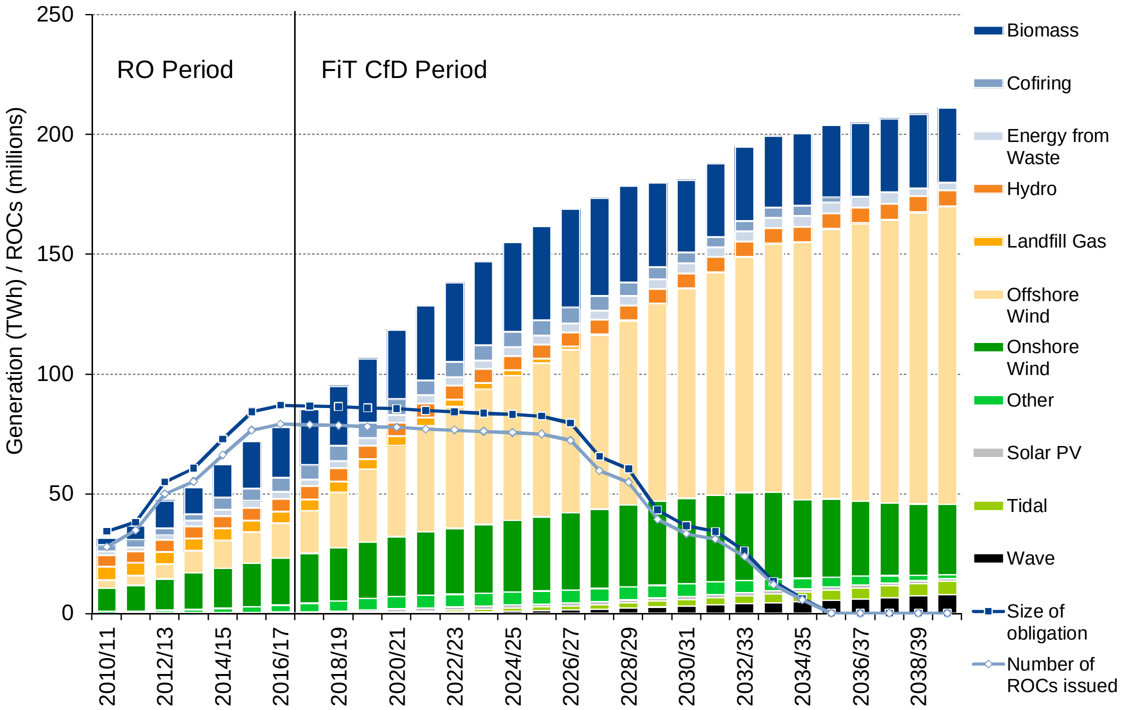
	Onshore wind	Offshore wind	New biomass	Biomass conversion	Enhanced co-firing	Wave & Tidal	All
Capacity in 2012/2013	5,959	3,580	471	1,315	0	3	14,506
Additional capacity to 2015/2016	+1,895	+500	+35	+713	0	+40	+3,341

Note: See Table 6 for the definition of aggregated technology categories, New Biomass includes all biomass defined in Table 6 except biomass conversion.

Source: DECC calculated from Pöyry results

4.1.2 Option 2, Minimum Scope

Figure 9 – Modelled renewables generation and ROCs for the Minimum Scope option



Note 1: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD.

Note 2: See Table 6 for the definition of aggregated technology categories

Figure 9 shows the generation of renewable electricity by technology for the Minimum Scope option.

In the RO period, generation under the RO is projected to exceed the level in the Do Nothing option by 5.0 TWh (see Table 10). This is due to higher ROC bands for offshore wind and enhanced cofiring. At 1ROC/MWh it was the assumed potential investment in enhanced co-firing goes ahead. This increases projected capacity under the RO by 0.6 GW (4.3 TWh). The projected increase in offshore wind capacity is 0.4 GW (1.2 TWh) (see Table 11).

Table 10 – Key results, comparison with Do Nothing (real 2010 prices)

Large-scale renewable capacity in 2015/16 (GW)*	+0.8
Large-scale renewable generation in 2015/16 (TWh)*	+5.0
ROCs issued in 2015/16 (Millions)*	-2.7
Lifetime cost of the RO (£billion)	-1.1
Lifetime system costs (£billion)	-0.5

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

Table 11 – Capacity installed by technology under banding review period, comparison with Do Nothing

	Onshore wind	Offshore wind	New biomass	Biomass conversion	Enhanced co-firing	Wave & Tidal	All
Capacity (MW)	-146	+359	0	0	+581	-40	+752

Note: See Table 6 for the definition of aggregated technology categories, New Biomass includes all biomass defined in Table 6 except biomass conversion.

Source: DECC calculated from Pöyry results

Whilst renewable generation is projected to be higher in this option than the Do Nothing option, the number of ROCs issued is projected to be lower. This is because lower ROC bands are projected to result in lower deployment for some technologies e.g. onshore wind and wave and tidal. However, this is not sufficient to offset the increase in deployment from offshore wind and enhanced co-firing (see Table 11).

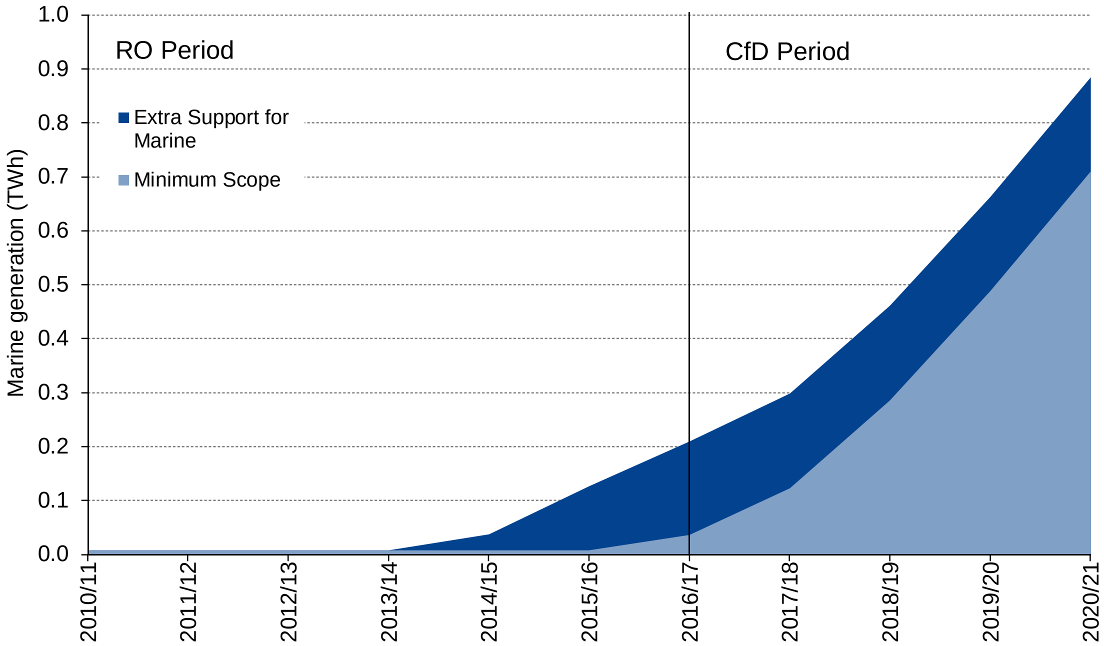
In particular, no difference is projected in the amount of fossil fuel fired capacity converted to biomass. Relatively high load factors and longer assumed technical lifetimes mean the conversions still appear economic despite the ROC band being 1ROC/MWh rather than 1.5ROCs/MWh. It should be noted, however, that the decision to convert to biomass is plant specific. The importance of modelling stations individually is heightened in relation to biomass conversion given the small number of plants, and large amount of capacity that each represents.

The lower number of projected ROCs issued means the projected cost of the RO is £1.1 billion less under Minimum Scope than the Do Nothing option. These results stem from the assumptions used in the modelling. It is possible that lower bands could lead to a lower capacity deployment if generation costs are not covered.

New renewables deployment under the FiT CfD is assumed to be the same as under the Do Nothing scenario.

4.1.3 Option 3, Extra Support for Marine

Figure 10 – Modelled marine generation under the Extra Support for Marine option against the Minimum Scope option



Note: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD.

The Extra Support for Marine option is the same as the Minimum Scope option, with the exception of a 5ROCs/MWh band rather than 2ROCs/MWh band for wave and tidal. This results in an increase in generation from these technologies (see Figure 10).

Relative to the Minimum Scope option the increase in projected generation for marine technologies under the RO reaches almost 0.2TWh/year (approx. 0.2% of total renewable generation). This leads to a corresponding increase in ROCs issued of 0.9million/year.

Table 12 – Key results, comparison with Do Nothing (real 2010 prices)

Large-scale renewable capacity in 2015/16 (GW)*	+0.8
Large-scale renewable generation in 2015/16 (TWh)*	+5.2
ROCs issued in 2015/16 (Millions)*	-1.8
Lifetime cost of the RO (£billion)	-0.8
Lifetime system costs (£billion)	+1.1

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

Table 13 – Capacity installed by technology under banding review period, comparison with Do Nothing

	Onshore wind	Offshore wind	New biomass	Biomass conversion	Enhanced co-firing	Wave & Tidal	All
Capacity (MW)	-146	+359	0	0	+581	+11	+803

Note: See Table 6 for the definition of aggregated technology categories, New Biomass includes all biomass defined in Table 6 except biomass conversion.

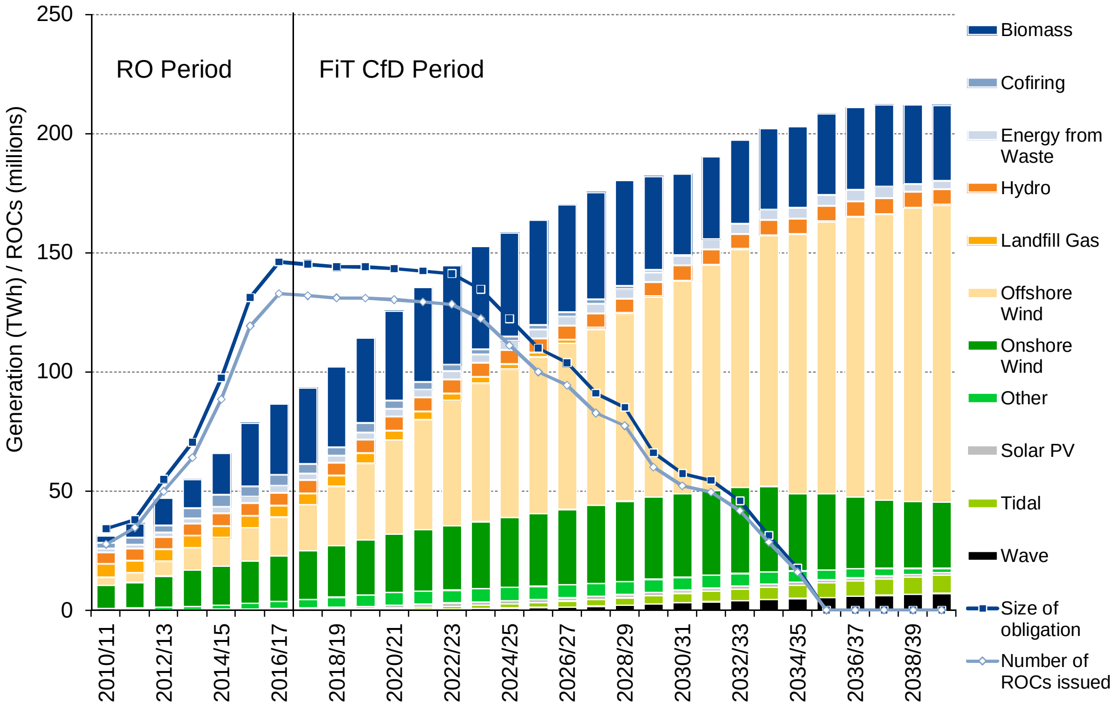
Source: DECC calculated from Pöyry results

Table 12 compares the key results of the Extra Support for Marine scenario with the Do Nothing scenario, and Table 13 shows the difference in installed capacity under the banding review period compared to the Do Nothing scenario. Both tables show similar results to the Minimum Scope scenario. As the wave and tidal capacity is higher, and more ROCs are issued to marine technologies, the reduction in ROCs issued, and size of the obligation relative to the Do Nothing scenario is smaller than under the Minimum Scope option.

The difference in system costs shown for the Extra Support for Marine relative to the Minimum Scope option should be treated with caution. The relationship we were asked to assume between future marine costs and future deployment means costs fall more steeply in the Minimum Scope option than the Extra Support for Marine option.

4.1.4 Option 4, Portfolio Approach

Figure 11 – Modelled renewables generation and ROCs for Portfolio Approach option



Note 1: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD.

Note 2: See Table 6 for the definition of aggregated technology categories

Figure 11 shows the generation of renewable electricity by technology for the Portfolio Approach option. In this option, DECC provided us with bands set at a level to bring on half the annual deployment potential in the RO period.

This approach results in a greater projected rate of deployment than the other options modelled (see Table 15). The projected installed capacity of offshore wind and biomass is under the RO is 0.8 GW (2.8 TWh) and 1.3 GW (3.2 TWh) greater than in the Do Nothing option[19].

Table 14 – Key results, comparison with Do Nothing (real 2010 prices)

Large-scale renewable capacity in 2015/16 (GW)*	+1.8
Large-scale renewable generation in 2015/16 (TWh)*	+14.6
ROCs issued in 2015/16 (Millions)*	+51.2
Lifetime cost of the RO (£billion)	+19.3
Lifetime system costs (£billion)	+22.6

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. It therefore includes existing capacity not supported by the RO or FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results.

19 The figures quoted do not include capacity assumed to be installed under the FiT CfD

Technologies such as biomass and PV, that have relatively high assumed costs compared to their proposed bands in other options, benefit most in this option. Projected capacity for Wave and Tidal is also higher in this scenario as higher capital grants were assumed to enable half of the deployment potential to be economic.

The projected new capacity for onshore wind under the RO is 0.3 GW (0.9 TWh) lower than under the Do Nothing option. As in the Do Nothing option the potential investment in enhanced co-firing is not assumed to go ahead. Despite the 1.1ROC/MWh awarded, DECC asked us to assume it did not go ahead as a result of there only being a 0.1ROC/MWh differential between standard co-firing and enhanced co-firing.

This is projected to be the most expensive option at £19.3 billion more support required than the Do Nothing option (see Table 14). In addition to higher projected generation, this is also the result of higher support levels averaging 1.6 ROCs/MWh

Table 15 – Capacity installed by technology under banding review period, comparison with Do Nothing

	Onshore wind	Offshore wind	New biomass	Biomass conversion	Enhanced co-firing	Wave & Tidal	All
Capacity (MW)	-346	+844	+1,252	0	0	+19	+1,826

Note: See Table 6 for the definition of aggregated technology categories, New Biomass includes all biomass defined in Table 6 except biomass conversion.

Source: DECC calculated from Pöyry results

4.2 Sensitivities

A set of seven sensitivities were run to understand the impacts of some of the key input assumptions on the modelling results. These were to test the effect of:

- fossil fuel prices;
- deployment potential;
- future costs of offshore wind; and
- the overall target for renewable energy.

Specifically the individual sensitivities run were:

- High Fossil Fuel Prices (Do Nothing);
- Low Fossil Fuel Prices (Do Nothing);
- High Fossil Fuel Prices (Extra Support for Marine);
- Low Fossil Fuel Prices (Extra Support for Marine);
- Lower Deployment Potential;
- High Offshore Learning Rates; and
- Low Ambition (as an alternative counterfactual).

Sensitivities were run using the Extra Support for Marine option assumptions with a couple of exceptions. The high and low fossil fuel price sensitivities were conducted on the Do Nothing option, as well as the Extra Support for Marine option to assess the impact of changing RO bands in a high or low fossil fuel price world. The Low Ambition sensitivity was not run on the Extra Support for Marine option. This sensitivity used the technology band assumptions from the Do Nothing option, but also used different policy assumptions than the other Options and Sensitivities run. The policy assumptions used for this sensitivity were based on the RO before the introduction of the 2020 Renewable Energy Targets.

4.2.1 Sensitivity to fossil fuel price assumptions

Future fossil fuel prices are a key assumption in determining future investment in renewable generation under the RO. This is because as long as gas and coal remain the dominant electricity generating technologies, the prices of these fuels will be a significant determinant of projected electricity prices. Electricity prices impact on investment in renewables operating under the RO as they are one of the two main income streams (the other being ROCs) available to these generators. See Chapter 2 for more information on the interactions modelled.

To understand how uncertainty in the fossil fuel price assumptions impact on the electricity market and renewables deployment, we modelled the Do Nothing option and Minimum Scope option using DECC's high and low projections of future fossil fuel prices.

Table 16 shows the key results for the high and low fossil fuel price sensitivities. Under the high fossil fuel price sensitivities, higher assumed fossil fuel prices result in additional investment in renewables under the RO. This increases projected RO costs, as a greater volume of projected generation is supported. System costs are also projected to be higher in the high fossil fuel price sensitivities. This is because gas and coal generation is assumed to be more expensive due to the relatively high cost of fossil fuel. The converse is true for the low fossil fuel price sensitivities.

Table 16 – Key results for high and low fossil fuel price sensitivities (real 2010 prices)

	Do Nothing	Difference: High Fossil Fuel Prices	Difference: Low Fossil Fuel Prices	Extra Support for Marine	Difference: High Fossil Fuel Prices	Difference: Low Fossil Fuel Prices
Large-scale renewable capacity in 2015/16 (GW)*	17.8	+2.6	-4.0	18.7	+2.7	-5.0
Large-scale renewable generation in 2015/16 (TWh)*	66.4	+13.5	-21.2	71.6	+11.7	-26.9
ROCs issued in 2015/16 (millions)*	81.6	+17.7	-30.0	79.8	+17.5	-27.9
Lifetime cost of the RO (£billion)	41.7	+9.0	-13.0	40.8	+9.2	-12.2
Lifetime system costs (£billion)	650.8	+9.1	-41.5	651.9	+12.1	-42.8

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

Table 17 – Comparison of key results for fossil fuel price sensitivities under the Extra Support for Marine option against Do Nothing option (real 2010 prices)

	Do Nothing: High Fossil Fuel Prices	Do Nothing: Central Fossil Fuel Prices	Do Nothing: Low Fossil Fuel Prices	Extra Support for Marine, difference: High Fossil Fuel Prices	Extra Support for Marine, difference: Central Fossil Fuel Prices	Extra Support for Marine, difference: Low Fossil Fuel Prices
Large-scale renewable capacity in 2015/16 (GW)*	20.5	17.8	13.9	+0.8	+0.8	-0.2
Large-scale renewable generation in 2015/16 (TWh)*	79.9	66.4	45.2	+3.4	+5.2	-0.5
ROCs issued in 2016/17 (millions)*	99.3	81.6	51.6	-1.9	-1.8	+0.3
Lifetime cost of the RO (£billion)	50.6	41.7	28.6	-0.7	-0.8	0.0
Lifetime system costs (£billion)	659.9	650.8	609.3	+4.1	+1.1	-0.2

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

Table 17 shows how the key results for the Extra Support for Marine option compare to the Do Nothing option when DECC's High, Central and Low fossil fuel price assumptions are used. The difference shown for each Extra Support for Marine sensitivity is compared to the respective fossil fuel price sensitivity under the Do Nothing option.

There is little difference between the results of the options under the low fossil fuel price sensitivities. This is because the levels of support are not sufficient to make additional capacity economic.

Under the central and high fossil fuel price sensitivities, the difference in capacity between the options is almost the same. This is the result of two opposing effects on onshore and offshore wind with build under the remaining technologies remaining almost the same between the sensitivities. The increase from the offshore wind band of 1.5ROCs/MWh in the Do Nothing option to 2ROCs/MWh in the Extra Support for Marine option has less impact on deployment of offshore wind under the high fossil fuel price sensitivities. This is because a significant amount of new potential capacity is projected to be economic anyway under high electricity prices. The fall in onshore wind band from 1ROC/MWh to 0.9ROCs/MWh also has less impact in the high fossil fuel price sensitivity, because again most of the potential new onshore wind is likely to come on stream under high wholesale electricity prices, even at the lower level of support.

The difference in generation and system costs is greater between the options using central fossil fuel prices than using high fossil fuel prices. This is due to changes in the projected level of standard co-firing, which are not shown in the capacity figures. Under the Do Nothing scenario, higher assumed coal prices lead to higher projected co-firing as the relative economics between coal and biomass become more favourable to biomass. Under the Extra Support for Marine option, higher projected biomass capacity leads to greater constraints on the level of biomass available (this option already assumes 4.3 GWh of enhanced co-firing) and so co-firing is far more constrained in this sensitivity.

In the following sections we first consider further:

- the difference in the fossil fuel price projections and how they affect the electricity price projections;
- how different wholesale price projections impact on renewables deployment; and
- the cost of support under the different sensitivities.

4.2.1.1 Impact on wholesale electricity price projections

Figure 12 shows DECC's High, Central and Low coal and gas price projections that were assumed in the model runs. Figure 13 shows the modelled wholesale electricity price under the Extra Support for Marine and Do Nothing options using different fossil fuel price assumptions.

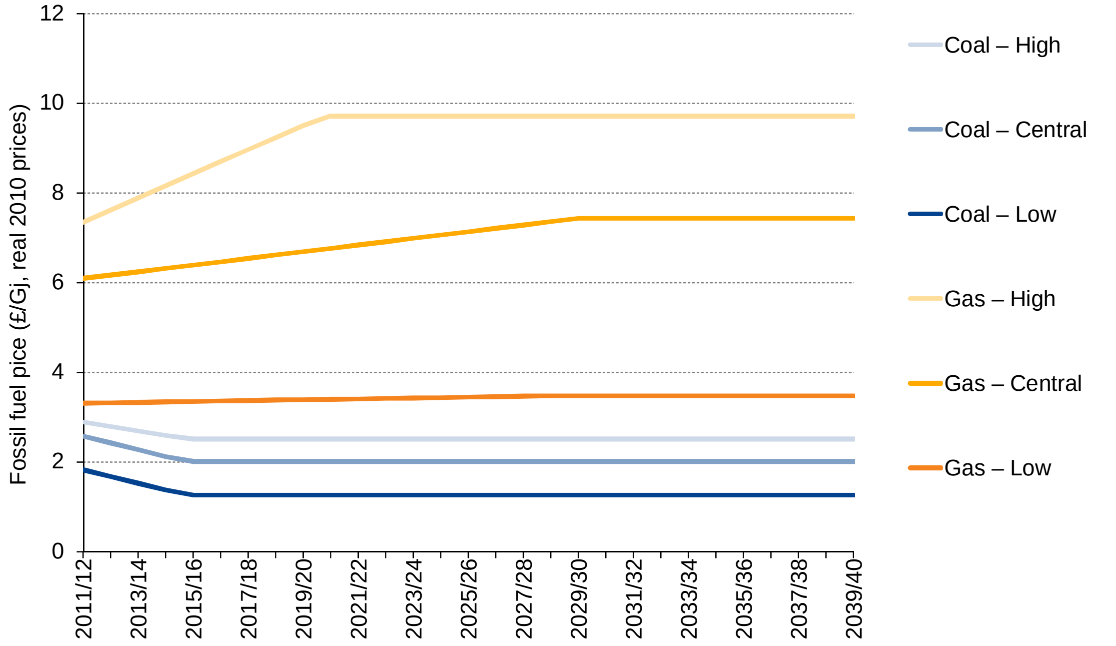
Wholesale electricity prices across the sensitivities are projected to rise to around 2030. This is primarily due to the assumed rise in wholesale gas prices and the carbon price floor, which remain unaltered between sensitivities (see Section 3.2).

Under the high fossil fuel price sensitivities, electricity prices are on average £14/MWh higher between 2011/12 and 2020/21 than electricity prices projected using central fossil fuel price assumptions. This equates to around 0.3 ROCs/MWh beyond the level of intended support.

Under the low fossil fuel price sensitivity the difference is more profound reflecting the wider gap between the central and high projected gas prices. The difference in gas prices have a greater effect than the difference in coal prices, as gas is projected to be the marginal plant for a greater proportion of the time. Electricity prices are on average projected to be £21/MWh lower between 2011/12 and 2020/21. This equates to around 0.5 ROCs/MWh that would be necessary to make up the difference in income.

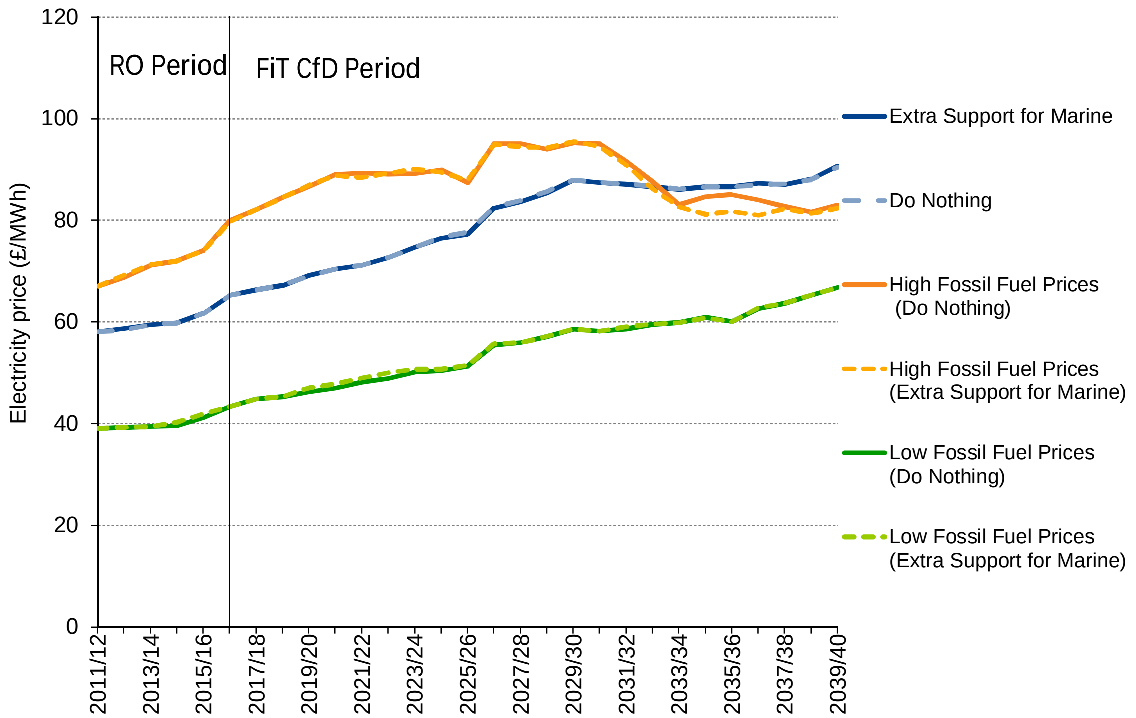
Beyond 2030, projected wholesale electricity prices flatten in the central fossil fuel price scenarios, and fall in the high fossil fuel price sensitivities. This is because low carbon generation, with low marginal costs, and capital costs supported partly outside the electricity market, becomes more dominant. This makes fossil fuel and carbon prices less important in influencing average wholesale electricity prices.

Figure 12 – Gas and coal prices (£/GJ, real 2010 prices)



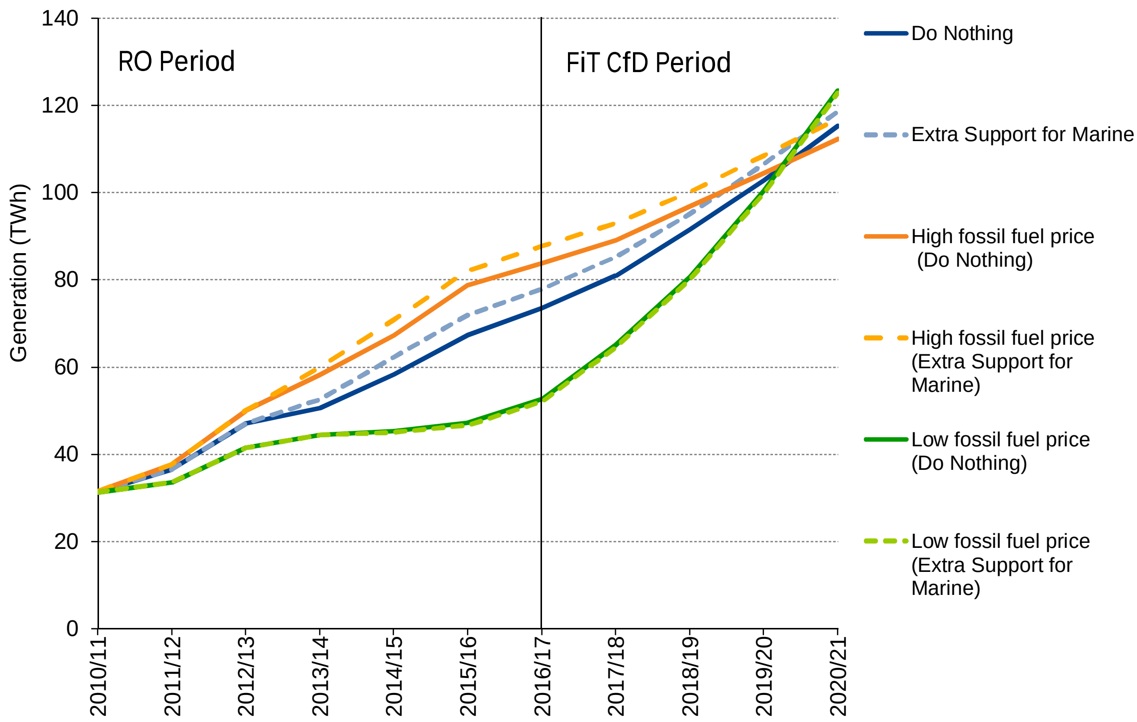
Source: DECC

Figure 13 – Modelled wholesale electricity prices using High, Central and Low fossil fuel price assumptions (£/MWh, real 2010 prices)



4.2.1.2 Impact on renewable generation projections

Figure 14 – Modelled renewable generation using High, Central and Low fossil fuel price assumptions (TWh)



Note: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD

Figure 14 shows the range of modelled renewable generation resulting from different fossil fuel price assumptions. The sensitivities using high assumed fossil fuel prices bring on more renewable generation during the RO period. For the sensitivity on the Extra Support for Marine option this reaches 12 TWh of additional annual generation under the RO. This comes from higher projected wholesale electricity prices (see Figure 13), resulting in higher investment in new renewable capacity.

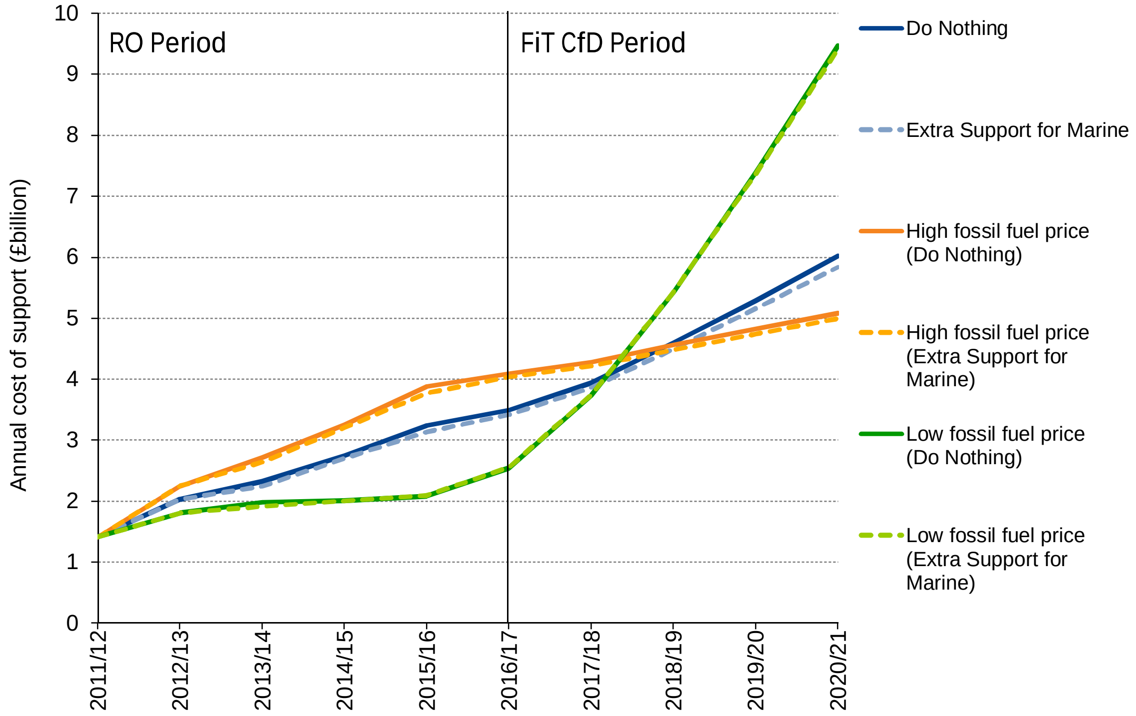
Under the low fossil fuel price sensitivities, very little new renewables capacity is developed. For the sensitivity on the Extra Support for Marine option this means 27 TWh less projected renewable annual generation under the RO than under the central fossil fuel price scenario.

The greater impact on generation in the low fossil fuel sensitivities than the high fossil fuel sensitivities mirrors the more significant change in projected wholesale electricity prices for these sensitivities.

In the FiT CfD period, support under FiT CfDs was assumed to be set at a level that would bring on sufficient renewable electricity to enable electricity's contribution towards the UK's 2020 renewable energy targets to be met. This means, in a situation where fossil fuel prices are lower than DECC had anticipated, the FiT CfD would be expected to do more. As a result, similar levels of renewable generation are projected across all scenarios by 2020/21.

4.2.1.3 Impact on cost of support and system costs

Figure 15 – Modelled cost of support using high, central and low fossil fuel price assumptions (£billion, real 2010 prices)



Note 1: In 2016/17 the additional cost of support shown from 2015/16 is a mixture of additional supported under the RO and additional support under the FiT CfD

Note 2: The cost of support modelled for generators supported by the FiT CfD is calculated using an estimate for the FiT CfD 'strike price' required for each technology. Given uncertainty over the design of the FiT CfD, actual 'strike prices' are likely to vary from estimated 'strike prices'. The chart is intended to show an indicative trend only in how support could vary under different fossil fuel price scenarios.

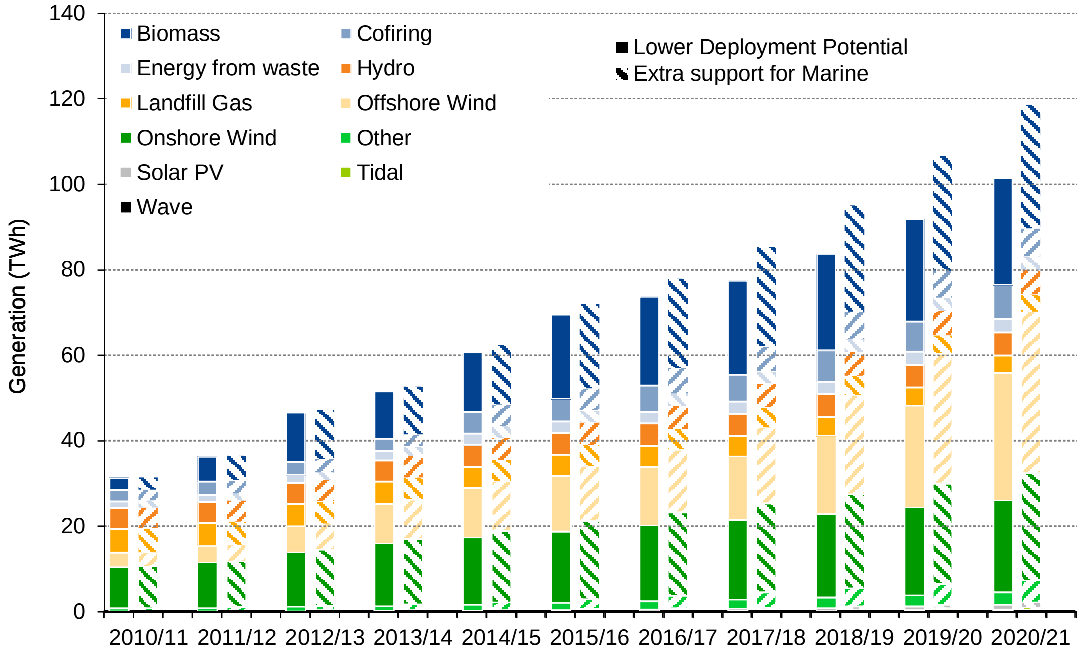
Figure 15 compares the cost of support for renewable electricity (excluding the small-scale FiT, RHI and LECs) for the different fossil fuel price sensitivities. The cost of support up to 2015/16 is solely the cost of the RO. Post 2015/16, the cost of support also includes projects supported by the FiT CfD. The levels of support post 2015/16 should be treated with extreme caution. The simplistic modelling assumptions for the FiT CfD support are likely to be very different from where the strike prices are actually set. For example, a more cost-effective mix of renewable technologies could be incentivised to hit electricity's share of the 2020 renewable target.

During the RO period, the high fossil fuel price sensitivities result in the highest projected cost of support, likewise the low fossil fuel price sensitivities show the lowest projected cost of support. This is consistent with the differing levels of renewable generation projected in these sensitivities (see Figure 14). By the end of the RO period, the range of costs across the sensitivities is approximately £1.5 billion/year.

During the FiT CfD period, the projected cost of support in the low fossil fuel price sensitivity increases at a much faster rate. There are two reasons for this. First, the FiT CfD strike prices are set at a higher rate to encourage more renewable generation to make up the gap between existing generation and that needed to meet renewables targets. Second, lower projected wholesale electricity prices mean the Government has to make up a larger difference between the FiT CfD strike price and the wholesale electricity price. This causes annual projected subsidy costs in the low price sensitivities to overtake the central fossil fuel price scenarios in around 2018.

4.2.2 Sensitivity to Lower deployment potential assumptions

Figure 16 – Modelled renewable generation using a Arup's High and Central deployment potentials (TWh)



Note 1: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD.

Note 2: See Table 6 for the definition of aggregated technology categories

In this sensitivity, the assumptions made were the same as for the Extra Support for Marine option, but the annual deployment potential assumed was Arup's central, as opposed to high, potential for each technology.

Figure 16 shows the projected renewable generation by technology in the Lower Deployment Potential sensitivity against the Extra Support for Marine option.

In general, the total annual generation in the central case is approximately 65-95% of the high case, depending on the year and technology. The only exception to the reduction in projected generation is cofiring, which is projected to increase, as the pressure on biomass resource is lower due to the reduction in biomass generation.

Table 18 – Key results, comparison with Extra Support for Marine (real 2010 prices)

Large-scale renewable capacity in 2015/16 (GW)*	-0.7
Large-scale renewable generation in 2015/16 (TWh)*	-2.0
ROCs issued in 2015/16 (Millions)*	-2.2
Lifetime cost of the RO (£billion)	-0.4
Lifetime system costs (£billion)	-9.2

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

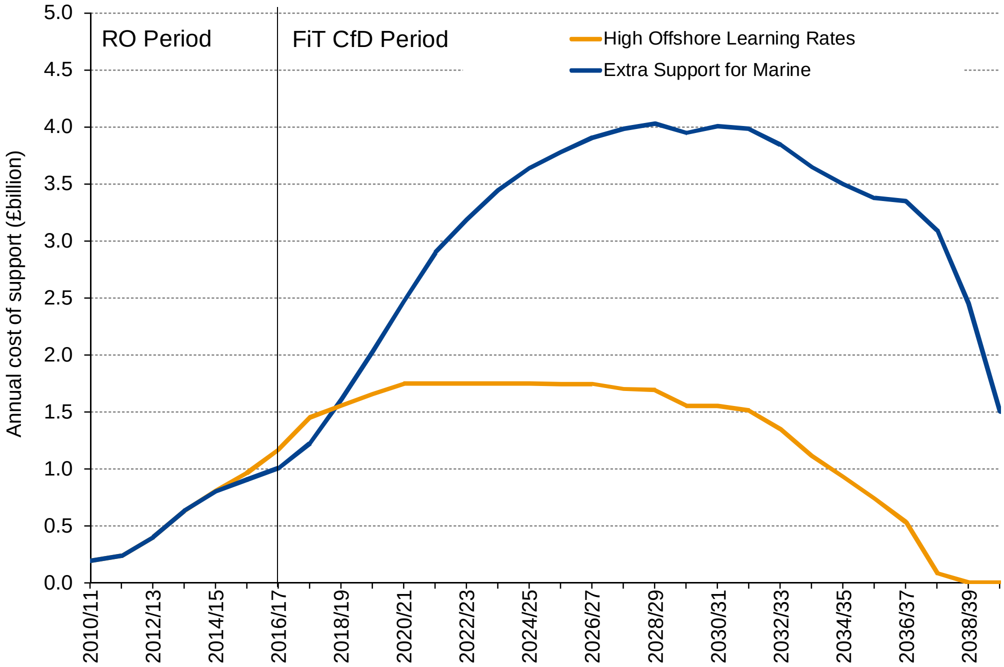
Source: DECC, calculated from Pöyry results

Projected renewable generation from capacity built under the RO is 2 TWh lower than under the Extra Support for Marine option.

In this sensitivity renewable electricity's contribution to the renewable energy targets would not be expected to be met, unless the level of FiT CfD support was adjusted to account for the lower deployment potential.

4.2.3 Sensitivity to higher offshore wind learning rates

Figure 17 – Modelled offshore wind subsidy costs under Central and High learning rate assumptions (£billion, real 2010 prices)



Note 1: In 2016/17 the additional cost of support shown from 2015/16 is a mixture of additional supported under the RO and additional support under the FiT CfD

Note 2: The cost of support modelled for generators supported by the FiT CfD is calculated using an estimate for the FiT CfD 'strike price' required for each technology. Given uncertainty over the design of the FiT CfD, actual 'strike prices' are likely to vary from estimated 'strike prices'. The chart is intended to show an indicative trend only in how support could vary under different fossil fuel price scenarios.

In this sensitivity, the assumptions were the same as the Extra Support for Marine option, but investment to reduce the costs of offshore wind capex was assumed to result in a steeper fall in costs. This fall was in line with DECC's target of a levelised cost for offshore wind of £100/MWh by 2020.

In the RO period, this results in a 63 MW increase in projected installed capacity, which increases RO support costs. In the FiT CfD period the level of support was set to bring on the same proportion of the annual deployment potential as in the Extra Support for Marine option, but this is possible at a much lower cost.

Table 19 – Key results, comparison with Extra Support for Marine (real 2010 prices)

Large-scale renewable capacity in 2015/16 (GW)*	+0.1
Large-scale renewable generation in 2015/16 (TWh)*	+0.2
ROCs issued in 2015/16 (Millions)*	+0.4
Lifetime cost of the RO (£billion)	+0.2
Lifetime system costs (£billion)	+9.4

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.
Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results.

Figure 17 shows the projected annual cost of support for offshore wind compared to the Extra Support for Marine option.

The main benefit from a steeper fall in costs comes under FiT CfD. The strike price can set at a lower level, and is not even required beyond April 2022. This leads to more offshore wind being installed in later years in this sensitivity.

4.2.4 *Sensitivity to lower renewables ambition*

This sensitivity represents a policy framework in which EU 2020 targets for renewable energy have not been set. It takes its policy assumptions from the national legislation that was in place prior to April 2010, when changes resulting from the targets had not yet been incorporated. Table 20 outlines the key differences between the policy assumptions in this sensitivity and the Extra Support for Marine option.

Table 20 – Comparison of policy assumptions under the Low Ambition sensitivity and the Extra Support for Marine option

	Extra Support for Marine	Low Ambition
Carbon pricing mechanism	EU-ETS and CPS	EU-ETS only
RO end date	2037	2027
When RO closes to new generators	2017	2027
Headroom %	10%	8%
Cap on obligation	uncapped	20% of suppliers sales
FiT CfD in existence	Yes	No
Small-Scale FiT in existence	Yes	No
RHI in existence	Yes	No

Figure 18 – A comparison of modelled electricity prices under a Low Ambition sensitivity and the Extra Support for Marine option
(£/MWh, real 2010 prices)

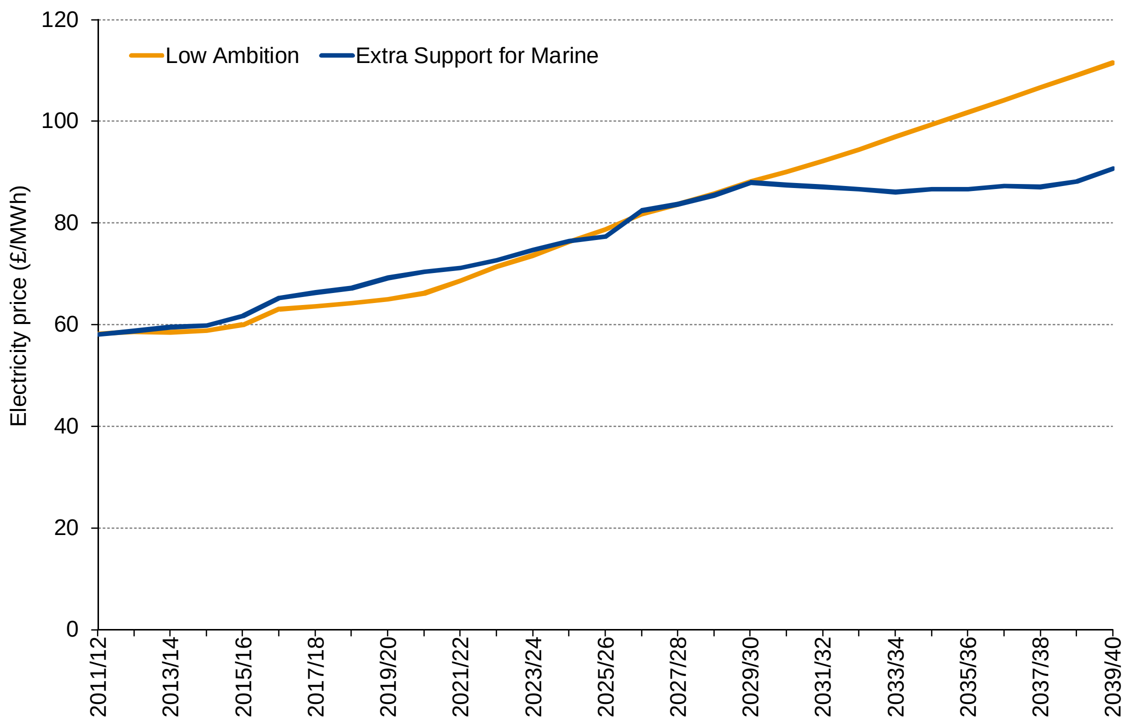
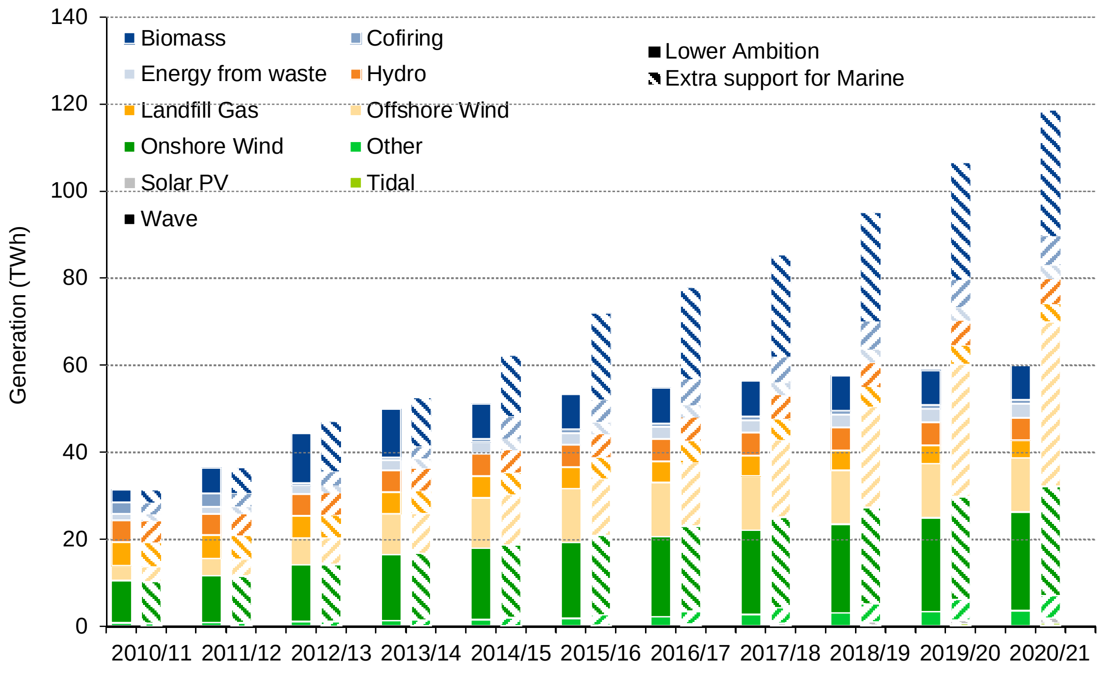


Figure 18 shows the projected wholesale electricity prices for the Low Ambition scenario against the Extra Support for Marine option.

The projected electricity price is lower under the Low Ambition sensitivity until around 2024/25. This is due to the absence of a Carbon Price Floor mechanism. The reason the difference is not greater is that that higher levels of renewables in the Extra Support for Marine option put downward pressure on electricity prices. Over time, as renewable and nuclear capacity increases, the downward pressure becomes so great that wholesale electricity prices flatten in the Extra Support for Marine option. This means beyond 2030 projected prices are higher in the Low Ambition sensitivity.

Figure 19 – A comparison of modelled renewable generation in the Low Ambition sensitivity and the Extra Marine Support for Marine option (TWh)



Note 1: In 2016/17 the additional generation shown from 2015/16 is a mixture of additional generation supported by the RO and additional generation supported by the FiT CfD for the Extra Support for Marine option.

Note 2: See Table 6 for the definition of aggregated technology categories

Figure 19 shows the projected renewable electricity generation in the Low Ambition sensitivity compared with the Extra Support for Marine option. In this sensitivity very little growth in renewable generation is projected, and most of the additional renewable capacity built is onshore wind. This is due to its low cost relative to other renewable technologies.

The lower deployment in this scenario is down to a combination of:

- lower wholesale electricity prices in earlier years (see Figure 18);
- the RO ending in 2027 (as opposed to 2037), providing less subsidy over the lifetime of a project;
- falling ROC prices due to the cap on the level of the obligation at 20% of suppliers' sales; and,
- beyond April 2017, the absence of a FiT CfD.

The lower projected installed capacity in this scenario leads to a lower number of ROCs projected to be issued during its lifetime despite the RO being open to new projects until closes in 2027. This means the cost of the RO is lower. The lower level of renewables, nuclear and CCS is also projected to lead to lower system costs.

Table 21 – Key results, comparison with Do Nothing and Extra Support for Marine options (real 2010 prices)

	Difference from Do Nothing	Difference from Extra Support for Marine
Large-scale renewable capacity in 2015/16 (GW)*	-2.1	-2.9
Large-scale renewable generation in 2015/16 (TWh)*	-13.4	-18.5
ROCs issued in 2015/16 (Millions)*	-19.1	-17.4
Lifetime cost of the RO (£billion)	-9.9	-9.1
Lifetime system costs (£billion)	-72.3	-73.4

* DECC defined large-scale renewable electricity as all renewable electricity excluding that supported by the small-scale FiT. Generation and ROCs issued from capacity installed in 2015/16 is assumed to generate for the whole year, rather than part-way through the year, as was modelled.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

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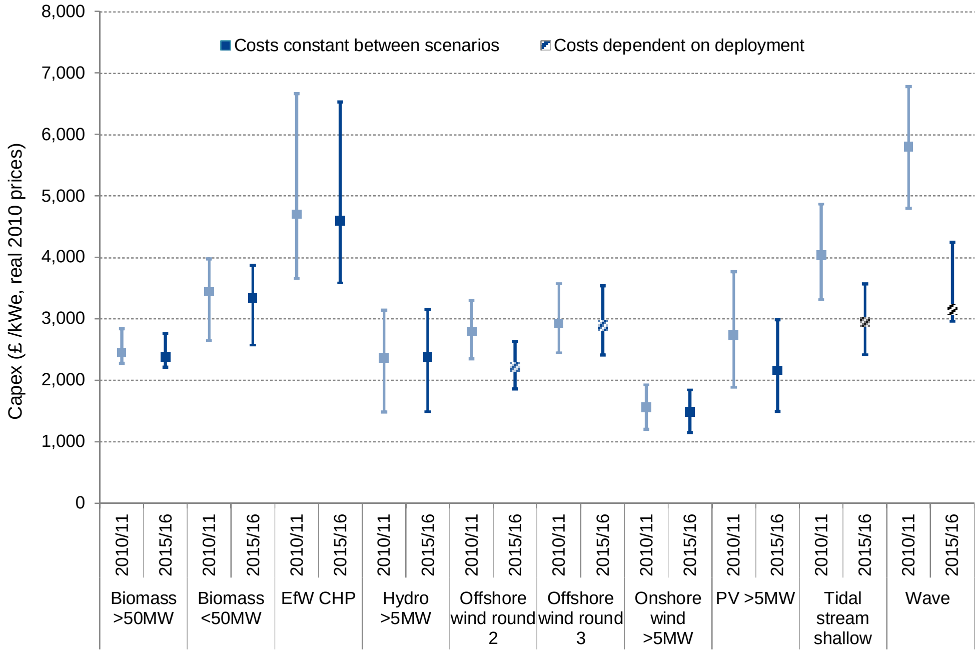
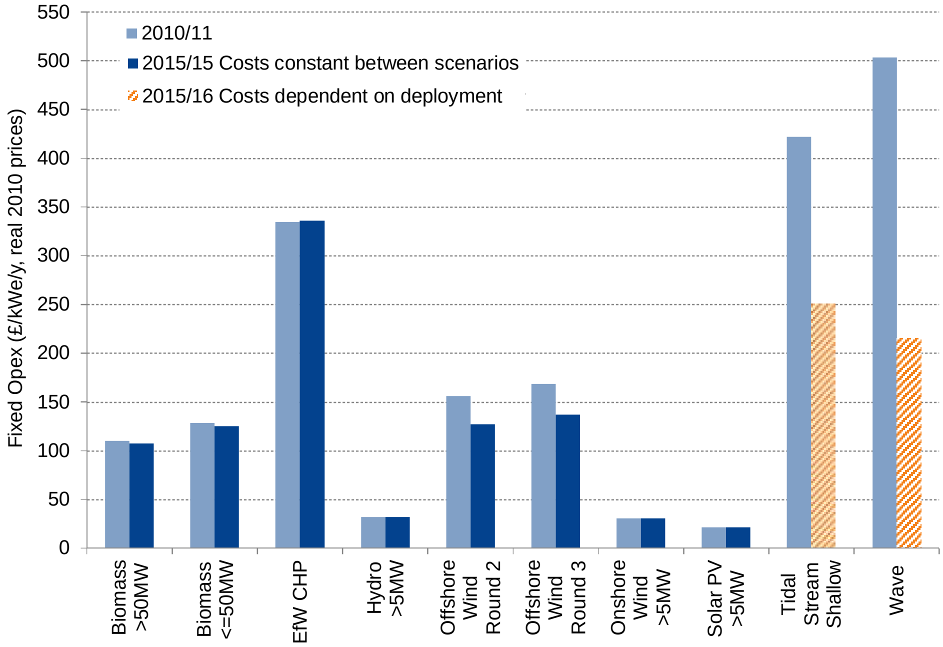
ANNEX A – COST ASSUMPTIONS

Figure 20 – Capex assumptions for main renewable technologies (£/kW, real 2010 prices)



Note: Where costs are dependent on deployment, the cost for the Extra Support for Marine option is shown
Source: DECC, Arup, Ernst & Young

Figure 21 – Opex assumptions for main renewable technologies (£/kW, real 2010 prices)



Note: Where costs are dependent on deployment, the cost for the Extra Support for Marine option is shown
Source: DECC, Arup, Ernst & Young

Figure 22 – Fuel price assumptions, energy input basis (£/MWh_{th}, real 2010 prices)

Technology	Fuel price (£/MWh_{th})
Bioliquids	86
Biomass (<50MW)	12
Biomass (>50MW)	25
Biomass (CHP)	25
Biomass (conversion from existing coal plant)	25
Biomass (Energy crops)	25
Cofiring (CHP)	25
Cofiring (Energy Crops)	25
Cofiring (Standard, <10% biomass)	22 to 30
Cofiring (Enhanced, >15% biomass)	22 to 30

Source: DECC, AEA

Figure 23 – Gate fee assumptions, energy input basis (£/MWh_{th}, real 2010 prices)

Technology	Gate fee (£/MWh_{th})
Advanced Conversion Technology	29
Anaerobic Digestion	10
Energy from Waste	29

Source: DECC

Figure 24 – Assumed discount rates by financial close year under the RO

	2010 - 2016	2017 - 2019	2020 - 2025	2026 - 2030
ACT (Power only)	13%	13%	12%	12%
AD (Power only)	13%	12%	12%	12%
AD (CHP)	14%	13%	13%	13%
Bioliquid (Power only)	12%	12%	12%	12%
Biomass (Power only)	13%	13%	12%	12%
Biomass (CHP)	14%	14%	13%	13%
EfW (Power only)	12%	12%	12%	12%
EfW (CHP)	13%	13%	13%	13%
Geothermal (Power only)	23%	23%	16%	13%
Geothermal (CHP)	24%	24%	17%	14%
Hydro	8%	8%	8%	8%
Offshore wind (Round 2)	12%	12%	10%	10%
Offshore wind (Round 3)	13%	13%	12%	10%
Onshore wind	10%	10%	10%	10%
PV	8%	8%	8%	8%
Sewage gas	10%	10%	10%	10%
Tidal stream	15%	15%	13%	12%
Wave	14%	14%	13%	12%

Source: DECC

Figure 25 – Assumed discount rates by financial close year under the FiT CfD

	2010 - 2016	2017 - 2019	2020 - 2025	2026 - 2030
ACT (Power only)	12%	12%	11%	11%
AD (Power only)	12%	11%	11%	11%
AD (CHP)	13%	12%	12%	12%
Bioliquid (Power only)	11%	11%	11%	11%
Biomass (Power only)	12%	12%	11%	11%
Biomass (CHP)	13%	13%	12%	12%
EfW (Power only)	11%	11%	11%	11%
EfW (CHP)	12%	12%	12%	12%
Geothermal (Power only)	21%	21%	15%	12%
Geothermal (CHP)	22%	22%	16%	13%
Hydro	7%	7%	7%	7%
Offshore wind (Round 2)	10%	10%	9%	9%
Offshore wind (Round 3)	12%	12%	11%	9%
Onshore wind	9%	9%	9%	9%
PV	7%	7%	7%	7%
Sewage gas	9%	9%	9%	9%
Tidal stream	14%	14%	12%	11%
Wave	13%	13%	12%	11%

Source: DECC

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ANNEX B – TECHNICAL PARAMETER ASSUMPTIONS

Table 22 – Key technical parameters assumed

	Efficiency (HHV)	Construction time	Load Factor	Operational Lifetime
ACT (Power only)	21%	2	84%	23
AD (Power only)	36%	1	84%	21
AD (CHP)	36%	1	84%	21
Bioliquids (Power only)	37%	1	73%	10
Biomass (>50MW)*	33%	3	72%-90%	25
Biomass (<50MW)*	28%	2	70%-90%	25
Biomass (Conversion from existing coal plant)*	30%	1	72%-90%	2
Biomass (Energy crops)*	33%	3	70%-90%	23
Biomass (CHP)	19%	3	79%-90%	23
Co-firing (Standard 10% biomass)**	32%	1	n/a	9
Co-firing (Enhanced, 15% biomass)	31%	1	85%	22
Co-firing (Energy crops)**	32%	1	n/a	9
Co-firing (CHP, 10% biomass)	19%	3	90%	9
EfW (Power Only)	19%	3	83%	29
EfW (CHP)	19%	3	83%	29
Geothermal (Power Only)	n/a	3	91%	25
Geothermal (CHP)	n/a	3	91%	25
Hydro (>5MW)	n/a	1	46%	41
Hydro (<5MW)	n/a	1	46%	41
Offshore Wind (Round 2)	n/a	3	38%	24
Offshore Wind (Round 3)	n/a	3	40%	22
Onshore Wind (>5MW)	n/a	2	29%	24
Onshore Wind (<5MW)	n/a	2	25%	24
PV (>5MW)	n/a	0	11%	25
PV (<5MW)	n/a	0	11%	25
Sewage Gas	35%	2	68%	28
Tidal Stream (England, Wales & NI, Shallow)***	n/a	3	27%-53%	20
Tidal Stream (Scotland, Deep)***	n/a	2	33%-41%	20
Tidal Stream (Scotland, Shallow)***	n/a	3	27%-33%	20
Wave (England, Wales and NI)***	n/a	2	25%-35%	20
Wave (Scotland)***	n/a	2	25%-35%	20

*Biomass load factors were modelled according to their marginal costs relative to other plants. They tended to fall over time as the installed capacity of wind and nuclear increased. The range of load factors shown is for the Extra Support for Marine option.

** Load factors are not given for standard co-firing as the assumptions on co-firing were based on generation and no specific capacity relating to that generation was assumed

***A range of load factors was assumed according to the commissioning date of the plant

Source: DECC, Arup, Ernst & Young

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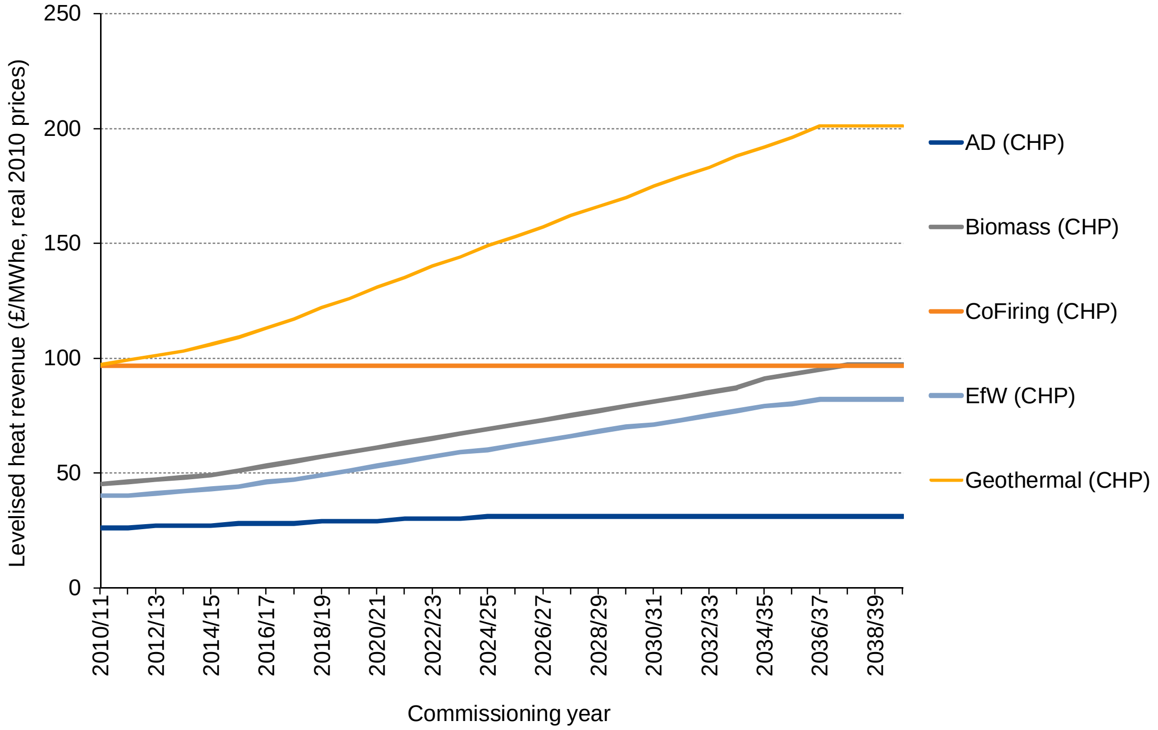
ANNEX C – REVENUE ASSUMPTIONS

Table 23 – revenue assumptions assumed by technology

	RO	Wholesale electricity market	Capital grant	FIT	RHI	Gate fees	Steam revenues	LECs	CfD
ACT (Power only)	✓	✓	-	-	-	✓	-	✓	✓
AD (CHP)	-	-	-	✓	-	✓	✓	✓	-
AD (Power only)	-	-	-	✓	-	✓	-	✓	-
Bioliquids (Power only)	✓	✓	-	-	-	-	-	✓	✓*
Biomass (conversion from existing coal plant)	✓	✓	-	-	-	-	-	✓	-
Biomass (>50MW, standard or energy crops)	✓	✓	-	-	-	-	-	✓	✓
Biomass (<50MW using standard biomass)	✓	✓	-	-	-	-	-	✓	✓
Biomass (CHP)	✓	✓	-	-	✓	-	✓	✓	✓
Enhanced CoFiring (Enhanced, 15% biomass)	✓	✓	-	-	-	-	-	✓	-
Cofiring (Standard 10% biomass or energy crops)	✓	✓	-	-	-	-	-	✓	-
Cofiring (CHP, 10% biomass, 90% coal)	✓	✓	-	-	-	-	✓	✓	✓
EfW (CHP)	✓	✓	-	-	-	✓	✓	✓	-
EfW (Power only)	-	✓	-	-	-	✓	-	✓	-
Geothermal (CHP)	✓	✓	-	-	✓	-	✓	✓	-
Geothermal (Power only)	✓	✓	-	-	-	-	-	✓	-
Hydro (>5MW)	✓	✓	-	-	-	-	-	✓	✓
Hydro (<5MW)	-	-	-	✓	-	-	-	✓	-
OffshoreWind (Round 2)	✓	✓	-	-	-	-	-	✓	✓
OffshoreWind (Round 3)	-	-	-	-	-	-	-	✓	✓
OnshoreWind (>5MW)	✓	✓	-	-	-	-	-	✓	✓
OnshoreWind (<5MW)	-	-	-	✓	-	-	-	✓	-
PV (>5MW)	✓	✓	-	-	-	-	-	✓	-
PV (<5MW)	-	-	-	✓	-	-	-	✓	-
Sewage Gas	✓	✓	-	-	-	-	-	✓	-
TidalStream	✓	✓	✓	-	-	-	-	✓	✓
Wave	✓	✓	✓	-	-	-	-	✓	✓

* Bioliquids were assumed to receive the same level of support under the FiT CfD as biomass<50MW, rather than using a specific calculation for the support required for bioliquids.
Source: DECC

Figure 26 – Assumed levelised heat revenues by technology (£/MWhe, real 2010)



Source: DECC

Table 24 – ROC bands for different options

	Current Bands	Minimum Scope	Extra Support for Marine	Portfolio Approach
ACT (Power only)	2	0.5	0.5	0
Bioliquids (Power only)	1.5	1.4	1.4	6.9
Biomass (>50MW)	1.5	1.5	1.5	2.4
Biomass (<50MW)	1.5	1.5	1.5	1.9
Biomass (Energy crops)	2	(2015/16) 1.9	(2015/16) 1.9	3.3
Biomass (Conversion from existing coal plant)	1.5	1	1	1.3
Biomass (CHP)	2	(2015/16) 1.4 + RHI	(2015/16) 1.4 + RHI	4.8
CoFiring (Standard, <10% biomass)	0.5	0.5	0.5	0.9
CoFiring (Enhanced, 15% biomass)	0.5	1	1	1.1
CoFiring (Energy crops)	1	1	1	0.9
CoFiring (CHP, 10% biomass)	1	1	1	1
EfW (CHP)	1	0.5	0.5	0
Geothermal (Power only)	2	(2015/16) 1.9	(2015/16) 1.9	3
Geothermal (CHP)	2	(2015/16) 1.9	(2015/16) 1.9	4.7
Hydro (>5MW)	1	0.5	0.5	0.1
OffshoreWind (Round 2)	1.5*	(2015/16) 1.9	(2015/16) 1.9	2.5
OffshoreWind (Round 3)	1.5*	1.5	1.5	2.5
OnshoreWind (>5MW)	1	0.9	0.9	0.8
PV (>5MW)	2	(2015/16) 1.9	(2015/16) 1.9	6.6
Sewage Gas	0.5	0.5	0.5	0.4
Tidal Stream (England, Wales & NI, Shallow)	2	(2015/16) 1.9	5**	3.8
Tidal Stream (Scotland, Shallow)	3	(2015/16) 1.9	5**	3.8
Tidal Stream (Scotland, Deep)	3	(2015/16) 1.9	5**	3.8
Wave (England, Wales & NI)	2	(2015/16) 1.9	5**	5.9
Wave (Scotland)	5	(2015/16) 1.9	5**	5.9

Note: Where a year is given in brackets, this is the year in which the new band is assumed to take effect.

*The band for offshore wind is currently 2ROCs/MWh, but was due to drop to 1.5 ROCs/MWh from April 2014.

**The band for tidal and wave was assumed to drop to 4.85ROCs/MWh after the first 50 MW of new marine capacity was installed

Source: DECC

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ANNEX D – ELECTRICITY MARKET MODELLING RESULTS

Table 25 – Electricity price projections by scenario

Fossil fuel price	Scenario	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
High	Do Nothing	67	69	71	72	74	80	82	84	87	89	95	83
	Extra Support for Marine	67	69	71	72	74	80	82	84	87	89	95	82
Central	Do Nothing	58	58	59	60	62	65	66	67	69	70	88	90
	Extra Support for Marine	58	59	59	60	62	65	66	67	69	70	88	91
	Low Ambition	58	59	58	59	60	63	64	64	65	66	88	111
Low	Do Nothing	39	39	39	40	41	43	45	45	46	47	59	67
	Extra Support for Marine	39	39	39	40	42	43	45	45	47	48	59	67

Figure 27 – Non-renewable capacity under Do Nothing option (GW)

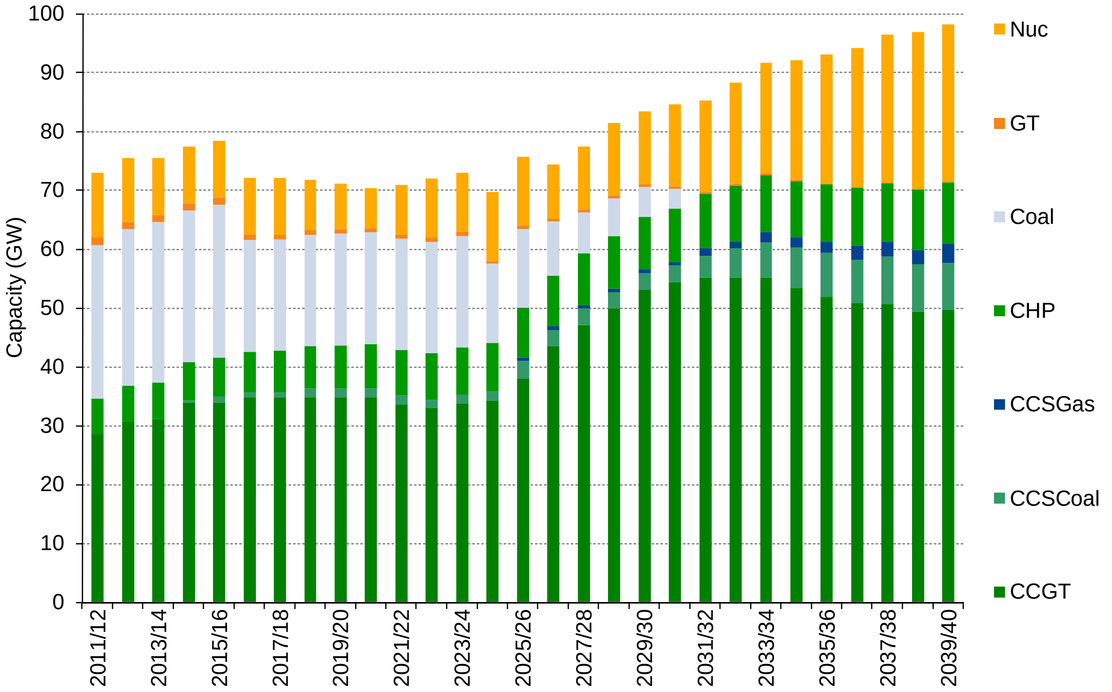
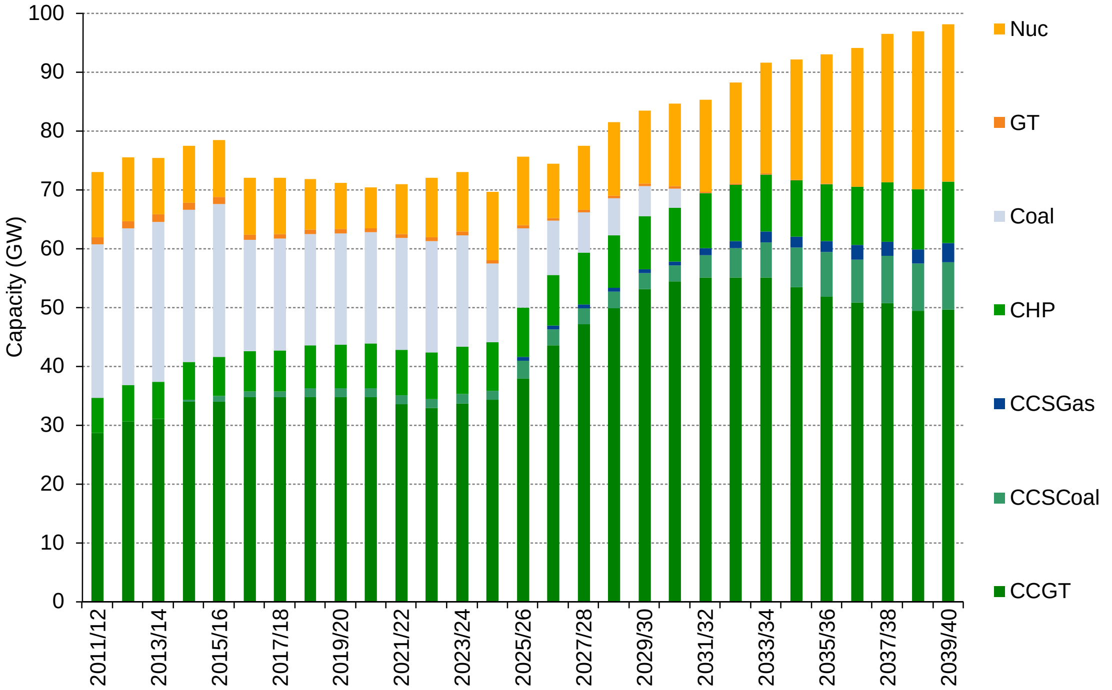


Figure 28 – Non-renewable capacity under Extra Support for Marine option



ANNEX E – PROJECTED COSTS ACROSS THE OPTIONS MODELLED

Table 26 – Breakdown of costs under the four options

		Difference		
	Do Nothing	Minimum Scope	Extra Support for Marine	Portfolio Approach
Lifetime system costs[12] (£billion), of which:	**650.8**	**-0.5**	**+1.1**	**+22.6**
Renewable generation costs	226.6	+2.4	+4.0	+30.7
Non-renewable generation costs	351.0	-1.8	-1.9	-6.7
Balancing costs	22.5	+0.1	+0.1	+0.4
EUA costs	50.7	-1.1	-1.2	-1.8
Lifetime consumer costs[34] (£billion), of which:	**433.4**	**-1.1**	**-0.8**	**+19.6**
RO costs	41.7	-1.1	-0.8	+19.3
Balancing costs	22.5	+0.1	+0.1	+0.4
Wholesale price	369.2	-0.1	-0.1	-0.1
Lifetime producer surplus (£billion)	**18.9**	**-1.5**	**-1.5**	**+1.2**

1. System costs do not include all system costs e.g. transmission, distribution costs and retail costs are not included.

2. The difference in system costs shown for the Minimum Scope and Extra Support for Marine options should be treated with caution. The relationship we were asked to assume between future marine costs and future deployment means costs fall more steeply in the Minimum Scope option than the Extra Support for Marine option.

3. The consumer cost and system costs do not represent all costs to consumers as other costs which may be assumed to remain constant (e.g. supplier transaction) are not included.

4. The consumer cost does not include assumed FiT CfD subsidy costs, as the design of the scheme and technology specific 'strike prices' are yet to be determined. This means that whilst wholesale prices might be lower to 2039/40 in scenarios where wind and nuclear generation is higher, reducing the cost to consumers, the increase in consumer costs as a result of the FiT CfD will not be taken into account.

Note: All figures rounded to one decimal place and costs discounted at the social discount rate of 3.5%.

Source: DECC, calculated from Pöyry results

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ANNEX F – MODELLING RESULTS FOR THE OPTIONS

Table 27 – Do Nothing – Renewable capacity by technology (MW)

Modelled Renewable Capacity (MW)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	3	6	9	11	14	16	18	20	21	23	31	25
AD (Power only)	52	85	125	175	239	314	388	455	499	511	511	121
AD (CHP)	9	11	12	15	18	23	30	41	56	71	71	40
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	144	360	531	674	788	1,092	1,092
Biomass (<50MW)	373	456	456	456	484	516	520	519	510	543	894	470
Biomass (Conversion from existing coal plant)	750	1,315	1,315	2,028	2,028	2,028	2,028	2,028	2,028	2,028	1,463	-
Biomass (Energy crops)	-	-	-	-	-	-	-	21	70	182	1,236	1,236
Biomass (CHP)	1	15	22	22	22	84	162	239	332	407	852	1,565
CoFiring (Standard, <10% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (CHP, 10% biomass)	18	18	18	36	36	36	54	54	54	54	-	-
EfW (Power only)	279	285	326	332	338	344	352	364	377	390	477	300
EfW (CHP)	8	21	90	92	94	97	100	103	106	109	139	175
Geothermal (Power only)	-	-	-	3	9	9	9	9	9	9	9	9
Geothermal (CHP)	-	-	0	2	4	8	13	22	33	49	49	49
Hydro (>5MW)	1,456	1,462	1,468	1,474	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480
Hydro (<5MW)	221	235	251	267	285	304	325	347	370	395	489	606
Landfill gas	937	933	914	893	886	880	852	794	755	692	40	40
OffshoreWind (Round 2)	1,678	2,680	3,580	4,080	4,080	4,712	4,971	5,719	6,830	7,584	8,541	4,586
OffshoreWind (Round 3)	-	-	-	-	-	-	912	2,064	3,289	4,584	16,152	32,277
OnshoreWind (>5MW)	4,778	5,926	6,634	7,220	7,820	8,294	8,784	9,273	9,842	10,367	14,171	11,746
OnshoreWind (<5MW)	40	45	52	62	75	94	120	156	208	268	331	269
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	100	145	190	257	358	433	547	718	974	1,311	1,311	1,119
Sewage Gas	186	189	191	194	196	199	202	186	178	164	142	33
Tidal Stream (England, Wales & NI, Shallow)	1	1	1	1	1	4	15	30	43	62	260	364
Tidal Stream (Scotland, Deep)	-	-	-	-	-	1	4	8	12	22	265	657
Tidal Stream (Scotland ,Shallow)	-	-	-	4	23	28	47	74	96	130	521	1,053
Wave (England, Wales & NI)	-	-	-	-	-	1	2	4	8	11	153	416
Wave (Scotland)	1	1	1	7	19	29	38	59	91	116	921	2,375
Total	**10,893**	**13,829**	**15,656**	**17,630**	**18,510**	**20,078**	**22,334**	**25,317**	**28,944**	**32,349**	**51,600**	**62,103**

Table 28 – Do Nothing – Renewable generation by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	47	65	84	102	120	133	143	154	220	174
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	568	2,193	3,364	4,657	5,698	8,529	8,529
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,719	3,939	4,092	4,055	3,995	4,164	6,910	3,566
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	-	-	-	-	-	-	82	358	991	9,447	9,447
Biomass (CHP)	2	61	147	175	175	461	1,033	1,588	2,256	2,907	6,337	11,346
CoFiring (Standard, <10% biomass)	2,502	2,502	-	-	-	1,818	1,586	2,696	2,156	2,501	380	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	500	500	500	500	500	500	500	499	496	491	483	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	13	51	75	75	75	75	75	75	62
Geothermal (CHP)	-	-	1	8	25	51	87	140	220	329	392	384
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,734	2,232
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,399	13,441	14,949	16,746	19,862	22,837	27,152	15,138
OffshoreWind (Round 3)	-	-	-	-	-	-	1,597	5,212	9,374	13,787	53,750	108,632
OnshoreWind (>5MW)	10,663	12,999	15,306	16,931	18,433	19,756	20,943	22,158	23,541	24,891	34,609	28,181
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	907	1,057
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	553	568	582	597	611	627	616	605	591	558	519	190
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	5	9	26	66	107	149	613	895
Tidal Stream (Scotland , Deep)	-	-	-	-	-	1	7	19	31	55	745	1,863
Tidal Stream (Scotland, Shallow)	-	-	-	9	52	95	131	199	271	343	1,251	2,602
Wave (England, Wales & NI)	-	-	-	-	-	2	4	9	16	25	368	1,053
Wave (Scotland)	3	3	3	11	33	63	88	127	197	272	2,221	6,001
Total	**36,464**	**47,054**	**50,531**	**58,273**	**67,339**	**73,533**	**80,934**	**91,460**	**102,774**	**115,237**	**176,596**	**211,312**

Table 29 – Minimum Scope – Renewable capacity by technology (MW)

Modelled Renewable Capacity (MW)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	3	6	8	10	12	15	17	18	20	21	30	25
AD (Power only)	52	85	125	175	239	314	388	455	499	511	511	121
AD (CHP)	9	11	12	15	18	23	30	41	56	71	71	40
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	125	305	385	459	527	757	757
Biomass (<50MW)	373	456	456	456	484	516	520	519	510	543	853	429
Biomass (Conversion from existing coal plant)	750	1,315	1,315	2,028	2,028	2,028	2,028	2,028	2,028	2,028	1,463	-
Biomass (Energy crops)	-	-	-	-	-	19	55	167	286	409	1,521	1,521
Biomass (CHP)	1	15	22	22	22	84	162	216	265	310	729	1,442
CoFiring (Standard, <10% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Enhanced, 15% biomass)	-	-	581	581	581	581	581	581	581	581	581	-
CoFiring (Energy crops)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (CHP, 10% biomass)	18	18	18	36	36	36	54	54	54	54	-	-
EfW (Power only)	279	285	326	332	338	344	352	364	377	390	477	300
EfW (CHP)	8	21	90	92	94	97	100	103	106	109	139	175
Geothermal (Power only)	-	-	-	3	9	9	9	9	9	9	9	9
Geothermal (CHP)	-	-	0	2	4	8	13	22	33	49	49	49
Hydro (>5MW)	1,456	1,462	1,468	1,474	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480
Hydro (<5MW)	221	235	251	267	285	304	325	347	370	395	489	606
Landfill gas	937	933	914	893	886	880	852	794	755	692	40	40
OffshoreWind (Round 2)	1,678	2,680	3,580	4,080	4,439	5,071	5,330	6,078	7,189	7,943	8,900	4,945
OffshoreWind (Round 3)	-	-	-	-	-	-	912	2,064	3,289	4,584	16,152	32,277
OnshoreWind (>5MW)	4,778	5,926	6,488	7,074	7,674	8,148	8,638	9,127	9,696	10,221	14,025	11,746
OnshoreWind (<5MW)	40	45	52	62	75	94	120	156	208	268	331	269
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	100	145	190	257	358	433	547	718	974	1,311	1,311	1,119
Sewage Gas	186	189	191	194	196	199	202	186	178	164	142	33
Tidal Stream (England, Wales & NI, Shallow)	1	1	1	1	1	4	15	30	43	62	260	364
Tidal Stream (Scotland, Deep)	-	-	-	-	-	1	4	8	12	22	265	657
Tidal Stream (Scotland ,Shallow)	-	-	-	-	-	5	25	51	73	107	498	1,150
Wave (England, Wales & NI)	-	-	-	-	-	1	2	4	8	11	153	416
Wave (Scotland)	1	1	1	1	1	12	21	41	73	99	903	2,708
Total	**10,893**	**13,829**	**16,090**	**18,054**	**19,262**	**20,830**	**23,086**	**26,047**	**29,630**	**32,971**	**52,139**	**62,679**

Note: The difference in capacity modelled for marine technologies in 2039/40 in this scenario should be treated with caution. The relationship we were asked to assume between future marine costs and future deployment means costs fall less steeply in this scenario and generation is subsequently higher beyond.

Table 30 – Minimum Scope – Renewable generation by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	45	60	75	91	109	122	132	143	209	174
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	492	1,868	2,634	3,263	3,837	5,905	5,905
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,719	3,939	4,092	4,055	3,995	4,164	6,601	3,258
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	-	-	-	-	75	325	832	1,758	2,715	11,682	11,606
Biomass (CHP)	2	61	147	175	175	461	1,033	1,495	1,899	2,266	5,372	10,381
CoFiring (Standard, <10% biomass)	2,502	2,502	-	-	-	924	723	1,205	1,094	1,474	384	-
CoFiring (Enhanced, 15% biomass)	-	-	2,161	4,322	4,322	4,322	4,322	4,322	4,322	4,322	4,322	-
CoFiring (Energy crops)	500	500	500	500	500	498	496	489	479	476	479	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	13	51	75	75	75	75	75	75	62
Geothermal (CHP)	-	-	1	8	25	51	87	140	220	329	392	384
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,734	2,232
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,992	14,626	16,135	17,935	21,056	24,030	28,340	15,653
OffshoreWind (Round 3)	-	-	-	-	-	-	1,597	5,212	9,374	13,787	53,750	108,632
OnshoreWind (>5MW)	10,663	12,999	15,117	16,565	18,068	19,390	20,578	21,792	23,175	24,525	34,243	28,181
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	907	1,057
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	553	568	582	597	611	627	616	605	591	558	519	190
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	5	9	26	66	107	149	613	895
Tidal Stream (Scotland , Deep)	-	-	-	-	-	1	7	19	31	55	745	1,863
Tidal Stream (Scotland, Shallow)	-	-	-	-	-	7	43	112	183	256	1,163	2,830
Wave (England, Wales & NI)	-	-	-	-	-	2	4	9	16	25	368	1,053
Wave (Scotland)	3	3	3	3	3	17	42	81	151	227	2,176	6,756
Total	**36,464**	**47,054**	**52,502**	**62,209**	**71,797**	**77,636**	**85,065**	**94,887**	**106,351**	**118,421**	**179,935**	**211,073**

Note: The difference in the generation modelled for marine technologies in 2039/40 in this scenario should be treated with caution. The relationship we were asked to assume between future marine costs and future deployment means costs fall less steeply in this scenario and generation is subsequently higher beyond.

Table 31 – Extra Support for Marine – Renewable capacity by technology (MW)

Modelled Renewable Capacity (MW)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	3	6	8	10	12	15	17	18	20	21	30	25
AD (Power only)	52	85	125	175	239	314	388	455	499	511	511	121
AD (CHP)	9	11	12	15	18	23	30	41	56	71	71	40
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	125	305	385	459	527	757	757
Biomass (<50MW)	373	456	456	456	484	516	520	519	510	543	853	429
Biomass (Conversion from existing coal plant)	750	1,315	1,315	2,028	2,028	2,028	2,028	2,028	2,028	2,028	1,463	-
Biomass (Energy crops)	-	-	-	-	-	19	55	167	286	409	1,521	1,521
Biomass (CHP)	1	15	22	22	22	84	162	216	265	310	729	1,442
CoFiring (Standard, <10% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Enhanced, 15% biomass)	-	-	581	581	581	581	581	581	581	581	581	-
CoFiring (Energy crops)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (CHP, 10% biomass)	18	18	18	36	36	36	54	54	54	54	-	-
EfW (Power only)	279	285	326	332	338	344	352	364	377	390	477	300
EfW (CHP)	8	21	90	92	94	97	100	103	106	109	139	175
Geothermal (Power only)	-	-	-	3	9	9	9	9	9	9	9	9
Geothermal (CHP)	-	-	0	2	4	8	13	22	33	49	49	49
Hydro (>5MW)	1,456	1,462	1,468	1,474	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480
Hydro (<5MW)	221	235	251	267	285	304	325	347	370	395	489	606
Landfill gas	937	933	914	893	886	880	852	794	755	692	40	40
OffshoreWind (Round 2)	1,678	2,680	3,580	4,080	4,439	5,071	5,330	6,078	7,189	7,943	8,900	4,945
OffshoreWind (Round 3)	-	-	-	-	-	-	912	2,064	3,289	4,584	16,152	32,277
OnshoreWind (>5MW)	4,778	5,926	6,488	7,074	7,674	8,148	8,638	9,127	9,696	10,221	14,025	11,746
OnshoreWind (<5MW)	40	45	52	62	75	94	120	156	208	268	331	269
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	100	145	190	257	358	433	547	718	974	1,311	1,311	1,119
Sewage Gas	186	189	191	194	196	199	202	186	178	164	142	33
Tidal Stream (England, Wales & NI, Shallow)	1	1	1	1	3	6	17	32	45	64	262	364
Tidal Stream (Scotland, Deep)	-	-	-	-	1	2	5	9	12	23	266	657
Tidal Stream (Scotland ,Shallow)	-	-	-	11	29	34	54	81	102	136	528	1,053
Wave (England, Wales & NI)	-	-	-	0	2	3	4	6	10	13	155	416
Wave (Scotland)	1	1	1	7	19	29	38	59	91	116	921	2,375
Total	**10,893**	**13,829**	**16,090**	**18,071**	**19,313**	**20,882**	**23,137**	**26,098**	**29,681**	**33,022**	**52,191**	**62,249**

Table 32 – Extra support for Marine – Renewable generation by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	45	60	75	91	109	122	132	143	209	174
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	492	1,868	2,634	3,263	3,837	5,905	5,905
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,719	3,939	4,092	4,055	3,995	4,164	6,601	3,258
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	-	-	-	-	75	325	832	1,758	2,715	11,682	11,606
Biomass (CHP)	2	61	147	175	175	461	1,033	1,495	1,899	2,266	5,372	10,381
CoFiring (Standard, <10% biomass)	2,502	2,502	-	-	-	924	723	1,205	1,094	1,474	384	-
CoFiring (Enhanced, 15% biomass)	-	-	2,161	4,322	4,322	4,322	4,322	4,322	4,322	4,322	4,322	-
CoFiring (Energy crops)	500	500	500	500	500	498	496	489	479	476	479	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	13	51	75	75	75	75	75	75	62
Geothermal (CHP)	-	-	1	8	25	51	87	140	220	329	392	384
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,734	2,232
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,992	14,626	16,135	17,935	21,056	24,030	28,340	15,653
OffshoreWind (Round 3)	-	-	-	-	-	-	1,597	5,212	9,374	13,787	53,750	108,632
OnshoreWind (>5MW)	10,663	12,999	15,117	16,565	18,068	19,390	20,578	21,792	23,175	24,525	34,243	28,181
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	907	1,057
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	553	568	582	597	611	627	616	605	591	558	519	190
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	11	17	35	74	115	156	621	895
Tidal Stream (Scotland , Deep)	-	-	-	-	1	4	10	22	34	58	748	1,863
Tidal Stream (Scotland, Shallow)	-	-	-	21	78	120	156	225	296	369	1,276	2,602
Wave (England, Wales & NI)	-	-	-	1	3	6	9	13	21	30	373	1,046
Wave (Scotland)	3	3	3	11	33	63	88	127	197	272	2,221	6,001
Total	**36,464**	**47,054**	**52,502**	**62,238**	**71,915**	**77,810**	**85,239**	**95,062**	**106,526**	**118,596**	**180,109**	**210,082**

Table 33 – Portfolio Approach – Renewable capacity by technology (MW)

Modelled Renewable Capacity (MW)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	3	6	8	9	11	14	16	17	19	20	29	24
AD (Power only)	52	85	125	175	239	314	388	455	499	511	511	121
AD (CHP)	9	11	12	15	18	24	32	43	58	72	72	40
Bioliquids (Power only)	-	-	238	475	713	713	713	713	713	713	- 0	- 0
Biomass (>50MW)	-	-	-	-	-	132	319	399	479	559	879	879
Biomass (<50MW)	373	456	519	588	701	733	738	736	727	760	1,072	582
Biomass (Conversion from existing coal plant)	750	1,315	1,315	2,028	2,028	2,028	2,028	2,028	2,028	2,028	1,463	-
Biomass (Energy crops)	-	-	-	-	150	162	191	303	415	527	1,549	1,399
Biomass (CHP)	1	15	22	96	194	256	334	391	430	467	874	1,416
CoFiring (Standard, <10% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (CHP, 10% biomass)	18	18	18	36	36	36	54	54	54	54	-	-
EfW (Power only)	279	285	326	332	338	344	352	364	377	390	477	300
EfW (CHP)	8	21	90	92	94	97	100	103	106	109	139	175
Geothermal (Power only)	-	-	-	10	28	28	28	28	28	28	28	28
Geothermal (CHP)	-	-	0	2	5	9	14	22	34	49	49	49
Hydro (>5MW)	1,456	1,462	1,468	1,474	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480
Hydro (<5MW)	221	235	251	267	285	304	325	347	370	395	489	606
Landfill gas	937	933	914	893	886	880	852	794	755	692	40	40
OffshoreWind (Round 2)	1,678	2,680	3,580	4,206	4,924	5,556	5,815	6,563	7,674	8,428	9,385	5,242
OffshoreWind (Round 3)	-	-	-	-	-	-	912	2,064	3,289	4,584	16,152	32,277
OnshoreWind (>5MW)	4,778	5,926	6,488	6,874	7,474	7,948	8,438	8,927	9,496	10,021	13,825	11,091
OnshoreWind (<5MW)	40	45	52	62	75	94	120	156	208	268	331	269
PV (>5MW)	-	-	7	19	41	41	41	41	41	41	41	34
PV (<5MW)	100	145	190	257	358	433	547	718	974	1,311	1,311	1,119
Sewage Gas	186	189	191	192	195	198	200	184	176	161	139	30
Tidal Stream (England, Wales & NI, Shallow)	1	1	1	1	3	6	17	32	45	64	340	583
Tidal Stream (Scotland, Deep)	0	0	1	2	3	4	7	12	15	25	269	657
Tidal Stream (Scotland ,Shallow)	1	2	5	16	34	39	59	86	107	141	533	1,057
Wave (England, Wales & NI)	0	0	1	1	2	3	4	7	10	14	156	416
Wave (Scotland)	6	11	14	20	31	42	51	72	104	129	934	2,379
Total	**10,898**	**13,842**	**15,836**	**18,142**	**20,348**	**21,918**	**24,173**	**27,137**	**30,709**	**34,042**	**52,566**	**62,291**

Table 34 – Portfolio Approach – Renewable generation by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	42	49	58	73	90	104	114	124	191	153
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	757	2,272	3,786	4,543	4,543	4,543	4,543	4,543	- 0	- 0
Biomass (>50MW)	-	-	-	-	-	520	1,959	2,744	3,392	4,032	6,839	6,839
Biomass (<50MW)	2,930	3,265	3,839	4,373	5,140	5,648	5,804	5,766	5,706	5,875	8,328	4,046
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	-	-	-	591	1,230	1,440	1,931	2,819	3,703	11,930	10,748
Biomass (CHP)	2	61	147	475	1,185	1,815	2,386	2,862	3,237	3,533	6,522	10,194
CoFiring (Standard, <10% biomass)	2,502	2,502	3,502	4,502	3,530	3,837	3,061	2,585	2,987	2,779	383	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	500	500	500	500	481	473	478	476	470	471	480	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	- 0	40	154	226	226	226	226	226	226	181
Geothermal (CHP)	-	-	1	9	28	54	90	143	223	332	395	385
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,734	2,232
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,782	14,000	16,227	17,737	19,540	22,667	25,641	29,944	15,637
OffshoreWind (Round 3)	-	-	-	-	-	-	1,597	5,212	9,374	13,787	53,750	108,766
OnshoreWind (>5MW)	10,663	12,999	15,117	16,310	17,567	18,889	20,076	21,291	22,673	24,023	33,741	26,822
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	907	1,057
PV (>5MW)	-	-	4	12	28	39	39	39	39	39	39	26
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	553	568	582	593	604	620	607	594	576	541	500	171
Tidal Stream (England, Wales & NI, Shallow)	6	6	8	12	22	29	45	83	122	178	1,526	3,166
Tidal Stream (Scotland , Deep)	0	1	2	4	8	12	18	29	41	65	756	1,862
Tidal Stream (Scotland, Shallow)	2	7	15	41	98	140	176	245	316	389	1,296	2,614
Wave (England, Wales & NI)	0	1	1	2	5	8	11	15	23	32	374	1,054
Wave (Scotland)	9	22	35	47	70	99	124	163	233	309	2,258	6,014
Total	**36,473**	**47,082**	**54,900**	**65,818**	**78,605**	**86,508**	**93,395**	**102,278**	**114,211**	**125,630**	**182,075**	**211,926**

ANNEX G – MODELLING RESULTS FOR THE SENSITIVITIES

Table 35 – High Fossil Fuel Prices (Do Nothing) – Renewable generation by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	47	66	84	102	120	133	143	154	220	174
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	296	1,142	1,789	2,602	3,404	7,311	7,311
Biomass (<50MW)	2,940	3,285	3,859	4,393	5,036	5,398	5,491	5,424	5,335	5,439	8,883	4,593
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	455	1,301	1,691	2,087	2,531	2,680	2,782	2,908	3,034	9,985	7,502
Biomass (CHP)	2	61	147	175	175	348	693	1,029	1,432	1,861	5,450	11,003
CoFiring (Standard, <10% biomass)	2,502	2,540	3,187	2,755	3,027	3,046	2,959	4,313	4,118	3,856	379	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	500	462	418	415	435	443	456	463	469	477	483	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	- -	0	13	51	75	75	75	75	75	75	57
Geothermal (CHP)	-	-	1	8	25	55	95	148	227	337	399	391
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,742	2,240
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	4,904	8,096	11,501	14,179	15,997	17,516	18,428	19,524	21,422	23,214	26,518	10,782
OffshoreWind (Round 3)	-	-	-	-	-	-	965	3,149	5,664	8,330	47,023	104,365
OnshoreWind (>5MW)	10,876	13,444	16,055	18,113	20,116	21,632	22,713	23,817	25,083	26,315	37,150	27,187
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	918	1,068
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	557	579	600	618	632	651	647	643	636	611	580	248
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	8	11	20	44	69	94	529	859
Tidal Stream (Scotland , Deep)	-	-	-	-	-	1	4	11	19	33	716	1,848
Tidal Stream (Scotland, Shallow)	- -	0	2	17	65	105	127	168	211	255	1,111	2,517
Wave (England, Wales & NI)	-	-	-	-	-	1	3	5	10	15	356	1,049
Wave (Scotland)	3	3	5	14	37	61	76	99	141	187	2,123	5,970
Total	**37,678**	**49,957**	**58,215**	**67,257**	**79,026**	**84,297**	**89,580**	**97,305**	**104,995**	**112,700**	**171,909**	**199,124**

Table 36 – Low Fossil Fuel Price (Do Nothing) – Renewable capacity by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	47	65	84	101	115	127	135	144	210	166
AD (Power only)	193	441	711	1,040	1,458	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	922	3,564	5,583	8,120	10,621	18,522	18,522
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,591	3,809	4,068	4,085	4,076	4,368	8,179	4,838
Biomass (Conversion from existing coal plant)	2,957	5,913	2,957	-	-	-	-	-	-	-	-	-
Biomass (Energy crops)	-	-	-	-	-	47	183	286	416	545	6,470	6,470
Biomass (CHP)	2	61	147	175	175	664	1,640	2,589	3,730	4,943	9,233	11,750
CoFiring (Standard, <10% biomass)	-	-	-	-	-	-	-	-	-	2,782	373	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	500	500	500	500	500	500	500	500	500	500	490	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	-	24	49	49	49	49	49	49	49
Geothermal (CHP)	-	-	1	7	21	48	87	140	220	316	367	359
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,714	2,184
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,399	14,179	16,755	19,810	25,117	30,222	36,343	24,352
OffshoreWind (Round 3)	-	-	-	-	-	-	2,729	8,903	16,014	23,554	68,681	122,564
OnshoreWind (>5MW)	10,235	12,109	13,616	14,200	14,444	15,477	17,568	19,728	22,101	24,451	34,654	30,905
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	903	1,053
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	550	557	564	568	568	583	584	586	583	563	528	203
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	5	11	35	88	144	200	619	855
Tidal Stream (Scotland , Deep)	-	-	-	-	-	2	12	32	53	94	797	1,895
Tidal Stream (Scotland, Shallow)	-	-	-	-	28	69	130	247	369	493	1,492	2,760
Wave (England, Wales & NI)	-	-	-	-	-	3	7	15	28	43	389	1,064
Wave (Scotland)	3	3	3	9	30	70	113	179	298	428	2,401	6,091
Total	**33,531**	**41,423**	**44,369**	**45,270**	**47,137**	**52,575**	**65,040**	**80,651**	**100,396**	**123,338**	**206,601**	**246,039**

Table 37 – High Fossil Fuel Prices (Extra Support for Marine) – Renewable capacity by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	43	55	66	80	98	111	121	132	198	153
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	296	1,142	1,690	2,262	2,817	4,984	4,984
Biomass (<50MW)	2,950	3,305	3,879	4,413	5,056	5,418	5,511	5,444	5,355	5,459	8,067	3,754
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	455	1,301	1,691	2,087	2,531	2,680	2,895	3,255	3,626	11,939	9,456
Biomass (CHP)	2	61	147	175	175	348	693	1,029	1,382	1,715	4,759	10,312
CoFiring (Standard, <10% biomass)	2,502	2,540	2,729	1,843	1,201	1,220	1,134	1,643	1,606	1,527	383	-
CoFiring (Enhanced, 15% biomass)	-	-	2,161	4,322	4,322	4,322	4,322	4,322	4,322	4,322	4,322	-
CoFiring (Energy crops)	500	462	418	415	435	443	456	462	465	471	480	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	- -	0	13	51	75	75	75	75	75	75	57
Geothermal (CHP)	-	-	1	8	25	55	95	148	227	337	399	391
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,742	2,240
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	4,904	8,096	11,501	14,283	16,501	18,316	19,229	20,325	22,224	24,016	27,319	10,516
OffshoreWind (Round 3)	-	-	-	-	-	-	965	3,149	5,664	8,330	47,023	103,235
OnshoreWind (>5MW)	10,876	13,444	16,055	18,113	20,116	21,633	22,715	24,104	25,953	27,774	39,145	29,632
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	916	1,066
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	557	579	600	618	632	651	647	643	636	611	580	248
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	6	15	21	31	53	77	111	1,356	3,022
Tidal Stream (Scotland , Deep)	-	-	-	1	4	7	10	17	25	39	722	1,846
Tidal Stream (Scotland, Shallow)	-	2	5	29	93	139	161	202	245	289	1,146	2,534
Wave (England, Wales & NI)	-	-	0	1	3	6	7	10	15	20	361	1,049
Wave (Scotland)	3	3	5	14	37	61	76	99	141	187	2,123	5,970
Total	**37,687**	**49,979**	**59,937**	**70,795**	**82,071**	**87,649**	**92,932**	**100,110**	**108,480**	**116,867**	**177,996**	**200,424**

Table 38 – Low Fossil Fuel Price (Extra Support for Marine) – Renewable capacity by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	42	49	56	68	82	94	102	111	177	144
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	922	3,564	5,583	8,120	10,616	18,106	18,106
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,591	3,809	4,068	4,085	4,075	4,364	8,383	5,039
Biomass (Conversion from existing coal plant)	2,957	5,913	2,957	-	-	-	-	-	-	-	-	-
Biomass (Energy crops)	-	-	-	-	-	47	183	286	416	544	5,762	5,762
Biomass (CHP)	2	61	147	175	175	664	1,640	2,589	3,741	4,962	8,995	11,755
CoFiring (Standard, <10% biomass)	-	-	-	-	-	-	-	-	-	2,785	372	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	500	500	500	500	500	500	500	500	500	500	491	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal (CHP)	-	-	1	7	21	48	87	140	220	316	367	359
Hydro (>5MW)	4,316	4,343	4,356	4,368	4,392	4,403	4,403	4,403	4,403	4,403	4,403	4,403
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,714	2,184
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,399	14,179	16,755	19,810	25,117	30,222	36,343	24,352
OffshoreWind (Round 3)	-	-	-	-	-	-	2,729	8,903	16,014	23,554	68,681	122,564
OnshoreWind (>5MW)	10,235	12,109	13,616	13,943	13,943	14,977	17,067	19,227	21,600	23,950	34,152	31,152
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	903	1,053
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	550	557	564	568	568	583	584	586	583	563	526	201
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	8	13	37	88	142	225	1,448	3,034
Tidal Stream (Scotland , Deep)	-	-	-	-	-	2	12	32	53	94	797	1,892
Tidal Stream (Scotland, Shallow)	-	-	-	21	78	125	187	304	426	550	1,549	2,760
Wave (England, Wales & NI)	-	-	-	0	3	7	12	19	32	48	393	1,064
Wave (Scotland)	3	3	3	9	30	70	113	179	298	428	2,401	6,091
Total	**33,530**	**41,423**	**44,351**	**44,993**	**46,614**	**52,031**	**64,496**	**80,104**	**99,858**	**122,830**	**205,722**	**247,447**

Table 39 – High Offshore Learning Rates – Renewable capacity by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	45	60	75	91	109	122	132	143	209	174
AD (Power only)	193	441	711	1,040	1,457	1,970	2,515	3,030	3,437	3,644	3,689	648
AD (CHP)	35	45	57	72	93	126	175	244	339	447	499	255
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	492	1,868	2,634	3,263	3,837	5,905	5,905
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,719	3,939	4,092	4,055	3,995	4,164	6,601	3,258
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	-	-	-	-	75	325	832	1,758	2,715	11,682	11,606
Biomass (CHP)	2	61	147	175	175	461	1,033	1,495	1,899	2,266	5,372	10,381
CoFiring (Standard, <10% biomass)	2,502	2,502	-	-	-	924	723	1,205	1,094	1,474	384	-
CoFiring (Enhanced, 15% biomass)	-	-	2,161	4,322	4,322	4,322	4,322	4,322	4,322	4,322	4,322	-
CoFiring (Energy crops)	500	500	500	500	500	498	496	489	479	476	479	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	13	51	75	75	75	75	75	75	62
Geothermal (CHP)	-	-	1	8	25	51	87	140	220	329	392	384
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	644	699	759	823	894	969	1,050	1,137	1,229	1,326	1,734	2,232
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,678	13,199	14,834	16,343	18,143	21,265	24,239	28,975	16,081
OffshoreWind (Round 3)	-	-	-	-	-	-	1,597	5,212	9,374	13,787	77,833	189,194
OnshoreWind (>5MW)	10,663	12,999	15,117	16,565	18,068	19,390	20,578	21,792	23,175	24,525	34,243	28,181
OnshoreWind (<5MW)	92	101	114	132	157	193	242	312	409	532	907	1,057
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	82	117	160	213	293	376	467	603	806	1,089	1,244	1,031
Sewage Gas	553	568	582	597	611	627	616	605	591	558	519	190
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	11	17	35	74	115	156	621	895
Tidal Stream (Scotland , Deep)	-	-	-	-	1	4	10	22	34	58	748	1,863
Tidal Stream (Scotland, Shallow)	-	-	-	21	78	120	156	225	296	369	1,276	2,602
Wave (England, Wales & NI)	-	-	-	1	3	6	9	13	21	30	373	1,046
Wave (Scotland)	3	3	3	11	33	63	88	127	197	272	2,221	6,001
Total	**36,464**	**47,054**	**52,502**	**62,342**	**72,123**	**78,018**	**85,447**	**95,270**	**106,735**	**118,805**	**204,827**	**291,073**

Table 40 – Lower Deployment Potential - Renewable capacity by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	43	53	63	76	92	103	112	121	175	128
AD (Power only)	160	330	494	682	893	1,111	1,324	1,531	1,730	1,923	2,436	1,020
AD (CHP)	35	42	50	60	73	92	119	154	199	250	349	312
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	694	1,388	1,628	2,495	3,212	6,291	6,291
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,684	3,784	3,886	3,895	3,845	3,995	6,988	3,552
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	10,220	15,985	15,985	15,985	15,985	15,985	15,985	5,765	-
Biomass (Energy crops)	-	-	-	-	-	63	126	148	227	292	3,528	3,468
Biomass (CHP)	2	61	147	175	175	364	714	986	1,292	1,605	3,904	6,690
CoFiring (Standard, <10% biomass)	2,502	2,502	-	-	-	986	989	1,978	1,887	2,691	368	-
CoFiring (Enhanced, 15% biomass)	-	-	2,161	4,322	4,322	4,322	4,322	4,322	4,322	4,322	4,322	-
CoFiring (Energy crops)	500	500	500	500	500	500	500	500	500	500	494	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,574	1,667	1,853	2,031	2,071	2,110	2,154	2,219	2,298	2,378	2,900	1,874
EfW (CHP)	45	96	390	648	664	681	700	720	742	764	958	1,185
Geothermal (Power only)	-	-	-	2	11	18	18	18	18	18	18	16
Geothermal (CHP)	-	-	-	1	5	11	18	30	47	69	82	81
Hydro (>5MW)	4,310	4,320	4,336	4,352	4,368	4,385	4,399	4,413	4,423	4,433	4,433	4,433
Hydro (<5MW)	632	665	697	730	765	803	843	887	933	982	1,185	1,434
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,992	13,727	14,080	15,229	17,474	19,909	25,580	12,338
OffshoreWind (Round 3)	-	-	-	-	-	-	786	3,010	6,263	10,010	42,161	78,954
OnshoreWind (>5MW)	10,493	12,630	14,474	15,527	16,589	17,538	18,387	19,225	20,171	21,055	27,287	18,348
OnshoreWind (<5MW)	91	99	109	124	143	169	204	251	315	394	652	722
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	81	115	156	207	283	362	446	572	760	1,019	1,161	954
Sewage Gas	552	563	574	585	596	608	591	575	554	515	495	168
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	9	12	20	41	63	93	705	1,418
Tidal Stream (Scotland , Deep)	-	-	-	-	1	3	7	14	22	38	499	1,242
Tidal Stream (Scotland, Shallow)	- -	0 -	0	14	52	80	104	150	197	246	833	1,725
Wave (England, Wales & NI)	-	-	-	0	2	4	6	9	14	20	249	698
Wave (Scotland)	3	3	3	8	23	43	60	86	132	183	1,481	4,009
Total	**36,220**	**46,490**	**51,529**	**60,640**	**69,489**	**73,715**	**77,428**	**83,672**	**91,746**	**101,393**	**145,583**	**151,283**

Table 41 – Low Ambition - Renewable capacity by technology (GWh)

Modelled renewable generation (GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2029/30	2039/40
ACT (Power only)	13	27	47	65	84	102	120	133	143	154	220	174
AD (Power only)	128	265	446	646	855	1,180	1,589	1,914	2,117	2,221	2,243	324
AD (CHP)	63	71	81	92	108	130	160	201	258	323	354	153
Bioliquids (Power only)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (>50MW)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (<50MW)	2,930	3,265	3,591	3,591	3,591	3,591	3,591	3,478	3,345	3,345	3,341	-
Biomass (Conversion from existing coal plant)	2,957	8,140	7,411	4,454	4,454	4,454	4,454	4,454	4,454	4,454	-	-
Biomass (Energy crops)	-	-	-	-	-	-	-	-	-	-	-	-
Biomass (CHP)	2	61	147	175	175	175	175	175	175	175	175	-
CoFiring (Standard, <10% biomass)	2,502	2,502	-	-	-	-	-	-	-	-	680	-
CoFiring (Enhanced, 15% biomass)	-	-	-	-	-	-	-	-	-	-	-	-
CoFiring (Energy crops)	500	500	500	500	500	500	500	500	500	500	500	-
CoFiring (CHP, 10% biomass)	71	142	142	213	284	284	355	426	426	355	-	-
EfW (Power only)	1,593	1,681	1,846	2,026	2,069	2,111	2,160	2,234	2,326	2,418	3,062	2,123
EfW (CHP)	45	96	390	649	665	683	702	723	746	769	986	1,252
Geothermal (Power only)	-	-	-	-	24	49	49	49	49	49	49	49
Geothermal (CHP)	-	-	0	4	12	25	43	73	121	186	2,431	6,351
Hydro (>5MW)	4,316	4,343	4,368	4,393	4,417	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Hydro (<5MW)	623	644	664	686	709	734	761	790	821	853	1,228	2,081
Landfill gas	5,346	5,192	5,129	5,015	4,938	4,902	4,805	4,566	4,299	4,016	282	223
OffshoreWind (Round 2)	3,918	6,123	9,263	11,574	12,399	12,399	12,399	12,399	12,399	12,399	12,083	-
OffshoreWind (Round 3)	-	-	-	-	-	-	-	-	-	-	-	-
OnshoreWind (>5MW)	10,663	12,999	15,117	16,310	17,311	18,283	19,258	20,249	21,398	22,513	30,755	33,426
OnshoreWind (<5MW)	90	94	97	100	105	112	122	136	156	180	710	3,489
PV (>5MW)	-	-	-	-	-	-	-	-	-	-	-	-
PV (<5MW)	59	59	59	59	59	59	59	59	59	59	59	-
Sewage Gas	550	557	564	575	589	604	590	576	559	524	474	148
Tidal Stream (England, Wales & NI, Shallow)	5	5	5	5	5	5	5	5	5	5	4	-
Tidal Stream (Scotland , Deep)	-	-	-	-	-	-	-	-	-	-	-	23
Tidal Stream (Scotland, Shallow)	-	-	-	-	-	-	-	-	-	-	-	-
Wave (England, Wales & NI)	-	-	-	-	-	-	-	-	-	-	-	-
Wave (Scotland)	3	3	3	3	3	3	3	3	3	3	-	-
Total	**36,376**	**46,773**	**49,870**	**51,135**	**53,358**	**54,814**	**56,328**	**57,572**	**58,787**	**59,928**	**64,064**	**54,245**

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