Title: **RO banding levels from 1/4/13 to 31/3/17**	Impact Assessment (IA)
IA No: DECC0075	**Date:** 09/11/2011
	Stage: Consultation
Lead department or agency: DECC	**Source of intervention:** Domestic
	Type of measure: Secondary legislation
Other departments or agencies: OfGem	**Contact for enquiries:** Ben.Marriott@decc.gsi.gov.uk

Summary: Intervention and Options

Cost of Preferred Option 3				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, One-Out?**	**Measure qualifies as**
£-1,100m	N/A	N/A	No	N/A

What is the problem under consideration? Why is government intervention necessary?

The UK needs to radically increase its deployment of renewable electricity to meet the UK share of the EU 2020 renewable energy target. The Renewables Obligation (RO) is currently the main mechanism of support for large-scale renewable electricity. It is due to close to new stations from 1st April 2017, but will continue to provide support for accredited stations until its full closure in 2037.

Government intervention is necessary because without it there would be insufficient investment in renewables technologies on the scale and timelines needed to meet renewables targets. The RO support (banding) levels for individual technologies are reviewed every four years, to ensure that they continue to represent VfM and to meet the other objectives of the scheme.

What are the policy objectives and the intended effects?

RO bands for the period 2013/14 to 2016/17 have been proposed that will ensure that the RO will support renewables deployment to help meet the UK 2020 renewable energy target in a cost-effective manner. Recommendations on banding should increase the efficiency of the RO to ensure value for money, minimising consumer costs and deliver deployment consistent with meeting UK renewables goals. By incentivising deployment of renewable electricity the RO supports delivery of wider energy and climate change goals to 2050, including GHG emissions reductions and energy

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

The RO banding review is a statutory obligation for the Government. The role of the RO has recently been considered against other options in the Electricity Market Reform (EMR) consultation and White Paper. The decision was taken to retain the RO to support existing RO-accredited renewable electricity installations; have a transitional phase from the introduction of the new FIT with CfD mechanism to support low-carbon electricity to 31/3/17, when new eligible renewable installations will have the choice between support under the new mechanism and support under the RO; and that from 1st April 2017 all support for large-scale renewable electricity will be under the new mechanism. Details are set out in the EMR White Paper.

Different options have been considered for setting the RO bands from 1/4/13 to 31/3/17, including: (1) keep the current bands; (2) 'minimum scope', a set of bands to keep the UK on track to the 2020 renewables target in a cost-effective manner; (3) as 'minimum scope', but with extra support for wave and tidal stream technologies; and (4) 'portfolio', diversifying effort across renewable technologies. The preferred option is 'minimum scope' with extra support for wave and tidal, as it delivers a cost-effective mix and tries to secure the long-term growth and viability of the marine industry. Other banding review decisions considered include grandfathering; definition changes of advanced conversion technologies and the energy crop uplift; a cap for bioliquids; and the co-firing cap.

Will the policy be reviewed? It will not be reviewed. **If applicable, set review date:** Month / Year

Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** **No**	**< 20** **No**	**Small** **No**	**Medium** **No**	**Large** **No**
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:** **-64**	**Non-traded:** **N/A**	

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: ______________________________ Date: ______________

Summary: Analysis & Evidence

Policy Option 2

Description:

Minimum scope in line with reaching the 2020 renewables target

Price Base Year 10/11	PV Base Year 11/12	Time Period Years 29	Net Benefit (Present Value (PV)) (£m)		
			Low:	**High:**	**Best Estimate: 470**

COSTS (£m)	**Total** (Constant Price)	**Transition** Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low	Optional		Optional	Optional
High	Optional		Optional	Optional
Best Estimate	N/A		**38**	**680**

Description and scale of key monetised costs by 'main affected groups'

The monetised costs are expressed as changes in overall system generation costs and balancing costs, rounded to two significant figures. There is also a distributional cost to electricity producers and suppliers due to reductions in RO support for some technologies.

Other key non-monetised costs by 'main affected groups'

Air quality impacts (note these could be net costs or net benefits); any reduction in security of electricity supply due to small increase in intermittent generation.

BENEFITS (£m)	**Total** (Constant Price)	**Transition** Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	Optional		Optional	Optional
High	Optional		Optional	Optional
Best Estimate	N/A		**64**	**1,100**

Description and scale of key monetised benefits by 'main affected groups'

The monetised benefits are the costs of fewer EUA purchases to the UK power sector and are rounded to two significant figures. These benefits fall to electricity consumers. There is also a distributional benefit to consumers in the form of reduced average electricity bills due to reductions in RO support for some technologies.

Other key non-monetised benefits by 'main affected groups'

Wider macroeconomic impacts associated with the reduction in the retail electricity prices; developing renewables industries (note the net impact on whole economy of developing renewable industries is subject to macroeconomic displacement and crowding out); reducing risk of missing UK's 2020 renewables target and of incurring potentially unlimited infraction fines; increased security of supply of primary fuels due to reductions in fossil fuel imports.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5

Key assumptions include (further detail in Annex 5):

- Current technology costs and learning rate
- Maximum build rates by technology
- Biomass availability and fuel prices
- Fossil fuel prices
- Hurdle rates

BUSINESS ASSESSMENT (Option 2)

Direct impact on business (Equivalent Annual) £m:			**In scope of OIOO?**	**Measure qualifies as**
Costs:	**Benefits:**	**Net:**	No	N/A

Summary: Analysis & Evidence — Policy Option 3

Description:

Minimum scope plus 5 ROCs/MWh for marine (wave and tidal stream)

Price Base Year	PV Base Year	Time Period Years	Net Benefit (Present Value (PV)) (£m)		
			Low: -4200bn	High: +250	Best Estimate: -1,100

COSTS (£m)	Total Transition (Constant Price) Years		Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	Optional		Optional	Optional
High	Optional		Optional	Optional
Best Estimate	N/A		120	2,200

Description and scale of key monetised costs by 'main affected groups'

The monetised costs are increases in overall system generation costs and balancing costs, rounded to two significant figures. There is also a distributional cost to electricity producers and suppliers dues to reductions in RO support for some technologies.

Other key non-monetised costs by 'main affected groups'

Air quality impacts (note these could be net costs or net benefits) ; any reduction in security of supply due to small increase in intermittent generation.

BENEFITS (£m)	Total Transition (Constant Price) Years		Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	Optional		Optional	Optional
High	Optional		Optional	Optional
Best Estimate	N/A		64	1,200

Description and scale of key monetised benefits by 'main affected groups'

The monetised benefits are the costs of fewer EUA purchases to the UK power sector and are rounded to two significant figures. These benefits fall to electricity consumers. There is also a distributional benefit to consumers due to reductions in RO support for some technologies.

Other key non-monetised benefits by 'main affected groups'

Wider macroeconomic impacts associated with the reduction in the retail electricity prices; bringing forward wave and tidal stream technologies as options for the decarbonising the power sector and meeting rising electricity demand; developing renewables industries (note the net impact on whole economy subject to macroeconomic displacement and crowding out); reducing risk of missing UK's 2020 renewables target and of incurring potentially unlimited infraction fines; increased security of supply due to reductions in fossil fuel imports.

Key assumptions/sensitivities/risks — **Discount rate (%)** 3.5

Key assumptions as for option 2.

Sensitivity analysis (detailed in the Evidence Base) has been carried out with respect to:

- the level of future fossil fuel prices;
- renewable technologies' deployment potential; and
- the rate of cost reduction in offshore wind.

BUSINESS ASSESSMENT (Option 3)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs:	Benefits:	Net:	No	N/A

Summary: Analysis & Evidence — Policy Option 4

Description:

Portfolio approach

Price Base Year	PV Base Year	Time Period Years	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate: -23,000

COSTS (£m)	Total Transition (Constant Price) Years		Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	Optional		Optional	Optional
High	Optional		Optional	Optional
Best Estimate	N/A		**1,400**	**24,000**

Description and scale of key monetised costs by 'main affected groups'

The monetised costs are increases in overall system generation costs and balancing costs, rounded to two significant figures. There is also a distributional cost to electricity producers and suppliers dues to reductions in RO support for some technologies.

Other key non-monetised costs by 'main affected groups'

Air quality impacts (note these could be net costs or net benefits) ; any reduction in security of supply due to small increase in intermittent generation.

BENEFITS (£m)	Total Transition (Constant Price) Years		Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	Optional		Optional	Optional
High	Optional		Optional	Optional
Best Estimate	N/A		**100**	**1,800**

Description and scale of key monetised benefits by 'main affected groups'

The monetised benefits are the costs of fewer EUA purchases to the UK power sector and are rounded to two significant figures. These benefits fall to electricity consumers. There is also a distributional benefit to consumers due to reductions in RO support for some technologies.

Other key non-monetised benefits by 'main affected groups'

Wider macroeconomic impacts associated with the reduction in the retail electricity prices; bringing forward wave and tidal stream technologies as options for the decarbonising the power sector and meeting rising electricity demand; developing renewables industries (note the net impact on whole economy subject to macroeconomic displacement and crowding out); reducing risk of missing UK's 2020 renewables target and of incurring potentially unlimited infraction fines; increased security of supply due to reductions in fossil fuel imports.

Key assumptions/sensitivities/risks — **Discount rate (%)** 3.5

Key assumptions as for option 2.

Sensitivity analysis (detailed in the Evidence Base) has been carried out with respect to:

- the level of future fossil fuel prices;
- renewable technologies' deployment potential; and
- the rate of cost reduction in offshore wind.

BUSINESS ASSESSMENT (Option 3)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs:	Benefits:	Net:	No	N/A

References

No.	Legislation or publication
1	Electricity Act 1989 as amended by the Energy Act (2008)
2	Renewables Obligation Orders 2009, 2010, 2011
3	Electricity Market Reform White Paper
4	Pöyry (forthcoming), *Potential Impact of Revised RO Bands*

Evidence Base (for summary sheets)

The Evidence Base is set out as follows:

1) Problem under consideration
2) Rationale for intervention
3) Policy objective
4) Analytical approach
5) Description of options considered (for banding decisions)
6) Impacts of each option (for banding decisions)
    a. Renewables deployment and the electricity mix
    b. Non-renewable generation mix
    c. Impact on total generation costs (excluding carbon)
    d. Impact on EUA purchase costs
    e. Impact on balancing costs
    f. NPV of all monetised costs and benefits
    g. Non-monetised impacts
    h. Distributional impacts
    i. Sensitivity analysis
7) Other banding review decisions (excluding banding)
    a. Grandfathering
    b. Definitional changes to gasification and pyrolysis
    c. Definitional changes to eligibility for the energy crops uplift
    d. A cap for bioliquids
    e. The co-firing cap
8) Wider impacts
9) Economic impacts
10) Summary and preferred option with description of implementation plan

1. Problem under consideration

1. The EU Renewable Energy Directive commits the UK to meeting 15% of its energy needs from renewable sources by 2020. To achieve this, renewable electricity supply from large scale generation will need to increase from around 5% today to around 29% (under the central renewables deployment scenario) by 2020. Further deployment of renewable electricity will need to come from smaller scale generation (<5MW), including micro generation.

2. The Renewables Obligation (RO), introduced in 2002, has been the Government's main financial policy mechanism for incentivising the deployment of renewable electricity generation in the UK. It has also played an important part in our programme for securing reductions in carbon dioxide emissions, alongside other policy measures such as the Climate Change Act 2008. Since the introduction of the RO in 2002, there has been a near trebling in the UK's renewable generation, from 1.8% to 6.6% in 2010.[1]

3. From the RO's introduction in 2002/03 until 2008/09, all technologies received the same banding of 1 ROC/MWh of renewable electricity. New bands were then set for new stations in the four years from 2009/10 to 2012/13. An early review of the banding for offshore wind was held in 2009, which led to the band for offshore wind increasing from 1.5 to 2 ROCs/MWh for new stations up to and including 2013/14, after which it was due, on current bands to fall back to 1.5 ROCs/MWh.

4. In sections 5 and 6, this Impact Assessment (IA) considers the options for setting bands for new stations in the various renewable technologies from 2013/14 to 2016/17 (except for offshore wind where the band is already set for 2013/14 so it only considers the appropriate level of support

[1] RO-eligible electricity generation as a proportion of UK electricity sales, source: Energy Trends, June 2011

2014/15 to 2016/17). Bands need to be reviewed periodically to ensure that: subsidy levels are set as cost-effectively as possible, they help to bring forward renewable technologies to achieve the UK's renewable energy target, and deliver good value for money for electricity consumers, who pay the costs of the RO. This review of the RO bands is necessary to ensure that the Government takes account of the latest information in setting support levels for renewable electricity, in order that the RO will continue to support renewable generation in an efficient and cost-effective way.

5. In section 7, the IA considers different options relating to various RO non-banding policy issues (grandfathering, the co-firing cap, the bioliquids cap and definitional changes to some bands) and their impacts.

2. Rationale for intervention

6. The EU Renewables Directive commits the EU to meet 20% of its energy needs from renewable sources by 2020, with the UK share of this at 15%. In order to meet this, Government needs to financially support large-scale renewable electricity technologies, as current costs are higher than their conventional alternatives, and would not be undertaken at the levels required or in the timescales needed.

7. Renewable technologies are also needed as part of the global effort to reduce emissions – the need for urgency and the risk of higher damage costs in the future underpin the need for action now. In the electricity sector new technologies can struggle to compete with conventional technologies and policies to support early stage development and bring costs down longer term is critical. Evidence suggests that the cost of deploying new technologies typically falls as volumes increase, supply chains are established and commitments to further expansion rise.[2]

8. There are a number of market failures and other barriers which would lead to too little investment in renewable technologies in the absence of government intervention. These include the greenhouse gas emissions negative externality (i.e. the damage costs of GHG emissions are not factored into investor decision making, although this is being partially addressed by the EU Emissions Trading System, supported by the Carbon Price Floor); positive externalities stemming from investment in innovative and emerging technologies; the homogenous nature of electricity as a product (from a consumers' perspective electricity is electricity[3], which means that it is difficult for renewable generators to compete on anything other than price); imperfect information and limited access to capital. The RO provides a financial incentive to invest in renewable electricity technologies to help overcome these market failures and barriers. The RO banding review is looking at whether the RO support is still set at the right levels to secure investment in renewables alongside value-for-money for the electricity consumers who bear the costs of RO support.

9. The Coalition Government has made clear its commitment to maintaining a banded RO alongside other support mechanisms, such as the new Feed-In Tariff with Contract for Difference mechanism (FIT with CfD), that will be introduced through Electricity Market Reform, with the aim of securing a significant increase in investment in renewable electricity generation.

10. Since the introduction of the banding, there have been a number of changes to the underlying assumptions that affect the level of support required: changes to underlying fossil fuel prices, generation costs, the carbon price, and our understanding of the level of deployment that is coming forward. There is therefore a need to review the support levels provided by the RO to different technologies to ensure they are cost effective, and will bring forward technologies that are needed both to meet the renewable energy target and longer term decarbonisation goals.

3. Policy objective

11. The Government's objectives for the banding review are to:
    - Ensure that the RO will support renewables growth to help meet the UK 2020 renewables target

[2] See for example UKERC, 2009, *Decarbonising the UK Energy System: Accelerated Development of Low-Carbon Energy Supply Technologies*

[3] Although suppliers may label their electricity and tariffs according to its emissions.

- Increase the efficiency of the RO to ensure value for money
- Support technologies with the potential for mass deployment
- Ensure coordination with other DECC financial incentives schemes.

12. By supporting delivery of renewable electricity, the RO supports delivery of wider energy and climate change goals to 2050, including GHG emissions reductions, decarbonising of the UK grid and energy security.

13. DECC therefore proposes a set of RO bands that are consistent with continued deployment of renewable electricity generation to meet the UK renewable energy target. In doing so DECC have taken account of updated information on the cost of technologies, and the impact of chosen bands on costs to consumers. More details are set out in our discussion of our approach to setting bands, and in the cost-benefit section.

14. These objectives are in line with DECCs legal obligations. The Secretary of State is obliged by virtue of Section 32D(4) of the Electricity Act 1989 (as amended by the Energy Act 2008) to have regard to a series of matters, summarised below, in setting RO bands:

    i) The costs and revenues associated with generation by the different technologies
    ii) The desirability of securing the long-term growth and viability of industries associated with the technologies
    iii) Costs to consumers and impacts on the market for ROCs
    iv) The achievement of renewables targets arising out of European obligations

15. Therefore the impact assessment sets out the impact on deployment of renewable technologies, and associated costs and benefits – including costs to consumers - of proposed changes to the RO bands, against the counterfactual of continuing with current banding levels. This impact assessment also estimates as far as possible a number of other impacts, including:

    i) Carbon impacts
    ii) Security of supply impacts
    iii) Air quality impacts
    iv) Ensuring compatibility with/ minimising risk of not being on a cost-effective pathway to 80% decarbonisation of the economy by 2050.

4. Analytical approach

16. To inform the banding review consultation, new evidence has been gathered by Arup, supported by their subcontractors Ernst & Young, on the deployment potential and generation costs of renewable electricity technologies currently or potentially eligible for RO support.[4] Other sources of evidence were used including project pipeline data[5] and research commissioned by the CCC for their renewables review.[6]

17. The Arup research has provided estimates of current costs of renewable electricity technologies through access to proprietary information, use of external reports, and, above all, consultation with renewable developers. The estimates were provided in the form of a range of low (10th percentile of sample data), median and high (90th percentile of sample data) capex, opex, and other parameters for each technology, reflecting the distribution of costs across renewables developers. Arup also made projections of future generation costs, based on their assumed learning rates (cost reductions with increased deployment reflecting technological learning, economies of scale etc.), global deployment projections from the IEA Blue Map scenarios[7] and future prices of key cost drivers such as labour and industrial commodities.

[4] Arup (2011) available alongside the consultation document at: http://www.decc.gov.uk/en/content/cms/consultations/cons_ro_review/cons_ro_review.aspx
[5] From the Office for Renewable Energy Deployment, DECC
[6] Mott MacDonald (2011), *Costs of Low Carbon Generation Technologies*, available at hmccc.s3.amazonaws.com/Renewables%20Review/MML%20final%20report%20for%20CCC%209%20may%202011.pdf
[7] It was assumed that offshore wind, wave and tidal stream costs are driven by UK deployment rather than global deployment.

18. Arup also gathered information on maximum deployment potential, in the form of annual new build rates for each technology. Low, medium and high estimates of these annual build rates were developed to reflect varying levels of non-financial barriers to deployment, such as planning, supply chain and grid constraints. The Arup estimates of generation costs and deployment potential were used to create annual stepped supply curves for each technology.[8] The high version of the annual maximum build rates was used for these, reflecting the high level of ambition the Government has to tackle non-financial barriers to renewables deployment, as detailed in the Renewables Roadmap.[9] Development of the supply chain, grid extensions and planning success will be just as important as providing the right financial incentives in achieving the 2020 renewables target.

19. This supply curve data was provided to Pöyry consultants, alongside similar data for non-renewables technologies and a raft of other assumptions (as set out in the key assumptions section below and Annex 5), in order to input it into their electricity market model to assess the impacts of different RO banding scenarios on electricity system costs and renewables deployment. Using the central assumptions as given to Pöyry (and the electricity prices that come out of their model), DECC have estimated the range of ROC bandings required to meet the assumed investor hurdle rates (i.e. to make investments worthwhile for the given cost ranges) for each technology in 2014/15. This was done by comparing generation costs and revenues in a simple discounted cashflow model (see Table 1 for a summary of the cost and revenues used in the cash-flow analysis). Note that below whenever 'ROC banding required' is referred to, it is in this sense of the ROC band required to make the investment viable at the given set of costs.

Table 1

Cash flows	
Costs	***Revenues***
Capex	Electricity sales revenue
Opex	ROC revenue
Fuel cost (for biomass technologies)	LEC revenue
	Gate fees (payment for some waste technologies)
	Avoided costs of alternative heat generation or revenue from selling steam (CHP)

20. Several different RO banding scenarios were simulated through the Pöyry electricity market model. The impacts of changes to RO bandings on renewables deployment, subsidy costs, and resource costs (including carbon and balancing costs) were analysed. Cost-benefit analysis on the different options based on the modelling by Pöyry is presented below in section 6.

21. The Banding Review consultation document presented ranges of projected deployment for each technology under Options 1 and 3. The upper ends of these ranges were based on analysis undertaken by Pöyry using a lower set of hurdle rates than DECC's central assumptions, and the most up-to-date available DECC fossil fuel price assumptions at the time, which were first published in 2009 and reviewed but unchanged in 2010. The lower ends of the ranges were based on DECC analysis of the likely changes to deployment using DECC's central hurdle rates.

22. The main analysis contained in this Impact Assessment is based on the final Pöyry analysis using the DECC central hurdle rates set out in Annex 5, but does not use the new updated fossil fuel prices, published in October 2011. This analysis suggests that deployment of some technologies falls slightly below the range presented in the consultation document. For example, the estimated

[8] As Arup's medium cost estimates represent the median, the supply curves take into account cost skewedness. If the median equals the mid-point of the low to high range, then the distribution is fairly even, while a median above (below) the mid-point implies costs are more skewed towards the higher (lower) end. Therefore, our supply curve, which assumes five cost tranches (low, low/medium/, medium, medium/high, high), each with 20% of the available potential, assumes more deployment potential at lower costs, if costs are skewed towards the low side, while it assumes more deployment potential at higher costs, if costs are skewed towards the high side.

[9] DECC (2011), *UK Renewable Energy Roadmap*, available at www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf

generation from 'large-scale' renewables generation[10] by 2016/17 is 72TWh/y under central fossil fuel prices (47-87TWh/y with low/high fossil fuel prices), compared with the consultation document central estimate of 73 to 75TWh/y. It is expected that using the new set of fossil fuel price assumptions instead would drive an increase in deployment across all technologies, back to (or very close to) the positions for each technology set out in the consultation document. DECC analysis of the likely impact of using that the new fossil fuel price projections in place of the old for deployment in each technology is set out below. The final IA, which will be issued along with the Governments response next year, will use the updated set of fossil fuel price assumptions.

Uncertainty and granularity of the bands

23. Generation costs vary across projects (as reflected in the ranges used) and are also uncertain for any individual project, especially further out into the future. There is a range of uncertainties around central levelised costs, relating to, for example: capital costs, hurdle rates, availability profiles, biomass fuel prices and/or waste gate fees.

24. Assumptions on investor expectations of wholesale electricity prices can influence the ROC banding needed significantly, i.e. if lower wholesale electricity prices are assumed, a higher ROC band is needed for the investment to break even. For the central scenario, it is assumed that investors base their decisions on the modelled wholesale electricity prices from Pöyry, but that they have just five years of foresight, after which they assume electricity prices are constant in real terms at the level of the fifth year. In reality, different investors will have different views of future wholesale electricity prices.

25. Figure 1 shows how the level of required ROCs varies under three wholesale electricity price series: Pöyry wholesale with five-year foresight, Pöyry wholesale with perfect foresight, and a sensitivity which considers the impact of adopting the latest published fossil fuel prices on the Pöyry wholesale price (with five-year foresight). Perfect foresight assumes investors simply take account of projected wholesale price increases over the whole lifetime of the investment. For each technology, the range of ROC bandings required is shown across low to high generation costs (vertically) and across the three different wholesale electricity price assumptions (horizontally).

26. Given these uncertainties, it is judged that the appropriate degree of granularity for setting RO bands is in tenths of ROCs. A tenth of a ROC is worth around £4/MWh.

27. In selecting final options for modelling, DECC has selected bands that will bring on different proportions of the available supply of technologies – targeting bands at the top end of the cost scale for more cost-effective technologies, and towards the lower end of the scale for the more expensive. From the results of the electricity modelling, DECC then considered the relative costs and benefits of different ROC regimes, to recommend a regime which stimulates renewables deployment in a cost-effective manner. Annex 2 includes a table which gives a justification for each of the bands in the lead scenario. Further detail on choice of bands is in the consultation document.

Key assumptions

Interactions with Electricity Market Reform*:*

28. In the modelling of impacts by Pöyry consultants, full implementation of the Electricity Market Reform has been assumed, i.e.
    - An Emissions Performance Standard (EPS)
    - A capacity mechanism[11]
    - Carbon Price Floor
    - A system of feed-in tariffs with contract for difference[12] (FIT with CfD) to support low carbon technologies including renewables

[10] Defined as all UK renewables generation excluding that supported by feed-in tariffs for small-scale installations in Great Britain.
[11] Assumed to be implemented if capacity margins are expected drop below 10%.

29. After the introduction of the new FIT with CfD (the first contracts are expected in 2014), renewables developers will have the choice between support under the RO and support under the FIT with CfD, until the closure of the RO to new stations from 1/4/17. It is not possible to know at this stage whether individual investors will choose the RO or the FIT/CfD from 2014. Therefore, the simplifying assumption has been that new renewables stations commissioning in 2013/14, 2014/15 and 2015/16 will all be supported under the RO (except where they are eligible for small-scale FITs). In the last year of the four years of the banding review period, 2016/17, it is assumed that projects commissioned choose the new FIT with CfD support scheme instead (due to the risk of construction overrun leading to missing the RO end-date). In reality, some new renewables stations may choose the FIT with CfD in earlier years, and some may choose the RO in 2016/17, if they judge the risk of missing the RO end-date to not be significant. Figure 1 below shows the 'required ROCs 'ranges for 2014/15, which is the middle year of three in which the new RO bandings are assumed to have an impact.

Generation costs

- Capital expenditure and operating expenditure for renewable technologies are taken from the research by Arup and their sub-contractors Ernst & Young, and for non-renewable technologies from PB (2011)[13]. Assumptions for biomass and waste fuel costs come from DECC analysis based on AEA (2010)[14] and the Waste & Resources Action Programme (WRAP) (2011)[15], and are summarised at Annex 5.
- Hurdle rates, defined here as the minimum expected internal rate of return at which investors will decide to proceed with a project, are based on Arup research and Oxera (2011) and summarised at annex 5.
- Heat revenues have been calculated using the avoided cost of heat generation approach. This is based on gas boiler costs of £30/kW capex and £0.2/kW/y opex from AEA/Nera (2009)[16], DECC gas fuel price assumptions and DECC carbon price assumptions published in June 2010 (where the installation would be large enough to be in the EU-ETS). They are summarised at annex 5.

Fossil fuel prices

30. The analysis has used DECC fossil fuel price projections (published alongside UEP40 in June 2010) for gas, coal and oil fuel prices in the power sector, and for the heat revenues. Updated fossil fuel prices were recently published with UEP43 in October 2011[17]. It was not possible to update all the analysis using the new fossil fuel prices. However, there is a sensitivity using the new central fossil fuel prices included in this IA. The analysis will be fully updated using the updated FF prices to inform the Government's response to consultation on the RO banding levels and the full results will be presented in the final IA.

Summary of modelling approach

31. All assumptions were fed into Pöyry's Eureca electricity market model and ROCket renewable electricity model. ROCket models renewable investor decisions and deployment, using the supply curve approach described above. Eureca models non-renewable investment decisions, short-run despatch decisions and how supply meets demand overall. The modelling approach involves iteration between the two models, with wholesale electricity prices from the Eureca model driving investor decisions in the ROCket model, which then influences electricity prices.

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[12] For full details, see the Electricity Market Reform White Paper, available at: http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx

[13] PB (2011), *Electricity Generation Cost Model – 2011 Update Revision 1,* available at www.decc.gov.uk/assets/decc/11/meeting-energy-demand/nuclear/2153-electricity-generation-cost-model-2011.pdf

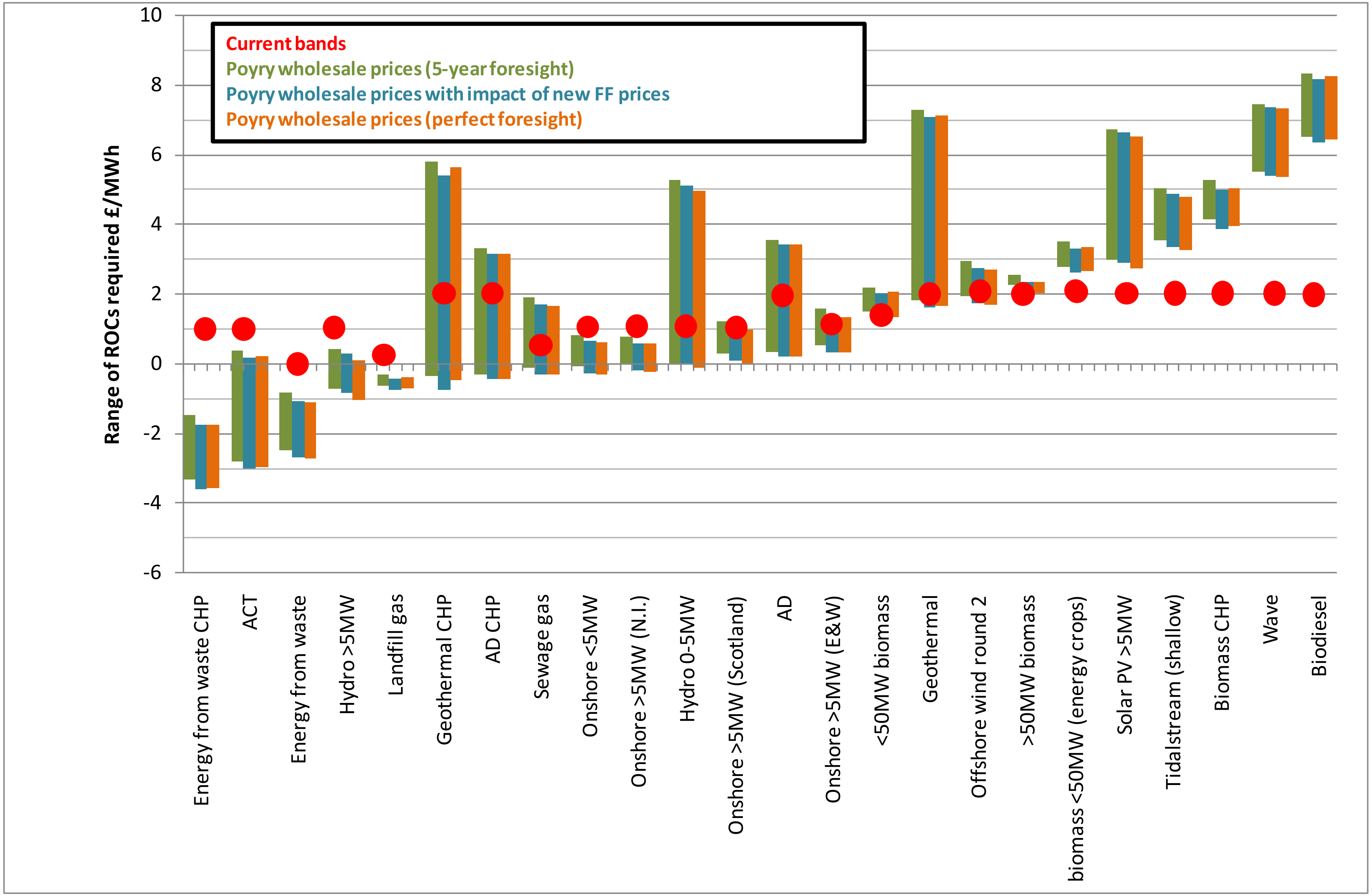
[14] AEA (2010), *UK and Global Bioenergy Resource – Final Report*, available at: www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/policy/1464-aea-2010-uk-and-global-bioenergy-report.pdf

[15] WRAP (2011), *Gate Fees Report, 2011*, available at www.wrap.org.uk/downloads/Gate_Fees_Report_2011.6d9cbcca.11007.pdf

[16] AEA/Nera (2009) *UK Supply Curve for Renewable Heat,* available at www.rhincentive.co.uk/library/regulation/0907Heat_Supply_Curve.pdf

[17] Available at: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

Figure 1: Range of possible required ROC bandings based on Arup cost data (2014 commissioning)



5. Description of options considered (including do nothing)

32. The three packages of banding options considered in detail below. Table 2 shows the banding levels for each technology used in each option, followed by a detailed description of the options. Note the options relating to scheme design decisions other than banding levels (grandfathering, technology definitions and caps), and their impacts, are described separately in section 7.

Table 2 Technology banding option packages considered, bandings in ROCs/MWh of renewable electricity supplied

Technology	Option 1 - current bandings	Option 2 – minimum scope	Option 3 – extra support for marine	Option 4 – portfolio approach
Wave	5 in Scotland, 2 in rest of UK	2	5 with project cap of 30MW	5.9
Tidal stream	3 in Scotland, 2 in rest of UK	2	5 with project cap of 30MW	3.8
Solar PV	2	2		6.6
Onshore wind	1	0.9		0.8
Offshore wind	2 to 2013/14; 1.5 2014/15 onwards	2 to 2014/15, 1.9 2015/16, 1.8 2016/17		2.5
Hydro	1	0.5		0.1
Co-firing of biomass	0.5	0.5		0.9
Enhanced co-firing	Eligible for co-firing, 0.5	1		1.1
Biomass conversion	Eligible for dedicated biomass, 1.5	1		1.3
Dedicated biomass	1.5	1.5 to 2015/16, falling to 1.4 in 2016/17		1.9 for small (<50MW); 2.4 for large (>50MW)
Dedicated biomass with CHP	2	2 to 2014/15, then eligible for dedicated biomass, 1.5 + RHI		4.8
Dedicated energy crops	2	2 to 2014/15, 1.9 2015/16, 1.8 2016/17		3.3
Dedicated energy crops with CHP	2	2 to 2014/15, then new stations eligible for dedicated energy crops band	As minimum scope	1.5
Co-firing of biomass with CHP	1	1 to 2014/15, then eligible for co-firing, 0.5 + RHI		1
Co-firing of energy crops	1	1		0.9
Co-firing of energy crops with CHP	1.5	1.5 to 2014/15, then eligible for co-firing with energy crops, 1 + RHI		1.5
Energy from waste with CHP	1	0.5		0
Standard gasification, standard pyrolysis	1	0.5 (with revised definition)		0
Advanced gasification, advanced pyrolysis	2	2 (with revised definition)		0
Landfill gas	0.25	0		0
Sewage gas	0.5	0.5		0.4

AD	2	2 to 2014/15, 1.9 2015/16, 1.8 2016/17		1.6 power only, 1.2 CHP
Geopressure	1	1		1
Geothermal	2	2 to 2014/15, 1.9 2015/16, 1.8 2016/17		4.7 power only, 3.3 CHP
Tidal impoundment – barrage or lagoon	2	2 to 2014/15, 1.9 2015/16, 1.8 2016/17		6.7
Dedicated bioliquids	Eligible for dedicated biomass band	Eligible for dedicated biomass band		6.9 power only, 5.9 CHP

Option 1 – Do nothing

33. This option involves leaving the bands as they are now, as shown in the second column of the table above. It also retains the cap on co-firing at 12.5% of all ROCs in a given period.

Option 2 – Minimum scope

34. The bandings above in the third column of table 2 were selected as a cost-effective way of remaining on track over the banding review period (1/4/13 to 31/4/17) towards reaching large-scale electricity's share of the renewables target, estimated at 108TWh/y in 2020.

The marginal cost of meeting the target – offshore wind

- In order to meet our 2020 renewables target cost-effectively, the most expensive technology required is some additional offshore wind. The analysis suggests that the cheapest offshore wind potential in 2014/15 will require 2 ROCs/MWh to deploy, and therefore this level of support is the marginal cost of meeting the target. Arup have also projected that the costs of offshore wind will fall fairly quickly. This option therefore degresses the offshore wind banding over the banding review period: in 2015/16 support falls to 1.9 ROCs/MWh, and in 2016/17 to 1.8 ROCs/MWh. As offshore wind remains the marginal technology to meet the renewable target, and this option aims to keep on track to meet the 2020 renewables target in the most cost-effective way, the maximum ROC rate is reduced for all technologies in line with the reductions for offshore wind.

- As part of the Renewables Roadmap, launched on 12th July 2011, the Government set up a task force to work with industry to lower costs of offshore wind further. The aim is to achieve a levelised cost for offshore wind of £100/MWh by 2020. By bringing down costs over time, support for offshore wind over the banding review period may be reduced without adversely impacting deployment levels.

Reducing support where possible

- This option reduces support for technologies where, according to analysis of costs and revenues for each technology, support can be cut without affecting deployment. This was the case for hydro, standard gasification and pyrolysis[18], Energy from Waste with CHP[19], biomass conversion, and landfill gas. This takes rents, or excess profits, out of the system, whilst maintaining high or maximum deployment of the cheapest technologies. Within technologies, such as coal to biomass conversions, this option targets the more cost-effective potential.

[18] This based on the Arup evidence on ACT. The consultation is calling for evidence on the potential of standard and advanced ACT according to the revised standard and advanced definitions.

[19] This is based upon the Arup evidence for CHP. The consultation is calling for further evidence on all renewable combined heat and power technologies' generation costs and deployment potential.

- This option also reduces support for onshore wind by 10% in order to reflect long-term cost movements and deter more expensive, poorly sited projects. It tackles significant oversubsidy received by coal to biomass conversions by introducing a new band at 1 ROC, so they will no longer receive 1.5 ROCs/MWh in the new banding period. Enhanced co-firing, using a minimum of 15% biomass fuel, is a relatively cost-effective technology. As 0.5 ROCs (the standard co-firing band) is, according to the Pöyry modelling, insufficient to bring on deployment, this option introduces a new band for enhanced co-firing at 1 ROC/MWh.

- Dedicated biomass is left at its current banding of 1.5 ROCs/MWh, with the exception of coal to biomass conversion. This banding is at the bottom of the range of 'required ROCs', as shown in Figure 1. While this may restrict deployment, it is considered prudent to not incentivise the entire potential of biomass, as this may restrict its availability for use in heat and transport. The Government is developing a UK Bio-energy Strategy to be published around the turn of the year.

- The rationale for supporting bioliquids is based on there being sustainable sources of feedstocks available for renewable generation that do not divert resources from other sectors. Modelling of bioliquids availability to 2020 indicates that supply will be constrained and the Government considers that the use of bioliquids should be prioritised in other sectors such as food and transport. For these reason, options 2 and 3 do not propose to offer greater levels of support for bioliquids, and instead propose that they continue to receive the same support as generation using solid biomass.[20]

Co-firing and removal of cap

- Co-firing is a relatively cost-effective technology. Under all the options except the Do nothing option, the co-firing cap (i.e. the limit of 12.5% of all ROCs that can be co-firing ROCs in any one period) is removed from 1st April 2013.

Option 3 – Additional support for marine technologies

35. This option is the same as option 2 minimum scope, with the exception that 5 ROCs/MWh are provided for wave and tidal stream across the UK.

36. In addition, £20m of innovation funding has recently been announced for wave and tidal stream technologies over the Spending Review period, subject to satisfactory value-for-money assessment, to support the first demonstration arrays of these technologies. Cost evidence collected by Ernst & Young (2010)[21], suggested by Arup to be the best source for marine technologies, corroborated by evidence from RenewableUK, suggests that the first arrays will require higher ROC support (significantly above 2 ROCs) in addition to innovation funding to make them financially viable. In terms of meeting the 2020 renewables target cost effectively, wave and tidal stream technologies are too expensive to play a part. However, there is a case to be made for marine – the UK is the global leader, and so the UK is a price maker in this market; therefore – the more that gets deployed, the more costs should be driven down. The future costs and benefits of supporting marine technologies, summarised below, are extremely uncertain. If marine is to be an option post-2020, it requires support now, to get it towards a commercial footing.

Option 4 – Portfolio approach

37. This option takes the approach of setting ROC bandings at a rate to bring on roughly half of the potential for each renewable technology and aims to ensure consistent treatment across technologies. This option brings on some of each technology, taking a portfolio approach to spread the risks of non-delivery of deployment.

[20] Levelised cost analysis undertaken by DECC estimated cost ranges for biodiesel feedstock in 2020 and implies support between 5.0–7.8 ROC's to bring forward deployment, largely due to high costs of biodiesel. In comparison, cost estimates assuming used cooking oil and pyrolysis oil feedstocks suggest between 2.6–6.8 ROC's, and 1.2–5.6 ROC's respectively would be required to bring forward bioliquid deployment, indicating there may still be continued limited usage at lower levels of support.

[21] Ernst & Young (2010), *Cost and financial support for wave, tidal stream and tidal range technologies*

6. Impacts of each option

38. This section describes the impact of each option on renewables deployment, system generation costs, carbon costs and balancing costs, of which the latter three form the monetised costs and benefits. It goes on to describe non-monetised impacts, and distributional impacts on electricity consumers and producers. Finally, sensitivity analysis is presented which considers the impact of new fossil fuel prices. Note the options relating to policy decisions other than banding levels (grandfathering, technology definitions and caps), and their impacts, are described separately in section 7.

39. The results for all options are taken from Pöyry modelling using the hurdle rates contained in annex 5.

A Renewable deployment and the electricity mix

40. Annex 3 gives full details the capacity and generation mix under current bands, as well as the new build supported by the RO under the different options considered over the banding review period from 2013/14 to 2015/16. Tables 3 and 4 below summarise this information for the main technologies.

Table 3 Modelled new build capacity under different options, MW

Modelled Capacity (MW)	Total deployment by 2012/13	New build under the RO during the 2013-17 Banding Review period			
		Option 1 current bands	Option 2 minimum scope	Option 3 marine	Option 4 portfolio approach
Offshore wind[22]	3,600	500	860	860	1,300
Onshore wind (>5MW)*	6,000	1,900	1,700	1,700	1,500
Biomass conversion	1,300	710	710	710	710
Enhanced co-firing	-	-	580	580	-
Dedicated biomass	460	28	28	28	250
Wave and tidal stream	3	40	-	51	59
Other 'large-scale'**	3,200	170	160	160	1,300
Total 'large-scale'**	**15,000**	**3,300**	**4,100**	**4,100**	**5,200**

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

[22] Note this and the generation figure in Table 4 for offshore wind include build during 2013/14, whose banding is not being considered in this banding review. The 2013/14 offshore wind build is 900MW, producing around 3.0TWh per year.

Table 4 Modelled generation from new build capacity under different options, GWh per year[23]

Modelled annual generation (GWh per year)	Generation from capacity built before 1/4/13	Generation from net new build under the RO during the 2013-17 Banding Review period:			
		Option 1 current bands	Option 2 minimum scope	Option 3 marine	Option 4 portfolio approach
Offshore wind[23]	11,000	1,700	2,800	2,800	4,100
Onshore wind (>5MW)*	14,000	5,000	4,700	4,700	4,800
Biomass conversion[24]	10,000	5,600	5,600	5,600	5,600
Enhanced co-firing	-	-	4,300	4,300	-
Dedicated biomass[25]	3,600	260	260	260	2,100
Wave and tidal stream	8	130	-	180	220
Other 'large-scale'**	16,000	-1,400	-1,400	-1,400	9,200
Total 'large-scale'**	**55,000**	**11,000**	**16,000**	**16,000**	**26,000**

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

41. As noted above, the simplifying assumption has been made that new stations with the choice between the RO and new FIT with CfD will choose the RO up until 31st March 2016, and the FIT with CfD thereafter. This implies that the RO bandings will influence build over the first three years of the banding review period (though in reality it may be that some new build still occurs under the RO in 2016/17 and some RO build modelled before that is actually supported by the FIT with CfD).

42. **Option 2 minimum scope** brings on an additional 580MW of renewable enhanced co-firing capacity that does not come on under current bands (under current bands there is no separate band for enhanced co-firing and the standard co-firing rate is not enough to bring on any enhanced capacity), delivering around 4.3 additional TWh/y of generation towards the 2020 renewables target. It also increases the new build of offshore wind relative to current bands, from 500MW to around 860MW of new build. This is due to the extra support under the minimum scope option in 2014/15 and 2015/16, with 2.0 and 1.9 ROCs/MWh rather than 1.5 ROCs/MWh under current bands. The extra new build delivers around 1.2TWh/y of additional generation towards the renewables target. With support at 1.5 ROCs/MWh for dedicated biomass, only 28MW is deployed in the new banding review period under the RO. This contrasts with the much larger dedicated biomass pipeline, with around approximately 3GW of consented capacity and capacity waiting for construction.[26] The large pipeline potential is included in the Arup supply curves, but at the assumed capex, opex and fuel costs based on Arup and AEA research, most of the supply curves for small and large dedicated biomass are not financially viable. However, some of the capacity assumed to come on in 2012/13 in the Pöyry modelling may be delayed into the banding review period. The consultation is asking for evidence of whether costs and revenue assumptions used are appropriate or not.

43. Option 2 cuts support for biomass conversion (from 1.5 to 1 ROCs/MWh), for Advanced Combustion Technologies (ACT), energy from waste with CHP and hydro, without any negative impact on the new build in these technologies. The results for ACT should be treated with caution, however. The consultation[27] is calling for evidence on the costs and deployment potential of ACT according to the proposed revised definitions.

44. It also cuts support for onshore wind (from 1 to 0.9 ROCs/MWh) and marine technologies (down to 2 ROCs/MWh in Scotland). This reduces new build onshore wind over the period by around 150MW or 8%. Generation from new build onshore wind falls from 5.0TWh/y under current bands to 4.7TWh/y

[23] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FIT with CfD.
[24] New capacity and generation figures for biomass conversion and other 'large-scale' are net of decommissioning.
[25] Note the generation figures are derived by DECC from the Pöyry modelling and are not in all cases quite consistent with the capacity figures, e.g. co-firing capacity is excluded, but co-firing generation is included.
[26] This figure is based on data from the Renewable Energy Planning Database, available online, and represents dedicated biomass stations, excluding CHP and conversion stations. However, it should be noted that the database is updated regularly and that it is not always possible to identify exact RO technology groupings for every station.
[27] DECC (2011), *Renewables Obligation Order 2012 – Consultation*, available at:
http://www.decc.gov.uk/en/content/cms/consultations/cons_ro_review/cons_ro_review.aspx

under the option 2 band. New build of wave and tidal stream from 2013/14 to 2015/16 falls from 17MW and 23MW respectively (together generating around 0.13TWh/y) to zero.

45. The net impact of option 2 across the technologies is to increase renewables capacity by around 750MW and renewables generation by around 5.0TWh over 2013/14/ to 2015/16.

46. **Option 3 marine** has the same renewables deployment impacts relative to current bandings as option 2 minimum scope, except with regard to marine technologies. Instead of falling to zero as in option 2, under option 3 wave deployment from 2013/14 to 2015/16 under the RO increases to 19MW (2MW more than under current bands) giving 0.05TWh/y of generation, and tidal stream deployment increases to 32MW (10MW more than under current bands) giving 0.13TWh/y of generation from tidal stream new build during the 2013-17 banding review period. Note that in all options, as detailed at Annex 5, it is assumed that marine technologies are given grants in addition to RO support, provided it does not exceed state aid limits.

47. Finally, option 4 portfolio approach has quite a different renewables deployment pattern. In order to bring on roughly half of the potential for each renewable technology, this option gives less support than current bands for ACT, biomass conversion, co-firing with energy crops, EfW CHP, hydro, onshore wind and sewage gas. This results in around 350MW less deployment of these technologies over the RO period, and they deliver around 0.3TWh/y less generation towards the renewables target. All other technologies are given more support (i.e. higher ROC levels) than under current bands, which results in 2.2GW more deployment in these other technologies than under current bands over the RO period, which delivers around 15TWh/y additional generation towards the renewables target. Enhanced co-firing does not come on in this scenario, as with 0.9 ROCs/MWh, standard co-firing is a more attractive proposition than enhanced co-firing. The majority of this additional deployment is from new build bioliquids (4.5TWh/y), standard co-firing (1.0TWh/y), offshore wind (4.1TWh/y) and dedicated biomass with and without CHP (3.3TWh/y). Overall, option 4 provides 1.8GW additional renewables capacity and 15TWh/y additional generation, compared to maintaining current bands.

B Non-renewable generation mix

48. Option 2 minimum scope and option 3 extra support for marine have the same (rounded) impact on non-renewable generation. Unrounded, option 3 marine shows slightly more displacement of non-renewable generation due to more renewable technologies (i.e. marine) coming online. The table below shows non-renewable generation over time for option 3 extra support for marine, and the change relative to Option 1.

Table 5 Great Britain[28] non-renewable generation in TWh under Option 3 extra support for marine

	2011/12		2012/13		2013/14		2014/15		2015/16			2020/21		2025/26		2030/31	
	TWh	•	TWh	•	TWh	•	TWh	•	TWh	•		TWh	•	TWh	•	TWh	•
CCGT	76	-3	66	2	74	-2	66	-2	61	-2		63	-3	51	-3	106	-9
CCSCoal and CCS Gas	0	0	0	0	0	0	2	0	7	0		11	-1	24	-1	23	-1
Non-renewable CHP	23	-1	24	-1	25	-1	25	-1	26	-1		31	-2	31	-2	36	-2
Coal	135	-5	134	-9	124	-9	123	-9	121	-9		83	-9	26	-4	3	0
GT	1	0	1	0	1	0	1	0	1	0		1	0	-	0	-	0
Nuclear	68	-2	67	-2	61	-2	61	-2	61	-2		48	-2	84	-4	105	-5
Oil					0	0						0	0	0	0	0	0
Total non-renewable generation in GB	304	-10	292	-9	285	-14	279	-14	277	-14		237	-16	216	-13	273	-16

C Impact on total generation costs (excluding carbon)

49. The table below shows the impacts of each of the options on generation costs relative to option 1 current bands in present value (PV) terms, discounted at the social discount rate. Generation costs are defined as annuitised capital costs, plus operating and fuel costs. Note that EUA purchase cost

[28] Pöyry did not model non-renewable capacity and generation for Northern Ireland. The UK non-renewables costs are based on pro-rating the GB costs by demand levels.

are excluded from the non-renewable generation costs given below. Options 2, 3 and 4 bring on more renewable generation than option 1, at a higher generation cost than the non-renewable generation displaced.

Table 6 Generation costs to 2039/40, PV (2010/11 prices)

	Option 1 - current bands	Change relative to option 1		
		Minimum scope - Option 2	Marine - Option 3	Portfolio approach – Option 4
Renewable Generation costs (£m)	230,000	+2,400	+4,000	+31,000
Non-Renewable Generation costs (£m)	350,000	-1,800	-1,900	-6,700
Total generation costs (£m)	**580,000**	**+580**	**+2,100**	**+24,000**

Estimates rounded to two significant figures

50. Renewable generation costs are substantially higher in the Marine scenario than in the minimum scope scenario owing to the additional generation and balancing costs with more marine generation. In addition, learning rates are endogenously related to capacity levels for marine technologies i.e. costs fall by a certain percentage each time capacity doubles. As the initial capacity is lower in the minimum scope scenario, costs fall much more quickly for a similar level of additional uptake, therefore the additional cost in the "Marine" scenario will also increase over time.[29] These assumptions will be kept under review, and a final assessment will be published in the Impact Assessment which accompanies the Government Response to the RO banding consultation.

D Impact on EUA (carbon credits in the EU-ETS) purchase costs

51. Table 7 below shows the impacts of each of the options on costs relating to carbon emissions relative to option 1 current bands in present value terms, discounted at the social discount rate. Option 2 minimum scope brings on more renewable generation, and hence displaces some fossil fuel generation relative to the current bands scenario. This saves around £1bn in EUA purchase costs for CO_2 emissions in the UK power sector. The carbon savings within the UK power sector detailed below will be offset by lower savings elsewhere within the capped EU-ETS sector, implying no net reductions in carbon emissions.

52. Option 3 extra support for marine increases wave and tidal stream generation, slightly increasing the carbon savings, whilst option 4 portfolio approach brings on significantly more renewable generation, displacing more fossil fuel generation and so bringing higher reductions in carbon credit purchase costs. Note EUA purchase costs are excluded from the non-renewable generation costs described above.

Table 7 EUA purchase costs to 2039/40, PV (2010/11 prices)

		Change relative to option 1		
	Option 1 - current bands	Minimum scope - Option 2	Marine - Option 3	Portfolio approach – Option 4
Lifetime grid emissions (Mt)	2,300	-63	-64	-99
EUA purchase costs (£m)	51,000	-1,100	-1,200	-1,800

Estimates rounded to two significant figures

E Impact on balancing costs

53. The net increase in wind generation brought on by option 2 minimum scope relative to option 1 current bands, increases total balancing costs over the period, particularly in later years when there is more wind on the system overall. Option 3 extra support for marine increases the balancing costs more by bringing on more intermittent technologies, and portfolio approach, option 4, does this to a greater extent. Table 8 below shows the system balancing costs (note, these are not included in the generation costs above).

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[29] This results stems from the assumption that the learning rates start operating from a set year of 'commercialisation', whatever the level of deployment is by that year. This is a modelling simplification.

Table 8 Balancing costs to 2039/40, PV (2010/11 prices)

		Change relative to option 1		
	Option 1 - current bands	**Minimum scope - Option 2**	**Marine - Option 3**	**Portfolio approach – Option 4**
Balancing costs (£m)	22,000	+100	+120	+400

Estimates rounded to two significant figures

F NPV of all monetised costs and benefits

54. The table below summarises the monetised impacts. Note, the signing below (unlike in the tables above) is positive for a social benefit and negative for a social cost. Relative to current bandings, option 2 minimum scope increases the net cost through higher total generation costs and slightly higher balancing costs associated with higher levels of wind generation. There is a positive impact through reducing fossil fuel generation which reduces carbon emissions from the power sector and hence the associated EUA (carbon credit) purchase costs.

55. Option 3 has net costs relative to option 1 current bands, as it brings on relatively expensive renewables generation and displaces relatively cheaper conventional generation. Option 4 portfolio approach has a much higher net cost, as it brings on significantly more renewables generation, including the relatively expensive renewables technologies, which have higher costs than the generation from the conventional technologies they displace.

Table 9 Monetised costs and benefits to 2039/40 summary, NPV (2010/11 prices)

£m	**Option 2 relative to option 1**	**Option 3 relative to option 1**	**Option 4 relative to option 1**
Reduction (+) / increase (-) in generation costs	-580	-2,100	-24,000
Reduction (+) / increase (-) in EUA purchase costs	+1,100	+1,200	+1,800
Reduction (+) / increase (-) in balancing costs	-100	-120	-400
Total impact	**+470**	**-1,100**	**-23,000**

Estimates rounded to two significant figures

G Non-monetised impacts

56. It should be noted that the monetised costs and benefits above do not include several potentially significant impacts, including air quality impacts and aspects of security of supply such as security of fuel sources. Air quality impacts will be reviewed for the Government Response to this consultation.

Security of supply impacts

57. By increasing the amount of renewable generation and displacing fossil fuel generation, options 2, 3 and 4 increase security of supply relative to the do nothing option, but at the same time by increasing the amount of intermittent generation slightly, these options have negative security of supply implications, in that they may increase the small probabilities of brown-outs or even black-outs. However, it is assumed here that these small amounts of extra intermittent generation will be accommodated on the grid with an increase in other kinds of balancing services – back-up generation, interconnection, storage and/or demand-side response. Higher balancing costs are estimated above.

58. Other important impacts which are not monetised include the wider macroeconomic impacts of changes in retail electricity prices – lower electricity bills (than would otherwise have been in place – i.e. lower rises in bills) mean lower costs to industry and more real income for consumers. Non-carbon impacts on air quality due to changes in emissions are not monetised, and neither are the carbon impacts from the manufacture and transport of renewable generating equipment and fuel rather than conventional generating equipment and fuel in the Do Nothing counterfactual, option 1.

Impacts on other industries competing for biomass resource

59. Continuing support for biomass-related electricity technologies could impact on other sectors, such as the Wood Panel Industry (WPI), Paper and Pulp sectors, which compete with electricity for use of that feedstock . Isolating the potential impact of the RO on these sectors is extremely difficult given the potential impact of other policies and market drivers on the demand of the relevant feedstocks. Nevertheless in order to reflect the finite nature of the feedstocks for biomass and their competing uses, the AEA Technology analysis that underpinned the availability and prices of biomass and waste feedstocks for the RO considered other potential uses of biomass and took account of the alternative uses before determining available resources for energy (electricity, heat and transport). In addition, two further modifications were made to the AEA scenarios in the work which underpins this IA: first, to take account of demands from the heat and transport sectors, and second, to take account of the impact of sustainability standards in the RO. These changes restricted the available bioenergy supply in the electricity sector compared with the original AEA scenarios.

60. However, it is recognised it might be useful to compare demands from different sectors with the AEA scenarios in order to give an indication of future calls on the resource. Options 2 and 3 suggest that the biomass electricity could need around 21m oven-dried tonnes (odt) of woody biomass resource by 2020. DECC analysis for the RHI[30] suggested that woody biomass used for renewable heat applications would need a further 5m odt by 2020. Current data[31] suggest that wood based panel mills consume just over 2 million odt of wood based biomass, the vast majority of which comes from UK sources. This compares with an AEA supply estimate of 63 million odt by 2020 being used in the DECC central scenario. Should supply develop in this way, it would mean there would be sufficient resource to cover energy and WPI uses. However, it is recognised that these estimates are uncertain and that the projected supply levels would rely on considerable use of imports.

61. Despite this conclusion, it is recognised that the full impact of the RO (and other renewable policies) on the demand and prices for these feedstocks is very difficult to estimate. To the extent that the biomass market becomes more internationally traded in the future, the impact of the RO on demand or prices is likely to be limited. An analysis of the potential impacts of UK bio-energy policies on other sectors of the economy will be considered as part of the Government's development of the UK bio-energy strategy which is expected to be published around the turn of the year.

Risk of missing 2020 renewables target and ensuring compatibility with/ minimising risk of not being on a cost-effective pathway to 80% decarbonisation of the economy by 2050

62. Options 2 and 3 reduce the risk of missing the 2020 renewables target by continuing offshore wind deployment in the UK (as option 1 sees a stop to offshore wind deployment), and by assumption continuing cost reductions in that sector as a result. Analysis of costs and potentials data from Arup suggests that additional offshore wind does form part of a cost-effective mix for reaching the 2020 target.

63. It should be noted that the lower monetised benefit for option 3 relative to option 2 above, only reflects the relatively high generation costs of early marine deployment in the RO banding review period (2013-17). The impacts relating to enabling an option for future UK marine deployment are not monetised. Options 3 reduces risks associated with decarbonisation and expansion of the power sector required to 2030 and 2050 to meet the carbon budgets leading to an 80% overall cut in greenhouse gas emissions by 2050. It does this by creating two more low-carbon technology options, wave and tidal stream, for the generation mix. Their potential is uncertain, but they could eventually reach around 27GW in 2050.[32] Marine technologies' outputs are expected to be more predictable than that of wind generation, which is expected to imply lower balancing costs. That is not monetised here.

64. Marine technologies in the long term may also prove relatively expensive overall and not a cost-effective part of the future low-carbon mix. Future relative technology costs are very uncertain. No

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[30] See forthcoming RHI Impact Assesssment at: www.decc.gov.uk/
[31] UK Wood Production and Trade (provisional figures) May 2011. Forestry Commission
[32] According to Ernst & Young (2010), *Costs of and financial support for wave, tidal stream and tidal range technologies*. Their total wave and tidal stream deployment range in 2050 is 9-43GW.

attempt is made here to monetise their option value. Whether future marine deployment turned out to have a net benefit would depend on many uncertain factors, including the speed of cost reductions in wave and tidal stream technologies, the availability and cost of alternative low-carbon technologies and the system balancing costs relating to the intermittency of wave and tidal stream compared to wind.

H. Distributional impacts

65. Changing RO bands can change levels of renewables deployment, and hence the levels of RO costs falling on consumers; wholesale prices (impacting on retail prices) can be reduced on average when more wind is on the system; and system balancing costs increase with more intermittent generation.

1. RO support costs

66. The changes in bands in the different options have a number of impacts on electricity consumers. The table below shows how option 2 reduces the level of RO support costs, which is ultimately paid for by consumers, owing to the reduction in rents by reducing bandings, and incentivising the more cost-effective renewable technologies. Options 3 does not reduce RO costs as much because it brings on marine technologies at a relatively high level of ROCs (5 ROCs/MWh). Note that there are some impacts on RO support costs beyond 2015/16, as different levels of dedicated biomass build change the amount of biomass available for co-firing in future years. The PV of lifetime changes to RO support costs is a reduction of £850m.

Table 10 RO support costs to 2039/40 (2010/11 prices)

£m	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Current bands	1,400	1,800	2,300	2,700	3,200	3,300
Impact of option 2, minimum scope	-	-	-160	-140	-220	-210
Impact of option 3, marine	-	-	-79	-47	-100	-76
Impact of option 4, portfolio approach	-	-	+280	+850	+1600	+2100

Estimates rounded to two significant figures

2. Wholesale price impacts

67. By bringing on slightly more wind generation, on average over the modelling lifetime to 2039/40, option 2 minimum scope reduces wholesale prices relative to the current bands. The net present value to consumers of these lower wholesale prices is a benefit of around £57m in PV terms. Options 3 and 4 are assumed to deliver the same wholesale prices as option 2, and hence the same benefit relative to current bands.

3. Net impact on consumers (including balancing costs)

68. The net impact on consumers relative to current bands, comes to a reduction in costs to consumers of around £1.1bn in NPV terms for option 2 minimum scope, and around £790m for option 3 marine. These net impacts include wholesale cost of electricity savings and balancing costs.

Table 11 Costs to consumers of banding options compared to maintaining current bands (2010/11 prices)

	Option 2 relative to option 1	Option 3 relative to option 1	Option 4 relative to option 1
Total impact on consumers (£m)	-1,100	-790	-20,000

Estimates rounded to two significant figures

4. Bill impacts

69. The reductions in consumer costs of around £0.8-1.1bn over the modelling lifetime from options 2 and 3 relative to option 1 result in small reductions in average annual bills of around 0.1-0.2% for both domestic and non-domestic consumers.

70. In terms of absolute contribution people's the bills, the RO as a whole is projected to contribute around £50 to the average household's annual electricity bill by 2016. Switching from current bands to the preferred option 3 marine is estimated to save households a little over a pound a year, as shown in the table below.

Table 12 Absolute contribution to average household electricity bills of RO support costs under current bands and the preferred option

	2011	2012	2013	2014	2015	2016
Current bands, £	20.5	26.0	33.5	40.0	47.0	50.0
Option 3 marine, £	20.5	26.0	32.5	39.5	45.5	48.5

Estimates rounded to nearest 50p

5. Producer surplus

71. The costs of generating renewable electricity will vary depending on many factors, it is therefore impossible to set support levels to exactly the level required for investment to occur and no more for every single renewable plant. There are a range of different required levels of support in any defined technology category, and there will always be some with lower required levels of support than that set that get excess profits, which is producer surplus. By reducing the bands where the analysis suggests that reducing them would have a zero or low impact on deployment, option 3 extra support for marine reduces rents from £33.2bn to £31.7bn over the modelling lifetime to 2039/40. These rents are defined simply as the sum of positive cashflow NPVs (discounting at the hurdle rates) for renewables plant.

I Sensitivity analysis

72. The numbers presented above are based on the DECC fossil fuel price scenarios published in June 2010 On October 2011 DECC published a new set of fossil fuel prices. While it has not been possible to incorporate the new numbers in all the analysis above, DECC has undertaken sensitivity analysis to illustrates how renewables deployment varies under the updated central DECC fossil fuel price scenario published in October 2011. The Impact Assessment accompanying the government response to the consultation will be based on the DECC fossil fuel price projections published in October 2011.

Sensitivity 1: High fossil fuel prices

1. Renewable deployment and the electricity mix

73. Tables 13 and 14 summarise the capacity and generation mix in a world of high fossil fuel prices[33] for current bands and the new-build supported by the RO under the preferred option (option 3 extra support for marine) over the 2013-17 banding review period. Full details are available in annex 4. Generally, due to renewable technologies becoming more cost-competitive under high fossil fuel

[33] High fossil fuel price assumptions (as central and low) used were the latest available DECC projections at the time the analysis was carried out, first published May 2009, and reviewed but left unchanged in June 2010. New DECC fossil fuel price projections were published in October 2011, but there was not enough time to use these in the analysis. There will be updated analysis to inform the Government Response to the consultation, and that will use the new fossil fuel price projections.

prices, more renewable capacity is being built over the period in both option 1 current bands and option 3 when compared to central fossil fuel price scenarios.

Table 13 Modelled new build capacity under different options, MW *(difference to deployment under central fossil fuel prices in brackets)*

Modelled Capacity (MW)	Total deployment by 2012/13 (High FF)		New build under the RO during the 2013-17 Banding Review period: Option 1 current bands (High FF)		Option 3 marine (High FF)	
Offshore wind[34]	4,300	*(+760)*	1,100	*(+600)*	1,300	*(+490)*
Onshore wind (>5MW)*	6,200	*(+230)*	2,400	*(+550)*	2,400	*(+690)*
Biomass conversion	1,300	*(0)*	710	*(0)*	710	*(0)*
Enhanced co-firing	-	*(0)*	-	*(0)*	580	*(0)*
Dedicated biomass	460	*(+3)*	220	*(+190)*	220	*(+190)*
Wave and tidal stream	3	*(0)*	45	*(+5)*	59	*(+7)*
Other 'large-scale'**	3,300	*(+120)*	370	*(+200)*	360	*(+200)*
Total 'large-scale'**	**16,000**	***(+1100)***	**4,900**	***(+1300)***	**5,700**	***(+1600)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.
Estimates rounded to two significant figures or nearest MW

74. Under high fossil fuel prices, option 3 brings on around 580MW of renewable enhanced co-firing capacity that does not come on under current bands (as there is no separate band for enhanced co-firing and the standard co-firing rate is not enough to bring on any enhanced capacity), delivering around 4.3 additional TWh/y of generation towards the 2020 renewables target. This is equivalent to what happens under central fossil fuel prices.

Table 14 Modelled generation from new build capacity under different options, GWh per year[35] *(difference to deployment under central fossil fuel prices in brackets)*

Modelled annual generation (GWh per year)	Generation from capacity built by 1/4/13 (High FF)		Generation from net new build under the RO during the 2013-17 Banding Review period: Option 1 current bands (High FF)		Option 3 marine (High FF)	
Offshore wind	13,000	*(+2500)*	3,600	*(+2000)*	4,400	*(+1600)*
Onshore wind (>5MW)*	15,000	*(+520)*	6,500	*(+1500)*	6,500	*(+1800)*
Biomass conversion[36]	10,000	*(0)*	5,600	*(0)*	5,600	*(0)*
Enhanced co-firing	-	*(0)*	-	*(0)*	4,300	*(0)*
Dedicated biomass	3,600	*(+20)*	1,800	*(+1500)*	1,800	*(+1500)*
Wave and tidal stream	8	*(0)*	150	*(+21)*	210	*(+31)*
Other 'large-scale'**	17,000	*(+930)*	3,100	*(+4500)*	1,300	*(+2700)*
Total 'large-scale'**	**59,000**	***(+4000)***	**21,000**	***(+9000)***	**24,000**	***(+7700)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.
Estimates rounded to two significant figures or nearest MW

75. Under high fossil fuel prices, option 3 also increases the new-build of offshore wind relative to current bands, from 1.1GW under current bands to 1.3GW under option 3. The extra new build compared to current bands delivers around 0.8TWh/y (4.4 minus 3.6 from table 13) of additional generation towards the renewables target. In comparison, under central fossil fuel price assumptions offshore wind build increases from 0.5GW under current bands to 0.9GW under option 3, so by slightly more than under high fossil fuel prices, contributing an additional 1.2TWh (2.83 minus 1.65) to the renewables target. Total capacity of offshore wind in 2015/16 is 1.2GW higher under high fossil fuel prices than under central fossil fuel prices in option 3.

[34] Note this and the generation figure in Table 12 for offshore wind include build during 2013/14, whose banding is not being considered in this banding review.
[35] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is therefore greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FIT with CfD.
[36] New capacity and generation figures for biomass conversion and other 'large-scale' are net of decommissioning.

76. The net impact of option 3 in a high fossil fuel price world is to increase renewables new-build in the new 2013-17 banding review period by around 0.8GW compared to under current bands reaching a total large-scale renewables capacity of 21GW in 2015/16 and to increase renewables generation towards the 2020 renewables target by 3.4TWh/y.

77. In comparison, under central fossil fuel prices, renewable new-build increases by less as a result of the changes in bands (around 0.8GW) to reach a total large-scale renewables capacity of 19GW in 2015/16 and renewable generation towards the 2020 renewables target increases by 5.2TWh/y as result of the changes in bands. Although the increase in renewables generation as a result of changes in bands is lower in a high fossil fuel prices world compared to a central, the overall level of renewables generation is higher under both current bands and option 3 marine. Under high fossil fuel prices total renewables generation brought on by in the 2013-17 banding review period under option 3 is 24TWh/y (compared to 21TWh/y under current bands), whilst under central fossil fuel prices it is 16TWh/y (compared to 11TWh/y under current bands).

2. Monetised costs and benefits

78. Under high fossil fuel prices, renewable generation costs for the preferred option 3 marine are £3.8bn higher while non-renewable generation costs are £1.4bn higher than under current bands. This compares to, under central fossil fuel prices, £4.0bn higher renewable generation costs and £1.9bn lower non-renewable generation costs than under current bands in the scenario.

79. Under high fossil fuel prices, option 3 is associated with 74Mt less CO_2 emissions and hence £1.6bn lower carbon credit purchase costs than under current bands. This compares to 64Mt less CO2 emissions and £1.2bn lower carbon credit purchase costs under option 3 than under current bands in a world with central fossil fuel prices.

80. Under high fossil fuel prices, balancing costs are £420m higher in option 3 than under current bands with high fossil fuel price assumptions due to more offshore wind in the system. This compares to £120m higher balancing costs than under current bands with central fossil fuel prices.

81. The table below summarises the monetised impacts. Note, the signing below is positive for a benefit and negative for a cost. Table 15 shows that the total impact of option 3 under high fossil fuel prices is a £4.2bn net welfare cost as compared to current bandings in a high fossil fuel price scenario. This compares to a £1.1bn cost under central fossil fuel prices. Option 3 in a high fossil fuel price world imposes a larger net present cost than in a central fossil fuel price world, due to more renewables being deployed.

Table 15 Monetised differences in welfare to 2039/40 summary, NPV (2010/11 prices)

	Option 3 (High FF) relative to option 1 (High FF)
Reduction (+) / increase (-) in generation costs	-£5.3bn
Reduction (+) / increase (-) in EUA purchase costs	+£1.6bn
Reduction (+) / increase (-) in balancing costs	-£420m
Total impact	**-£4.1bn**

Estimates rounded to two significant figures

3. Distributional impacts

82. Under high fossil fuel prices, option 3 reduces the cost of the RO. The lifetime (to the end of the RO in 2037) reduction in RO costs from option 3 comes to an NPV of £670m (real 2010/11 prices), relative to current bands. This compares to a reduction in RO costs under central fossil fuel prices of £410m. RO costs are higher in a high fossil fuel price world due to more renewable generation coming on and hence more ROCs being issued.

Table 16 RO support costs under high fossil fuel prices

£million, real 2010/11 prices undiscounted	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Current bands (high FF)	1,400	1,800	2,700	3,200	3,900	4,000
Impact of option 3, marine (high FF)	0	0	-79	-41	-100	-58

Estimates rounded to two significant figures

83. Under high fossil fuel prices, option 3 extra support for marine reduces wholesale prices relative to the current bands. The net present value to consumers of these lower wholesale prices is a benefit of around £1700m in NPV terms. This compares to around a benefit of £57m in NPV terms under central fossil fuel prices.

84. Under high fossil fuel prices, the net impact on consumers of option 3 extra support for marine relative to current bands, comes to a net benefit of around £1900m in NPV terms for option 3. This compares to a £790m net benefit under central fossil fuel prices. The difference is primarily due to the difference in wholesale price impacts.

Sensitivity 2: Low fossil fuel prices

1. *Renewable deployment and the electricity mix*

85. Tables 17 and 18 summarise the capacity and generation mix in a world of low fossil fuel prices[37] for current bands and the new-build supported by the RO under the preferred option (option 3 extra support for marine) over the 2013-17 banding review period. Full details are available in annex 4. Generally, due to renewable technologies becoming less cost-competitive under low fossil fuel prices, significantly less renewable capacity is being built over the period in either option 1 current bands or option 3 when compared to central fossil fuel price scenarios.

Table 17 Modelled new build capacity under different options, MW *(difference to deployment under central fossil fuel prices in brackets)*

Modelled Capacity (MW)	Total deployment by 2012/13 (Low FF)		New build under the RO during the 2013-17 Banding Review period: Option 1 current bands (Low FF)		Option 3 marine (Low FF)	
Offshore wind[38]	3,600	*(0)*	500	*(0)*	500	*(-360)*
Onshore wind (>5MW)*	5,500	*(-450)*	460	*(-1400)*	260	*(-1500)*
Biomass conversion	750	*(-570)*	-750	*(-1500)*	-750	*(-1500)*
Enhanced co-firing	-	*(0)*	-	*(0)*	-	*(-580)*
Dedicated biomass	460	*(0)*	-	*(-28)*	-	*(-28)*
Wave and tidal stream	3	*(0)*	31	*(-9)*	49	*(-2)*
Other 'large-scale'**	3,200	*(-2)*	160	*(-10)*	140	*(-24)*
Total 'large-scale'**	**13,000**	***(-1000)***	**390**	***(-2900)***	**200**	***(-3900)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.
Estimates rounded to two significant figures or nearest MW

86. Under low fossil fuel prices, option 3 brings on around 200MW less of onshore wind capacity than current bands. There is also less hydro, geothermal and ACT deployment than under current bands. Total capacity of these technologies in 2015/16 is 2.1GW lower under low fossil fuel prices than under central fossil fuel prices in option 3. Due to higher ROC bandings for marine, more capacity of these technologies is being built. In comparison, under central fossil fuel price assumptions

[37] Low fossil fuel price assumptions (as central and low) used were the latest available DECC projections at the time the analysis was carried out, first published May 2009, and reviewed but left unchanged in June 2010. New DECC fossil fuel price projections were published in October 2011, but there was not enough time to use these in the analysis. There will be updated analysis to inform the Government Response to the consultation, and that will use the new fossil fuel price projections.
[38] Note this and the generation figure in Table 12 for offshore wind include build during 2013/14, whose banding is not being considered in this banding review.

enhanced co-firing is economically viable and brings on 580MW of capacity under option 3; this is not the case with low fossil fuel prices. With central fossil fuel prices offshore wind new-build also increases under option 3 by 0.4GW due to the change in bandings under option 3, while under low fossil fuel prices no additional offshore is coming on under option 3 compared to current bands.

87. The 200MW less onshore wind deployed during the banding review period at the proposed 0.9 ROCs under option 3 with low fossil fuel prices, compares to around 150MW less at 0.9 ROCs rather than 1.0 ROCs with central fossil fuel prices. Due to the low coal price in the low fossil fuel price scenario it is not economic for coal stations to fully convert to biomass. There is only one conversion in 2011/12 operating for 2 years. When this station stops operating, this shows as a reduction in capacity and generation over the banding review period in tables 16 and 17.

Table 18 Modelled generation from new build capacity under different options, GWh per year[39] ***(difference to deployment under central fossil fuel prices in brackets)***

Modelled annual generation (GWh per year)	Generation from capacity built by 1/4/13 (Low FF)		Generation from net new build under the RO during the 2013-17 Banding Review period:			
			Option 1 current bands (Low FF)		Option 3 marine (Low FF)	
Offshore wind	11,000	*(0)*	1,700	*(0)*	1,700	*(-1190)*
Onshore wind (>5MW)*	13,000	*(-1000)*	1,200	*(-3800)*	740	*(-3900)*
Biomass conversion[40]	5,900	*(-4500)*	-5,900	*(-12000)*	-5,900	*(-12000)*
Enhanced co-firing	-	*(0)*	-	*(0)*	-	*(-4300)*
Dedicated biomass	3,600	*(0)*	-	*(-260)*	-	*(-260)*
Wave and tidal stream	8	*(0)*	99	*(-34)*	170	*(-12)*
Other 'large-scale'**	13,000	*(-2500)*	1,000	*(-2400)*	930	*(-2340)*
Total 'large-scale'**	**47,000**	***(-8000)***	**-1,900**	***(-13000***	**-2,400**	***(-19000)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.
Estimates rounded to two significant figures or nearest MW

88. The net impact of option 3 in a low fossil fuel price world is to reduce renewables new-build in the 2013-17 banding review period by around 0.2GW compared to option 1 current bands, reaching around 14GW in 2015/16. This reduces new renewables generation towards the 2020 renewables target by around 0.5TWh/y. Total renewables generation from the new build under the 2013-17 banding review towards the 2020 renewables target is negative 2.4TWh/y net of the large reduction (5.9TWh/y) in biomass conversion generation due to decommissioning. Excluding this reduction in biomass conversion, generation from the new build under low fossil fuel prices during the 2013-17 banding review period is positive 3.5TWh/y.

89. In comparison, under central fossil fuel prices, renewable new-build increases by 0.8GW compared to current bands to reach a total large scale renewables capacity of around 19GW in 2015/16 under option 3 and renewables generation towards the 2020 renewables target increases by 5.2TWh/y to reach around 16TWh/y of generation from new build under the 2013-17 banding review towards the 2020 target. So under low fossil fuel prices, the contribution of new build under the new bands is greatly reduced.

2. Monetised costs and benefits

90. Under the preferred option 3 marine in a low fossil fuel prices world, renewable generation costs are £1.3bn lower than under current bands while non-renewable generation costs are £990m higher. This compares to £4.0bn higher renewable generation costs and £1.9bn lower non-renewable generation costs than under current bands in the scenarios with central fossil fuel prices.

[39] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is therefore greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FIT with CfD.
[40] New capacity and generation figures for biomass conversion and other 'large-scale' are net of decommissioning.

91. Option 3 with low fossil fuel prices does not significantly change carbon emissions compared to current bands, with a negligible reduction of 0.2Mt in CO2 emissions in the power sector. Due to the timing of the small changes in fossil fuel generation (reductions earlier and increases later), and the profile of forecast EUA prices, there is a £24m increase in EUA (carbon credit) purchase costs with option 3 compared to under current bands. This compares to 64Mt less CO2 emissions and £1.2bn lower carbon credit purchase costs under option 3 than under current bands in a world with central fossil fuel prices.

92. Balancing costs are £27m lower in option 3 than under current bands with low fossil fuel price assumptions due to having less onshore wind in the system. This compares to £120m higher balancing costs than under current bands with central fossil fuel prices.

93. The table below summarises the monetised impacts. Note, the signing below (unlike in the tables above) is positive for a benefits and negative for a cost. Table 19 shows that the total impact of option 3 under low fossil fuel prices is a £250m net increase in welfare as compared to current bandings in a low fossil fuel price scenario. This compares to a £1.1bn decrease in welfare under central fossil fuel prices.

Table 19 Monetised differences in welfare to 2039/40 summary, NPV (2010/11 prices)

	Option 3 (Low FF) relative to option 1 (Low FF)
Generation costs	+£300m
EUA purchase	-£24m
Balancing costs	-£27m
Total impact	**+£250m**

Estimates rounded to two significant figures

3. Distributional impacts

94. Under low fossil fuel prices, option 3 reduces the cost of the RO. The lifetime (to the end of the RO in 2037) reduction in RO costs from option 3 comes to an NPV of £21m (real 2010/11 prices), relative to current bands under low fossil fuel prices, much less than under central fossil fuel prices, primarily due to less new deployment under current bands receiving a lower ROC rate under option 3. RO costs are lower across all options in a low instead of central fossil fuel price world due to less renewable generation coming on and hence less ROCs being issued.

Table 20 RO support costs under low fossil fuel prices

£million, real 2010/11 prices undiscounted	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Current bands (low FF)	1,400	1,800	2,000	2,000	2,100	2,100
Impact of option 3, marine (low FF)	0	0	-66	-2	+10	+7

Estimates rounded to two significant figures or nearest million

95. Under low fossil fuel prices, option 3 marine increases wholesale prices relative to the current bands. The net present value to consumers of these higher wholesale prices is a cost of around £1.5bn in NPV terms. This compares to a benefit to consumers of around £57m in NPV terms under central fossil fuel prices.

96. Under low fossil fuel prices, the net impact on consumers relative to current bands, comes to a net cost of around £1.5bn in NPV terms for option 3. This compares to a £790m net benefit under central fossil fuel prices.

<u>Sensitivity 3: lower annual maximum build rates for renewable technologies</u>

97. This sensitivity has not been modelled for option 1 current bands. The following discussion therefore compares capacity, generation and costs between the proposed lead option (option 3) under (1) high and (2) central maximum build rates and does not provide a comparison to option 1 current bands. This is different to the discussion on high and low fossil fuel price sensitivities above.

98. Lower maximum build rates assume that efforts to overcome non-financial barriers to deployment such as supply chain, planning and grid are not so successful. This is a modelling assumption; that less build is possible in any given year.

99. In the central case for analysis, the high maximum build rates from Arup (2011) were used, reflecting the government's high ambitions for addressing non-financial barriers to deployment. This sensitivity looks at the Arup central maximum build rates.

1. Renewable deployment and the electricity mix

100. Tables 21 and 22 summarise the capacity and generation mix in a world with low annual build rates for current bands and the preferred option (option 3 extra support for marine) over the 2013-17 banding review period. Full details are available in annex 4. Generally, due to more constraints on deployment, with central build rates less renewable capacity is being built over the period under option 3 when compared to the central scenario with high maximum build rates.

Table 21 Modelled new build capacity under different options, MW *(difference to deployment under central assumptions in brackets)*

Modelled Capacity (MW)	**Total deployment by 2012/13**		**New build under the RO during the 2013-17 Banding Review period: Option 3 marine**	
Offshore wind[41]	3,600	*(0)*	860	*(0)*
Onshore wind (>5MW)*	5,800	*(-190)*	1,300	*(-490)*
Biomass conversion	1,300	*(0)*	710	*(0)*
Enhanced co-firing	-	*(0)*	580	*(0)*
Dedicated biomass	460	*(0)*	19	*(-9)*
Wave and tidal stream	3	*(0)*	34	*(-17)*
Other 'large-scale'**	3,200	*(-10)*	140	*(-19)*
Total 'large-scale'**	**14,000**	***(-200)***	**3,600**	***(-530)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

101. Under central maximum build rates, option 3 brings on around 490MW (1.3TWh/y) less onshore wind new-build during the 2013-17 banding review period than option 3 with high maximum build rates (the latter being the central assumption). There is also less new-build coming on for small dedicated biomass plants, geothermal, tidal stream, wave, large hydro and ACT due to more constraints on deployment. Option 3 with central maximum build rates means that renewables new-build reduced by around 530MW in the 2013-17 banding review period, compared to under high build rates, whilst renewables generation towards the 2020 renewables target falls by around 1.6TWh/y.

[41] Note this and the generation figure in Table 4 for offshore wind include build during 2013/14, whose banding is not being considered in this banding review. The 2013/14 offshore wind build is 900MW, producing around 3.0TWh per year.

Table 22 Modelled generation from new build capacity under different options, GWh per year[42] ***(difference to deployment under central assumptions in brackets)***

Modelled annual generation (GWh per year)	Generation from capacity built by 1/4/13		Generation from net new build under the RO during the 2013-17 Banding Review period: Option 3 marine	
Offshore wind	11,000	*(0)*	2,800	*(0)*
Onshore wind (>5MW)*	14,000	*(-430)*	3,400	*(-1,300)*
Biomass conversion[43]	10,000	*(-0)*	5,600	*(0)*
Enhanced co-firing	-	*(0)*	4,300	*(0)*
Dedicated biomass	3,600	*(0)*	190	*(-70)*
Wave and tidal stream	8	*(0)*	120	*(-60)*
Other 'large-scale'**	16,000	*(-42)*	-1,600	*(-140)*
Total 'large-scale'**	**55,000**	***(-480)***	**15,000**	***(-1570)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

2. Welfare implications

102. Non-renewables generation costs under the preferred option 3 with high maximum build rates are £32bn higher compared to generation costs of the preferred option 3 with central maximum build rates. Renewable generation costs are £42bn lower under central build rates instead of high build rates. This results in total generation costs being £10bn lower with central build rates.

103. Option 3 with central build rates is associated with around 140Mt more CO2 emissions and hence £4.3bn higher carbon credit purchase costs when compared to option 3 with high build rates. This is the case due to far less renewable generation under central maximum build rates.

104. Balancing costs are £3.2bn lower in option 3 with central build rates than with high build rates, in particular due to having less onshore wind in the system.

105. The table below summarises the monetised differences in welfare under the different renewables build rate potential assumptions. Note, the signing below (unlike in the tables above) is positive for a benefits and negative for a cost. Table 23 shows that the total impact of option 3 with central build rates is a £9..2bn reduction in costs as compared to option 3 with high build rates. This reduction in costs is due to significantly less renewables in the system, resulting in the UK not meeting its renewable targets.

Table 23 Monetised differences in welfare to 2039/40 summary, NPV (2010/11 prices)

	Option 3 (central build rates) relative to option 3
Reduction (+) / increase (-) in generation costs	+£10bn
Reduction (+) / increase (-) in EUA purchase costs	-£4.3bn
Reduction (+) / increase (-) in balancing costs	+£3.2bn
Total impact	**+£9.2bn**

Estimates rounded to two significant figures

3. Distributional impacts

106. With the lower maximum build rates, due to significantly less renewable deployment, the RO costs fall. The lifetime (to the end of the RO in 2037) reduction in RO costs from option 3 under lower maximum build rates with comes to an NPV of £350m (real 2010/11 prices), compared to option 3 under central assumptions.

[42] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is therefore greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FIT with CfD.
[43] New capacity and generation figures for biomass conversion and other 'large-scale' are net of decommissioning.

Table 24 RO support costs under low annual maximum build rates

£million, real 2010/11 prices undiscounted	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Option 3 (central assumptions)	1,400	1,800	2,200	2,700	3,100	3,200
Difference with lower build rates	0	0	-28	-47	-76	-90

Estimates rounded to two significant figures

Sensitivity 4: High offshore wind innovation

107. This sensitivity has not been modelled for option 1 current bands. The following discussion therefore compares capacity, generation and costs between the proposed lead option under (1) central offshore wind innovation cost reduction assumptions and (2) high offshore wind cost reduction assumptions and does not provide a comparison to option 1 current bands. This is different to the discussion on high and low fossil fuel price sensitivities above.

108. The offshore wind cost reductions follow a straight line in this sensitivity to reach a levelised cost of around £100/MWh for offshore wind commissioned in 2020. The £100/MWh compare to round 2 levelised costs reaching £130/MWh for offshore wind commissioned in 2020 under central assumptions and therefore implies higher offshore wind innovation. In this sensitivity, the medium construction cost for round 2 offshore wind commissioned in 2015/16 is £2307/kW compared to £2486/kW for round 2 under the central cost reductions assumptions. The gap between the two sets of offshore wind costs gets wider in later years beyond the 2013-17 banding review period. However, deployment beyond this banding review period will depend on policy for the FIT with CfD, which is not considered in this Impact Assessment.

1. *Renewable deployment and the electricity mix*

109. Tables 25 and 26 summarise the capacity and generation mix in a world with low annual build rates for current bands and the preferred option (option 3 extra support for marine) over the 2013-17 banding review period. Full details are available in annex 4. Generally, more offshore wind deployed as its cost fall faster, making more of its supply curve economically viable in any given year.

Table 25 Modelled new build capacity under different options, MW ((*difference to deployment under central assumptions in brackets*)

Modelled Capacity (MW)	Total deployment by 2012/13		New build under the RO during the 2013-17 Banding Review period: Option 3 marine	
Offshore wind[44]	3,600	*(+0)*	920	*(+63)*
Onshore wind (>5MW)*	6,000	*(+0)*	1,700	*(+0)*
Biomass conversion	1,300	*(+0)*	710	*(+0)*
Enhanced co-firing	-	*(+0)*	580	*(+0)*
Dedicated biomass	460	*(+0)*	28	*(+0)*
Wave and tidal stream	3	*(+0)*	51	*(+0)*
Other 'large-scale'**	3,200	*(+0)*	160	*(+0)*
Total 'large-scale'**	**15,000**	***(+0)***	**4,200**	***(+63)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

With high offshore wind innovation, option 3 brings on 63MW (0.21TWh/y) more offshore wind new-build during the 2013-17 banding review period than option 3 with central offshore wind innovation assumptions.

[44] Note this and the generation figure in Table 4 for offshore wind include build during 2013/14, whose banding is not being considered in this banding review. The 2013/14 offshore wind build is 900MW, producing around 3.0TWh per year.

Table 26 Modelled generation from new build capacity under different options, GWh per year[45] **(*(difference to deployment under central assumptions in brackets*)**

Modelled annual generation (GWh per year)	**Generation from capacity built by 1/4/13**		**Generation from net new build under the RO during the 2013-17 Banding Review period: Option 3 marine**	
Offshore wind[42]	11,000	*(+0)*	3,000	*(+210)*
Onshore wind (>5MW)*	14,000	*(+0)*	4,700	*(+0)*
Biomass conversion[46]	10,000	*(+0)*	5,600	*(+0)*
Enhanced co-firing	-	*(+0)*	4,300	*(+0)*
Dedicated biomass	3,600	*(+0)*	260	*(+0)*
Wave and tidal stream	8	*(+0)*	180	
Other 'large-scale'**	16,000	*(+0)*	-1,400	*(+0)*
Total 'large-scale'**	**55,000**	***(+0)***	**17,000**	***(+210)***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

2. Welfare implications

110. Under option 3, renewable generation costs are £35bn higher with high offshore wind innovation than central rates, due to more offshore wind deployment in the 2013-17 banding review period and beyond (cheaper than under central assumptions but still a relatively expensive technology for much of the period) while non-renewable generation costs are £25bn lower (due to less non-renewable generation being required), resulting in total generation costs being £10bn higher with high offshore wind innovation.

111. Option 3 with high offshore wind innovation is associated with 75Mt less CO2 emissions and hence £3.2bn lower carbon credit purchase costs than option 3 with central offshore wind innovation assumptions. The lower CO2 emissions with high offshore wind innovation are due to more offshore wind in the system.

112. Balancing costs are £2.5bn higher in option 3 with high offshore wind innovation than with central innovation assumptions, due to more offshore wind in the system.

113. The table below summarises the monetised impacts. Note, the signing below (unlike in the tables above) is positive for a benefit and negative for a cost. Table 27 shows that the total impact of option 3 with high offshore wind innovation assumptions is a £9.4bn net loss of welfare as compared to option 3 with central offshore wind innovation assumptions.

Table 27 Monetised costs and benefits to 2039/40 summary, NPV (2010/11 prices)

	Cost of option 3 (high offshore innovation) relative to option 3
Reduction (+) / increase (-) in generation costs	-£10bn
Reduction (+) / increase (-) in EUA purchase costs	+£3.2bn
Reduction (+) / increase (-) in balancing costs	-£2.5bn
Total impact	**-£9.4bn**

Estimates rounded to two significant figures

3. Distributional impacts

114. With high offshore wind innovation, option 3 increases the cost of the RO as more offshore wind becomes viable at the proposed ROC rates. The lifetime (to the end of the RO in 2037) increase in RO costs from option 3 with high offshore wind innovation as compared to RO costs associated with central offshore wind innovation comes to an NPV of £220m (real 2010/11 prices).

[45] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is therefore greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FIT with CfD.
[46] New capacity and generation figures for biomass conversion and other 'large-scale' are net of decommissioning.

Table 27 RO support costs with high offshore wind innovation

£million, real 2010/11 prices undiscounted	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Option 3 (central assumptions)	1,400	1,800	2,200	2,700	3,100	3,200
Difference with high offshore innovation	0	0	0	8	17	17

Sensitivity 5: New central fossil fuel prices

115. The table below shows the renewables deployment with option 3 extra support for marine under the central fossil fuel prices published in 2010 used in the Pöyry analysis, and how it compares to deployment under the central fossil fuel prices published by DECC in October 2011. The latter is based on DECC analysis. It can be seen that because higher gas prices in the period to 2020 increase wholesale prices relative to the older set of fossil fuel prices prices, renewables deployment is higher in many cases. It is not higher in all cases due to the assumption of stepped supply curves detailed above.

116. Onshore wind deployment under the new fossil fuel prices could be around 0.5GW higher, offshore wind deployment around 240MW higher and dedicated biomass could double to around 60MW in the 2013-17 banding review period.

Table 28 Renewables deployment under option 3, extra support for marine under updated fossil fuel price assumptions

	Capacity built by 2012/13		New capacity built in 2013-17 banding review period	
	DECC 2010 fossil fuel prices	New October 2011 fossil fuel prices	DECC 2010 fossil fuel prices	New October 2011 fossil fuel prices
ACT	6	6	6	8
AD	24	24	4	4
Bioliquids	-	-	-	-
Biomass Conversion	1,300	1,300	710	710
Dedicated energy crops	-	-	-	-
Large dedicated biomass (>50MW)	-	-	-	-
Small dedicated biomass (<50MW)	460	460	28	63
Dedicated biomass CHP	15	15	7	7
Enhanced co-firing	-	-	580	580
Co-firing of biomass with CHP	18	18	18	18
Co-firing of energy crops**	-	-	-	-
Energy from waste with CHP	21	21	73	73
Energy from waste power-only (includes existing CHP)	290	290	53	53
Geothermal	-	-	14	15
Large hydro (>5MW)*	1,700	1,700	21	21
Landfill gas	930	930	-46	-46
Offshore wind	3,600	3,600	860	1,100
Large onshore wind (>5MW)*	6,000	6,400	1,700	2,300
Large solar PV (>5MW)	30	30	6	6
Sewage gas	190	190	7	9
Tidal range	-	-	-	-
Tidal stream	1	2	32	33
Wave	1	1	19	19
Total	**15,000**	**15,000**	**4,100**	**5,000**

7. Other banding review decisions

117. As part of the banding review Government is also consulting on the following scheme design options. Whilst the banding options have been assessed quantitatively, using economic modelling, the scheme design options have been assessed qualitatively.

A) Grandfathering

118. Grandfathering is a firm policy intention to fix the level of support for installations for the whole duration of their operating lifetime. In July 2010, the Government declared its intention to change the grandfathering rules for biomass generation, and stated its intention to grandfather support for biomass and AD and EFW, but not to grandfather support for bioliquids in the RO. The impact

assessment published in July 2010 estimated the impact of grandfathering for plant that generated prior to April 2013.[47]

119. The current consultation sets out the approach to grandfathering ROC levels for plant accrediting post April 2013. The policy intention post 2013 is to maintain the current position, for dedicated biomass, AD and energy from waste from CHP - to grandfather new accreditations from 1st April 2013 to 31st March 2017 at the support levels prevailing at the time of accreditation - and to make the following changes:

1) Creation of two new bands for conversion and for enhanced co-firing which will be grandfathered at their new rates.

2) Grandfather bioliquids at their new rates, but there will be a cap on bioliquids of around 2 TWh/y.

3) Grandfather the 'energy crops uplift' and the 'CHP uplift' at the levels prevailing at the time of accreditation. This means maintaining the differential between standard co-firing (not grandfathered) and energy crops; and grandfathering dedicated energy crops and dedicated biomass with CHP at the full banding level prevailing at the time of accreditation. For dedicated biomass with CHP, this level is proposed to be 2 ROCs/MWh to 2014/15; 1.9 ROCs/MWh in 2015/16 and 1.8 ROCs/MWh in 2016/17.[48]

120. The exception to this grandfathering decision is standard co-firing. Standard co-firing requires minimal additional capital expenditure to coal generation, especially compared with the capital expenditure for other renewable technologies. Co-firing generators can switch between coal and biomass (up to around 10%) fuel sources in response to changing relative fuel prices. Future relative coal and biomass prices are extremely uncertain, and hence it is not thought appropriate to set the level of ROC support for the full period of up to 20 years. However, as announced in the EMR White Paper, it is proposed to grandfather all existing installations at their rates on 31st March 2017, for the rest of their 20 year support periods (or up to 2027 for some plant). From 1st April 2017, the RO will be closed to new accreditations.

121. The decision to grandfather biomass technologies, as set out above, was taken after consideration of alternative options (similar to those discussed in the impact assessment accompanying the government response in July 2010):

Option 1) Do not grandfather, but hold regular reviews of support (~every four years) to take account of changes in fuel prices

Option 2) Grandfather a minimum level of support to cover capex and opex but not fuel. Regular reviews of support to cover fuel costs

Option 3) Link support levels to a fuel price index

122. These options aim to take account of fuel price changes in the support level for biomass. While this would put biomass technologies more on a par with non biomass technologies, the biomass grandfathering impact assessment set out some of the potential difficulties:

- If reviews are set to take account of fuel prices, there is potential for gaming / collusion between generators and fuel suppliers, to increase fuel prices at around the time of review. In order to prevent collusion between suppliers of biomass and developers leading to inflated prices at the time of ROC review, the fuel element of ROCs would need to be fixed to a globally traded biomass price index. There are many different biomass technologies, and many different feedstocks, which would mean that any index would not necessarily match fuel used by plant in operation. This would give developers a clear index against which they could hedge their fuel costs, but would not necessarily reflect movements in prices of indigenous biomass sources. For these reasons options to link ROC support to fuel price changes were not adopted.

[47] See : http://www.decc.gov.uk/assets/decc/consultations/rhi/256-impact-assessment.pdf.
[48] Note that it is proposed to close combined heat and power bands to new accreditations from 1st 2015 (i.e. remove the uplift), and to provide support to CHP technologies thereafter through a combination of RO support and RHI support.

- Moreover the number of feedstocks used in biomass would mean that a system that matched price increases to costs of individual plant would be very complex. DECC received evidence to demonstrate that the proportion of fuel to non fuel costs varied considerably between individual biomass plant.

123. In addition to the risk of gaming, option 1 would involve significant administrative costs, as once the RO is closed to new accreditations, there will be no regular general RO banding reviews covering new stations to which the review of support for existing installations in non-grandfathered technologies could be added at minimal to low extra cost. It would be expected that option 1 would bring on less biomass deployment than full grandfathering, as it would provide less certainty of future support.

124. Option 2 might bring on a little more deployment than option 1, as it provides more certainty of support. However linking part of the support to fuel prices would not be seen as bankable as full grandfathering, and therefore the extra deployment would probably be significantly less than under full grandfathering.

125. Finally option 3 provides certainty of support to cover costs, and would be expected to lead to more renewables deployment. However as discussed above the practicality of such an option is not clear, as biomass feedstock prices vary considerably across sources and localities and there is currently no representative index of those prices. Administratively, it would be difficult and costly to use multiple indexes for different biomass and waste technologies. There is also the risk, clearer and greater than in options 1 and 2, that biomass suppliers could raise feedstock prices above their marginal costs, and get excess profits, in the knowledge that biomass generators could pay for the increased prices through an automatic increase in the RO support level.

126. In analysis of costs and benefits above, biomass technologies have been modelled as being grandfathered in both the counterfactual, and under proposed new bands. The impact on costs and benefits are therefore those associated with the new banding levels. Biomass conversion and enhanced co-firing have been modelled in the counterfactual as being captured by the current dedicated biomass and co-firing bands. The new bands for conversion and enhanced co-firing have been set with reference to costs in the ARUP report, and it is assumed that these bands are both set at 1 ROC/MWh from 2013, and that it is grandfathered. The costs of this change are included in the overall cost of the lead scenario.

Grandfathering Bioliquids

127. Bespoke analysis of the Restats database and the Ofgem sustainability report for 2009/2010[49] indicates that in 2010, generation using bioliquids is estimated at 125GWh of electricity generation. This is in a mix of dedicated biomass and co-firing, and it is expected that, under current proposals, and with levels of support grandfathered, these levels of generation would continue. It is further expected that in the absence of grandfathering few new dedicated bioliquid projects could secure finance, and therefore grandfathering is assumed to increase the level of generation from bioliquids.

128. Under ARUP cost assumptions, and the proposed ROC levels, the modelling does not assume additional deployment of electricity from bioliquids, and it can therefore be assumed that impact of grandfathering ROCs for bioliquids will be small. Nonetheless it is anticipated that the increased certainty offered by the policy could have the impact of bringing forward the small amount of low cost bioliquid deployment identified. The total supported generation from bioliquids would, however, be capped at around 2TWh/y.

Grandfathering Energy crops uplift

[49] OfGem (2011), Annual Sustainability Report 2010-11, available at www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/FuelledStations/Documents1/Annual%20Sustainability%20Report%202010-11.pdf

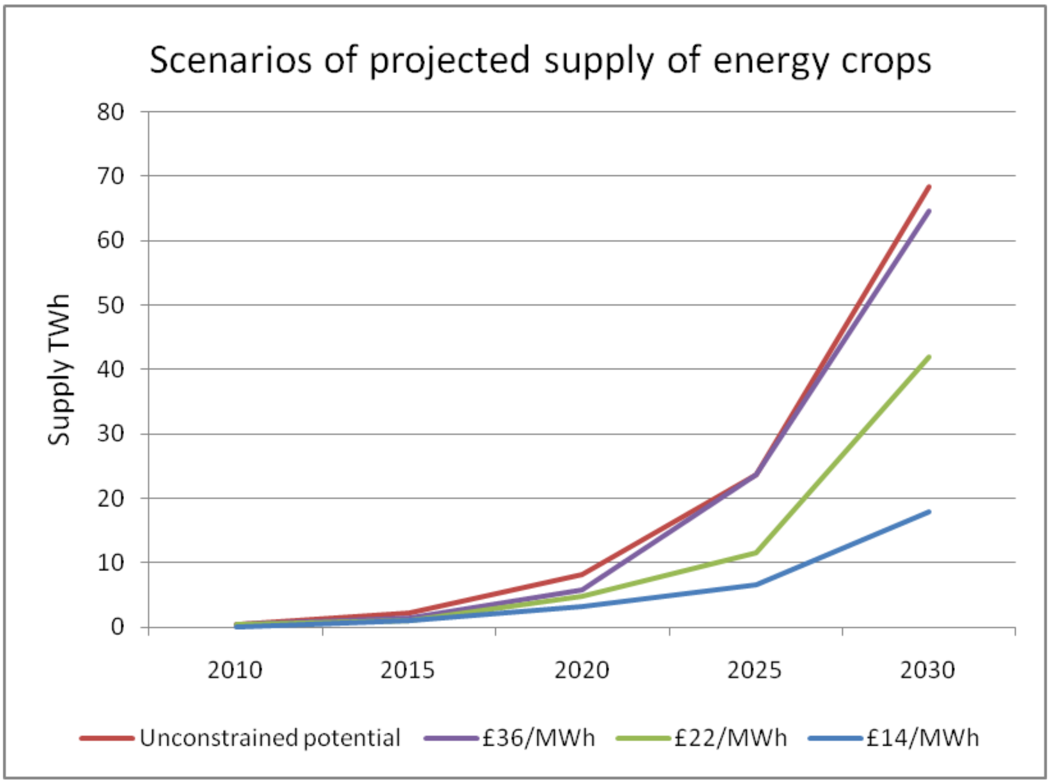
129. Government's current policy is to not grandfather where the support level covers primarily a fuel cost. Grandfathering the energy crop uplift therefore represents a departure from current policy. The reasons for doing so are:

- the need to increase the total biomass resource available for energy use to 2020 and beyond. Energy crops are one of the few sources of biomass that the UK can grow and expand production;
- to minimise the impacts of bio-electricity on other biomass (wood) using industries;
- to achieve the security of supply benefits of having a diversity of indigenous biomass sources and supply chains; and
- to create new opportunities for UK farmers.

130. In 2010, energy crops were used to generate 60GWh of electricity. Uptake of the uplift since 2009 has been slow. This is in part due to the fact that perennial energy crops take a minimum of three years to establish and grow, but will crop for up to 10 years. There has also been a reluctance on the part of growers and energy suppliers to engage in long term contracts without financial surety.

131. Analysis by AEA of future potential global biomass resource indicated that, assuming the use of marginal land and increasing yields and that global food demands are met first, the growth of energy crops in the UK could provide primary energy equivalent to an additional 5TWh in 2020 and up to 50 TWh in 2030 (see Figure 2 below). Grandfathering would therefore protect existing UK investment and set the framework for an increase in the use of energy crops over the medium to longer term.

Figure 2 : Projected supply of energy crops in different scenarios.



Note: The unconstrained potential is the same at all price points. The scenarios showing supply at different prices assume no market or other constraints are overcome. The AEA study showed that supply will vary according to how the market is able to overcome these barriers.

B) Proposed changes in definitions of 'standard' and 'advanced' ACTs (gasification and pyrolysis).

132. Gasification and pyrolysis can generate electricity directly by burning their syngas or liquid fuel to raise steam, but they also have the potential, if various technical issues can be overcome, to be both more efficient in the production of power and heat and to produce renewable fuels and products,

including transport biofuels and bioSNG for injection in the gas grid. These innovative technologies may play an important part in meeting renewable energy targets and wider climate change and energy security goals beyond 2020.

133. There are currently two bands – standard and advanced – for each technology, defined and differentiated by the calorific output of the syngas or liquid fuel produced and used to generate electricity. The calorific values for the ‘advanced pyrolysis’ and ‘advanced gasification’ bands were introduced in 2009 and set at a level which was considered necessary to allow the syngas or liquid produced to be used independently rather than directly combusted, and to clearly separate the technology from incineration.

134. Although these banding arrangements were designed to encourage more innovative and efficient forms of energy generation, there is little evidence that this is working, particularly given the limited deployment projections.

135. The consultation document proposes replacing the standard and advanced pyrolysis and gasification bands with two new ACT bands to ensure that support is differentiated between generating electricity using external combustion engines (such as Rankine cycles) and those more innovative versions of the technologies, which can produce a syngas or liquid capable of generating electricity using more efficient internal combustion engines such as gas turbines, and which have the potential to produce a wider range of energy outputs and products, such as second generation biofuels.

136. It also proposes that in order to increase the capacity for delivering these road transport and aviation biofuels in the medium term, the eligibility under the two new ACT bands be expanded to include liquid fuels that are produced by further chemical or biological processing of the syngas produced from pyrolysis or gasification and used to generate electricity.

137. Overall impacts on industry of the proposed changes are likely to be limited. ACTs are grandfathered under the RO, so any project currently in the pipeline and accredited by Ofgem before 1 April 2013 will be subject to the existing banding arrangements. However, companies who may be planning to develop standard ACTs after this date, would therefore be likely to experience a decrease in anticipated ROC income.

138. Accreditation and calculation of ROC entitlement under the proposed new definitions would be more straightforward administratively and less costly than at present for both for industry and Ofgem, since it would be based on the presence or absence of a technology, rather than monitoring the calorific value of energy outputs on a monthly basis. Currently monitoring equipment would not be needed under the proposed new banding arrangements, and so would represent a saving to industry.

C) Definitional changes to eligibility for the energy crops uplift

139. The energy crop uplift was introduced in 2009 to encourage the planting within the UK of perennial crops such as Miscanthus and short rotation coppice species such as willow and poplar so as to increase the available biomass resource which does not directly impact on food prices or divert food to energy use. The consultation document sets out the proposal to redefine those energy crops which will be eligible for the uplift since concerns have been raised by some non-governmental organisations (NGOs) that the existing definition could allow a wider variety of crops than originally intended, including food crops, to benefit. Continuing with the current definition could therefore lead to unintended consequences. The Government proposes to close this loophole so as to prevent crops which are (a) not perennial or (b) which are food crops and which (c) do not require additional support in order develop the supply chain from being subsidised. This can be done by one of two ways:

i. Restrict the definition to perennial energy crops only through exclusion
ii. Restrict the definition to named energy crops through a positive list

140. Restricting the definition to "perennial energy crops only" risks inclusion of perennial food crops such as palm oil, unless it is defined such a manner so as to exclude any crop which could also be used as a food crop. Ensuring a legally water-tight exclusion of such crops from the definition will be difficult. Restricting the definition to named energy crops risks excluding valuable crops unless the list is reviewed regularly or made less species specific. However, it is easier to legally define. On balance, the latter is easier to understand and enforce and less open to legal challenge on interpretation.

141. Currently there are no energy crops which do not meet the proposed revised definition claiming ROCs. Changes to the definition of energy crops are therefore not expected to result in economic loss to energy crop producers or energy suppliers.

D) Setting a cap for bioliquids

142. The consultation document sets out the proposal to support the use of bioliquids in enhanced co-firing and conversion, subject to an overall cap on bioliquids in the RO. It is not proposed to differentiate support for bioliquids from other biomass sources. However, there is concern that, given competing uses for bioliquids, that grandfathered support for bioliquids could lead to a high proportion of dedicated bioliquids stations, which would draw in bioliquid sources from other priority sectors – and could cause a 'lock in' of feedstock. This effect is likely to be minimised by the application of a cap. The proposals to limit both the level of support and the level of deployment of bioliquids greatly reduce the risks associated with grandfathering existing and planned generation.

143. In relation to the Renewables Obligation, a cap of 4% of the total number of ROCs is likely to prevent obligated suppliers from receiving support for bioliquid electricity generation that exceeds 2TWh of bioliquid electricity generation within a year. It is important to note that setting a cap alone does not guarantee transport biofuels will not be diverted into electricity production, but lowers the risk of market pull from other sectors.

144. Analysis by AEA[50] and E4Tech[51] shows that there is likely to be a constrained supply of sustainable biofuel to 2020. Table 28 shows illustrative ranges for electricity generation from sustainable feedstocks in 2020 (based on DECC analysis, using E4Tech and NNFCC data):

Table 29 Electricity generation from sustainable feedstocks in 2020

Bioliquid	Electricity generated in 2020 (TWh)
Transport fuel	0 – 0.032
Non-transport fuel	2.0 – 2.5

The theoretical deployment potential for bioliquids, estimated by NNFCC[52], is much higher than that forecast above. These are given in Table 29, which shows the technical deployment rates with no constraints applied to take into account the support level or availability/ price of feedstock:

Table 30 Theoretical potential for bioliquids in 2020

Scenario	**Electricity generation (TWh)**
Low	4.7
Medium	7.7
High	12.9

145. A cap of around 2TWh in 2020 therefore corresponds to the lower estimate of non-transport bioliquids in 2020. This corresponds with the OfGem sustainability report[53] which shows that the

[50] AEA (2011), *UK and Global Bioenergy Resource – Final Report,* available at www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/policy/1464-aea-2010-uk-and-global-bioenergy-report.pdf

[51] E4Tech (2010), *Biomass prices in the heat and electricity sectors in the UK,* available at www.rhincentive.co.uk/library/regulation/100201Biomass_prices.pdf

[52] Evaluation of Bioliquid Feedstocks & Heat, Elec. & CHP Technologies, NNFCC 11-016, www.nnfcc.co.uk/tools/evaluation-of-bioliquid-feedstocks-and-heat-electricity-and-chp-technologies-nnfcc-11-016

primary bioliquid feedstocks used under the RO for electricity generation were of a type not suitable for transport use and were used primarily in co firing and dedicated bioliquid generation. The intention is not for the cap to limit the current use or projects about to come on stream, and it is expected that, assuming no further growth, the current level of deployment would still be apparent in 2020.

E) The co-firing cap

146. Currently the RO includes a cap for standard co-firing of 12.5%. This means that licensed suppliers are restricted to producing only 12.5% of their overall obligation from co-firing of regular biomass ROCs. It is proposed to remove the co-firing cap from 2013/14 onwards to allow more generation from this cost-effective renewable technology. Standard co-firing is supported by 0.5ROCs/MWh.

147. Historically, the total ROCs presented by suppliers did not reach the 12.5% cap, due to a combination of (a) either lack of attractiveness due to high biomass prices in comparison to coal; and/or (b) the cap itself sending a restricting signal to the market and so limiting uptake. For 2011/12 the total Renewables Obligation is set at around 38m ROCs, implying a maximum of 4.7m ROCs would be available for co-firing.

148. The modelling finds that at central assumptions the cap makes no difference to standard co-firing going forward, as it is not economic relative to burning coal. However, it needs to be noted that the modelling does not take account of the variability of relative coal and biomass prices and past experience suggests that co-firing will come on and off as relative prices change, so that even if on average it is cheaper to burn coal in a given year, there may be some periods where it is cheaper to burn biomass. There is also uncertainty surrounding future average coal and biomass prices. Under DECC's high coal price scenario, there would be some standard co-firing in the modelling even though it uses average annual prices.

149. While there is no evidence to date, the cap could constrain co-firing in the future. Removing the co-firing cap would remove this uncertainty. Given its cost-effectiveness, this could reduce the overall cost of the RO in comparison to more expensive technologies.

150. While removing the co-firing cap might be beneficial for the overall cost of the RO, there is a risk of under-predicting the amount of co-firing when setting the obligation level each year due to added uncertainty. Under-predicting the amount of co-firing might result in significantly reduced ROC prices, which in turn results in reduced investor confidence.

151. Another possible issue associated with removing the co-firing cap is that it might result in biomass resource, which is limited, being shifted away from other cost-effective biomass technologies or other sectors, such as heat and transport.

8. Wider impacts

Equality

152. This policy has no significant bearing on protected characteristics, including age, disability, gender reassignment, pregnancy and maternity, race, religion or belief, sex and sexual orientation.

[53] Sustainability Report on biomass fuelled generating stations for 2009/10 obligation period, OfGem, search.ofgem.gov.uk/highlight.aspx?aid=6581&pckid=755724950&rn=5&sp_id=1497126324&lid=113468398&highlight=sustainability+report#firsthighlight

Environmental Impacts

153. The greenhouse gas emissions impacts are covered in section 6. The proposed banding options lead to carbon savings within the UK power sector, but these will be offset by increases in emissions elsewhere within the capped EU-ETS traded emissions sector. There will therefore be no net impact on greenhouse gas emissions.

Wider environmental issues

154. The RO provides the Government's support scheme for renewables electricity generation. It incentivises investment in renewables projects which help to move the UK away from fossil fuel dependency towards a low carbon economy with consequential carbon savings from displaced fossil fuel generation.

155. Individual projects supported under the RO that are deemed to have the potential to cause significant adverse impacts are required to undertake an Environmental Impact Assessment (Directive 85/337/EEC) as part of the planning process.

Social Impacts – only relevant impact here is rural proofing

156. A large proportion of renewable energy is produced in rural areas and affects businesses involved in the growth (of biomass) and generation of renewable energy and rural communities living in the vicinity of new developments. Increasing the proportion of energy from renewable sources will mean more renewable energy developments in rural areas.

157. Certain forms of renewable development impact disproportionately on rural areas and there can be resistance to new developments. However, any resistance needs to be viewed in the light of Government's commitment to increasing renewable energy to meet its longer term goals and in order to tackle climate change. In addition, a high proportion of the new renewable generation needed between now and 2020 will take the form of offshore wind generation, some of which will be built some distance from shore.

158. Although there has been no separate or explicit assessment of the needs of rural areas, the proposals are set within this wider policy context and aim to ensure that the impacts on consumers and their bills are reasonable.

159. Separate legislation exists with a focus on ensuring that the environmental and social impacts of development are fully taken into account, outside the scope of the RO.

160. Development of RO policy has been subject to extensive consultation. This has previously included business interests within the renewables sector and consumer interests. It has also included relevant rural business groups (including NFU and CLA as well as the wind sector) but has not sought to engage rural community groups in particular.

Sustainable Development

161. The RO is aimed at increasing the deployment of renewable electricity generation in order to move the UK away from fossil fuel dependency towards a low carbon economy in preparation for a future when supplies of gas and oil will become tighter and more expensive.

162. The RO includes sustainability reporting requirements for the use of biomass in electricity generation. This will be reported annually and will help inform Government policy on sustainable use of biomass for electricity generation.

163. This consultation also includes the intention to keep under the review the use of crops for anaerobic digestion so as to ensure that the intended growth in this technology has no unintended consequences on conversion or change in agricultural land use in the UK.

9. Economic Impacts

Competition

164. The RO is a market-based instrument that operates in a competitive market for electricity. It is open to all participants in renewable generation. The way in which the RO recycles money from the buy-out fund should act as a positive incentive to competition between suppliers, and reduce barriers to entry for renewable electricity generators.

Small Firms

165. The major impact of the RO on the large majority of small business is likely to come from increased costs of electricity which, while affecting all electricity consumers, are likely to represent a larger proportion of income for smaller companies, as they are less likely to have their own generation compared to – particularly - larger industrial users with heavy electricity requirements. Options 2 and 3 both result in lower RO support costs however.

166. The majority of smaller businesses involved in renewables generation are likely to support under FITs, as the simplicity and income-certainty of FITs makes them better suited to small business needs. Small businesses involved in licensed electricity supply should not experience any additional burdens from the proposals.

10. Summary and preferred option with description of implementation plan

Preferred option and summary

167. The preferred option is option 3 extra support for marine technologies. It delivers 16TWh/y of additional generation from new build over the 2013-17 banding review period towards the 2020 renewables target, compared to 11TWh/y under option 1 current bands. Under central assumptions, this achieves the 'large-scale'[54] renewable electricity deployment required to meet the UK's interim and 2020 renewable energy targets under the Renewable Energy Directive.

168. Option 3 also saves money for the electricity consumers who bear the cost of the RO by focussing on the more cost-effective technologies and cutting out excess profits to renewables developers. The latter is achieved through reducing support in technologies such as hydro above 5MW (sub-5 MW hydro is supported by FITs), energy from waste with CHP and biomass conversion, but without reducing renewables deployment.

169. The Government's expectation is that renewables support will not remain high forever, but reduce as the costs of renewable technologies come down. The proposed RO banding for offshore wind, considered the marginal cost of meeting the 2020 renewables target, is therefore reduced from 2.0 to 1.9 ROCs/MWh in 2015/16 and then to 1.8 ROCs/MWh in 2016/17 as offshore wind costs are projected to fall, and the banding for all other technologies beginning at 2 ROCs/MWh are proposed to fall likewise (with the except of wave and tidal stream). Complementary policies will help bring down renewable generation costs, such as innovation support programmes, support for the development of wind turbine manufacturing facilities at ports and a joint HMG-business taskforce has

[54] 'Large-scale' renewable electricity is defined as all UK renewable electricity except that in Great Britain from stations with an installed capacity below 5MW in AD, solar PV, wind and hydro technologies, i.e. except that electricity which is eligible for support under the small-scale FITs scheme.

been set up to ensure all key parties work together to deliver the innovation and supply chain development required.

170. Extra support for wave and tidal stream technologies is provided under the preferred option as these are technologies where the UK is a 'price-maker', leading the way in their development. They have significant deployment potential in the UK, with perhaps around 27GW (9-43GW) of deployment potential by 2050.[55] The costs and benefits of support for wave and tidal stream technologies are very uncertain, and depend on many factors, such as how their generation costs come down over time, the deployability of other large-scale low-carbon electricity technologies and how their generation costs develop over time. Wave and tidal stream have 'option value', in that in some potential future states of the world they could deliver new industries and jobs to the UK,[56] and be a cost-effective part of the generation mix, although in other states of the world they may have greater costs than benefits. Support under the RO and complementary innovation funding keep open the wave and tidal stream options for the UK in the future.

Table 31 Monetised costs and benefits to 2039/40 summary, NPV (2010/11 prices)

£m	**Option 2 relative to option 1**	**Option 3 relative to option 1**	**Option 4 relative to option 1**
Reduction (+) / increase (-) in generation costs	-580	-2,100	-24,000
Reduction (+) / increase (-) in EUA purchase costs	+1,100	+1,200	+1,800
Reduction (+) / increase (-) in balancing costs	-100	-120	-400
Total impact	**+470**	**-1,100**	**-23,000**

Estimates rounded to two significant figures

Implementation

171. The RO is administered and enforced by Ofgem, who report annually on their administration of the RO and conduct regular audits in relation to compliance with the RO.

172. DECC is responsible for monitoring the impact of the RO on the development of renewable energy and collects detailed information on growth in renewable energy generation and projects under development.

[55] Ernst & Young (2010), *Costs of and financial support for wave, tidal stream and tidal range technologies in the UK*

[56] Promoting renewable technologies leads to new jobs and growth in renewables industries, but these are balanced by job reductions in other sectors, such that the net result on aggregate employment and output is uncertain.

Annex 1: Post Implementation Review (PIR) Plan

173. A PIR should be undertaken, usually three to five years after implementation of the policy, but exceptionally a longer period may be more appropriate. If the policy is subject to a sunset clause, the review should be carried out sufficiently early that any renewal or amendment to legislation can be enacted before the expiry date. A PIR should examine the extent to which the implemented regulations have achieved their objectives, assess their costs and benefits and identify whether they are having any unintended consequences. Please set out the PIR Plan as detailed below. If there is no plan to do a PIR please provide reasons below..

Basis of the review: The effectiveness of the RO will be reviewed on an ongoing basis. The UK has to report on progress towards the Renewable Energy Target, and will therefore be monitoring deployment levels. The cost of the RO will be monitored at least annually, as DECC has responsibility for setting the level of the obligation.
Review objective: The review will assess costs and deployment of technologies supported through the RO. It will also consider the cost effectiveness of the RO scheme.
Review approach and rationale: This will involve reviewing monitoring data, consideration of technology costs and resource potential, and an assessment of uptake rates.
Baseline: The impact assessment is measured against a counterfactual of current banding levels. Monitoring will also be done against a counterfactual of no renewable electricity growth - to measure the full cost and impact of the renewable obligation as a whole.
Success criteria: Deployment of a cost-effective renewable electricity capacity in line with that required to meet the UK's 2020 renewables target.
Monitoring information arrangements: Renewable capacity and deployment under the Renewables Obligation is collected by Ofgem, whilst the Renewable Energy Planning Database has information on the pipeline of new projects. These sources are regularly interrogated by DECC's Office for Renewable Energy Deployment, in order to monitor progress towards the 2020 renewables target and costs to consumers under the consumer levy control framework.
Reasons for not planning a PIR: The RO is an established instrument which has been reviewed by the NAO, and the banding review has formed a review of the instrument. The deployment and costs of renewable electricity deployment will be reviewed on an ongoing basis.

Annex 2 – Detail of proposed bands and rationales

1. Note it is assumed that combined heat and power technologies will be supported jointly through the RHI and RO from 2015/16 onwards, and hence from that date that there will be no CHP bands in the RO available for new accreditations.[57]

2. In all the options, bioliquids remain part of existing dedicated biomass, ACT, co-firing and dedicated biomass CHP bands.

3. The ROC ranges stated represent how many ROCs are required to meet the target internal rates of return ('hurdle rates') at the bottom and top of the supply curves, according to the Arup (2011) low and high capex assumptions for plant commissioning in 2014/15.

4. Note also that for all biomass technologies ranges are based on central biomass resource prices (figure 1 above shows the impact on the ranges of adding ranges to biomass prices as well as capex).

Table 1

Technology	Current banding	Lead scenario ROC banding	Justification
Dedicated biomass	1.5	1.5 to 2015/16, falling to 1.4 in 2016/17	Analysis suggests a range of 1.5-2.2 ROCs for small dedicated biomass stations. Cost evidence suggests that larger scale biomass needs 2.3-2.6 ROCs – due to an increased proportion of imported fuel. The recommended rate is at the lower end of the range, as considerable biomass conversion and enhanced co-firing are expected. Biomass may in some cases be better used in other sectors.
Conversion	1.5	1	In the Pöyry modelling, investors are assumed to compare four options for coal plant: burning coal, standard co-firing, enhanced co-firing and full conversion. At 1 ROC, all the coal plants assumed to have the potential to convert to biomass do so.
Enhanced co-firing	0.5	1	Analysis suggests a range of 1-1.1.
Dedicated biomass with CHP, dedicated energy crops with CHP	2	2 to 2014/15	Analysis suggests a ROC range of 4.2-5.3 ROCs with 90% imported fuel costs and 10% imported, and 2.5-3.6 for 10% imported fuel costs and 90% imported. The proposed band is set at the marginal rate (offshore wind). This band is not available to new accreditations after 2014/15 (support for heat to be provided through the RHI).
Standard co-firing	0.5	0.5	Analysis suggests that there is a range of 0.6-1.2 ROCs. The current and proposed new band is set at 0.5 ROCs. The modelling shows that there is no standard co-firing coming on at that rate, however, the modelling also shows generation from co-firing in the high fossil fuel prices sensitivity. The band is proposed at this level in order to maintain a differential of incentive to encourage enhanced co-firing. Enhanced co-firing, will provide greater certainty for meeting the 2020 renewables target than standard co-firing.
Standard Co-firing CHP	1	1 to 2014/15	Based on cost evidence gathered by Mott MacDonald, which Arup believe to be the best available source of evidence on co-firing CHP. Analysis using Mott MacDonald data does suggest 1 ROC is sufficient to incentivise any deployment potential in this technology. It is therefore proposed to keep the banding at its current level; this band will not be available

[57] From the introduction of the RHI to 2014/15, new stations in CHP technologies eligible for the RHI will have the choice between the relevant dedicated RO CHP band, and claiming the relevant RHI tariff plus relevant RO power-only band. From 2015/16, new stations will get the relevant RHI tariff plus relevant RO power-only band.

			to new accreditations after 2014/15 (support for heat to be provided through the RHI).
Co-firing of energy crops with CHP	1.5	1.5 to 2014/15	Arup did not collect data on this technology and the early review of banding for this technology did not reveal evidence of any deployment potential. The consultation proposes keeping the banding at its current level and asks for additional evidence. This band will not be available to new accreditations after 2014/15 (support for heat to be provided through the RHI).
Energy from Waste with CHP	1	0.5	Based on new cost information, which suggests zero RO support is required; the analysis includes a gate fee of £75/t that EfW CHP plants are assumed to receive. However the evidence on gate fees is not clear cut (i.e. gate fees could be lower), so the proposal is a drop from the current 1 ROC level, to 0.5, instead of zero in order to make EfW CHP more attractive than EfW power only.
Standard ACT (gasification and pyrolysis)	1	0.5 Consultation calling for further evidence	The ROC range based on Arup costs is 0-0.4. This reflects a gate fee of £75/t that ACT plants are assumed to receive. However, the evidence on gate fees is not clear cut (i.e. gate fees could be lower, which could justify ROC support) so the proposal is for a drop from the current 1 ROC to 0.5, instead of zero, in order to encourage deployment. The consultation is calling for further evidence on costs and deployment potential.
Advanced ACT (gasification and pyrolysis)	2	2 Consultation calling for further evidence	The ROC range based on Arup ACT costs is 0-0.4, though it is not clear that those costs are representative of advanced ACT. Costs are expected to be much higher than for standard ACT. The consultation is calling for further evidence on costs and deployment potential.
AD	2	2 to 2014/15 1.9 in 2015/16 1.8 in 2016/17	Analysis suggests a ROC range of 0.4 to 3.6 ROCs for a project that starts operating in 2014. All of the AD modelled is small scale and will hence receive FITs; 2 ROCs is in line with the lowest support under FITs, and reduces in line with the marginal cost (offshore wind) under the RO. Deployment of AD is expected to take place primarily under FITs.
Dedicated energy crops	2	2 to 2014/15 1.9 in 2015/16 1.8 in 2016/17	Analysis suggests for small dedicated plants with energy crops a range of 2.8-3.5 ROCs (i.e. 1.3 ROCs more than for a small dedicated biomass plant – which uses cheaper domestic biomass); this difference results from the assumed energy crops/ biomass price (mainly domestic) differentials estimated by AEA.
Co-firing with energy crops	1	1	Based on the biomass and energy crop assumptions, co-firing with energy crops is not estimated to be more expensive than a plant co-firing biomass at 0.5 ROCs (with mainly imported fuel), as imported biomass prices are believed to be similar to energy crop prices. Nevertheless, the use of energy crops would diversify the feedstock base, create jobs in the energy crops industry and limit competition with other biomass using industries.
Landfill gas	0.25	0	Analysis suggests no RO support is needed to make new projects financially viable. Therefore, it is proposed that support be reduced to zero. According to the Arup evidence, there is not further deployment potential for landfill gas.
Sewage gas	0.5	0.5	Analysis suggests a ROC range from 0 to 1.9 ROC. Central support is around 0.3 ROCs, so 0.5 ROCs is proposed in order to bring on a substantial portion of the available untapped supply – but not extending to the most expensive

			forms of this technology.
Offshore wind	2	2 to 2014/15 1.9 in 2015/16 1.8 in 2016/17	Analysis suggests a ROC range of 2.0-3.0 ROCs for R2 offshore wind (with an operation start in 2014) and a ROC range of 2.6-3.9 ROCs for R3 offshore wind (with an operation start in 2017). 2 ROCs are thought to incentivise the cheapest part of the offshore wind supply curve, the part that is necessary to meet our 2020 targets. Assuming an operation start in 2015 results in a ROC range of 1.8-2.7 and an operation start in 2016 results in a ROC range of 1.6-2.5. Based on this R2 cost evidence, the proposal is to support levels down to 1.9 ROCs in 2015/16 and 1.8 ROCs in 2016/17 to show commitment to incentivise cost reductions in offshore wind and incentivise the most cost-effective offshore wind. The R3 offshore evidence is highly uncertain according to E&Y who provided it. The very first R3 is expected to have similar characteristics for R2. Therefore HMG are not proposing a separate R3 band for the banding review period.
Onshore wind	1	0.9	Analysis suggests for large scale suggests a ROC range of -0 to 1.6 across the UK: 0.6-1.6 in England & Wales, 0.3 to 1.2 in Scotland and 0-0.8 in Northern Ireland, based on historic load factor differences across the countries. Setting support levels at 0.9 is estimated to bring on the most cost-effective part of the onshore supply curve, and shows a commitment to reducing support over time, incentivising efficiency. (Small onshore wind has a range of 0.5-1.8 ROCs; supported under FITs).
Solar PV	2	2 to 2014/15 1.9 in 2015/16 1.8 in 2016/17	Analysis suggests a ROC range of 3.0-6.8 ROCs. The proposal is to set support at the marginal rate (offshore wind). Small-scale solar is supported under FITs.
Hydro	1	0.5	Analysis suggests large-scale hydro has a required ROC range of 0-0.5. The proposal is to set support at the high end of the range to incentivise all large-scale hydro on the supply curve (small scale hydro has a ROC range of 0.2-5.9 ROCs and is supported by FITs) as it is cost-effective.
Geothermal	2	2 to 2014/15 1.9 in 2015/16 1.8 in 2016/17	Analysis suggests for geothermal suggests a ROC range of 1.9-7.3. The ROC range is wide for geothermal due to the large range of possible capital costs. The proposal is to set support at the marginal rate (offshore wind)
Wave and tidal stream	2	5	Analysis suggests the need for around 4 ROCs to support tidal stream and around 6 ROCs wave even with 25% capital grants to support demonstration projects. However, the underlying costs are very uncertain. It is more expensive than alternatives for achieving the 2020 renewables target, however there are arguments in favour of enhanced support for the technology. The UK is leading the sector and marine could play its part in a cost-effective mix to 2030 and 2050 if its costs fall with mass deployment. The proposal is to set support at 5 ROCs.
Tidal range	2	2 to 2014/15 1.9 in 2015/16 1.8 in 2016/17	Analysis suggests high required ROC levels for these technologies (a recent study by Peel Holdings on their proposals for a Mersey barrage showed a RO banding in the region of 10 ROCs as being necessary to allow the project to proceed). The proposal is to set support at the marginal rate (offshore wind) as it is not cost-effective to 2020, and there is little prospect of large cost reductions.

Annex 3 Details of capacity and generation mix under different options

Installed capacity in 2012/13 by technology, and new build capacity from 2013/14 to 2015/16 under different options (except 2013/14 existing capacity and 2014/15 to 2015/17 new build for offshore wind)

		New build under the RO during the 2013-17 Banding Review period:			
Modelled Capacity (MW)	**Total deployment by 2012/13**	**Option 1 current bands**	**Option 2 minimum scope**	**Option 3 marine**	**Option 4 portfolio approach**
ACT	6	8	6	6	5
AD and AD CHP	24	4	4	4	4
Bioliquids	-	-	-	-	710
Biomass Conversion	1,300	710	710	710	710
Dedicated energy crops	-	-	-	-	150
Large dedicated biomass (>50MW)	-	-	-	-	-
Small dedicated biomass (<50MW)	460	28	28	28	250
Dedicated biomass CHP	15	7	7	7	180
Enhanced co-firing	-	-	580	580	-
Co-firing of biomass with CHP	18	18	18	18	18
Co-firing of energy crops	-	-	-	-	-
Energy from waste with CHP	21	73	73	73	73
Energy from waste power-only[58]	290	53	53	53	53
Geothermal	-	14	14	14	33
Large hydro (>5MW)***	1,700	21	21	21	21
Landfill gas	930	-46	-46	-46	-46
Offshore wind	3,600	500	860	860	1,300
Large onshore wind (>5MW)***	6,000	1,900	1,700	1,700	1,500
Large solar PV (>5MW)***	30	6	6	6	47
Sewage gas	190	7	7	7	6
Tidal range	-	-	-	-	-
Tidal stream	1	23	-	32	37
Wave	1	17	-	19	22
Total large-scale renewable electricity[59]	**15,000**	**3,300**	**4,100**	**4,100**	**5,200**

* Landfill gas capacity is expected to fall with decommissioning.
** A higher ROC banding for solar PV might also incentive more uptake of small scale solar PV under the RO, if support is more generous than feed-in tariffs. This impact is not considered in the table above.
*** Includes <5MW in Northern Ireland.
**** Includes deployment in 2013/14

58 Includes a small amount of existing CHP.
59 'Large–scale' used as a convenient shorthand, but defined as all renewable electricity excluding that supported by FITs, i.e. some small-scale included.

Generation mix in 2012/13 with current bands, and generation from new build capacity built 2013/14 to 2015/16 under different options (except 2013/14 existing and 2014/15 to 2015/17 new build for offshore wind)

Modelled annual generation (GWh/y)	Generation from capacity built by 01/04/2013	Generation from net new build under the RO during the 2013-17 Banding Review period:			
		Option 1 current bands	Option 2 minimum scope	Option 3 marine	Option 4 portfolio approach
ACT	38	56	44	44	48
AD and AD CHP	98	34	34	34	34
Bioliquids	-	-	-	-	4,500
Biomass Conversion	10,000	5,600	5,600	5,600	5,600
Dedicated energy crops	-	-	-	-	1,200
Large dedicated biomass (>50MW)	-	-	-	-	-
Small dedicated biomass (<50MW)	3,600	260	260	260	2,100
Dedicated biomass CHP	120	57	57	57	1,200
Enhanced co-firing	-	-	4,300	4,300	-
Co-firing of biomass**	2,500	-2,500	-2,500	-2,500	1,000
Co-firing of biomass with CHP	140	140	140	140	140
Co-firing of energy crops**	500	-	-	-	-19
Energy from waste with CHP	140	530	530	530	530
Energy from waste power-only (includes existing CHP)	1,700	390	390	390	390
Geothermal	-	110	110	110	240
Large hydro (>5MW)****	5,000	84	84	84	69
Landfill gas	5,200	-350	-350	-350	-350
Offshore wind	11,000	1,700	2,800	2,800	4,100
Large onshore wind (>5MW)****	14,000	5,000	4,700	4,700	4,800
Large solar PV (>5MW)****	29	7	7	7	42
Sewage gas	580	43	43	43	51
Tidal stream	5	88	-	130	160
Wave	3	46	-	51	61
Total large-scale renewable electricity	**55,000**	**11,000**	**16,000**	**16,000**	**26,000**

* Landfill gas capacity is expected to fall with decommissioning.
**Co-firing of biomass and co-firing of energy crops generation given is generation from existing plant in 2012/13, and changes in that generation. No new build is assumed.
*** A higher ROC banding for solar PV might also incentive more generation from small scale solar PV under the RO, if support is more generous than feed-in tariffs. This impact is not considered in the table above.
**** Includes <5MW in Northern Ireland.
***** Includes deployment in 2013/14

Annex 4 Sensitivity analysis

Sensitivity 1: High fossil fuel prices – Details of capacity and generation mix

Installed capacity in 2012/13 by technology, and new build capacity from 2013/14 to 2015/16 under different options (except 2013/14 existing capacity and 2014/15 to 2015/17 new build for offshore wind)

Modelled Capacity (MW)	Total deployment by 2012/13 (High FF)	New build under the RO during the 2013-17 Banding Review period:	
		Option 1 current bands (high FF)	Option 3 marine (high FF)
ACT	6	8	6
AD and AD CHP	24	4	4
Bioliquids	-	-	-
Biomass Conversion	1,300	710	710
Dedicated energy crops	120	200	200
Large dedicated biomass (>50MW)	-	-	-
Small dedicated biomass (<50MW)	460	220	220
Dedicated biomass CHP	15	7	7
Enhanced co-firing	-	-	580
Co-firing of biomass with CHP	18	18	18
Co-firing of energy crops	-	-	-
Energy from waste with CHP	21	73	73
Energy from waste power-only[60]	290	53	53
Geothermal	-	14	14
Large hydro (>5MW)**	1,700	21	21
Landfill gas	930	-46	-46
Offshore wind	4,300	1,100	1,300
Large onshore wind (>5MW)**	6,200	2,400	2,400
Large solar PV (>5MW)**	30	6	6
Sewage gas	190	9	9
Tidal range	-	-	-
Tidal stream	1	27	39
Wave	1	18	20
Total large-scale renewable electricity[61]	**16,000**	**4,700**	**5,700**

* Landfill gas capacity is expected to fall with decommissioning.
** Includes <5MW in Northern Ireland.

[60] Includes a small amount of existing CHP.
[61] 'Large–scale' used as a convenient shorthand, but defined as all renewable electricity excluding that supported by FITs, i.e. some small-scale included.

Generation mix in 2012/13 with current bands, and generation from new build capacity built 2013/14 to 2015/16 under different options (except 2013/14 existing and 2014/15 to 2015/17 new build for offshore wind)

Modelled renewable generation (GWh/y)	Generation from capacity built by 01/04/2013 (High FF)	Generation from net new build under the RO during the 2013-17 Banding Review period: Option 1 current bands (high FF)	Option 3 marine (high FF)
ACT	38	56	34
AD and AD CHP	98	34	34
Bioliquids	-	-	-
Biomass Conversion	10,000	5,600	5,600
Dedicated energy crops	910	1,600	1,600
Large dedicated biomass (>50MW)	-	-	-
Small dedicated biomass (<50MW)	3,600	1,800	1,800
Dedicated biomass CHP	120	57	57
Enhanced co-firing	-	-	4,300
Co-firing of biomass	2,500	490	-1,300
Co-firing of biomass with CHP	140	140	140
Co-firing of energy crops	460	-28	-28
Energy from waste with CHP	140	530	530
Energy from waste power-only (incl. existing CHP)	1,700	390	390
Geothermal	-	110	110
Large hydro (>5MW)***	5,000	84	84
Landfill gas	5,200	-350	-350
Offshore wind	13,000	3,600	4,400
Large onshore wind (>5MW)***	15,000	6,500	6,500
Large solar PV (>5MW)***	29	7	7
Sewage gas	590	51	51
Tidal stream	5	110	160
Wave	3	49	54
Total large-scale renewable electricity	**59,000**	**20,000**	**24,000**

* Landfill gas capacity is expected to fall with decommissioning.
**The negative figures for co-firing of biomass and co-firing of energy crops is due to enhanced co-firing becoming more financially attractive under proposed bandings.
*** Includes <5MW in Northern Ireland.

Sensitivity 2: **Low fossil fuel prices – Details of capacity and generation mix**

Installed capacity in 2012/13 by technology, and new build capacity from 2013/14 to 2015/16 under different options (except 2013/14 existing capacity and 2014/15 to 2015/17 new build for offshore wind)

Modelled Capacity (MW)	**Total deployment by 2012/13 (Low FF)**	**New build under the RO during the 2013-17 Banding Review period:**	
		Option 1 current bands (low FF)	**Option 3 marine (low FF)**
ACT	6	8	5
AD and AD CHP	25	4	4
Bioliquids	-	-	-
Biomass Conversion	750	-750	-750
Dedicated energy crops	-	-	-
Large dedicated biomass (>50MW)	-	-	-
Small dedicated biomass (<50MW)	460	-	-
Dedicated biomass CHP	15	7	7
Enhanced co-firing	-	-	-
Co-firing of biomass with CHP	18	18	18
Co-firing of energy crops	-	-	-
Energy from waste with CHP	21	73	73
Energy from waste power-only[62]	290	53	53
Geothermal	-	10	4
Large hydro (>5MW)***	1,700	21	15
Landfill gas	930	-46	-46
Offshore wind	3,600	500	500
Large onshore wind (>5MW)***	5,500	460	260
Large solar PV (>5MW)***	30	6	6
Sewage gas	190	1	1
Tidal range	-	-	-
Tidal stream	1	15	31
Wave	1	16	18
Total large-scale renewable electricity[63]	**13,000**	**390**	**200**

*The negative figure for conversion is due to a plant being operational in 2011/12 but not anymore in 2015/16.
** Landfill gas capacity is expected to fall with decommissioning.
*** Includes <5MW in Northern Ireland.

[62] Includes a small amount of existing CHP.
[63] 'Large–scale' used as a convenient shorthand, but defined as all renewable electricity excluding that supported by FITs, i.e. some small-scale included.

Generation mix in 2012/13 with current bands, and generation from new build capacity built 2013/14 to 2015/16 under different options (except 2013/14 existing and 2014/15 to 2015/17 new build for offshore wind)

Modelled renewable generation (GWh/y)	Generation from capacity built by 01/04/2013 (Low FF)	Generation from net new build under the RO during the 2013-17 Banding Review period:	
		Option 1 current bands (Low FF)	Option 3 marine (Low FF)
ACT	38	56	22
AD and AD CHP	98	33	34
Bioliquids	-	-	-
Biomass Conversion	5,900	-5,900	-5,900
Dedicated energy crops	-	-	-
Large dedicated biomass (>50MW)	-	-	-
Small dedicated biomass (<50MW)	3,600	-	-
Dedicated biomass CHP	120	57	57
Enhanced co-firing	-	-	-
Co-firing of biomass	2	-	-
Co-firing of biomass with CHP	140	140	140
Co-firing of energy crops	500	-	-
Energy from waste with CHP	140	530	530
Energy from waste power-only (incl. existing CHP)	1,700	390	390
Geothermal	-	78	29
Large hydro (>5MW)***	5,000	84	59
Landfill gas	5,200	-350	-350
Offshore wind	11,000	1,700	1,700
Large onshore wind (>5MW)***	13,000	1,200	740
Large solar PV (>5MW)***	29	7	7
Sewage gas	560	7	7
Tidal stream	5	56	120
Wave	3	43	47
Total large-scale renewable electricity	**47,000**	**-1,900**	**-2,400**

*The negative figure for conversion is due to a plant being operational in 2011/12 but not anymore in 2015/16.
** Landfill gas generation is expected to fall with decommissioning.
*** Includes <5MW in Northern Ireland.

<u>Sensitivity 3</u>: **Central maximum build rates – Details of capacity and generation mix**

Installed capacity in 2012/13 by technology under the preferred lead option (option 3 marine), and new build capacity over the period 2013/14 to 2015/16 under high and central maximum build rates* (except 2013/14 existing capacity and 2014/15 to 2015/17 new build for offshore wind)

Modelled Capacity (MW)	**Total deployment by 2012/13**	**Total deployment by 2012/13 (central build rate)**	**New build under the RO during the 2013-17 Banding Review period:**	
			Option 3 marine	**Option 3 marine (central build rate)**
ACT	6	6	6	5
AD and AD CHP	24	24	4	2
Bioliquids	-	-	-	-
Biomass Conversion	1,300	1,300	710	710
Dedicated energy crops	-	-	-	-
Large dedicated biomass (>50MW)	-	-	-	-
Small dedicated biomass (<50MW)	460	460	28	19
Dedicated biomass CHP	15	15	7	7
Enhanced co-firing	-	-	580	580
Co-firing of biomass with CHP	18	18	18	18
Co-firing of energy crops	-	-	-	-
Energy from waste with CHP	21	21	73	73
Energy from waste power-only[64]	290	290	53	52
Geothermal	-	-	14	3
Large hydro (>5MW)***	1,700	1,700	21	17
Landfill gas	930	930	-46	-46
Offshore wind	3,600	3,600	860	860
Large onshore wind (>5MW)***	6,000	5,800	1,700	1,300
Large solar PV (>5MW)***	30	30	6	6
Sewage gas	190	190	7	6
Tidal range	-	-	-	-
Tidal stream	1	1	32	22
Wave	1	1	19	13
Total large-scale renewable electricity[65]	**15,000**	**14,000**	**4,100**	**3,600**

*To note that option1 current bands has not been modelled using central build rates. Therefore, this sensitivity table shows differences in build between option 3 marine only.
** Landfill gas capacity is expected to fall with decommissioning.
*** Includes <5MW in Northern Ireland.

[64] Includes a small amount of existing CHP.
[65] 'Large–scale' used as a convenient shorthand, but defined as all renewable electricity excluding that supported by FITs, i.e. some small-scale included.

Generation mix in 2012/13 under the preferred option (option 3 marine), and comparison of generation from new build capacity built over the period 2013/14 to 2015/16 under high and central maximum build rates* (except 2013/14 existing and 2014/15 to 2015/17 new build for offshore wind)

Modelled renewable generation (GWh/y)	Generation from capacity built by 01/04/2013	Generation from capacity built by 01/04/2013 (central build)	Generation from net new build under the RO during the 2013-17 Banding Review period:	
			Option 3 marine	Option 3 marine (central build rates)
ACT	38	38	44	30
AD and AD CHP	98	95	34	21
Bioliquids	-	-	-	-
Biomass Conversion	10,000	10,000	5,600	5,600
Dedicated energy crops	-	-	-	-
Large dedicated biomass (>50MW)	-	-	-	-
Small dedicated biomass (<50MW)	3,600	3,600	260	190
Dedicated biomass CHP	120	120	57	57
Enhanced co-firing	-	-	4,300	4,300
Co-firing of biomass	2,500	2,500	-2,500	-2,500
Co-firing of biomass with CHP	140	140	140	140
Co-firing of energy crops	500	500	-	-
Energy from waste with CHP	140	140	530	530
Energy from waste power-only (incl. existing CHP)	1,700	1,700	390	380
Geothermal	-	-	110	26
Large hydro (>5MW)***	5,000	4,900	84	70
Landfill gas	5,200	5,200	-350	-350
Offshore wind	11,000	11,000	2,800	2,800
Large onshore wind (>5MW)***	14,000	14,000	4,700	3,400
Large solar PV (>5MW)***	29	29	7	7
Sewage gas	580	570	43	33
Tidal stream	5	5	130	84
Wave	3	3	51	34
Total large-scale renewable electricity	**55,000**	**55,000**	**16,000**	**15,000**

*To note that option1 current bands has not been modelled using central build rates. Therefore, this sensitivity table shows differences in generation between option 3 marine only.
** Landfill gas generation is expected to fall with decommissioning.
*** Includes <5MW in Northern Ireland.

Sensitivity 4: **High offshore wind innovation – Details of capacity and generation mix**

Installed capacity in 2012/13 by technology under the preferred lead option (option 3 marine), and new build capacity over the period 2013/14 to 2015/16 under central and high offshore wind innovation assumptions* (except 2013/14 existing capacity and 2014/15 to 2015/17 new build for offshore wind)

Modelled Capacity (MW)	Total deployment by 2012/13	Total deployment by 2012/13 (high offshore wind innovation)	New build under the RO during the 2013-17 Banding Review period:	
			Option 3 marine	Option 3 marine (high offshore wind innovation)
ACT	6	6	6	6
AD and AD CHP	24	24	4	4
Bioliquids	-	-	-	-
Biomass Conversion	1,300	1,300	710	710
Dedicated energy crops	-	-	-	-
Large dedicated biomass (>50MW)	-	-	-	-
Small dedicated biomass (<50MW)	460	460	28	28
Dedicated biomass CHP	15	15	7	7
Enhanced co-firing	-	-	580	580
Co-firing of biomass with CHP	18	18	18	18
Co-firing of energy crops	-	-	-	-
Energy from waste with CHP	21	21	73	73
Energy from waste power-only[66]	290	290	53	53
Geothermal	-	-	14	14
Large hydro (>5MW)***	1,700	1,700	21	21
Landfill gas	930	930	-46	-46
Offshore wind	3,600	3,600	860	920
Large onshore wind (>5MW)***	6,000	6,000	1,700	1,700
Large solar PV (>5MW)***	30	30	6	6
Sewage gas	190	190	7	7
Tidal range	-	-	-	-
Tidal stream	1	1	32	32
Wave	1	1	19	19
Total large-scale renewable electricity[67]	**15,000**	**15,000**	**4,100**	**4,200**

*To note that option1 current bands has not been modelled using high offshore wind innovation assumptions. Therefore, this sensitivity table shows differences in build between option 3 marine only.
** Landfill gas capacity is expected to fall with decommissioning.
*** Includes <5MW in Northern Ireland.

[66] Includes a small amount of existing CHP.
[67] 'Large–scale' used as a convenient shorthand, but defined as all renewable electricity excluding that supported by FITs, i.e. some small-scale included.

Generation mix in 2012/13 under the preferred option (option 3 marine), and comparison of generation from new build capacity built over the period 2013/14 to 2015/16 under central and high offshore wind innovation assumptions* (except 2013/14 existing and 2014/15 to 2015/17 new build for offshore wind)

Modelled renewable generation (GWh/y)	**Generation from capacity built by 01/04/2013**	**Generation from capacity built by 01/04/2013 (high offshore wind innovation)**	**Generation from net new build under the RO during the 2013-17 Banding Review period:**	
			Option 3 marine	**Option 3 marine (high offshore wind innovation)**
ACT	38	38	44	44
AD and AD CHP	98	98	34	34
Bioliquids	-	-	-	-
Biomass Conversion	10,000	10,000	5,600	5,600
Dedicated energy crops	-	-	-	-
Large dedicated biomass (>50MW)	-	-	-	-
Small dedicated biomass (<50MW)	3,600	3,600	260	260
Dedicated biomass CHP	120	120	57	57
Enhanced co-firing	-	-	4,300	4,300
Co-firing of biomass	2,500	2,500	-2,500	-2,500
Co-firing of biomass with CHP	140	140	140	140
Co-firing of energy crops	500	500	-	-
Energy from waste with CHP	140	140	530	530
Energy from waste power-only (incl. existing CHP)	1,700	1,700	390	390
Geothermal	-	-	110	110
Large hydro (>5MW)***	5,000	5,000	84	84
Landfill gas	5,200	5,200	-350	-350
Offshore wind	11,000	11,000	2,800	3,000
Large onshore wind (>5MW)***	14,000	14,000	4,700	4,700
Large solar PV (>5MW)***	29	29	7	7
Sewage gas	580	580	43	43
Tidal stream	5	5	130	130
Wave	3	3	51	51
Total large-scale renewable electricity	**55,000**	**55,000**	**16,000**	**17,000**

*To note that option1 current bands has not been modelled using high offshore wind innovation assumptions. Therefore, this sensitivity table shows differences in generation between option 3 marine only.
** Landfill gas generation is expected to fall with decommissioning.
*** Includes <5MW in Northern Ireland.

Annex 5 Details of key assumptions

Table 1 Assumed Feedstock Prices for Solid Biomass and Waste Plant

£/MWh (fuel input)	Low	medium	high
UK-sourced woody biomass	*5*	*11*	*17*
Imported woody biomass	*24*	*27*	*31*
Small biomass <50MW	7	12	19
Large biomass >50MW	22	25	30
Small biomass energy crops <50MW	13	25	29
AD (assumed gate fee)	-38	-10	18
EfW/ ACT (gate fee)		-29	

Source: Internal analysis based on AEA (2011) and WRAP gate fee report (2010)

Table 2 Assumed feedstock prices for bioliquid plant

	Current	**2020**			**2030**			
£/MWh input		**Low**	**Central**	**High**	**Low**	**Central**	**High**	**Very High**
Biodiesel	86	97	10	108	83	97	112	173
Bioethanol	5	50	54	5	43	47	58	83

Source: AEA (2011)

Table 3 Assumed hurdle rates at different financial close rates

	2010 - 2016	**2017 - 2019**	**2020 - 2025**	**2026 - 2030**
Onshore wind	9.6%	9.6%	9.6%	9.6%
Offshore wind	11.6%	11.6%	9.6%	9.6%
Offshore wind R3	13.2%	13.2%	11.6%	9.6%
Geothermal	22.7%	22.7%	16.3%	12.7%
PV	7.5%	7.5%	7.5%	7.5%
Biomass	12.7%	12.7%	11.6%	11.6%
Bioliquid	11.9%	11.9%	11.9%	11.9%
EfW	11.9%	11.9%	11.9%	11.9%
AD	11.9%	11.9%	11.9%	11.9%
ACT	13.2%	13.2%	11.9%	11.9%
Landfill gas	9.6%	9.6%	9.6%	9.6%
Sewage gas	9.6%	9.6%	9.6%	9.6%
Hydro	7.5%	7.5%	7.5%	7.50%
Wave	13.8%	13.8%	13.2%	11.6%
Tidal stream	14.5%	14.5%	13.2%	11.6%
Tidal barrage	11.9%	11.9%	11.9%	11.9%

Source: DECC assumptions, based on Arup (2011), Oxera (2011) and Redpoint (2010)

1. The heat produced by CHP stations has a value which influences their project economics. This value may be through sale of the heat in the form of steam to a nearby buyer, or if the heat is used on-site, through avoiding the costs of generating the heat by other means. The latter costs are also relevant to the buyer, as if they were not buying the heat, they would have to generate it by other means (or find an alternative seller).

2. Heat revenues have been calculated using the avoided cost of heat generation approach. This is based on gas boiler costs of £30/kW capex and £0.2/kW/y opex from AEA/Nera (2009)[68], DECC gas fuel price assumptions and DECC carbon price assumptions (where the installation would be large enough to be in the EU-ETS).

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[68] AEA/Nera (2009) *UK Supply Curve for Renewable Heat,* available at www.rhincentive.co.uk/library/regulation/0907Heat_Supply_Curve.pdf

3. The values of heat revenues per MWh of electricity, will depend on the heat to power ratios of the CHP stations, as provided by Arup. The results vary significantly, as shown in the table below. Heat revenues are included in levelised costs with a negative sign.

Table 4 Heat revenues

Technology	Levelised heat revenue, £/MWh(e)
Energy from waste with CHP	£43
Geothermal with CHP	£102
Dedicated bioliquids with CHP	£41
ACT with CHP	£31
Dedicated biomass with CHP	£48

Marine revenues

4. It is possible that early wave and tidal stream arrays may be in receipt of grant funding, subject to state aids approval. DECC has recently announced a £20m marine funding programme. For the purposes of modelling, the following simplifying assumptions were made:
   - Grants are made to demonstration projects in addition to ROC bandings, subject to not exceeding state aid limits on maximum percentage of total investment costs.
   - Grants were limited to bringing on half of the available tidal stream and wave potential in individual years.

Small-scale electricity in feed-in tariff technologies (AD, solar PV, hydro and wind)

5. In the modelling, new installations with less than 5MW of installed capacity in these technologies are assumed to be supported under feed-in tariffs (FITs) rather than the RO. This is a simplification: whilst microgeneration (<50kW) is only supported by FITs, installations between 50kW and 5MW have the choice between RO and FIT support. FIT tariffs have generally given more generous support than the RO up to now, reflecting higher generation costs at lower capacities. However, some installations with the choice are likely to continue to accredit under the RO, for example if financial institutions are more familiar with the RO mechanism.

Fossil fuel prices

6. The analysis used the latest available finalised DECC fossil fuel price projections at the time it was carried out, i.e. those published in May 2009 and reviewed but left unchanged in June 2010. New fossil fuel price projections were published in October 2011[69]. These new projections were used alongside the older fossil fuel price projections by DECC in assessing levels of required ROCs and potential renewables deployment under existing and proposed bands, but not in the full electricity market despatch modelling carried out by Pöyry. There will be updated analysis to inform the Government Response to the consultation on RO banding levels which will used the updated fossil fuel prices.

Co-firing, enhanced co-firing and biomass conversions

7. In the Pöyry modelling, coal and co-firing plant are given three or four options: to burn coal, to co-fire (up to 10% biomass), to do enhanced co-firing (15% to 50% biomass for some plant only) and to convert to 100% biomass.

8. The choice of these alternatives for each coal/co-firing plant is made in the model according to which alternative gives the highest NPV of cashflows (discounting at the hurdle rate).

[69] Available at: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

Wholesale price income

9. As set out in the Evidence Base, it was assumed that plants receive the wholesale prices endogenously modelled by Pöyry consultants, and investment decisions are made with five-year foresight (from the point of the main financial investment decision – assumed to be just before construction begins) of rising wholesale prices (which rise due to the carbon price floor and rising gas prices). Thereafter wholesale prices are assumed by investors to be flat at the level of the fifth year. This market failure – information failure in a lack of certainty for investors about rising wholesale prices – means that ROC levels have to be set higher than in a world of perfect information about future wholesale prices, to achieve the same level of deployment.

10. The table below sets out the wholesale prices under the preferred option 3 extra support for marine with central, low and high fossil fuel prices (those fossil fuel prices used in the main analysis published in 2009 and reviewed but unchanged in 2010).

Table 5 Wholesale prices under option 3, extra support for marine

	GB wholesale electricity price		
	Central fossil fuel prices	Low fossil fuel prices	High fossil fuel prices
2011/12	£58	£39	£67
2012/13	£59	£39	£69
2013/14	£59	£39	£71
2014/15	£60	£40	£72
2015/16	£62	£42	£74
2016/17	£65	£43	£80
2017/18	£66	£45	£82
2018/19	£67	£45	£84
2019/20	£69	£47	£87
2020/21	£70	£48	£89
2021/22	£71	£49	£88
2022/23	£73	£50	£89
2023/24	£75	£51	£90
2024/25	£76	£51	£89
2025/26	£77	£51	£88
2026/27	£82	£56	£95
2027/28	£84	£56	£94
2028/29	£85	£57	£94
2029/30	£88	£59	£95
2030/31	£87	£58	£94

Source: Pöyry