Title: Onshore wind: closure of renewables obligation on 31st March 2016 **IA No:** DECC0195 **Lead department or agency:** Department of Energy and Climate Change **Other departments or agencies:**	Impact Assessment (IA) **Date:** 08/09/2015 **Stage:** Final **Source of intervention:** Domestic **Type of measure:** Primary legislation **Contact for enquiries:** michael.haslam@decc.gsi.gov.uk
Summary: Intervention and Options	**RPC Opinion:** Not Applicable

Cost of Preferred (or more likely) Option

Total Net Present Value	Business Net Present Value	Net cost to business per year (EANCB 2009 prices)	In scope of One-In, Two-Out?	Measure qualifies as
£160m	N/A	N/A	Out of Scope	Tax & Spend

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

The Government is committed to delivering the manifesto pledge to end new subsidies for onshore wind. The EU Renewable Energy Directive commits the UK to meeting 15% of its energy needs from renewable sources by 2020. The Renewables Obligation (RO) currently supports the overwhelming majority of current and pipeline renewable capacity for 2020 renewable levels. The Levy Control Framework (LCF) sets annual limits on the overall cost of DECC's levy funded policies, including the RO. The accompanying analysis to the Electricity Market Reform (EMR) Final Delivery Plan (December 2013) published indicative scenarios of deployment of renewable technologies in 2020, suggesting around 11 to 13GW of onshore wind could be deployed to the end of 2020, within the LCF budget. DECC's projections since then, based on the Renewable Energy Planning Database, and other sources, have increased to between 12 to 15GW in the absence of changes to the RO. In the absence of intervention, onshore wind could add to the over-allocation of renewable energy subsidies against the LCF. As the costs of the levy funded schemes are paid for by consumers through their energy bills, the Government takes potential risks to the LCF seriously and will act where necessary to ensure that costs are contained.

What are the policy objectives and the intended effects

The policy objective is to remain as close to the limits of the LCF and EMR Final Delivery Plan ranges as possible, by limiting spend on onshore wind under the RO while seeking to provide protection for projects that have made a significant financial commitment. The policy will result in a reduction in deployment of between 0 and 2.5GW, with a central estimate of 200MW, which will limit spend on onshore wind under the RO.

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

This IA considers Option 1: Do Nothing and Option 2: RO closure to new onshore wind from 1st April 2016 – a year earlier than planned - with a grace period for projects which, as of 18th June 2015, already had planning consent, a grid connection offer and acceptance or confirmation that no grid connection is required, and evidence of land rights for the site on which their project will be built. As announced on 18th June 2015 the Government's preferred option is Option 2. This option limits risk of future overspend against the LCF from new onshore wind under the RO, while seeking to attain projected EMR deployment rates and make provision for projects that have made a significant financial commitment.

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

Does implementation go beyond minimum EU requirements?			No		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** Yes	**< 20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** (0-63)	**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: Nick ***Date:*** 9/9/15

Summary: Analysis & Evidence Lead Policy Option

Description: Closure of renewables obligation to new onshore wind on 31st March 2016 subject to the grace period set out in this document.

FULL ECONOMIC ASSESSMENT

Price Base Year	PV Base Year	Time Period Years	Net Benefit (Present Value (PV)) (£m)		
2012	2013/14	24	**Low: £0**	**High: £2,030**	**Best Estimate: £160**

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				-
High				**£2,080m**
Best Estimate				**£170m**

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

The monetised costs are the increase in costs of EU Emissions Trading Scheme allowance (EUA) purchases to the UK power sector compared to the Do Nothing option (as less onshore wind is deployed, it is modelled that generation from fossil fuels increases and as a consequence more EUAs are purchased, compared to the Do Nothing option).

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

Wider impacts on sector investment, employment and supply chains. Air quality impacts due to increased fossil fuel generation. Option 2 reduces the ability for onshore wind to deliver additional capacity if other technologies do not deploy at the predicted levels for the 2020 renewables energy target compared to the Do Nothing option, but is in line with the forecast deployment range for this technology of 11 – 13GW.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				-
High				**£4,110m**
Best Estimate				**£330m**

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

The monetised benefits are the lower resource costs of generating electricity through modelled cheaper alternatives rather than onshore wind, due to reduced onshore wind uptake compared to Doing Nothing.

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

Reduced risk to LCF from over-allocation of renewable energy subsidies, and benefit to consumers from reductions in consumer energy bills (in 2016/17 average household electricity bills could be up to £3.40 (0.6%) lower, with a central estimate of around £0.30 (0.05%), compared to the Do Nothing option) (2014 prices).

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

The results are sensitive to expected deployment rates under the Do Nothing option, which are sensitive to assumptions over attrition rates and the speed at which projects can gain planning permission and complete construction. Monetised impacts are sensitive to onshore wind generation cost assumptions and assumed counterfactual generation costs and emission factors.

BUSINESS ASSESSMENT

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

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1. Problem under consideration

1.1. The Government was elected with a commitment to end new subsidies for onshore wind and also to change the law so that local people have the final say on onshore wind applications.[1]

1.2. The EU Renewable Energy Directive commits the UK to meeting 15% of its energy needs from renewable sources by 2020. The Renewables Obligation (RO), introduced in 2002, currently supports the overwhelming majority of current and future renewable capacity and has so far been the Government's main financial policy mechanism for incentivising the deployment of large scale renewable electricity generation in the UK. The RO places an obligation on UK electricity suppliers[2] to source an increasing proportion of the electricity they supply from renewable sources. Renewables Obligation Certificates (ROCs) are issued to operators of accredited renewable generating stations for the eligible renewable electricity they generate. ROCs are then used by suppliers to demonstrate that they have met their obligation.[3]

1.3. Since the introduction of the RO in 2002, there has been a significant increase in the UK's renewable generation, from 2.8% of all electricity generation to 19.1% in 2014.[4] In its current state the RO will close to new renewable generating capacity from 1st April 2017, whilst maintaining support for existing generating capacity in the scheme out to their respective end dates (of which the latest would be expected in 2037).[5] As part of the Electricity Market Reform (EMR), large-scale (i.e. greater than 5MW) renewable electricity projects will be eligible to receive support through the Contracts-for-Difference scheme (CFD).

1.4. The Government's view is that the CFD is a more cost-effective mechanism to support renewable energy generation than the RO. The CFD provides for earlier certainty of support levels than the RO and greater stability of revenue streams. By providing a fixed strike price investors are protected from wholesale price volatility and should benefit from a reduction in their cost of capital, which combined with a competitive allocation for CFDs should make the development of low carbon generation cheaper for both investors and consumers.

1.5. The first CFD allocation round took place in October 2014. On the 26th February 2015 DECC published the first CFD auction results and statistics.[6] The competitive auction was successful in allocating 27 contracts. In March 2015 25 projects signed contracts, worth over £300m per year,[7] which could bring forward over 2GW of renewable electricity capacity - bringing costs down and driving value for money for consumers (around £105m per year less than it would have been without competition).[8]

1.6. The Levy Control Framework (LCF) sets annual limits on the overall cost of DECC's levy funded policies.[9] The LCF is the means by which Government supports multiple low-carbon technologies, and as such any increase in spend for one sector from the LCF will reduce the level of support available for other sectors within the Framework. As the costs of the levy funded schemes are paid for by consumers through their energy bills, the Government takes potential risks to the LCF seriously and will act where necessary to ensure that costs are controlled and that consumers receive value for money from initiatives supported under the LCF.

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[1] https://s3-eu-west-1.amazonaws.com/manifesto2015/ConservativeManifesto2015.pdf

[2] The RO is executively devolved to Scotland and transferred to Northern Ireland meaning that the obligation on UK suppliers is made up of separate but concurrent obligations on suppliers in England and Wales, Scotland and Northern Ireland.

[3] If suppliers do not present a sufficient number of ROCs to Ofgem (which administers the scheme) to meet their obligation, they can pay an equivalent amount into a buy-out fund, which is re-distributed to those that submit ROCs once Ofgem's administration costs are paid for. Further detail on the Renewables Obligation can be found on Ofgem's website: https://www.ofgem.gov.uk/environmental-programmes/renewables-obligation-ro

[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/437937/Renewable_energy_in_2014.pdf

[5] The Renewables Obligation Closure Order 2014 came into effect on 9th September 2014 and provides for the RO to close to new capacity on 31st March 2017, subject to the grace periods set out in the Order.

[6] https://www.gov.uk/government/statistics/contracts-for-difference-cfd-allocation-round-one-outcome

[7] Including two new offshore wind farms, 15 onshore wind farms, and 3 new solar projects.

[8] The £105m reflects an update to the £110m benefit identified at the time of the CfD auction results, to reflect the number of projects which signed contracts.

[9] The LCF covers the RO, the small-scale Feed-In Tariffs scheme, Warm Homes, Investment Contracts for the Final Investment Decision Enabling for Renewables process, and CFD.

1.7.The Office for Budget Responsibility's latest projections show that subsidies raised from bills are currently set to be higher than when the control framework for DECC's levy-funded spending was agreed. This is due to a number of uncontrollable factors such as lower wholesale electricity prices, higher than expected uptake of the demand-led Feed in Tariffs (such as solar panels on roofs) and the RO, and a faster than expected advancement in the efficiency of the technology meaning renewables are projected to generate more electricity than previously estimated.

1.8.The Government was elected with a commitment to end new subsidies for onshore wind and to change the law so that local people have the final say on onshore windfarm applications. Onshore wind has deployed successfully to-date and is an important part of the UK's energy mix. On 18th June 2015 the Secretary of State for Energy and Climate Change announced that there is now enough onshore wind in the pipeline, subsidised by bill payers through the RO or CFD, for onshore wind to play a significant part in meeting our renewable energy commitments.

1.9.Analysis suggested that after taking account of early closure, 2020 onshore wind deployment would be above the middle of the range set out in the EMR Delivery Plan, DECC's best estimate of the contribution needed from onshore wind to meet 2020 targets. As a result, it is appropriate to curtail further deployment of onshore wind, balancing the interests of developers with those of the wider public.[10]

1.10.To this end the announcement stated that the Government would legislate to close the RO to new onshore wind from 1st April 2016 in Great Britain – a year earlier than previously planned.[11] To protect investor confidence in the wider renewables sector, a grace period would continue to give access to support under the RO to those projects which, as of June 18th 2015, already had planning consent, a grid connection offer and acceptance or confirmation that no grid connection is required, and evidence of land rights for the site on which their project will be built.[12] The Government stated that it wished to hear views from industry and other stakeholders before framing the terms of the grace period in the legislation.[13]

1.11.In conjunction with the announcement to close the RO to new onshore wind the Government also announced measures so that decisions for large onshore wind projects (greater than 50MW) are no longer made under the Planning Act 2008 and Electricity Act 1989 but instead under the Town and Country Planning Act (1990) in England and Wales. This measure will operate in England in conjunction with the new planning considerations set out on 18th June 2015 by the Secretary of State for Communities and Local Government. The effect of this will be to give local communities the final say on all new onshore wind planning applications and thus meet the Government's manifesto commitment.

1.12.On 7th July 2015 DECC published further information on the proposed RO grace period for new onshore wind and details on the engagement process with industry, developers and other stakeholders affected by the proposals.[14]

1.13.An engagement exercise was held with hundreds of industry representatives, developers, investors and supply chain representatives, across Scotland, England and Wales, which concluded on 31st July 2015. The engagement process included a series of roundtable discussions with core industry representatives, a range of bilateral meetings and several large stakeholder events. In addition, DECC received a substantial amount of written evidence from stakeholders across the UK energy sector, including onshore wind developers, trade bodies, investors, supply chain companies, as well as from the Devolved Administrations.

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[10] https://www.gov.uk/government/speeches/ending-new-subsidies-for-onshore-wind

[11] As energy policy is transferred in Northern Ireland the SofS announced that she was in discussions with NI Ministers about how commitments on onshore wind might be implemented in Northern Ireland.

[12] The Government will continue to offer projects that are subject to grid or radar delays a 12 month grace period to enter the RO, as set out in March 2014.

[13] The announcement also stated that for CfDs the tools were available to implement manifesto commitments on onshore wind and these would be set out when announcing plans in relation to further CfD allocations. The SofS also announced that she would be shortly considering options for continued support for community onshore wind projects through the feed-in tariff (FITs) as part of the review that DECC would be conducting this year.

[14] https://www.gov.uk/government/publications/renewables-obligation-ro-grace-period-for-new-onshore-wind

1.14. This Impact Assessment sets out the evidence used to inform the policy proposal as announced on 18th June 2015. DECC is carefully reviewing the feedback and evidence provided during the engagement exercise to ensure that the final policy strikes the right balance between the public interests involved - including protecting consumer bills and ensuring the right mix of energy - and the interests of onshore wind developers and the wider industry. The IA will be updated when we have reviewed the evidence from the engagement exercise.

1.15. The analysis set out in this IA is based on an aggregate assessment of the onshore wind pipeline. Although the analysis informing this IA considers individual projects (where information was provided by those projects), it does not make predictions or forecasts about which individual projects will or will not commission. Instead it assesses likely capacity changes in aggregate. The market and developers will determine which individual projects do or do not commission.

2. Rationale for intervention/policy objective

2.1. The policy objective is to implement the Government's manifesto commitment to end new subsidies for onshore wind, and remain as close as possible to the limits of the LCF by limiting spend on onshore wind under the RO (while seeking to provide protection for projects that have made a significant financial commitment).

2.2. The Secretary of States announcement on 18th June 2015 stated that, after taking account of early closure, onshore wind deployment under the RO was expected to be in the region of 11.6GW. With the addition of 0.75GW of onshore wind that has secured a CFD, onshore wind deployment was expected to be in the middle of the range set out in the EMR Delivery Plan, needed to meet the 2020 renewable energy target.

2.3. DECC's analysis informing the announcement on 18th June 2015 was based on the April 2015 Renewable Energy Planning Database (REPD) and intelligence from market participants. Further updates to the REPD have been accessible since the June announcement. However, to ensure consistency, this IA uses April REPD data and the market intelligence consistent with the analysis undertaken for the June announcement. This suggests:

- **10.4GW** of projects already operating or under construction;
- **0.75GW** of projects supported under CFDs;
- **2.9GW** with planning approval awaiting construction that could theoretically construct[15]; and
- **7.1GW** that has applied for planning approval across the UK and awaiting decisions by the relevant planning authority.

2.4. It is unlikely that all of the 2.9GW of projects with planning approval will construct, and even without closing the RO to new onshore wind a year early, DECC would not expect all the 7.1GW of projects that have applied for planning permission to be able to deploy before the 31st March 2017 closure date.

2.5. An assessment of the range of deployment potential is presented in Table 1, using assumptions about the proportion of projects which could commission by the 31st March 2017. This suggests that without intervention, 2020 onshore wind capacity could be between 12 and 15GW. Details on the assumptions made to inform this range are set out below.

[15] Adjusted estimate from REPD, in particular removing c900MW of projects assumed to be under construction and the c750MW of projects that were successful in the first CFD auction.

Table 1: Deployment for the Final Delivery Plan and revised estimates (Do Nothing option)

	Deployment Scenario	Low	Central	High
Final Delivery Plan scenarios[16]	**Deployment in 2020 under RO and CFD (GW)**		**11-13**	
Option 1: Do nothing option	*Operational*	*8.3*	*8.3*	*8.3*
	Under Construction	*2.2*	*2.2*	*2.2*
	Supported under CFDs	*0.7*	*0.7*	*0.7*
	With planning, awaiting construction	*0.6*	*1.2*	*1.8*
	Applied for planning	-	*0.2*	*2.5*
	Deployment in 2020 under RO and CFD (GW)	**11.8**	**12.5**	**15.5**

Note: Capacity figures rounded to nearest 100MW. Figures may not sum due to rounding.

2.6. All scenarios assume 8.3GW of capacity currently operational with a further 2.2GW under construction and 0.75GW supported through CFDs. The range in deployment concerns the proportion of projects with planning and could theoretically construct (2.9GW), and those which have applied for planning (7.1GW), which commission by 31st March 2017. Table 2 sets out the assumptions used across the low, central and high scenarios.

Table 2: Capacity deployment assumptions under the Do Nothing option

	Low	Central	High
With planning, awaiting construction (GW)		2.9	
Proportion deploying	20%	40%	60%
Capacity with planning commissioning (GW)	0.6	1.2	1.8
Applied for planning (GW)		7.1	
Assumption	No capacity which has applied for planning deploys	Average recent planning approval and construction rates	Projects are able to get planning approval and construct as quickly as the top 5% of recent projects
Capacity applied for planning commissioning (GW)	0	0.2	2.5

2.7. It is difficult to be certain about how much of the 2.9GW is likely to deploy. There are various factors that would result in increases or decreases of how much might be able to deploy. For example, some of the projects received planning approval before 2010, and therefore may be considered unlikely to go ahead, though this is not completely certain. Conversely, as the RO offers a higher level of support than CFDs, based on the auction outcomes from the first CFD allocation round, developers may be willing to take more commercial risk with the intention of accrediting under the RO in time; they may be also be less willing to take the risk given the

[16] The low scenario is consistent with high technology cost scenario in the Final Delivery Plan. The high scenario is consistent with the low technology cost scenario. See Final Delivery Plan documentation, Annex D: report from the system operator National Grid: https://www.gov.uk/government/uploads/system/uploads/ attachment_data/file/267614/Annex_D_-_National_Grid_EMR_Report.pdf

uncertainty about constructing in time. In addition, there are supply chain constraints to consider – within the UK, onshore build over the last few years has tended to be in the region of 1-1.5GW per year; it is far from certain that the supply chain would be able to respond so that all 2.9GW could be constructed before the end of 2016/17. Therefore, a range of deployment scenarios has been used.

2.8. The **Low** scenario is based on the conservative assumption that 20 per cent of the capacity with planning consent but which is awaiting construction would commission, and no capacity which has applied for planning consent deploys. In such a scenario onshore wind capacity is **11.8GW** in 2020.

2.9. In the **Central** scenario we assume that 40 per cent of the capacity awaiting construction deploy. The Central scenario also assumes that 0.2GW of the capacity which has applied, but does not yet have planning permission, commissions. This is based on how quickly projects have received planning approvals and then constructed over recent years. As a result, the Central scenario assumes **12.5GW** of onshore wind capacity by 2020.

2.10. In the **High** scenario, we assume that 60 per cent of the capacity awaiting construction deploy. We also make a more ambitious assumption about the amount of capacity commissioning which does not currently have planning permission. If all 7.1GW of projects in this category were able to get planning approval and construct as quickly as the top 5% of recent projects, around 2.5GW of the capacity could commission by the end of March 2017. As a result in the High scenario 2020 onshore wind capacity could be as high as **15.5GW**.[17]

2.11. All scenarios suggest deployment above the lower bound of the Final Delivery Plan range (11-13GW). The Office for Budget Responsibility's latest projections show that subsidies raised from bills are currently set to be higher than when the control framework for DECC's levy-funded spending was agreed.[18] This is due to a number of uncontrollable factors such as lower wholesale electricity prices, higher than expected uptake of the demand-led Feed in Tariffs (such as solar panels on roofs) and the RO, and a faster than expected advancement in the efficiency of the technology, meaning renewables are projected to generate more electricity than previously projected.

2.12. As a result of the Government's desire to ensure consumers are protected from higher energy bills, on the 22nd July 2015 DECC announced a series of proposals to deal with this projected over-allocation of renewable energy subsidies in addition to the early closure of the RO to new onshore wind.[19] The announcement included: confirmation of removing the guaranteed level of subsidy for biomass conversions and co-firing projects for the duration of the RO; launching a consultation on controlling subsidies for solar PV of 5MW and below under the RO; and a consultation on changes to the preliminary accreditation rules under the Feed-in Tariff (FIT) scheme.

2.13. In the absence of intervention, onshore wind could add to the over-allocation of renewable energy subsidies against the LCF. As the costs of the levy funded schemes are paid for by consumers through their energy bills, the Government takes potential risks to the LCF seriously and will act where necessary to ensure that costs are contained. Therefore, in order to reduce the risk of over-allocation to onshore wind, the preferred option is to close the RO to new onshore wind from 1st April 2016, a year earlier than planned, with a grace period for projects which, as of 18th June 2015, already have planning consent, a grid connection offer and acceptance or confirmation that no grid connection is required, and evidence of land rights for the site on which their project will be built, allowing these projects to accredit until 31st March 2017. The Government will continue to offer projects that are subject to grid or radar delays a 12 month grace period to enter the RO, as set out in March 2014.

[17] Under a more ambitious assumption that all projects are approved and construct as quickly as the fastest projects observed then 4.8GW of capacity could potentially commission. As such there is upside risk beyond the high scenario presented in this IA.

[18] Table 2.7 http://budgetresponsibility.org.uk/economic-fiscal-outlook-supplementary-fiscal-tables-july-2015/

[19] https://www.gov.uk/government/news/controlling-the-cost-of-renewable-energy

3. Description of options considered

3.1. The October 2014 IA which presented the impact of controlling spending on large-scale solar PV within the RO, considered alternative options to closing the RO to new capacity, including a supplier cap and a banding review.[20] For similar reasons as those set out in the Government's response to the large-scale solar consultation these options are not considered as alternative options to closing the RO to new onshore wind capacity a year earlier than planned.[21]

RO closure to new build Onshore wind (Option 2: preferred response option)

3.2. The preferred option, as announced on June 18th 2015, is to close the RO to new onshore wind from 1st April 2016, a year earlier than planned, with a grace period for projects which, as of 18th June 2015, already have planning consent, a grid connection offer and acceptance or confirmation that no grid connection is required, and evidence of land rights for the site on which their project will be built, allowing these projects to accredit until 31st March 2017.

3.3. The costs and benefits, based on analysis consistent with the 18th June policy announcement, are assessed in section 4, against the Do Nothing option (taking no action under the RO to constrain deployment of onshore wind).

3.4. The Government will continue to offer projects that are subject to grid or radar delays a 12 month grace period to enter the RO, as set out in March 2014.

3.5. This option will enable spending on (and deployment of) onshore wind to be reduced under the RO relative to not intervening, whilst still providing a grace period designed to protect projects that made a significant financial commitment on or before 18th June 2015.

3.6. It is difficult to forecast deployment up to the end of the RO due to uncertainties about behaviour of industry and developers. To reflect the uncertainty in onshore wind deployment, this IA considers a range of deployment reductions. At the time of the policy announcement, our best estimate was that implementing the policy in this way could lead to between 12 and 13GW of onshore wind capacity coming forward by 2020. This reduces the risk of deployment exceeding the upper end of the EMR Delivery Plan range, which there is a risk of in the Do Nothing option. Therefore, as a result of the policy option, onshore wind capacity could be up to 2.5GW lower than under the Do Nothing option, with capacity in the central scenario 200MW lower.

3.7. The deployment estimates under Option 2 are outlined in Table 3 below. This demonstrates that with closure of the RO from 2016/17 to new onshore wind projects, deployment could be between 11.8 and 12.9GW, with a central estimate of 12.3GW. Compared to the Do Nothing option the saving in annual RO spend could be up to £270m, with a central value of £20m (2011/12 prices).

Table 3: Deployment and annual spend for Option 2 (£2011/12)

	Deployment Scenario	Low	Central	High
Option 2 (recommended option) Close RO to new onshore wind from 1st April 2016 with grace period	Deployment (GW)	11.8	12.3	12.9
	Change in RO annual spend compared to Do Nothing option (£m)	-	-20	-270

Note: Capacity figures rounded to nearest 100MW. Spend figures are rounded to the nearest £10m

3.8. Option 2 is likely to increase the administrative costs of the scheme, faced by Ofgem. These costs are paid for through the buyout fund and so do not increase the overall costs of the

[20] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/360305/141001_-_RO_closure_IA_government_response_v0_6_IAG_2014.pdf

[21] https://www.gov.uk/government/consultations/consultation-on-changes-to-financial-support-for-solar-pv

scheme, but instead mean those electricity suppliers that submit ROCs receive slightly less back from the buyout fund than they would have done otherwise. To put this into context, the buyout fund in 2013/14 was around £40m, of which around £4.3m were Ofgem's administration costs (£2013/14 prices).[22] Ofgem forecast the cost for the administration of the RO for 2014-15 at £3.9m, roughly 0.12% of the estimated value of the scheme as a whole.[23]

3.9. There remains uncertainty around likely deployment under this option. Therefore, the estimated deployment and spend figures should be considered as scenarios, used to give an indicative range.

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[22] https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-buy-out-fund-2013-14

[23] https://www.ofgem.gov.uk/sites/default/files/docs/2014/09/comment_period_on_2014-15_ro_admin_costs_0.pdf

4. Monetised and non-monetised costs and benefits

4.1. This section outlines the monetised and non-monetised costs and benefits of the following shortlisted options:

- Option 1: Do Nothing
- Option 2: RO closure to new onshore wind from 1st April 2016 with grace period

Option 1: Do Nothing

4.2. Under this option RO bands for new onshore wind installations would remain at current levels as set out in Table 4.

Table 4: RO support bands for Onshore wind installations from 2015-17 (ROCs/MWh of renewable electricity supplied)[24]

Current Bands	2015/16	2016/17
Onshore wind	0.9	0.9

4.3. Table 5 summarises the deployment projections under the Do Nothing option consistent with the June 18th announcement, against those estimated for the Final Delivery Plan. The Final Delivery Plan examined a range of scenarios, with a deployment range between 11-13GW by 2020.[25] Under the Do Nothing option deployment, and therefore spend, is at risk of being above the deployment range presented in the Final Delivery Plan.

4.4. DECC's projections consistent with the June 18th announcement estimate that 2020 onshore wind deployment, in the absence of intervention, could be between 12 and 15GW. The upper end of this range is significantly higher than the 11-13GW set out at the time of the EMR Delivery Plan.

Table 5: Onshore wind deployment in 2020 under Final Delivery Plan and pipeline projections under Option 1

	Deployment Scenario	Low	Central	High
Final Delivery Plan scenarios	Deployment (GW)		11-13	
Option 1: Do nothing option	Deployment (GW)	11.8	12.5	15.5

Note: Capacity figures rounded to nearest 100MW

24 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/211292/ro_banding_levels_2013_17.pdf

25 See Final Delivery Plan documentation, Annex D: report from the system operator National Grid https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267614/Annex_D_-_National_Grid_EMR_Report.pdf

Table 6: Onshore wind deployment based on pipeline projections under Option 1

Option 1 – Cumulative deployment (GW)	Low	Central	High
Operational	*8.3*	*8.3*	*8.3*
Under Construction	*2.2*	*2.2*	*2.2*
Supported under CFDs	*0.7*	*0.7*	*0.7*
Awaiting construction	*0.6*	*1.2*	*1.8*
In planning	*-*	*0.2*	*2.5*
Total	**11.8**	**12.5**	**15.5**

4.5. This option takes no action to address the over-allocation of renewable energy subsidies against the LCF and does not mitigate the risk of further overspend from RO deployment. It is therefore not recommended.

Option 2: Preferred Option - RO closure to new onshore wind from 1st April 2016 with grace period

4.6. This option would allow new onshore wind projects to apply for RO accreditation until 31st March 2016. Projects which, as of 18th June 2015, already had planning consent, a grid connection offer and acceptance or confirmation that no grid connection is required, and evidence of land rights for the site on which their project will be built would benefit from a grace period giving them until 31st March 2017 to apply for RO accreditation.[26] Estimated deployment consistent with the June 18th announcement is given in Table 7, alongside the change in annual RO spend compared to the Do Nothing option.

Table 7: Onshore wind deployment in 2020 and change in annual RO annual spend relative Option 1 (£2011/12) based on pipeline projections under Option 2

	Deployment Scenario	Low	Central	High
Option 2: RO closure to Onshore Wind	Deployment (GW)	11.8	12.3	12.9
	Change in RO annual spend compared to Do Nothing option (£m)	-	-20	-270

Note: Spend figures are rounded to the nearest £10m

Table 8: Onshore wind deployment based on pipeline projections under Option 2

Option 2 – Cumulative deployment (GW)	Low	Central	High
Operational	*8.3*	*8.3*	*8.3*
Under Construction	*2.2*	*2.2*	*2.2*
Supported under CFDs	*0.7*	*0.7*	*0.7*
Awaiting construction	*0.6*	*1.2*	*1.8*
In planning	*-*	*-*	*-*
Total	**11.8**	**12.3**	**12.9**

4.7. Table 7 suggests that with the closure of the RO from 1st April 2016 to new onshore wind projects, annual RO spend could be up to £270m lower in comparison to the Do Nothing option. In the central scenario annual RO spend would be around £20m lower (2011/12 prices). As a result in 2016/17 average household electricity bills could be up to £3.40 (0.6%) lower, with a central estimate of around £0.30 (0.05%), compared to Option 1: Do Nothing. For medium-sized

[26] The Government will continue to offer projects that are subject to grid or radar delays a 12 month grace period to enter the RO, as set out in March 2014.

businesses average electricity bills in 2016/17 could be up to 0.8% lower under Option 2, with a central estimate of 0.1%, compared to Option 1: Do Nothing (2014 prices).[27] Therefore, in terms of the impact on electricity prices and bills, the option to take action under the RO is preferred to the Do Nothing option.

Monetised Impacts

4.8. The monetised costs and benefits associated with Option 2, relative to Option 1 (the Do Nothing scenario), are presented in the Table below. The costs and benefits assess the impact of the policy options on lifetime resource costs, and lifetime carbon costs. The low, central and high scenarios are based on the low, central and high deployment scenarios presented in Tables 5 and 7, and alternative input assumptions, discussed further below. The range in the Table below therefore reflects the combination of two factors: alternative deployment ranges and alternative assumptions about what will replace lower onshore wind generation under Option 2.

4.9. Following a similar methodology to the IA assessing the impact of controlling spending on large-scale solar PV within the RO,[28] in the low scenario the lifetime resource costs are calculated as the difference between the central levelised cost estimates of onshore wind and the long run variable cost (LRVC) of electricity supply.[29] As such, in the low scenario a lower level of onshore wind generation is assumed to be replaced by an increase in electricity from alternative sources, captured by the LRVC of electricity supply, which includes a mix of fossil fuel, renewable and other forms of low carbon generation.[30]

4.10. In the high scenario lifetime resource costs are calculated as the difference between the central levelised cost estimates of onshore wind and the marginal cost of generation from an indicative thermal generator.[31] As such, in the high scenario a lower level of onshore wind generation is assumed to be replaced by an increase in electricity generation from thermal generators (in particular CCGT generators).

4.11. The alternative values in the low and high scenarios are used to illustrate the potential range of impacts the policy option could have. The net impact of the policy option is dependent on which alternative energy source would generate in the absence of onshore wind generation. The low and high assumptions reflect two alternative assumptions, and combine with the capacity assumptions to provide a range on the potential net welfare impact. In the central scenario the marginal cost from the thermal generator is used, although an alternative impact using the LRVC is also presented at the end of this section.

4.12. If lower onshore wind generation is not replaced by alternative low carbon generation then we would also expect higher carbon emissions. The increase in CO_2 emissions under Option 2, relative to Option 1, is assessed by estimating the CO_2 emission intensity of the generation which replaces onshore wind. In the low scenario, the increase in carbon emissions from lower onshore wind generation is estimated using DECC's long run marginal emissions factors.[32] In the central and high scenario an estimated CCGT CO_2 emissions factor is used.[33] The UK power sector is part of the EU Emissions Trading System (EU-ETS). This means that any increases in UK power sector greenhouse gas emissions will be offset by reductions elsewhere in the EU-ETS. However, there is a cost to the UK from such emissions increases in terms of carbon allowance (known as EUAs) purchase costs. Therefore emission increases under Option 2,

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[27] A medium business energy user is defined here as a business within the CRC Energy Efficiency Scheme. Percentage bill impacts on other non-domestic consumers, for example small business users and Energy Intensive Industries (EIIs) are similar.

[28] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/360305/141001_-_RO_closure_IA_government_response_v0_6_IAG_2014.pdf

[29] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf DECC is currently undertaking an update to its generation cost estimates, however these are not yet available.

[30] LRVC values are presented in Table 9: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal. For this analysis a weighted average across the domestic, commercial and industrial sectors (central scenario) is used. Adjustment made to account for Transmission and Distribution costs.

[31] The indicative plant is assumed to be a CCGT plant. Costs are net of associated carbon costs.

[32] Table 1: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

[33] This takes the value of around $0.37kgCO_2/kWh$

relative to the Do Nothing option, are valued at the DECC central traded carbon appraisal values.[34]

4.13. Option 2 leads to lower resource costs as generation from onshore wind is reduced compared to the Do Nothing option. As the cost of generating additional electricity with new onshore wind capacity is higher than the electricity generating alternative in the central and high scenario, lower onshore wind generation lowers resource costs. In the central scenario the benefits from lower resource costs are £330m, whereas in the high scenario they are estimated to be £4,110m (Present Value (PV), 2012 prices).

4.14. However as a result of lower onshore wind generation, carbon emissions are higher under Option 2, relative to Option 1 in the central and high scenarios. Lifetime CO_2 emissions are up to 63MtCO_2e higher under Option 2, relative to Option 1. To reflect higher EUA purchases as a result of higher emissions under Option 2 (offset by increases elsewhere in the EU)[35], the emission change under Option 2 is valued using DECC central traded carbon appraisal values. In the central scenario the cost from increased EUA costs is £170m, whereas in the high scenario they are estimated to be £2,080m (PV, 2012 prices).

4.15. The Net Present Value of Option 2 compared to Option 1 reflects the overall impact of lower resource costs, but higher carbon costs, under Option 2 in comparison to Option 1. In the central scenario the benefits from lower resource costs (£330m) outweigh the cost from increased EUA purchases (£170m), with a £160m net benefit (NPV, 2012 prices). In the high scenario the benefits from lower resource costs (£4,110m) also outweigh the cost from increased EUA purchases (£2,080m), with a £2,030m net benefit (NPV, 2012 prices). In the low scenario onshore wind capacity levels are the same under Option 1 and Option 2, as such there are no costs or benefits associated with changes in onshore wind capacity.

Table 9: Net Present Value (NPV) of Option 2 compared to Option 1 (calculated over an assumed technology lifetime of 24 years for onshore wind to 2040/41, 2012 prices)[36]

Deployment Scenario	Low	Central	High
Benefits: Reduced lifetime resource costs, £m, PV, 2012 prices	-	+330	+4,110
Costs: Increased EUA costs, £m, PV, 2012 prices	-	-170	-2,080
NPV, £m, 2012	**-**	**+160**	**+2,030**

Source: DECC internal modelling. Note: all spend figures are rounded to the nearest £10m and discounted at the social discount rate. Figures may not sum due to rounding.

4.16. The low scenario implies that Option 2 would have no net impact, reflecting the fact that onshore wind capacity levels are the same in Option 2 as in the Do Nothing scenario. Given there is no change in capacity, it is not possible to observe the role of the alternative input assumptions in the low scenario. The costs of onshore wind generation, as implied by the levelised cost, are, in future years, lower than the costs of alternative generation when using the LRVC. As such, when using the LRVC, reductions in onshore wind capacity increase resource costs. In contrast, the marginal cost of a thermal generator is lower than the levelised cost of onshore wind generation and therefore reductions in onshore wind capacity imply a benefit from lower resource costs (as observed in the Central and High scenarios). The counterfactual assumptions also impact carbon costs, by changing the assumption over the amount of carbon generated in response to lower onshore wind generation.

[34] Table 3: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

[35] The UK power sector is part of the EU Emissions Trading System (EU-ETS). This means that any reductions in UK power sector greenhouse gas emissions will be offset by increases (or foregone reductions) elsewhere in the EU-ETS. However, there is a benefit to the UK from such emissions reductions in terms of avoided carbon allowance (known as EUAs) purchase costs.

[36] Assuming capacity commissions part-way through 2016/17 with a 24 year plant life. Present Value base of 2013/14.

4.17. To illustrate the impact of these assumptions, the central scenario could also be calculated using the assumptions used in the low scenario – that is, assuming the cost of replacement generation is DECC's LRVC, and using DECC's long-run marginal emissions factor. If this were the case the value of increased EUA costs under Option 2, relative to Option 1, would be £50m (PV, 2012 prices). Using the LRVC would also suggest higher resource costs under Option 2, relative to Option 1, as a result of the onshore wind levelised cost being lower than the LRVC in later years. As a result there would be an additional £50m (PV, 2012 prices) cost from Option 2 in comparison to the Do Nothing option. Using these alternative assumptions would therefore suggest an NPV of Option 2 compared to the Do Nothing scenario of -£100m (NPV, 2012 prices). The assumption that reduced onshore wind generation is replaced by increased generation from a CCGT plant is used in the Table above as it is deemed the most credible outcome for onshore wind capacity changes in the central and high scenario. However the alternative result is presented to illustrate the sensitivity of the results to alternative input assumptions.

4.18. The net impact of the policy option is dependent on what would generate in the absence of onshore wind generation. This counterfactual is unobservable. As a result this analysis assumes that the counterfactual is either the long run variable cost (LRVC) of electricity, which includes a mix of fossil fuel, renewable and other forms of low carbon generation or the marginal generation cost associated with a thermal generator. In other words, if onshore wind were allowed to continue to deploy as in the Do Nothing option it assumes (all other things being equal) electricity generated from a mix of other fossil fuel, renewable and low carbon alternatives would be displaced in the low scenario, and electricity generated by a CCGT generator would be displaced in the central and high scenario.[37]

4.19. In conclusion, from a net welfare analysis, it is preferable to take action under the RO to limit spend (and therefore deployment) of onshore wind compared to the Do Nothing option.

Non-monetised impacts

4.20. It should be noted that the monetised costs and benefits above do not include several wider impacts, principally those relating to investment, security of supply, the UK meeting its renewable energy targets, and potential macroeconomic effects. These are covered below, though given the change in onshore wind deployment in the central scenario in this impact assessment, these impacts are likely to be small and difficult to quantify.

4.21. Security of supply impacts: The Do Nothing option (Option 1) would marginally reduce reliance on imported fossil fuels relative to Option 2, but would also increase the amount of intermittent generation, which would increase the need for balancing services, back-up generation, interconnection, storage and/or demand-side response. The costs of any additional balancing services have not been quantified. They will depend on the overall level and composition of intermittent generation on the grid, meaning it is difficult to isolate the costs associated with onshore wind alone. DECC is currently undertaking a project on whole system impacts of different electricity generation technologies which aims to systematise DECC's understanding of whole system impacts and supplement DECC's modelling to formally take into account the whole system impacts (both costs and benefits) of low carbon, renewable and conventional technologies. The project focuses on the impacts on electricity generation and the transmission and distribution network; wider environmental and social impacts of electricity generation are not included.

4.22. Risk of missing 2020 renewables target: Option 2 reduces the ability for onshore wind to deliver additional capacity if other technologies do not deploy at the predicted levels for the 2020 renewables energy target compared to the Do Nothing option, but is in line with the forecast deployment range for this technology of 11 – 13GW, presented in the Final Delivery Plan, which took account of the 2020 renewable energy target.

4.23. Macroeconomic and Investment impacts: Growth in the onshore wind sector is anticipated to be lower under Option 2. However, certain resources are likely to be redeployed into other sectors

[37] An alternative approach to the NPV analysis would be to assess the policy option in a dispatch model. Although DECC's Dynamic Dispatch Model (DDM) is used in many cases to assess the NPV impact of policy changes, in this case, given the relatively small capacity changes in the central scenario, the costs and benefits of the policy are better presented without the use of a dispatch model.

meaning, any net impact on GDP is likely to be reduced. While this could lead to a reduction the number of people employed in the onshore wind sector, the net impact on GB-wide employment is uncertain. DECC is carefully reviewing the feedback and evidence provided during the engagement exercise to ensure that the final policy strikes the right balance between the public interests involved - including protecting consumer bills and ensuring the right mix of energy - and the interests of onshore wind developers and the wider industry.

4.24. Employment and supply chain impacts: According to the DECC Investment Report published in March 2015, as of 2013 there were an estimated 19,000 people employed in the onshore wind sector, with around £8bn worth of investment in onshore wind between 2010 and 2014.[38] The central scenario suggests a relatively small reduction in onshore wind deployment under Option 2, which may result in less employment in the onshore wind sector, and potential knock-on impacts on skills and supply chains, relative to the Do Nothing option. However, under Option 2 there is still a strong pipeline of projects due to deploy up to 2020, helping us to meet 2020 renewable energy targets. As such there is still investment and construction opportunities in the sector, as well as the ongoing maintenance and management opportunities associated with the increased stock of capacity (which by 2020 should be similar to deployment ranges estimated for the Delivery Plan).

4.25. Community benefits impact: The October 2014 publication, Community Benefits from Onshore Wind Developments: Best Practice Guidance for England, identified five potential community benefits associated with onshore wind development,[39] including: Community benefit funds; Benefits in-kind; Community investment (Shared ownership); Socio-economic community benefits and Material benefits.[40] Option 2 is expected to reduce the deployment of onshore wind projects and as such some communities will no longer gain from these potential benefits. Some of these benefits would be assessed as part of a planning application, and considered alongside any negative impacts on communities. Quantifying the value of lost potential community benefits is challenging. The potential value of community benefits will be varied and site specific. As the analysis in this IA does not consider the likelihood of individual projects commissioning, it is not possible to estimate individual community benefits lost as a result of Option 2 (or where those lost community benefits may be located). However, the wind industry though RenewableUK has consolidated the voluntary approach by producing a protocol which commits developers of onshore wind projects above 5MW in England to provide a community benefit package to the value of at least £5000 per MW of installed capacity per year, index-linked for the operational lifetime of the project. Assuming this was the value of the lost benefit to communities as a result of Option 2, the total cost to communities under the central scenario (with a 200MW reduction in onshore wind deployment relative to the Do Nothing option) would be around £1m a year, or a total discounted cost of just under £17m, for a typical onshore wind plant with an operational life of 24 years.

4.26. Environmental Issues: Option 2 will lead to lower levels of onshore wind deployment and hence increased carbon emissions within the UK power sector relative to the Do Nothing option, but these will be offset by decreases in emissions elsewhere in the EU within the capped EU-ETS traded emissions sector. It is therefore expected there will be no net impact on greenhouse gas emissions within the EU. Given the expected change in electricity generated through onshore wind is relatively small under the central scenario in Option 2, compared to total UK electricity generation, the resulting impact on air quality from a change in the generation mix is expected to be relatively small.

4.27. Small Firms: Compared to Option 1, Option 2 will result in slightly lower electricity RO support costs for electricity customers, including small firms. There may be an impact on some small supply chain firms supporting the onshore wind sector; and smaller and/or independent wind

[38] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/419024/DECC_LowCarbonEnergyReport.pdf

[39] Whilst the guidance was produced for England, it took into account examples of best practice from other parts of the UK where work is being undertaken in this area.

[40] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/363405/FINAL_-_Community_Benefits_Guidance.pdf
Community benefit funds are voluntary monetary payments from a developer to the community, usually provided via an annual cash sum. Benefits in-kind can include in-kind works, direct funding of projects, one-off funding, local energy discount schemes or any other non-necessary site-specific benefits. Socio-economic benefits include job creation, skills training, apprenticeships, opportunities for educational visits and raising awareness of climate change. Material benefits are derived from actions directly related to the development, such as improved infrastructure.

developers. DECC will continue to consider the feedback and evidence provided during the engagement exercise in order to ensure that the final policy strikes the right balance between the public interests involved - including protecting consumer bills and ensuring the right mix of energy - and the interests of onshore wind developers and the wider industry.

5. Summary and preferred option

5.1. The preferred response option, as announced on 18th June, is to close the RO to new onshore wind projects from 1st April 2016. Projects which, as of 18th June 2015, already had planning consent, a grid connection offer and acceptance or confirmation that no grid connection is required, and evidence of land rights for the site on which their project will be built would benefit from a grace period giving them until 31st March 2017 to apply for RO accreditation.

5.2. The Government will continue to offer projects that are subject to grid or radar delays a 12 month grace period to enter the RO, as set out in March 2014.

Table 10: Net Present Value of Option 2 compared to Option 1 (calculated over an assumed lifetime of 24 years for Onshore wind to 2040/41, 2012 prices)

	Low	Central	High
NPV (£m, 2012 prices)	-	£160	£2,030

Source: DECC internal modelling. Note: all spend figures are rounded to the nearest £10m and discounted at the social discount rate

5.3. In conclusion, based on analysis consistent with the 18th June announcement, it is preferable to take action under the RO to limit deployment of onshore wind compared to the Do Nothing option to minimise risks to the LCF of over-allocation of renewable energy subsidies. This option has a positive net present value under certain assumptions, helps to control costs to consumers and ensures we achieve a deployment level consistent with the range presented in the EMR Delivery Plan.

Implementation

5.4. 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.

5.5. 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.