Title: Contracts for Difference **IA No:** DECC0144 **Lead department or agency:** Department of Energy and Climate Change (DECC) **Other departments or agencies:** N/A	Impact Assessment (IA) **Date:** 10/10/2013 **Stage:** Consultation **Source of intervention:** Domestic **Type of measure:** Secondary legislation **Contact for enquiries:** Vikram.Balachandar@decc.gsi.gov.uk; Robert.Epstein@decc.gsi.gov.uk; Matthew.Taylor@decc.gsi.gov.uk

Summary: Intervention and Options

RPC: N/A

Cost of Preferred (or more likely) Option				
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**
£9.4bn	-	-	No	N/A

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

Reducing emissions from the power sector will become increasingly important to help us meet wider decarbonisation goals. There are several reasons to believe that the current market arrangements will not deliver power sector decarbonisation at lowest cost to the electricity consumer. Contracts for Difference (CfDs) lead to a more efficient allocation of risk among investors, consumers and Government than under existing policies, thereby resulting in decarbonisation at lower cost to the electricity consumer.

What are the policy objectives and the intended effects?

The Government is committed to meeting the legally binding decarbonisation targets as set out in the Climate Change Act 2008, and economy-wide carbon budgets. In addition, on 23 November 2012, the Government agreed a Levy Control Framework (LCF) to 2020/21, which sets upper limits on spending for electricity policies.

The policy objective is to facilitate meeting our decarbonisation targets at least cost to the electricity consumer over the longer-term, while also facilitating the ability to stay within the spending limits imposed by the LCF.

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

The quantitative benefits of implementation of the CfD regime are modelled relative to a "basecase", under which existing policy instruments (the Renewables Obligation and carbon pricing) are used to achieve the same level of electricity sector decarbonisation. The key benefits of decarbonising using the CfD are reductions in financing costs for investors and minimising generator rents under high wholesale prices.

In addition, we summarise (in Annex A) the rationale, principles and evidence in support of policy decisions reached on key aspects of CfD allocation policy and contract terms.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** 2018

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** Yes	**< 20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:**	**Non-traded:**	

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: 10 October 2013

Summary: Analysis & Evidence

Description: Implementation of the generic CfD process.

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2012	Time Period Years 2030	Net Benefit (Present Value (PV)) (£m)		
			Low:	**High:**	**Best Estimate: 9,400**

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low	N/A	N/A	N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**1,600**

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

Under CfDs, carbon costs up to 2030 are higher than the basecase (£1.1bn in NPV terms in the 100gCO_2/kWh emissions intensity scenario). The basecase achieves a slightly faster decarbonisation profile than CfDs, using existing policy instruments (RO and carbon pricing), because of the higher carbon price under the basecase. One effect of the higher carbon price to drive increased switching from coal to gas generation in the 2020s.
Administrative cost estimate of £0.5bn (NPV), consisting of: the institutional costs of National Grid delivering their CfD Delivery Body functions; the costs associated with setting up the CfD Counterparty; and administrative costs to energy sector businesses.

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

Possible additional administrative costs to businesses associated with preparing supply chain plans.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	N/A	N/A	N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**11,000**

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

Savings in generation costs savings, capital costs, system costs, unserved energy and interconnector energy (total of £11bn in the 100gCO_2/kWh emissions intensity scenario).

The key benefit of CfDs is their ability to lower the capital costs associated with decarbonisation – up to 2030 such benefits are estimated to be around £8.1bn in the 100gCO_2/kWh scenario.

The estimated capital cost reductions in turn reflect the combined impact of reductions in costs of capital and impact of the technology mix. Up to 2030, CfDs generate an NPV of £4.8bn from lower costs of capital alone (in the 100gCO_2/kWh scenario).

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

Qualitative analysis of detailed CfD policy is set out at Annex A

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

Some of the impacts described above may arise directly from primary legislation, due to the Secretary of State's powers to issue contracts directly outside of the generic process. We have not sought to attribute the benefits of the CfD regime between those being enabled directly by primary legislation versus secondary legislation.

The aggregate savings from the reduced cost of capital under the CfD depends on the level of low-carbon investment. Up to 2030, the NPV of financing cost reductions is £3.3bn in the 200gCO_2/kWh scenario and £7.2bn in the 50gCO_2/kWh scenario.

BUSINESS ASSESSMENT (Option 2)

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

Evidence Base (for summary sheets)

Background and Context

1. This Impact Assessment (IA) accompanies the Government's consultation on secondary legislation for the EMR programme. It considers the costs and benefits of long-term contracts to encourage investment in new, low-carbon, electricity generation ("Contracts for Difference" or "CfDs"). CfDs are one of the main elements of Government's Electricity Market Reform (EMR) programme.

2. The CfD scheme will work by stabilising revenues for generators at a fixed price level known as the Strike Price. Strike Prices are set by Government to attract a given level of investment in a particular technology. The CfD is an agreement to pay the difference between the "Strike Price" and the "reference price"– a measure of the average market price for electricity at a particular point[1]. Generators will receive revenue from selling their electricity into the market as usual. However, when the market reference price is below the strike price they will also receive a top-up payment from suppliers for the additional amount. Conversely if the reference price is above the strike price, the generator must pay back the difference.

3. For renewable generation, the CfD is intended to replace the Renewables Obligation (RO), the current mechanism for supporting large-scale renewable electricity. The RO functions effectively as a premium payment to generators, paid on renewable output, above the wholesale price:

   - Eligible renewable electricity generators report the amount of renewable electricity they generate on a monthly basis to the Office of the Gas and Electricity Markets (Ofgem).
   - Ofgem issues Renewables Obligation Certificates (ROCs) to electricity generators relating to the amount of eligible renewable electricity they generate.
   - Generators sell their ROCs to suppliers (or traders), which allows them to receive a premium in addition to the wholesale electricity price.

4. The Energy Bill will, subject to Royal Assent, enable the Secretary of State to implement the CfD. The CfD will be a Private Law Contract between a generator and the CfD Counterparty, a Government-owned limited company.

Scope of IA

5. This IA focuses on the costs and benefits of CfDs, including the impact of policy decisions reached on the following:

   - "Generic" (i.e. applying to most renewable generation technologies) contract terms for the CfD (the detail of which are not themselves subject to the current consultation[2]);
   - The generic CfD allocation mechanism, including Supply Chain Plan draft provisions.

6. Both of the above would be given effect by the draft secondary legislation published alongside the current consultation. Our policy on these areas is described in more detail in the accompanying consultation document and qualitatively appraised in Annex A.

7. This IA does not consider in detail the impacts of:

   - The process by which the CfD counterparty raises money from licensed electricity suppliers to settle difference payments under the CfD to generators (the "Supplier Obligation") – this is the subject of a separate IA accompanying the consultation on EMR secondary legislation;
   - The draft EMR Delivery Plan, including CfD strike prices (which were the subject of a separate consultation over July to September 2013);
   - Policy decisions on the technology mix or decarbonisation profile; or
   - CfD policy applying to technologies and/or projects not subject to the "generic" CfD allocation process (including nuclear and CCS), which is still under development (see footnote 20).

8. Much of the quantitative analysis presented is a summary of impacts of implementation of CfDs from the July 2013 EMR IA accompanying the consultation on the draft Delivery Plan[3].

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[1] The reference price is calculated under the CfD using a formula designed to produce a standardised reflection of the market price of electricity in £ per MWh (produced using baseload or intermittent generation respectively) for the relevant period.

[2] Most recently, we sought written feedback (by close 2 September) on the mechanics and the operation of the Draft CfD Terms published in August 2013. We expect to publish the final contract terms and allocation process by December 2013.

[3] Impact Assessment on Electricity Market Reform – ensuring electricity security of supply and promoting investment in low-carbon generation [Delivery Plan update: July 2013], https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225981/emr_delivery_plan_ia.pdf.

Policy Objective and Intended Effects

9. The Government is committed to meeting the legally binding decarbonisation targets as set out in the Climate Change Act 2008, and economy-wide carbon budgets. In addition, on 23 November 2012, the Government agreed a Levy Control Framework (LCF) to 2020/21, which sets upper limits on Government spending for electricity policies, reaching a total of £7.6bn (in real, 2011/2012 prices) annually by 2020/21[4].

10. The policy objective is to facilitate meeting our decarbonisation targets at least cost to the electricity consumer over the longer-term, while also staying within the spending limits imposed by the LCF.

Rationale for intervention

11. In summary, the rationale for intervention is that:

- Reducing emissions from the power sector will become increasingly important to help us meet wider decarbonisation goals;
- There are several reasons to believe that the current market arrangements will not deliver power sector decarbonisation at lowest cost to the electricity consumer; and
- CfDs lead to a more efficient allocation of risk among investors, consumers and Government than under existing policies, thereby resulting in decarbonisation at lower cost to the electricity consumer.

12. These points are explained in more detail below.

Government's decarbonisation goals

13. Whilst the UK is on target to reduce its greenhouse gas emissions in 2020 by 34% on 1990 levels, in line with carbon budgets and the EU target, the longer-term goals are more challenging. From 2020, further deep cuts in emissions from the power sector are likely to be necessary to keep us on a cost-effective path to meeting our 2050 commitments. Reducing emissions from the power sector will become increasingly important to help us meet wider decarbonisation goals[5].

Issues with current market arrangements

14. The reasons why the current market arrangements will not deliver power sector decarbonisation at lowest cost to the electricity consumer are that:

- The current EU Emissions Trading Scheme (ETS) cap, and associated price, is insufficient and not certain enough to deliver investment at the pace and scale required that is needed for the UK to meet its 2050 targets;
- While the Carbon Price Floor (CPF) provides additional certainty over the carbon price, it alone will not encourage the total amount of low-carbon investment required to decarbonise the power sector; and
- Market failures associated with innovation mean the market would not deliver the required investment even if the carbon price were to reflect fully the environmental costs associated with CO_2 emissions.

15. These points are explained in more detail below.

16. The EU ETS, a "cap and trade" system covering the EU electricity generation sector and energy intensive industries, has created a market in carbon so that emissions across the EU can be abated at least cost. Although the EU ETS has achieved certainty over EU net emissions, along with a strong signal regarding the future level of the declining cap, the level of this cap (and associated carbon price)

[4] https://www.gov.uk/government/news/government-agreement-on-energy-policy-sends-clear-durable-signal-to-investors

[5] HM Government, December 2011, "The Carbon Plan: Delivering our low carbon future", paragraphs 2.144 and 2.145 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/47613/3702-the-carbon-plan-delivering-our-low-carbon-future.pdf).
In addition, new Government clauses have been added to the Energy Bill, which enable a 2030 decarbonisation target range for the power sector to be set in secondary legislation. The decision to set a target range will be taken once the Committee on Climate Change has provided advice on the 5th Carbon Budget, which will cover the corresponding period (2028 – 2032), and once the Government has set that budget, which is due to take place in 2016. The power will not be exercised until the Government has set the 5th Carbon Budget.

is not consistent with the pace[6] and scale of decarbonisation that is needed for the UK to meet its 2050 targets. Thus the carbon price signal resulting from this cap has not been stable, certain or high enough to encourage sufficient investment in low-carbon electricity generation in the UK.

17. The Carbon Price Floor (CPF), which came into effect from 1 April 2013, is in part intended to provide greater support and certainty to the carbon price[7]. However, it alone will not encourage the total amount of low-carbon investment required to decarbonise the power sector. While higher carbon price trajectories could lead to faster decarbonisation and drive a higher level of low-carbon investment, they may not be sufficient to compensate for market failures associated with innovation.

18. Fossil fuel generators have benefitted over many years from learning by doing and the exploitation of economies of scale. There is evidence that given the opportunity to deploy at scale, some low-carbon technologies could reduce in cost. However, at current relative generation costs these technologies would be unable to compete with mature technologies, even with the support of a carbon price. Therefore, and given the "spillover" effects associated with innovation, in the short term there is a case for offering additional support to low-carbon technologies to drive reductions in cost.

The rationale for choosing the CfD

19. The Impact Assessment accompanying the July 2011 EMR White Paper[8] explained the case for CfDs against other potential options in more detail. In particular, it found that the CfD led to a more efficient allocation of risk among investors, consumers and Government, by allocating risk to those parties best able to manage or control it. In particular, the CfD:

    - insulates investors in low carbon generation from fossil fuel price risk, which they are unable to control, thereby leading to a reduction in the cost of capital to investors relative to alternative support mechanisms and, in turn, reductions in the costs to society and consumers of securing this investment; but
    - maintains exposure to a fluctuating wholesale price for those technologies that are able to respond to this signal in their operational decisions.

20. In addition, the CfD mitigates the risk of the potential for windfall profits. Because generators holding a CfD do not face (longer-term) changes in wholesale electricity prices, they are unable to benefit from increases in wholesale prices above those expected at the time of making their investment decision. This protects consumers against providing "rents" to CfD generators.

21. The paragraphs below explain in more detail:

    - The issues that low-carbon investors face in managing wholesale price risk; and
    - The difficulties of relying on market-based mechanisms to manage wholesale price risk.

22. Cost structures differ between low-carbon and conventional generation capacity investments. Low-carbon investments are typically characterised by high capital costs and low operational costs, while fossil-fuel generation tend to have relatively low capital costs and high operational costs. The current electricity market was developed in an environment where large-scale fossil fuel plant made up the bulk of the existing and prospective generation capacity, which presents a particular challenge for investment in low-carbon generation.

23. In the current market, the electricity price is set by the costs of the marginal generator, which is typically a flexible fossil fuel-fired plant. Fossil fuel generation therefore sets the price for all generation in the market, including low-marginal cost low-carbon generation such as nuclear and wind. This means that the electricity price, and hence wholesale electricity market revenue, is typically better correlated with the costs of a fossil fuel-fired plant than it is to the costs of low-carbon plant.

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[6] The Impact Assessment on the level of the fourth carbon budget (page 12) explained how an "early action" pathway – where greater emissions reductions are made early on – is more likely to be cost effective than an emissions pathway that leaves greater levels of emissions reductions to later years (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48080/1685-ia-fourth-carbon-budget-level.pdf).

[7] HM Government, 16 December 2010, "Impact Assessment of proposals to amend the climate change levy and fuel duty to support incentives for low-carbon electricity generation", paragraph 8 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/81274/consult_carbon_price_support_ia.pdf)

[8] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48133/2180-emr-impact-assessment.pdf

24. Non price-setting plant is therefore exposed to changes in the input costs, including both fuel and carbon, of price-setting plant. If these costs increase, revenues for non-price setting plant increase; if they decline, revenues for non-price setting plant also decline. Therefore whilst non price-setting plant can benefit from increases in the input costs of price-setting plant – costs which the price-setting plant can pass through – they are exposed to lower fuel or carbon prices in a way that price-setting plant are not (i.e. the input prices of non price-setting plants do not fall in line with wholesale prices). This increases the risk of investment in low-carbon capacity relative to investment in conventional capacity.

25. It is possible that for some technologies, the market will find ways of managing some elements of the revenue uncertainty, such as through contracting between generators and suppliers or through vertical integration of generation and supply. However this may result in unnecessarily high costs for consumers given the costs suppliers incur in managing this uncertainty.

Description of Options

26. This IA accompanying a consultation considers quantitatively the following two high-level options:

- Basecase - the counterfactual scenario where EMR does not take place; and
- Implementation of the generic CfDs.

27. These options are described in more detail below.

28. We present a summary of quantitative evidence on the impacts of implementation of CfDs relative to the basecase, based on the July 2013 EMR IA accompanying the consultation on the draft Delivery Plan[9], which is consistent with the latest policy on the terms of the CfD and the allocation process set out in August 2013[10].

29. The policy on key CfD terms and the CfD allocation process has developed since 2010 with significant input from stakeholders. The August 2013 CfD publications included a draft contract spine of a CfD and an explanation of key elements of the detailed allocation process and how it will be implemented. Annex A summarises:

- the policy decisions made on the detailed aspects of generic CfD allocation and contract terms;
- the rationale and supporting evidence base for these policy decisions; and
- the extent to which policy decisions are reflected in the quantitative modelling.

Basecase

30. In the absence of secondary legislation on EMR, we would not be able to implement the CfD regime. As such, we would need to rely on existing policies such as the Renewables Obligation (RO) and the EU-ETS and policies which the Government has committed itself to delivering, such as the Carbon Price Floor (CPF) policy announced in the Budget 2011. The basecase attempts to achieve the decarbonisation profile achieved under EMR using existing policy instruments, namely the RO and carbon pricing.

31. The assumptions underlying the basecase are explained in more detail in the July 2013 EMR IA[11], and are summarised in Table 1 below:

Table 1 Summary of basecase assumptions

2030 emissions intensity gCO2/KWh	2049 emissions intensity gCO2/KWh	Carbon pricing	Renewables Obligation (RO)
96	18	Carbon prices increase to £150/tonne in 2019, and rise to £175/tonne in 2030 and remain at that level until 2049 (broadly consistent with long-term decarbonisation ambitions).	RO support to meet 2020 renewable target and 2030 carbon emissions ambition. RO stays open to new renewable plants beyond 2017, closing in 2037.

[9] Impact Assessment on Electricity Market Reform – ensuring electricity security of supply and promoting investment in low-carbon generation [Delivery Plan update: July 2013], https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225981/emr_delivery_plan_ia.pdf.
[10] https://www.gov.uk/government/publications/electricity-market-reform-contracts-for-difference
[11] Paragraphs 69 to 75.

Note: Analysis is also undertaken for two other emission intensity pathways – 50gCO2/kWh in 2030 (leading to 50gCO2/kWh in 2040 and 25gCO2/kWh in 2049) and 200gCO2/kWh in 2030 (leading to 50gCO2/kWh in 2040 and 25gCO2/kWh in 2049).

Implementation of generic CfDs

32. The details of our policy positions on generic CfD allocation and contract terms are described in more detail in the accompanying consultation document and qualitatively appraised at Annex A. While the precise details of a number of the aspects of the policy could likely be flexed to some degree without affecting the quantitative results presented below, the aggregate impact of all these decisions is to make implementation of the generic CfDs feasible.

33. The one aspect of contract design that does materially affect the quantitative assessment of CfDs is contract length (see Annex B). The appraisal of this choice (from the perspective of a sample project) is covered in a separate note[12]. In this analysis, hurdle rates are fixed across the different options on CfD length considered, so there would be no difference between the options considered in the cost to society ("resource costs") of investing in low-carbon technology. However, there are differences between the options considered in the lifetime NPV of support payments, so there is a distributional impact.

34. Furthermore the total quantitative results presented below include the impacts of CfD deployment that may not be subject to the generic CfD process (e.g. early-stage CCS projects and early nuclear projects). This IA does not seek to distinguish between the impacts of generic CfDs versus bespoke/non-generic CfDs (nor does it distinguish between those effects being enabled directly by primary legislation versus those requiring secondary legislation). In addition, terms for non-generic CfDs are not considered in this IA.

35. As a result of lower exposure to fossil fuel price risk and the greater price certainty offered by CfDs, the cost of capital for investors in low-carbon generation is lower under a CfD. Initial analysis for the EMR White Paper suggested that CfDs could reduce hurdle rates for low-carbon investments by between 0.3 and 1.5 percentage points, depending on the technology and investor class. Independent verification of the cost of capital impacts showed broadly similar results[13]. The technology-specific hurdle rates used in this analysis are based on data and evidence drawn from various sources – Oxera[14] (2011), Arup[15] (2011), Redpoint[16] (2010) and KPMG[17] (2013). For more information about how these have been derived, please see DECC's Electricity Generation Costs 2013 report[18]. Annex B summarises the risks for renewables plants under the RO regime compared to the CfD.

36. Moreover, investors are able to secure support through a CfD at an earlier stage in development than under the Renewables Obligation, further reducing development risk. Finally, the structure of the CfD as a private law contract means that developers have greater certainty over their rights and obligations than in a scheme governed solely by regulations.

Cost-benefit analysis

Quantitative impacts of generic CFD implementation"

37. This section compares the basecase to a scenario which decarbonises through CfDs but does not include a Capacity Market

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12 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/227491/CfD_contract_length_note.pdf

13 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48133/2180-emr-impact-assessment.pdf & https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48136/2174-cepa-paper.pdf

14 http://hmccc.s3.amazonaws.com/Renewables%20Review/Oxera%20low%20carbon%20discount%20rates%20180411.pdf

15 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42843/3237-cons-ro-banding-arup-report.pdf

16 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42638/1043-emr-analysis-policy-options.pdf

17 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225619/July_2013_DECC_EMR_ETR_Report_for_Publication_-_FINAL.pdf

18 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_16_07_13_amend.pdf

38. Relative to the basecase outlined above, the July 2013 EMR IA shows that the impact of CfDs alone in decarbonising the power sector to an average emissions level of 100gCO_2/kWh in 2030 would result in a positive NPV of around £9.4bn to 2030. Scenarios targeting an emissions intensity of 50gCO_2/kWh and 200gCO_2/kWh in 2030 show net benefits of CfDs of £13bn and £5.5bn respectively[19]. We assume that taking forward secondary legislation on EMR enables the majority[20] of the benefits of the CfD regime. Table 2 below shows the breakdown of monetised costs and benefits in the 100gCO_2/kWh scenario.

Table 2 Change in Net Welfare (NPV) – CfDs only, compared to basecase (emissions intensity in 2030 = 100gCO_2/kWh)[21]

		NPV, £m (real 2012)		
		2012 to 2030	2012 to 2040	2012 to 2049
Net Welfare	Value of carbon savings	-1,100	-3,100	-5,000
	Generation cost savings	280	2,300	4,600
	Capital cost savings	8,100	17,000	23,000
	System cost savings	200	770	1,300
	Unserved energy savings	760	920	240
	Cost of Interconnector energy saved	1,700	2,200	2,200
	Change in Net Welfare	**9,900**	**20,000**	**26,000**
	Change in Net Welfare*	**9,400**		

Source: DECC modelling

*Inclusive of administrative costs of approximately £0.5bn up to 2030 (see section below on administrative costs for details).

39. The key benefit of CfDs is their ability to lower the capital costs associated with decarbonisation – up to 2030 such benefits are estimated to be around £8.1bn in the 100gCO_2/kWh scenario above (£7.0bn in the 200gCO_2/kWh scenario and £8.9bn in the 50gCO_2/kWh scenario). The estimated capital cost savings in turn reflect the combined impact of two factors:

[19] All NPV estimates reported are inclusive of CfD administrative costs up to 2030.

[20] Note: there are some impacts that arise directly from primary legislation, due to the Secretary of State's powers to issue contracts directly outside of the generic process. We have not sought to attribute the benefits of the CfD regime between those arising directly from primary legislation and those being enabled by secondary legislation. In addition, the detailed "generic" arrangements for the CfD subject to the current consultation are specific to renewable technologies. We will continue to work closely with nuclear and Carbon Capture and Storage (CCS) generators on arrangements for CfD allocation for these technologies.

[21] **Carbon savings:** The total carbon emissions for a year are multiplied by the appraisal value in that year to determine the total carbon costs for that year. An increase in carbon cost, other things remaining constant, leads to a decrease in net welfare.
Generation Costs: These are the sum of variable and fixed operating costs. The carbon component of the variable operating costs is removed – the EUA price is accounted for in the carbon costs, and the carbon price floor cost is a transfer between producers and the Exchequer so appears in the surplus calculations but not in the net welfare. An increase in generation costs leads to a decrease in net welfare.
Capital Costs: All new build is included (plants built by the model, and pipeline plants). Construction costs are annuitized over the economic lifetime of the plant, based on the hurdle rate. An increase in capital costs leads to a decrease in net welfare
System costs: These are the sum of the costs of building and operating the electricity system (TNUoS and BSUoS costs). These costs are calculated by National Grid models, based on DDM outputs. An increase in system costs leads to a reduction in net welfare.
Unserved energy: The estimation of Expected Unserved Energy takes plant outage probabilities, technology mix, demand and historical wind data and uses stochastic modelling to estimate a probability distribution of energy unserved. The mean unserved energy is valued at VOLL (defined by the user, assumed to be £17,000/MWh). An increase in unserved energy leads to a decrease in net welfare.
Interconnector energy: This measures the cost of electricity imported via the interconnectors net of the value of exports. If imports are greater or wholesale prices are higher than the cost of imported electricity is increased, scored as a reduction in net welfare.

- Financing cost impact: Benefits of decarbonising through CfDs rather than the RO and a higher carbon price, in terms of the impact on costs of finance.
- Technology mix impact: Relative benefits of CfDs being better able to target a cost-effective generation mix, in comparison to existing policy instruments.

Financing cost impact

40. The financing cost impacts are driven by the assumed reduction in the cost of capital provided by the CfD relative to the RO. Our cost of capital assumptions are explained in more detail in paragraphs 35 and 36 above. In order to isolate the savings due to reductions in the costs of capital, we compare modelling runs for EMR with and without CfD hurdle rate reductions.

41. This reflects the efficiency of delivering low-carbon investment through CfDs, relative to an alternative mechanism that would deliver the same generation mix but without financing savings. The comparison is made using the EMR modelling without a capacity market.

42. The results (see Table 3 below) suggest that, depending on the assumed level of decarbonisation in 2030, CfDs would generate an NPV of between £3.3bn and £7.2bn from lower costs of capital (up to 2030, including administrative costs), £11bn-£21bn up to 2040 and £17bn-£30bn up to 2049.

Table 3 Estimated financing cost reductions associated with the CfD (£bn, 2012 prices)

	2012 to 2030	2012 to 2040	2012 to 2049
200gCO2/kWh	3.3*	11	17
100gCO2/kWh	4.8*	15	22
50gCO2/kWh	7.2*	21	30

Source: Footnote 100 of the July 2013 EMR IA.

*Inclusive of administrative costs of approximately £0.5bn up to 2030.

Technology Mix Impact

43. There are differences between EMR and the basecase, which arise due to complexity in precisely matching the decarbonisation profile and generation mix under EMR and the counterfactual.

44. With regards to the decarbonisation profile in particular, the introduction of a higher carbon price to incentivise nuclear investment under the basecase results in a sharper reduction in emissions around 2020. Within the modelling, the higher carbon price in 2019 to incentivise investment in nuclear at the same rate as under EMR has additional impacts on the modelled generation mix. In response to the higher carbon price level under the basecases, unabated coal plants retire more quickly than they do under EMR, and as a result gas generation substitutes for coal generation in the basecase scenarios. As a consequence, the basecases have a lower emission intensity level in the early 2020s. This, along with the lower emissions intensity levels modelled under the basecase in the 2030s and early 2040s, is why CfDs are modelled as resulting in a net increase in carbon costs (see Table 2 above).

45. Different technologies have different operating and capital costs, therefore cost-benefit analysis results will be influenced by any differences in the technology mixes realised under EMR and the basecase scenario. If these differences were eliminated (i.e. the decarbonisation profile and generation mix were exactly the same), then this element would decrease to zero and the only source of benefits would be the pure financing benefits outlined above. These impacts are considered in more detail in the July 2013 EMR IA[22].

46. The difference between the financing cost impact in Table 3, and the capital cost savings presented in Table 2 reflect the net impact of different technology mixes on total capital costs, independent of cost of capital savings. The remaining CBA categories also result from differences in technology mix between the CfD and basecase modelling scenarios.

Administrative Costs

47. The administrative cost estimate of £0.5bn consists of:

- The institutional costs of National Grid delivering their CfD Delivery Body functions;
- The costs associated with setting up the CfD Counterparty;
- Administrative costs to energy sector businesses.

[22] Paragraphs 98 to 104.

48. The costs largely reflect:

- staff, IT, building costs and any external expertise which may be required for the institutional bodies[23]; and
- an estimate of the administrative costs of CfDs on energy sector businesses[24].

49. In August 2013[25], Government set out that, in order to be eligible to apply for a CfD, projects greater than 300MW will need to provide the Delivery Body with a letter from the Government certifying that it has prepared a supply chain plan which meets a defined standard. The administrative cost estimates above do not include estimates of costs to Government of reviewing supply chain plans or costs to businesses of preparing supply chain plans. The administrative costs to Government of reviewing supply chain plans are currently estimated to have a NPV cost to 2030 of around £1.8m (see Annex C). We will be seeking more evidence on the administrative costs to businesses of these measures and the benefits they produce.

Distributional impacts

50. The distributional impacts of the EMR package of measures, including price and bill impacts, are explained in more detail in July 2013 EMR IA[26]. As noted above (see "Scope of IA"), this IA does not consider in detail decisions on technology mix and rate of decarbonisation, which are the main drivers of the cost to consumer of low-carbon investment and in turn the distributional impacts of the EMR package.

Assumptions

51. Annex A of the July 2013 EMR IA explains the approach taken to the quantitative analysis, including an overview of the model used and key input assumptions.

[23] The estimates must be regarded as tentative as the component costs have not yet been fully determined, as they depend on the final agreed activities to be undertaken by the organisations.
[24] The EMR White Paper IA presented estimates of the costs to energy sector businesses, both generators and suppliers. These include application for CfD allocation and the costs of settlement (see section 3.8). The same CfD energy sector business cost assumptions presented in the White Paper IA are used in this analysis.
[25] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/233004/EMR_Contract_for_Difference_Contract_and_Allocation_Overview_Final_28_August.pdf, paragraph 3.10
[26] Sections 2.4 and 2.5.

Annex A: Summary of policy decisions on generic CfD allocation and contract terms and supporting rationale

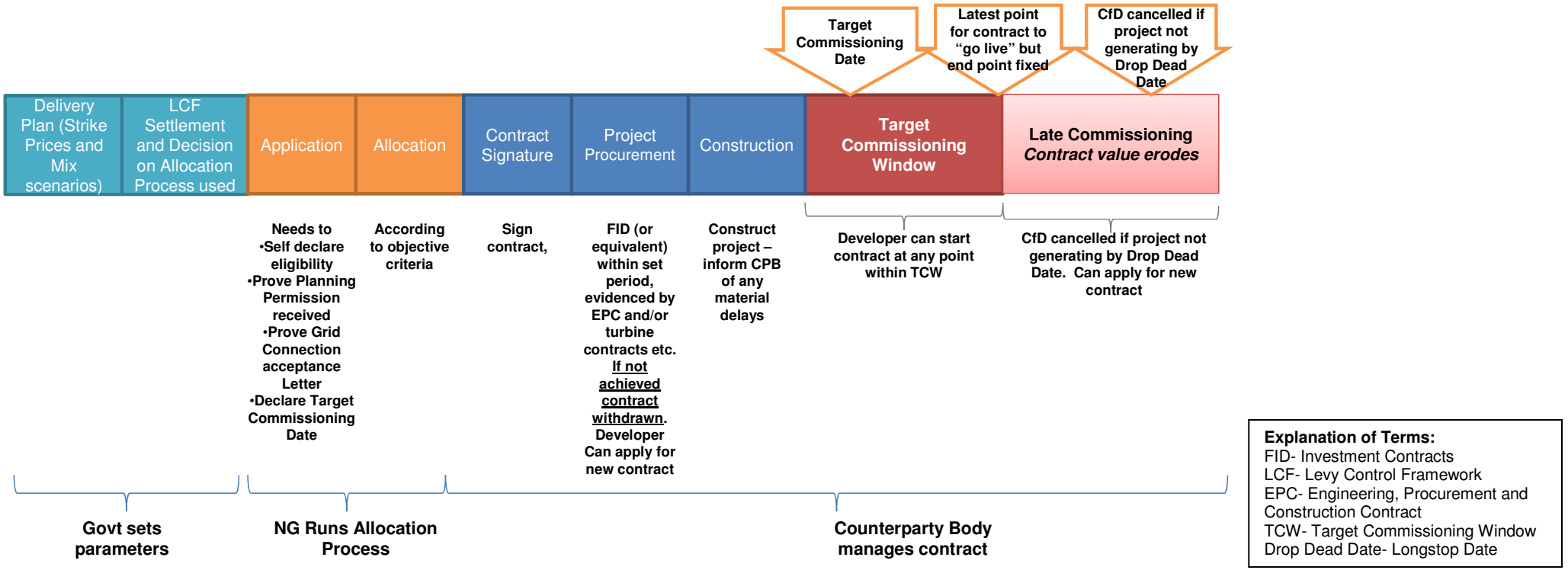
52. This Annex summarises:

- the policy decisions made on the detailed aspects of generic CfD allocation and contract terms[27];
- the rationale and supporting evidence base for these policy decisions; and
- the extent to which policy decisions are reflected in the quantitative modelling. This is reflected in the financing benefits we have modelled to be achieved under the CfD in the main body of this Impact Assessment.

CfD allocation

53. Figure 1 below summarises the generic allocation process. This IA does not consider policy decisions on budget management and Strike Price-setting.

Figure 1 Overview of generic allocation process



[27] These reflect the latest positions, as set out in the August 2013 suite of CfD policy documents: https://www.gov.uk/government/publications/electricity-market-reform-contracts-for-difference.

54. Table 4 summarises the rationale, basic principles and evidence for policy decisions made on generic CfD allocation. Note: The way the contract encourages timely delivery whilst making allowances for reasonable delays (through the use of Milestones, Target Commissioning Windows and Longstop Dates) is set out in more detail in Table 5 below.

Table 4 Summary of rationale for generic CfD allocation policy decisions

Area of policy	Description	Decision	Rationale
Price-setting	The process by which Strike Prices are set.	Initially, Strike Price prices will be set administratively[28]. The Government has clearly stated its intention to move to a competitive price discovery process for all low-carbon technologies as soon as practicable[29]. Government has noted that the following factors will affect our ability to introduce auctions or tenders[30]: • having confidence that there are enough potential participants in the auction or tender for there to be competitive tension; • knowing that the development capacity of the potential participants exceeds the volume of new development sought by the institution in a given time period or tendering round; and • knowing that the projects or technologies eligible for the tender or auction are comparable so that the strike price is a meaningful way to discriminate between them.	Chapter 6[31] of the EMR December 2010 Consultation Document noted that the price discovery characteristics of an auction should enable financial support to be set at a level just high enough to lead to deployment but not high enough to lead to excessive profits, with bids driven down by competition. However, given the EU 2020 Renewables Target, the different build times and stages of development of technologies, it was not deemed appropriate to set a hard deadline for transition to competitive price discovery for all renewables. Adopting a phased transition to competitive price discovery has a number of benefits as follows[32]: • it facilitates a move to competition as soon as market sectors will allow; • it reduces risk of hiatus caused by a pre-announced hard transition date for all technologies, whilst giving indicative dates for specific technologies; • it retains flexibility around the 2020 Target by allowing technologies with shorter build times to come forward 'unconstrained'; and • it does not stifle nascent technologies. Note: Our quantitative modelling does not distinguish between administrative Strike Price-setting and competitive price discovery. In particular, it does not account for the potential for lower Strike Prices under potential future competitive price discovery processes; nor does it account for the potential for increased risk of not securing support compared to the RO (see Annex B).

[28] "Electricity Market Reform: Policy Overview", November 2012, Figure 6 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65634/7090-electricity-market-reform-policy-overview-.pdf).
[29] "EMR: Contract for Difference: Contract and Allocation Overview", August 2013, paragraph 1.16 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/233004/EMR_Contract_for_Difference_Contract_and_Allocation_Overview_Final_28_August.pdf).
[30] "Planning our electric future: a White Paper for secure, affordable and low-carbon electricity", July 2011, paragraph 2.3.23 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48129/2176-emr-white-paper.pdf).

Area of policy	Description	Decision	Rationale
Application	The eligibility criteria that each technology will need to meet as a condition for entering the allocation process including the introduction of eligibility criteria linked to the development of a robust supply chain.	The Developer will need to provide evidence that: • The project is for a qualifying form of low carbon generation; • Planning Permission or Development Consent, plus Crown Estates Agreement for Lease where applicable, have been secured; • A Grid Connection Offer has been accepted; • Evidence that applicant is validly incorporated under the laws of the jurisdiction in which it is incorporated; and • Evidence (in the form of a certificate from Government) that a company's supply chain plan meets the eligibility condition that the project has a valid supply chain plan. Supply chain plans will set out how the project will support the long term economic growth and viability of the low carbon supply chain, how they will foster innovation and competition and support the development of skills. The Secretary of State may also publish all submitted plans, subject to addressing issues associated with commercial confidentiality	Following discussions with stakeholders the Government decided to provide pricing certainty to developers much earlier than under the RO and earlier than under the Government's original proposals. It will provide developers with earlier certainty of CfD award by enabling them to apply for a CfD at an earlier stage in their project development. Allowing projects to secure CfDs before they have been built or before they have taken a financial investment decision increases the risk that CfDs will be awarded to speculative projects which go on not to be built. To mitigate this risk it is necessary to ensure that applicant projects have achieved meaningful eligibility criteria which demonstrate they have a strong chance of progressing to commissioning. The eligibility criteria will ensure that: • the application is for a project that contributes to the UK's 2020 target for low carbon electricity generation from renewable energy; • the project developer is a legal entity capable of contracting a legal contract; • that the application is for a viable project that is likely to proceed, through the granting of development/planning consent for the specific project; and • projects that are already in receipt of Government support from other schemes to promote renewable electricity generation are not given further support for the same electricity. Developers can choose to make more progress in developing their projects before submitting their application for a CfD, if that approach enables them to better manage their risks and uncertainties. Note: The impact on the cost of capital of being able to secure support at an earlier stage of project development compared to the RO has not been separately modeled. However, it is assumed to be consistent with an overall reduction in risk from the CfD relative to the RO (see Annex B). By introducing the supply chain plans requirement, Government is highlighting the importance of supply chain development. Focusing on the way the projects are delivered can help develop the industrial base, reduce cost and encourage participation by smaller businesses, and promote innovation and skills. Publishing plans would improve transparency on how costs can be reduced and allow a degree of public scrutiny of projects. This could bring all developers up to

[31] Paragraphs 4 to 16 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42636/1041-electricity-market-reform-condoc.pdf).
[32] CfD Draft Operational Framework, Section A (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48373/5358-annex-b-feedin-tariff-with-contracts-for-differe.pdf).

Area of policy	Description	Decision	Rationale
			the standard of strongest performers in the sector in terms of supply chain support, supporting supply chain growth and competitiveness.
Allocation	The process by which the Delivery Body will allocate contracts and how that process will evolve over time.	• Under the administrative Strike Price-setting phase, contracts will be initially allocated on a 'First Come, First Served' (FCFS) basis, whilst there is sufficient CfD Budget. There are some scenarios in which FCFS may only last for a short period or may not be able to operate at all. • Once a trigger has been met (for example if a significant part, perhaps 50%, of the CfD Budget has been allocated through FCFS allocation) the Delivery Body will check whether Government has room within the Levy Control Framework (LCF) to allow FCFS allocation to continue. • If there is insufficient LCF budget available, the Delivery Body will begin to allocate CfDs through Allocation Rounds. • If there is more capacity trying to secure a CfD than can be supported by the remaining Budget, then a constrained allocation process will be run allowing projects to be ranked by price with CfDs being secured by the least expensive projects[33].	Notwithstanding the need to allocate CfDs within a budget envelope, the Government's intention is not to artificially restrict the allocation of CfDs, or to impose allocation processes that are unnecessarily costly. Reflecting this, when Government has a high degree of confidence that the demand for CfDs in any given year will comfortably fit within the overall budget envelope, and subject to wider value for money considerations, CfDs will be issued on a 'first-come-first-served basis'. Under this approach, developers can submit an application for a CfD at any time. This will ensure that developers have flexibility in when they can apply for CfDs, without needing to shape their project development process to meet the needs of a more restrictive allocation system. While there is still some LCF budget available, Allocation Rounds will allow the EMR Delivery Body to monitor and control the number of projects coming in to the system. It will ensure that there is an orderly process of securing CfD contracts, and will allow effective rationing (if needed) when demand for CfDs exceeds the available budget[34]. Note: Our quantitative modelling does not distinguish between unconstrained allocation (i.e. FCFS and unconstrained rounds) and constrained allocation. In particular, it does not account for the potential for lower Strike Prices under the rationing process; nor does it explicitly account for the potential for increased risk under rationing of not securing support compared to the RO (see Annex B).

[33] "EMR: Contract for Difference: Contract and Allocation Overview", August 2013, paragraphs 3.14 to 3.16 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/233004/EMR_-_Contract_for_Difference_-_Contract_and_Allocation_Overview_Final_28_August.pdf).

[34] CfD Operational Framework, November 2012, paragraphs 76 and 78 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66554/7077-electricity-market-reform-annex-a.pdf).

Area of policy	Description	Decision	Rationale
Appeals	Provisions that will allow developers to challenge the decisions made by the Delivery Body in respect of whether to award the relevant developer a CfD.	Developers who apply for a CfD will be provided with a right of appeal under secondary legislation (made pursuant to Section 10(6) of the Energy Bill) in respect of Delivery Body decisions on CfD eligibility and/or CfD allocation. This appeals process will take the form of an initial right of appeal to the Delivery Body and a subsequent right of appeal to Ofgem.[35]	The rationale for providing an appeals procedure is to give a route for allocation disputes to be settled in a timely manner and in a way which minimises costs[36]. In addition, through providing a formal disputes process greater clarity can be provided on the on-going running of the allocation process in the event of the dispute, which should help to reduce generators' perception of risk. The appeals system is designed such that the risk of disruption to the allocation process through disputes is controlled.

[35] Paragraphs 12 to 21 of Electricity Market Reform: Contract for Difference – Allocation Methodology for Renewable Generation (5 August 2013) (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/226976/Allocation_Methodology_-_MASTER_-_6_Aug_v_FINAL.pdf)
[36] Paragraph 8 of Electricity Market Reform: Contract for Difference – Allocation Methodology for Renewable Generation (5 August 2013) (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/226976/Allocation_Methodology_-_MASTER_-_6_Aug_v_FINAL.pdf)

Area of policy	Description	Decision	Rationale
Phased commissioning	Provisions that will allow large projects that deliver over a number of years to be accommodated.	• Each phase of a multi-year project to receive the strike price available for the delivery year of the first phase • Projects wishing to deliver in phases will be held to account against appropriately tailored Substantial Financial Commitment Milestones, Target Commissioning Dates, Longstop Dates (LSD) and Termination Provisions. • The total capacity of the project must not exceed 1500MW. • 35% of the capacity must be constructed in the first phase of the project; • The target commissioning date for the first phase must be no later than 31 March 2019; • The target commissioning date for the final phase must be the earlier of the two following points: ▪ no later than two years after the target commissioning date of the first phase; and ▪ no later than 31 March 2021.	The Renewables Obligation regime makes provision for offshore wind projects to structure their projects in a way that allows them to deploy over a number of years. In view of the fact that larger offshore wind projects are likely to be built in a series of stages and that Round 3 Offshore wind farms are more likely to be built in this way than Round 1 or Round 2 projects Government is prepared to facilitate phased commissioning within the CfD regime. It is intended that the CfD allocation process will ensure that phased projects can secure a CfD and have clarity about strike prices. At the same time the system will also seek to protect Government and consumers against risks of non-delivery, late delivery and gaming. The limitation on the size of phased projects reflects the fact that all projects to date are smaller than the limit imposed and is aimed at minimising the risk of separable projects seeking to brigade together to access higher strike prices than they would be able to achieve under normal circumstances. The provisions around dates by which the first and last phases of the project must commission are aimed at ensuring that projects don't seek to secure administrative strike prices when the majority of that project's capacity will be delivered in the period where competitive price setting is likely to apply. The provisions also ensure that phasing at this stage is only offered within a time horizon covered by the spending envelope agreed under the Levy Control framework (i.e. up to March 2021). Note: In our quantitative modelling, we assume projects deploying in different years are the subject of separate investment decisions – i.e. there are assumed to be no "phased" projects in our modelling.

Area of policy	Description	Decision	Rationale
Capacity adjustment	Amount by which a generator can reduce the project capacity (with and without penalty) between signing a CfD and commencement of payment.	• A specified amount of cost free flexibility may be exercised by the developer at the substantive financial commitment milestone • The project may adjust its capacity further by a specified maximum amount, but for each percentage point of under-delivery, the project will receive a strike price penalty • Further flexibility provided to reduce capacity delivered beyond this level, but with a reduction to the strike price, to encourage accurate planning and prevent under-allocation of the available budget for CfDs. • If the project delivers below a specified threshold [70% of the initial contracted capacity] then the CfD will be terminated	Government recognises that for certain technologies it is not always possible for developers to be absolutely precise about the size of plant they will ultimately build at the point when they will apply for the CfD. For example Wind Developers typically seek planning permission and a grid connection for the maximum possible capacity at a site and then optimise their proposal as they select a turbine vendor and get a clearer understanding of the site. Government wishes to allow developers a limited ability to amend the capacity they are contracted to deliver under the CfD while ensuring the contract provides a reasonable and meaningful incentive on developers to as far as possible commission the installed capacity as agreed at contract signature. This is necessary to mitigate the risk that a developer might deliberately overstate its installed capacity in order to increase the likelihood that its competitors will not receive a CfD. The Government's intent is not, however, to introduce a cliff edge for developers, for example where only a marginal shortfall in achieving the expected installed capacity could lead to termination of the contract. The aim is that capacity adjustment provisions should: • Provide flexibility at the right point(s); • Provide the right amount of flexibility to take real account of the sort of changes which can occur (notwithstanding the fact that geological issues are covered separately as are force majeure events – see Table 5 below); and • Not offer flexibility for incompetent project management. Note: Our quantitative modelling effectively assumes all projects are delivered to time and without adjustments to capacity – i.e. there are no Strike Price adjustments.

Generic contract Terms

55. Table 5 below summarises the rationale and evidence base for policy decisions made on generic contract terms.

Table 5 Summary of rationale for generic contract term policy decisions

CfD Term	Description	Decision	Rationale
Contract term	Length of the contract from point project is commissioned (i.e. starts generating).	Contract length standardised, but flexibility to adapt to technology requirements: • Renewables projects (under the "generic" allocation mechanism) – 15 years of payments. • Biomass conversion – all contracts cease to pay in 2027 (regardless of start date). • Flexibility for the Secretary of State to adjust contract term for projects where technology justifies a different duration (e.g. nuclear, CCS, tidal range and potentially large hydro projects).	Government's initial preference for a 15 year contract was set out in the CfD Draft Operational Framework[37] (Section D(iii)), published in March 2012. Government has subsequently confirmed this preference. This position is based on a trade-off between value for money for consumers and bankability for investors. Investors discount future costs and returns at a higher rate than Government's social discount rate. Other things being equal, this points towards shorter CfDs as the costs to consumers of future payments associated with longer CfDs are higher than the benefit to developers. On the other hand, Government is mindful of the need for projects to be able to raise debt finance for investment. A 15-year CfD length appears to represent an effective balance. In August 2013, Government published quantitative analysis supporting this decision[38]. The approach taken for biomass conversion projects is consistent with the approach under the Renewables Obligation and reflects the transitional nature of the technology. Note: Our quantitative modelling assumes 15 year contracts for all renewable technologies (apart from biomass conversions).

[37] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48373/5358-annex-b-feedin-tariff-with-contracts-for-differe.pdf
[38] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/227491/CfD_contract_length_note.pdf

CfD Term	Description	Decision	Rationale
Inflation indexation	How strike prices are adjusted for inflation.	Index-linked payments Strike price fully indexed 100% to Consumer Price Index (CPI) throughout entire term.	The EMR White Paper indicated that Government was minded to adjust the CfD Strike Price for inflation. Section D(iv) of the CfD Draft Operational Framework[39] set out Government's view that indexing a proportion of the Strike Price would represent an efficient allocation of risk: in the absence of indexation, the CfD Strike Price would reflect a risk premium associated with uncertainty over future inflation, which would increase costs to consumers. The Draft Operational Framework also set out Government's preference to link the Strike Price to a general index (for reasons of simplicity, applicability over a range of technologies and familiarity with investors). The (final) CfD Operational Framework, published in November 2012 (paragraphs 187 to 194)[40], confirmed our preference for linking the Strike Price to CPI and indicated we were considering the relative merits of full and partial indexation. In the EMR Spending Review Announcement of June 2013 we confirmed that the CfD strike price would be fully indexed in line with CPI throughout the entire term of the CfD[41]. Whilst some investors indicated a preference for RPI, we consider that there is a clear case for CPI to be used for indexation: it is the preferred government measure of general inflation; is governed by international legislation; and therefore is arguably more robust and durable than alternative indexation measures. We believe that full indexation should also accommodate the requirements of the wide a range of different investors we expect to come forward under the CfD. We believe that this should also be attractive to investors who have not traditionally participated in the financing of low carbon generation in the UK. Note: Our quantitative modelling is in real (CPI) terms. Strike Prices in our modelling are held constant in real terms. As such, our modelling assumes full indexation of the Strike Price to CPI.
Reference price	The difference payments are	Payments based on a reliable measure of the market price:	The EMR White Paper set out our view that intermittent generators and day-ahead generators should face different reference prices[42].

[39] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48373/5358-annex-b-feedin-tariff-with-contracts-for-differe.pdf
[40] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66554/7077-electricity-market-reform-annex-a.pdf
[41] https://www.gov.uk/government/publications/electricity-market-reform-delivering-uk-investment
[42] Annex B, paragraphs B.8 to B.11: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48130/2173-planning-electric-future-white-paper.pdf.

CfD Term	Description	Decision	Rationale
	based on the difference between the reference price (a measure of the electricity market price) and the strike price.	• For intermittent generation (e.g. wind), the reference price will be the GB day-ahead hourly price published under the GB European market hub coupling arrangements. The contract sets out the backup arrangements for where this price is not directly available • Baseload technologies (e.g. nuclear) – season-ahead price, moving to year-ahead price when conditions allow.	• Averaging the reference price provides strong incentives for generators to carry out maintenance at the right time and ensure plant is generating when prices are higher. This is a signal that baseload generators can respond to, but the maintenance schedule for intermittent plant (such as wind) is already largely driven by other factors such as wind patterns. Therefore, the efficiency benefits of averaging are significant for baseload plant but not for intermittent. • Averaging also creates additional risks for intermittent plant. Output from wind turbines tends to be correlated; this in turn means that high winds can drive electricity prices down and as such reduce wind generators' revenues. The scale of this effect depends on the amount of wind generation on the system, which in turn is driven largely by renewables targets. Generators cannot predict how much wind generation will be on the system in the future and therefore would find it hard to predict how the price they receive from the market relates to the average price; averaging therefore introduces risk for intermittent plant that is difficult for them to manage. • As such, for intermittent generation[43], the reference price should be drawn from the day-ahead market. While a real-time price would completely remove the risk described above, it would also mean generators would have no incentive to actively manage any of their output into the market. Rather, they would sell power very close to delivery which would increase system balancing challenges for the System Operator. • For baseload generation[44], the reference price should be drawn from the forward (year-ahead) market. Year-ahead prices effectively represent an average of market prices across the year of delivery, and so should provide incentives for baseload generators to schedule maintenance at the right times. Section D(i) of the CfD Draft Operational Framework[45] set out our view that the "GB Hub" price, because of regulatory and market developments, would likely provide the most credible, robust and enduring day-ahead index for intermittent generators. In addition, it removes "basis risk" for generators as (provided that generators trade their output on one of the participating exchanges) they will receive the single clearing price for each half hour. Following concerns expressed by industry about low liquidity, increased basis

[43] Annex B, paragraphs B.22 to B.27: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48130/2173-planning-electric-future-white-paper.pdf.
[44] Annex B, paragraphs B.34 to B.35: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48130/2173-planning-electric-future-white-paper.pdf.
[45] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48373/5358-annex-b-feedin-tariff-with-contracts-for-differe.pdf

CfD Term	Description	Decision	Rationale
			risk, collateral and larger clip sizes associated with year-ahead products, and that this could increase costs to consumers, we have decided that the reference price for baseload generation will initially be calculated from a season-ahead index.[46] Note: In our quantitative modelling, difference payments for intermittent CfD generators (wind, solar, marine) are settled with reference to a "spot" price (our modelling does not distinguish between the intraday price and the day-ahead price). Baseload CfD generators (nuclear, CCS, biomass and waste technologies) are settled with reference to the annual baseload price (i.e. time-weighted annual average spot price).
Refinancing	Whether to include any arrangements to recover higher returns from project refinancing.	No refinancing clause in the generic CfD contract. Bilaterally negotiated CfDs for large projects may have different approaches, including possible refinancing clauses.	When carrying out their investment appraisal, investors may factor in an expected level of gain from refinancing (albeit with some uncertainty around this central expectation). Imposing a refinancing gain-share clause would reduce investors' ability to capture upside potential from refinancing, without offering symmetric protection from downside risk. This might increase investors' perceptions of the riskiness of investment, increasing the cost of capital. Feedback from investors and developers was that the imposition of refinancing gain-share clauses could have created an upfront barrier to certain forms of investment, and may have introduced additional risk that is currently not present in the RO regime. However, it may be appropriate to include refinancing provisions where CfDs are directly negotiated. This is because the process of directly negotiating a CfD is likely to include the detailed scrutiny of financial models, which allows bespoke refinancing terms to be developed (where appropriate). The impact of this policy decision on the cost of capital has not been separately modeled. However, the approach to refinancing is not different from what currently exists under the RO. As such, it is assumed to be consistent with an overall reduction in risk from the CfD relative to the RO (see Annex B).

[46] "Electricity Market Reform – Contract for Difference: Contract and Allocation Overview", August 2013, paragraphs 4.24 to 4.28: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/233004/EMR_Contract_for_Difference_Contract_and_Allocation_Overview_Final_28_August.pdf.

CfD Term	Description	Decision	Rationale
Change in law	Protections given to generators against certain changes in law.	Generators protected against changes in law that target a project, technology or the CfD. Compensation available for material and unforeseeable changes in law that uniquely target specific technologies, individual projects or CfD holders as a group. Protection also covers political decisions to shut down a generator, and general changes in law that have discriminatory effects without objective justification. Protection extends to such changes in law that limit a generator's ability to either deliver its output or to receive appropriate payment. Compensation will adjust strike prices to reflect 100% of operating costs, a proportion of capital costs (tapering over time) and for lost revenues, over the term of the CfD.	In the CfD Draft Operational Framework published in May 2012 [section D(vi)], Government set out its intention that, in the case of a qualifying change in law, the CfD should be adjusted so as to preserve the overall balance of risk and reward in the contract. Following this date Government has further refined the nature of the changes in law which qualify for compensation, and the form that compensation should take. Details were most recently set out in August 2013. Change in law provisions which share risk between Government and investors are often used in major capital projects. The Government's view is that including such arrangements in the CfD is likely to represent better overall value for money for the consumer, as the alternative approach would see investors seeking higher strike prices to compensate for a range of potential future risks which may in fact not materialise. The provisions are two-way, so that any changes which are to the benefit of a generator should lead to compensation being provided to the CfD Counterparty body. These provisions are primarily designed to address the risk that the price stability afforded by the CfD is unduly impacted by unforeseeable changes in law, regulation or industry documentation. The CfD will therefore protect generators against specific and discriminatory changes in law and for changes in law that have an unjustifiable discriminatory effect. It will not protect against other general changes in law which are considered to be usual business risks that developers already take in the existing market without compensation. There is an obligation on generators to mitigate the impact of the change in law. However, where a qualifying change in law has a material impact on a project, compensation will be payable. Compensation can take a number of different forms depending on the impact on operational costs, capital costs and revenues. Compensation mechanics have been tailored in this way to reflect the impact of the change during the course of the CfD term. This should ensure that generators are not overly compensated for risks. The impact of these policy decisions on the cost of capital has not been separately modeled. However, it is assumed to be consistent with an overall reduction in risk from the CfD relative to the RO (see Annex B)

CfD Term	Description	Decision	Rationale
Other Strike Price adjustments	Protections given to generators against other changes in costs.	Protection against certain changes in network charges, relating to the costs of the balancing system (BSUoS) and transmission losses (TLM). Compensation in the scenario where government has directly intervened in the market and the result is that the relevant CfD generator is curtailed involuntarily and less than a minimum level of compensation is paid.	BSUoS (charges to cover network balancing) and TLM (an adjustment to cover transmission losses) both recover costs from generators that are normally passed through to the wholesale market price to a high degree. By removing exposure to the average wholesale price, the CfD would (in the absence of any Strike Price adjustments) expose generators to the risk of increases in these charges. As generators have limited ability to hedge changes in these charges, they may therefore require compensation for this additional risk, increasing costs to consumers. In addition, these charges also do not play a significant role in setting incentives to invest or operate efficiently. For these reasons, we consider there is a value-for-money case for providing a degree of cost pass-through for BSUoS and TLM. However, we do not consider there is a value for money case for providing cost pass-through for transmission network access (TNUoS) charges for generic CfDs. These charges have very large locational elements which play a significant role in setting incentives for efficient location of generation investment. We believe holders of CfDs of up to 15 years in length have some ability to manage the risk of changes to TNUoS through their initial choice of location. In addition, changes in TNUoS do not flow through fully to the wholesale price – i.e. the CfD is not introducing a risk to generators that is materially different to the risk they currently face under the RO. Greater penetration of low-carbon generation could increase the frequency of system operator actions to balance the electricity system or resolve transmission constraints. At present, generators affected by these system operator actions receive market-based compensation for the impact on their operations. Whilst we do not consider it likely, it is possible that the current system of market-based compensation could be replaced by one that does not provide generators with economic levels of compensation. The proposed compensation mechanism should ensure that investors do not increase hurdle rates in order to reflect a risk that is unlikely to crystallise. The impact of these policy decisions on the cost of capital has not been separately modeled. However, it is assumed to be consistent with an overall reduction in risk from the CfD relative to the RO (see Annex B).

CfD Term	Description	Decision	Rationale
Milestones	Parameters to ensure project delivery.	Each project will be subject to a milestone where they have to provide 'Evidence of Substantive Financial Commitment'. This Milestone is an obligation on the developer to demonstrate that they have made an investment in the project that suggests that there is a sufficient financial commitment to completion.	The objective of the Substantive Financial Commitment milestone is to provide the CfD counterparty with a means to assess whether a developer is committed to developing its project and to provide Government with assurance that the available budget will not be absorbed by highly speculative projects that fail to progress to commissioning. The milestone will also provide an early signal to Government on the timely delivery of a project and gives confidence that the UK is making sufficient progress towards its decarbonisation and renewables objectives. Once the Developer has made a substantive financial commitment to the project (broadly analogous to a financial investment decision), they are fully incentivised to construct the project as soon as possible and there is no need for the Counterparty to attempt to micromanage the development of that project.

CfD Term	Description	Decision	Rationale
Conditions precedent (including target commissioning windows and longstop dates)	Further parameters to ensure project delivery.	• Generator flexibility to deliver within a 'target commissioning window' • Payments for generation output commence once specified standards are met relating to connection, metering, capacity instalment, and contract payment/collateral requirements. • Satisfaction of conditions precedent outside of the target commissioning window leads to a reduction in the contract's payment term. Failure to satisfy by the long stop date could lead to termination.	Government acknowledges that the technical challenges associated with building projects of the eligible technologies can mean it is often not possible for projects to be able to be absolutely confident that they will deliver on a specified delivery date. As a result, projects will be allowed a specified penalty-free window in which they can deliver the capacity needed to trigger payments under the contract. The length of the target commissioning windows will be technology specific. As long as a project fully commissions within this window it will be able to receive payments under the CfD (according to its output) for the full duration of the contract term. Where a project fails to either start generating or starts generating but fails to meet the Further Conditions Precedent before the end of the Target Commissioning Window, the payment term will start from the last day of that window. This means that the duration of the generator's CfD will reduce by an amount commensurate with the length of the delay up until the Longstop Date. This is a proportionate response to late delivery of low carbon electricity under the contract and provides a financial incentive on the developer to commission the remaining capacity as soon as possible. Failure to commission at least 70% of the contracted capacity by the longstop date gives the Counterparty the right to terminate the project's CfD. This is for two reasons. Firstly, it prevents capacity being sterilised by projects which secure CfDs but then go on to never be built. Secondly, it provides an incentive for developers to make more accurate assessments of the capacity of project they intend to build than might be the case if they were offered unlimited flexibility to deliver less than originally contracted. This reduces the risk that other viable projects will be crowded out by speculative projects, or unscrupulous developers; reduces the risk of under-allocation of LCF resources; and allows the government to have more certainty about its progress towards meeting its biding decarbonisation and renewables targets.

CfD Term	Description	Decision	Rationale
Force Majeure	Criteria for when flexibility will be allowed on a generator's contractual obligations.	Protection against events outside of the control of the generator • Force Majeure will allow relief for circumstances beyond a generator's control (which will include a 'reasonable and prudent operator test'). • Additional flexibility where connection delays are caused by network operator.	Generators have limited ability to protect themselves against the risk of liability/breach under the CfD where their failure/delay is caused by circumstances beyond their control. As such, providing Force Majeure protection means that generators/investors should require a lower cost of capital to invest, reducing costs to consumers. The risk transfers to the societal level, where it can arguably be more efficiently handled. When aggregating across all projects (and other public policies/spending), the impacts of some randomly occurring factors may cancel out, such that the overall cost to consumers of providing Force Majeure protection viewed from a societal perspective is lower than the aggregate cost of exposing individual generators to risks beyond their control[47]. Providing Force Majeure protection should therefore provide better value for money in respect of the funding of CfDs, and encourage uptake of CfDs. Such Force Majeure protection is also common in commercial contracts within the energy sector, and therefore is something developers would expect to see in the contracts into which they enter. For similar reasons, we have allowed for equivalent Force Majeure protection to be given to the CfD Counterparty under the draft CfD terms.
Dispute resolution	Mechanism for resolving contractual disputes.	Clear process to resolve disputes in a timely manner, including with binding arbitration • generator and CfD Counterparty will seek to agree informal resolution of disputes, but with access to external, legally binding determination of disputes (through arbitration or expert determination). • Government has no contractual right to impose settlements.	It is a commercially accepted principle that commercial contracts require clarity on how disputes should be resolved. In order to preserve generator/investor certainty in respect of the CfD and the private law nature of the CfD, it is also important in the context of the CfD that this resolution process should involve independent determination of disputes without any government involvement. The use of a two stage process of (1) discussions between the parties, followed by (in the absence of resolution of the dispute by the parties), (2) binding LCIA[48] arbitration or binding expert determination is a familiar contractual approach to resolving disputes. It is an approach which should allow for disputes to be resolved in a timely manner, and which provides a reliable and independent forum for disputes to be resolved within.

[47] If instances of Force Majeure relief had no randomly occurring elements, but instead were systematically correlated with the overall performance of the economy, this would make it more difficult for the impact of providing relief to be diluted across the economy. Our assumption is that instances of Force Majeure relief will not be systematically correlated with the overall performance of the economy. By way of illustrative example, we would expect force majeure protection might apply to events such as terrorist attack, war and civil disobedience (provided in the circumstances that the relevant event fulfilled all the requirements of the definition of Force Majeure within the CfD).
[48] London Court of International Arbitration

CfD Term	Description	Decision	Rationale
Termination	Circumstances when contract can be terminated.	A proportionate approach to contract enforcement: • Includes breaches of contract by generators that affect the fundamental objectives of the CfD – such as, non-payment, fraud and non-delivery of capacity (subject to Force Majeure or delay to grid connection). • Cure periods for certain events encourage generators to move back into compliance with the contract Where events of default cannot be remedied and the termination right is triggered, the Government is proposing that the CfD counterparty should have the right to recover a lump sum termination payment by way of compensation of the early expiration of the contract. The Government is minded that this payment, which would be one way, would be calculated mechanically as the present value of the projected difference payments to be made by the generator over the remaining term of the contract.	The Government's ultimate objective is that low-carbon generation should be built and should operate for the full term of the contract. As such the termination provisions are intended to provide an appropriate and proportionate approach to contract enforcement in order to ensure projects are efficient and deliver value for money. The breaches that could give rise to the CfD Counterparty exercising its right to terminate the contract are focussed on those events which are fundamental to the objectives and operation of the contract, such as the legitimate functioning of generator and flow of payments. It is not appropriate for a generator to continue to benefit from the CfD if it is in default and unable to perform these fundamental obligations. However the Government appreciates that some of these breaches may be remediable. Therefore, it intends to offer realistic and practical remedy periods for those remediable events in order to offer generators the opportunity to move back into a position of compliance. This limits the risk faced by generators. The termination payment from generators to the CfD counterparty will be based on a calculation of the net present value of expected difference payments from the generator to the CfD counterparty over the remaining life of the contract. Should this calculation return a total net payment from the CfD Counterparty to the generator no termination payment is payable to the generator by the CfD Counterparty. The Government has considered whether termination rights should also be available to the generator as a result of CfD counterparty default. Its view is that such rights would be not be appropriate as the legislative underpinning of the scheme, together with the restrictive purpose of the CfD counterparty (that is, to enter into CfD contracts with low-carbon generators) should provide sufficient comfort to investors that the CfD counterparty will perform its obligations under the contract. The CfD counterparty will also be required by law to raise revenue from suppliers in order to make payments to CfD generators. This will, in turn, be supported by the secondary legislation on the detail of the supplier obligation, which will also be enforced as a relevant requirement. Unlike generators, the CfD counterparty will therefore have express legislative support in meeting its CfD obligations and will have no further commercial incentive that might lead to non-performance under the contract.

CfD Term	Description	Decision	Rationale
Difference payments	The basis on which payments are made	Government has decided that the CfD for intermittent and baseload generation should be paid on output with payments capped at an amount equal to the strike price[49].	Payments under the CfD can either be based on output (e.g. MWh), a measure of availability, or a mixture of both. Annex B of the EMR White Paper[50] described one possible CfD structure for "flexible" generation that involved paying on availability. Supporting low-carbon generation based solely on output can lead to dispatch distortions or negative pricing as this plant will generate even when the electricity price it receives is lower than its running costs, so that it can access support. However, the Government believes that support on metered output is more appropriate for intermittent and baseload generators for the following reasons[51]: • it is simpler as there is a clear and direct link between the low-carbon output and the low-carbon support; • there is no risk of paying when the plant is not available and not generating; and • analysis by consultants LCP[52] demonstrated that the distortions to the merit order are likely to be limited. In addition, paying intermittent plant on firm volume / availability means that they would have to pay back the difference between the reference price and the strike price when the former is higher. However, as intermittent plant cannot control their output, they would not know whether they would be generating (and thus earning the market price) in such a scenario. As a result, this would represent a significant and unknown risk for intermittent plant. However, the LCP analysis showed that there is significant potential for negative prices caused by paying on metered output. Government considered two options for addressing the consequent risks of increased costs of system operation and spiralling difference payments:

[49] Paragraph 173, CfD Operational Framework, November 2013 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66554/7077-electricity-market-reform-annex-a.pdf).
[50] Paragraphs B.36 to B.43 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48130/2173-planning-electric-future-white-paper.pdf).
[51] Section D(ii), CfD Draft Operational Framework (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48373/5358-annex-b-feedin-tariff-with-contracts-for-differe.pdf).
[52] "LCP's assessment of the dispatch distortions under the Feed-in Tariff with Contract for Differences policy", May 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48443/5693-lcp-assessment-of-the-dispatch-distortions-under-t.pdf). Note this conclusion is heavily dependent on assumptions around fuel prices and the carbon price, even if the CfD does alter the position of the CfD plant in the merit order, it can be argued that this meets Government objectives as it maximises the output from low-carbon plant that is being supported through the CfD.

CfD Term	Description	Decision	Rationale
			1. Paying CfD plant on output unless the reference price drops below zero, in which case payments would be on availability. 2. Paying CfD plant on output with payments capped at an amount equal to the strike price. The System Operator's view is that Option 1 price may produce a distortionary 'cliff-edge' effect, complicating and increasing the costs of system operation (including reserve costs). This would increase overall costs on consumers as reserve costs are ultimately passed through to energy bills. While Option 2 avoids this cliff-edge effect on system operation, it has the potential to increase revenue risk to investors. Revenue would not be guaranteed when prices are negative, and it is difficult for investors to assess accurately the magnitude of this risk. However, on the basis of the System Operator's modelling at the time of the November 2012 Operational Framework, which indicated that periods of negative prices are expected to be infrequent and are unlikely to occur until far into the future (less than 2% of the hours in 2030). Government considered the effect of this risk on strike prices is to be relatively marginal. As such, Option 2 was preferred[53]. Note: Our quantitative modelling assumes that CfDs are settled on the basis of output, adjusted for transmission losses, with payments capped at the Strike Price.

[53] CfD Operational Framework, paragraphs 161 to 173.

CfD Term	Description	Decision	Rationale
Metering arrangements	How low-carbon electricity generation is recorded for the purposes of billing.	Arrangements to support a wide-range of project types, using existing processes where possible: • Making use of existing settlement arrangements, where possible[54]. • Loss adjusted net metered energy[55]. • Arrangements will be developed for transmission, distribution and private wire generation[56]. Where necessary, further calculations will be applicable to derive the generator's difference payment for each Settlement Period. To derive this value the loss-adjusted net metered output would be multiplied by: • Renewable Qualifying Multiplier or "RQM" (in the case of fuels with variable renewable energy content) and • Qualifying Power Output or 'QPO' (in the case of qualifying CHP generating stations)	The key underlying principle for metering arrangements is that payments under the CfD will be made on the basis of net 'green' electricity that is generated and is available for sale. This approach, relative to alternative options, better maintains the link between the support provided and the electricity produced, and reflects the Government's objective to decarbonise the power sector[57]. Adjusting metered output for losses on the transmission (and/or distribution systems, where relevant) is consistent with existing settlement arrangements. We believe it is the appropriate basis against which to settle difference payments, as we believe that generation closer to demand (i.e. after transmission losses have been applied) should be worth more than generation at the notional balancing point. The processes for private wire generation will be designed to support fairness across the scheme, consistency, simplicity and competition. Note: Our quantitative modelling assumes that CfDs are settled on the basis of output adjusted for transmission losses. Where relevant, we make assumptions on the proportion of input fuel with renewable content in line with the latest available data.

[54] A BSC registered and compliant metering system is required by all CfD-eligible generators connected to the public electricity system. Generators (or the BSC Parties acting on their behalf (i.e. suppliers operating on behalf of embedded generators) should satisfactorily set up their metering and/or IT systems consistent with Section K and L of the BSC code to accurately measure their metered flows and to ensure their CfD assets are included in the BM Unit(s) associated with their CfD contract (which must not include other non-CfD assets).

[55] The CfD Operational Framework published in November 2012 proposed that difference payments would be calculated over a given settlement period, based on a generator's loss net adjusted metered energy for each settlement period, at the BSC boundary point (or other point agreed by the BSCCo via a metering dispensation). This was confirmed in the August 2013 publication.

[56] Although the same metered output model will apply to both BSC traded and private wire generators, under the CfD private wire generators will be required to follow the RO approach by providing both input and output data to the CfD Settlement Agent for each Settlement Period. The Agent will then net off the gross metered input from the gross metered output to arrive at a net metered output figure.

[57] CfD Operational Framework (November 2012), paragraph 154 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66554/7077-electricity-market-reform-annex-a.pdf).

Annex B: Comparison of risks to generators under the CfD and the RO

56. Table 6 below examines the risks for renewables plants under the RO regime compared to the CfD. Overall, CfDs should reduce risks and hence generators' cost of capital.

Table 6 Risks for renewables plants under the RO regime compared to the CfD

Risk area	Treatment under RO regime	Proposed treatment under generic CfD	Our assessment of the impact of CfD on this risk
1) Variability of overall revenue and offtake risk	Electricity offtake risk, forecasting/balancing risk and wholesale price risk sit with generators, mitigated (at a cost) through vertical integration and/or in some cases through PPAs Support payments are in certificates that independents have to sell to suppliers at a cost/risk, but the Obligation may provide an incentive on some suppliers to purchase renewable electricity over other forms of electricity.	Long term wholesale price risk removed, stabilising revenues. Offtake and forecasting/balancing risks remain with generators. Again, some generators may pay to mitigate offtake and imbalance risk through PPAs. Support payments in cash.	Reduction
2) Risk of change of support levels	Policy of grandfathering existing investments under the RO, but cannot fetter SoS discretion to change support levels for new or existing RO generators.	CfD allocation at earlier stage of project development locks in the strike price that a project will eventually receive at a far earlier stage than the RO. Strike price set in contract with no mechanism for SoS to change support levels once contract is signed.	Reduction

Risk area	Treatment under RO regime	Proposed treatment under generic CfD	Our assessment of the impact of CfD on this risk
3) Visibility and future market	Four years of visibility given in banding reviews but can be revised post-financial commitment and before the point of generator accreditation. Budget managed through revisions to RO bandings.	Five years of strike prices known at the time of the publication of the Delivery Plan, and locked in for each project at the point of allocation. Can similarly be revised for the later years in annual updates to the Delivery Plan. Potential for CfD allocation to be rationed in the event that more projects apply than can be supported by the available budget.	Both the RO and CfDs need to operate within the same budget envelope. CfD provides more certainty over the level of support. CfD may provide less certainty over whether there will be support if constrained allocation is triggered, whilst RO budget management would be through revisions to support levels - no clear net effect.
4) Credit risk	The tradable certificate (the ROC) may be sold to alternative suppliers or auctioned in circumstances of off-taker default. The recycle value to suppliers and hence the price paid to generators can vary but is protected against supplier bankruptcy through the RO Mutualisation Fund.	The CfD Counterparty (a government-owned private body) will establish a framework of backstops to ensure payment, including the requirement for suppliers to post collateral, a mutualisation system and a Supplier of Last Resort Scheme and Energy Company Administration Scheme.	No clear net effect.

Risk area	Treatment under RO regime	Proposed treatment under generic CfD	Our assessment of the impact of CfD on this risk
5) Change in Law	No Change in Law (CiL) protection is available in the RO. However generators may be able to recover some costs arising from certain changes in law (but only to the extent that they change the wholesale electricity price), or buy protection for some CiL risks through their PPA.	Some contractual protection is provided for both specific and discriminatory changes (in contrast to RO), and for general changes in law that have discriminatory effects without objective justification. This includes protection against events that would not be reflected in the wholesale price. No protection for other general CiL, and thus unable to benefit from some changes in law to the extent that this is passed through to wholesale prices due to a fixed strike price. Protection against certain changes in network charges, relating to the costs of the balancing system and transmission losses. Protection extends to such changes in law that limit a generator's ability to either deliver its output or to receive appropriate payment. As under the RO, generators would be able to buy additional protection through a PPA.	Reduction.
6) Indexation	Expected RO price each year linked to RPI; wholesale price may reflect inflation of costs of the marginal plant.	Strike price fully indexed to CPI.	No material change to risk, but differential in revenue inflation reflected in strike price.
7) Refinancing	No refinancing gain share provisions/requirements.	No refinancing clause in the generic CfD contract[58].	No change.
8) Duration	Exposure to wholesale market risks for the entire asset life with 20 years of top-up support (except for biomass conversions).	15 years of support (except for biomass conversions), then exposure to market risks with no top-up payments after 15 years (but heavily discounted in the investment decision).	No clear net effect to risk, but differential support duration reflected in strike price.

Source: Table 2 of "Annex B: Strike price methodology" to the Consultation on the draft EMR Delivery Plan, July 2013 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223652/emr_consultation_annex_b.pdf).

[58] Bilaterally negotiated CfDs for large projects may have different approaches, including possible refinancing clauses, but might have different strike prices.

Annex C: Supply chain standard

57. It is proposed that developers of generic projects greater than 300MW in capacity will be required to produce and submit supply chain plans detailing:

- whether a workforce with the necessary skills to undertake the construction is in place and, if not, whether the developer is confident the workforce can be secured (this to consider the deliverability of the project, and if it is likely to lead to low carbon generation being delivered);
- how those skills will be maintained for the life of the project, or, as the case may be, developed and maintained (this is to consider how the project will contribute to the development of skills in low carbon generation and development);
- whether the proposed project will go through a competitive procurement process to enable technically competent and cost-efficient suppliers, regardless of their location to compete for such contracts. This is to ensure the project will be delivered at the lowest possible cost (and will allow us to assess whether the proposed project is likely to lead to a reduction in the cost of generating electricity from the chosen generation type[59]); and
- what approaches have been taken or will be taken to implement this project in an innovative manner, including through research and development and technological development, to ensure that project costs are reduced and support reductions in future projects' Strike Prices for consumers.

58. By introducing the supply chain plans requirement, Government is highlighting the importance of supply chain development. Focusing on the way the projects are delivered can help develop the industrial base, reduce cost and encourage participation by smaller businesses, and promote innovation and skills. Publishing plans would improve transparency on how costs can be reduced and allow a degree of public scrutiny of projects. This could bring all developers up to the standard of strongest performers in the sector in terms of supply chain support, supporting supply chain growth and competitiveness. Taken together, the supply chain plans requirement has the potential to increase competition and lower development costs.

59. There are likely to be administrative costs to government to review these plans; these are currently estimated to have a NPV cost to 2030 of around £1.8m[60]. The administrative costs to industry are unknown but we would expect the costs to government of vetting the plans to be a lower bound on the costs to industry of producing these reports and we note that the costs could potentially be significantly higher.

60. We will be seeking more evidence on the costs these measures place on businesses, and any benefits they may produce.

[59] Numerous studies have demonstrated how increased competition in the low carbon supply chain could drive down the future cost of low carbon technologies; therefore Government is keen to improve the contestability of the low carbon supply chain. Actions of this type can help to ensure that the project is delivered in a sustainable and cost-efficient manner.

[60] This is the discounted cost of a G6 a G7 and an HEO based on the pay scales published in DECCs most recent "Equal Pay Review".