Title: Electricity Market Reform – Offtaker of Last Resort **IA No:** DECC0156 **Lead department or agency:** DECC	# Impact Assessment (IA) **Date:** 11/02/2014 **Stage:** Consultation **Source of intervention:** Domestic **Type of measure:** Secondary legislation **Contact for enquiries:** Christalla.kyriacou@decc.gsi.gov.uk Darryl.croft@decc.gsi.gov.uk

Summary: Intervention and Options

RPC Opinion: Not applicable

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, Two-Out?**	**Measure qualifies as**
-£283m	£0 to 34m	£0 to 2.5m	No	Tax and spend

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

Independent renewable generators (IRGs) typically require long-term Power Purchase Agreements (PPAs) with an offtaker to secure a buyer for their power in order to secure finance. It has become increasingly difficult for IRGs to secure PPAs on bankable terms – there are few offtakers considered sufficiently credit-worthy to offer long-term PPAs and those that are have a finite capacity to offer them. The lack of competition risks the availability of efficiently priced long-term PPAs. The transition from the Renewables Obligation to Contracts for Difference (CfDs) should remove some of the constraints that have caused the deterioration in terms but evidence suggests that there is a risk that the availability of bankable long-term PPAs could still remain constrained going forward. If the issue were not addressed it could remain difficult for IRGs to raise finance to develop projects, increasing the risk of failing to achieve our renewables target while also limiting competition in both the electricity generation and PPA markets.

What are the policy objectives and the intended effects?

The policy objective is to provide a guaranteed route-to-market for IRGs. The intended effects are to provide more certainty to their investors and lenders over route-to-market and PPA risks, open up a wider range of contracting strategies, and increase the range of possible offtakers. This could increase competition and innovation in the PPA market and alleviate some of the constraints which could prevent independent renewable projects from coming forward in future.

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

This Impact Assessment considers the impacts of an **Offtaker of Last Resort (OLR).** This would guarantee eligible generators that, at any time during the operation of their CfD, they will be able to access a "Backstop PPA" at a specified discount to the market reference price in that CfD.

A range of OLR designs are considered and set out in the evidence base. The lead option is characterised by (among other factors) a competitive allocation process for the Backstop PPA, a fixed Backstop PPA discount at £25/MWh and a quarterly levelisation process of any costs/rents incurred by backstop offtakers for managing a Backstop PPA. Alternative designs include an administrative allocation process, a fixed discount between £20/MWh and £30/MWh and a daily levelisation process.

Will the policy be reviewed? It will be reviewed.
If applicable, set review date: 2018/19 (see evidence base)

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:** -41 to 0	**Non-traded:** 0	

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

Signed by the responsible Minister: Date:

Summary: Analysis & Evidence

Description: Offtaker of Last Resort

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2014	Time Period Years 22	Net Benefit (Present Value (PV)) (£m)		
			Low: -£2.558bn	**High:** £0	**Best Estimate:** -£283m

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low	£0		£0	£0
High	£0		£369m	£4.709bn
Best Estimate	£0		£106m	£1.358bn

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

Reduced rents to incumbent offtakers/vertically integrated utilities (£0-1.152bn, midpoint £576m). Increased system imbalance costs (central cost scenario, £0-1.529bn, midpoint £765m, high cost scenario, £3.522bn). However, it is important to note that the incremental system imbalance costs associated with OLR arise only because renewable deployment in the counterfactual is below that in the EMR reference scenario. Overall system imbalance costs with the OLR are the same as in the EMR reference case. Expected business admin costs (largely preparing auction bids) (£0-34m, midpoint £17m). If OLR is never used then these costs would be zero.

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

Ofgem resource implications (more so with administrative allocation). Administrative costs to energy suppliers made mandatory offtakers (although these are likely to be small).

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	£0		£0	£0
High	£0		£169m	£2.151bn
Best Estimate	£0		£85m	£1.075bn

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

Improved PPA market competition increases rents to generators (i.e. an increase in consumer surplus through lower discounts) and consumers (i.e. an increase in consumer surplus through lower CfD strike prices under competitive strike price setting) (£0-1.152bn, midpoint £576m). Carbon savings from increased renewable generation between 0 and 41MtCO2e over the appraisal period (£0-998m, midpoint £499m). If OLR is never used, these benefits would still be applicable.

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

Improved generation market competition could lead to lower wholesale prices and CfD top-up payments and in the longer-term drive innovation, further reducing costs. While these have not been quantified, a break-even analysis suggests that **competition benefits equivalent to a 0.3% saving on average household electricity prices relative to the counterfactual would be sufficient to outweigh even the high cost scenario quantified**.

Increases the UK's ability to meet its 2020 renewables target in a cost-effective manner, reducing reputational risk and political risk (and associated cost of capital implications). In the short-term, improved security of supply and once the Capacity Market is introduced, avoided extra spend on capacity payments. Establishment of minimum revenues can also lower financing costs for new capital.

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

System imbalance costs and distributional impacts sensitive to outturn route-to-market costs and ability of suppliers to pass costs onto energy consumers. Success of the measure is also dependent on it being bankable. Moral hazard and adverse selection could also lead to undesirable impacts. A number of mitigating design features are intended to reduce the risk of OLR not being bankable and to reduce the materiality of any moral hazard incentives.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OITO?	Measure qualifies as
Costs: £0 to 92m	**Benefits:** £0-90m	**Net:** -£2.5m to 0	No	N/A

Evidence Base (for summary sheets)

Contents

Summary and preferred option

1. Evidence supports the conclusion that the terms offered by incumbent Power Purchase Agreement (PPA) providers have been deteriorating, particularly since 2010. In addition, while there are reasons why there may be an improvement in these terms from the transition from the Renewables Obligation (RO) to Contracts for Difference (CfDs), uncertainty over this transition and over future balancing costs could continue to act as a barrier to entry for new offtakers in the long-term PPA market, constrain the availability of long-term PPAs and limit the ability for projects to utilise shorter-term contracting strategies. These factors act as **barriers to entry for independent developers of power generation**.
2. In order to alleviate these constraints, the Government is considering the introduction of an Offtaker of Last Resort (OLR) which would guarantee eligible generators that, at any time during the operation of their CfD, they will be able to access a “Backstop PPA” at a specified discount to the market reference price. This would provide investors and lenders with more certainty over route-to-market and PPA risks; by capping the level of imbalance costs, lenders should be comfortable in sizing debt finance against revenues provided by the OLR rather than requiring a generator to sign a long-term PPA. The intended effect is that they will accept a wider range of shorter-term contracting strategies and offtakers, which will increase competition and innovation in the PPA market, alleviating some of the constraints which could prevent independent projects coming forward in future.
3. While a range of design options are considered, our lead option involves a competitive allocation of generation seeking a Backstop PPA to a backstop offtaker, a fixed Backstop PPA discount of £25/MWh and a quarterly levelisation process of any costs or rents incurred by backstop offtakers for managing a Backstop PPA. These particular design elements would minimise a number of costs and risks associated with the policy.
4. The OLR is not expected to add significant costs to business and society in the central scenario as those energy companies who would be obligated to offer backstop provisions are already expected to have the resources required to manage PPAs in place. Moreover, under central expectations of future route-to-market costs, we would not expect generators to ever request a Backstop PPA as market PPAs should continue to offer more attractive terms (i.e. lower discounts) than the Backstop PPA. Under central assumptions for route-to-market costs, and based on analysis by DECC and Baringa, the OLR is estimated to deliver a quantified net cost of between **£0 and 565m in NPV terms**. However, the policy was stress tested under higher route-to-market costs to determine the scale and distribution of any costs under such market conditions.
5. However, **if the OLR’s competitive benefits deliver cost savings equivalent to up to 0.3% of average domestic electricity prices over the period 2016-30, then the OLR is expected to provide a net benefit to society even in the high cost scenario**.
6. Overall, we therefore consider the costs to be small in comparison to the potential benefits of the policy.
7. Table 1 summarises the NPV estimates underpinning the figures in the policy summary.

Table 1: Summary of NPV calculations (real 2012 prices)

	Central route-to-market cost scenario		Midpoint (best estimate)	High route-to-market cost scenario
	CF1/lower bound	**CF2/upper bound**		**CF2/upper bound**
Quantified costs				
Loss of rents by incumbent offtakers through lower discounts	£0	£1.152bn	£576m	£1.152bn
Increased system imbalance costs	£0	£1.529bn	£765m	£3.522bn
Admin costs	£0	£34m	£17m	£34m
Total quantified costs (a)	**£0**	**£2.716bn**	**£1.358bn**	**£4.709bn**
Quantified benefits				
Transfer of rents to generators (through lower discounts) or consumers (through lower strike prices)	£0	£1.152bn	£576m	£1.152bn
Carbon savings	£0	£998m	£499m	£998m
Total quantified costs (b)	**£0**	**£2.151bn**	**£1.075bn**	**£2.151bn**
Total quantified net benefits (b-a)	**£0**	**-£565m**	**-£283m**	**-£2.558bn**

Background

8. Following a call for evidence, which closed on 16 August 2012[1], and analysis undertaken by Baringa examining the current and future state of the PPA market[2], the Government tabled amendments to the Energy Bill[3] providing it with a “backstop power” to enable it to take additional action, if necessary, to reduce barriers to securing long-term contracts (PPAs) for independent electricity generation investment, in order to support delivery of Government's Electricity Market Reform (EMR) programme. This Impact Assessment (IA) examines the arguments for and against a set of potential design options to achieve this.

9. This section provides background on:

    i. GB electricity trading arrangements;

    ii. the Renewables Obligation (RO);

    iii. Government's EMR programme; and

    iv. the role of Power Purchase Agreements (PPA).

GB electricity trading arrangements

10. The market is divided between network companies (transmission and distribution), generators and suppliers. National Grid is the System Operator responsible for the day to day real time operation of the network, ensuring that supply and demand is in balance at all times.

11. The wholesale market is divided into 30 minute periods for trading purposes; "normal" trading occurs until one hour prior to the start of each period - a point known as "gate closure". After gate closure, electricity generators and purchasers may not trade any further with each other, but may trade with National Grid.

12. Generally, market participants trade:

    i. Forward to mitigate "price risk", i.e. to give some certainty of the price for electricity sales/purchases; and

    ii. Spot and prompt to fine-tune positions (as factors such as weather, demand, and plant availability are better understood).

13. Participants are incentivised to contract fully against metered output through the use of imbalance charges, known as "cash-out" prices.

The Renewables Obligation

14. The Renewables Obligation (RO)[4] is currently the main financial mechanism by which the Government incentivises the deployment of large-scale renewable electricity generation. The RO places a mandatory requirement on licensed UK electricity suppliers to source a specified and annually increasing proportion of the electricity they supply to customers from eligible renewable sources or pay a penalty. The scheme is administered by Ofgem who issue Renewables Obligation Certificates (ROCs) to electricity generators in relation 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.

15. Suppliers present ROCs to Ofgem to demonstrate their compliance with the Obligation. Where they do not present sufficient ROCs, suppliers have to pay a penalty known as the buy-out price. The money collected by Ofgem in the buy-out fund is recycled on a pro-rata basis to suppliers who presented ROCs. Suppliers that do not present ROCs pay into the buy-out fund at the buy-out price, but do not receive any portion of the recycled fund.

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[1] The Government response to this consultation, including responses received by stakeholders as part of the consultation are available online at: https://www.gov.uk/government/consultations/barriers-to-long-term-contracts-for-independent-renewable-generation-investment.

[2] Available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/212754/baringa_ppa_market_liquidity_call.pdf.

[3] On 19 July 2013.

[4] Further information on the policy is available online at: https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/the-renewables-obligation-ro.

Government's EMR programme

16. On 12 July 2011, the Government published "Planning our electric future: a White Paper for secure, affordable and low-carbon electricity" (referred to in this document as the "EMR White Paper").[5] The EMR White Paper sets out key measures to attract low carbon investment, reduce the impact on consumer bills, and create a secure mix of electricity sources including gas, new nuclear, renewables, and carbon capture and storage.

17. Key elements of the reform package include:

    i. a Carbon Price Floor (announced in Budget 2011 and which came into force in April 2013) to reduce investor uncertainty, putting a fair price on carbon and providing a stronger incentive to invest in low-carbon generation now;

    ii. the introduction of new long-term contracts (CfDs) to provide stable financial incentives to invest in all forms of low-carbon electricity generation;

    iii. an Emissions Performance Standard (EPS) set at 450g CO_2/kWh to reinforce the requirement that no new coal-fired power stations are built without Carbon Capture and Storage (CCS), but also to ensure necessary short-term investment in gas can take place; and

    iv. a Capacity Mechanism, including demand response as well as generation, which is needed to ensure future security of electricity supply.

18. A CfD is a long-term contract between an electricity generator and a contract counterparty. The contract enables the generator to stabilise its revenues at a pre-agreed level (the strike price) for the duration of the contract. Under the CfD, payments can flow from the contract counterparty to the generator, and vice versa. By providing stability of revenues, the CfD should increase the rate of investment and lower the cost of capital, thereby reducing costs to consumers.

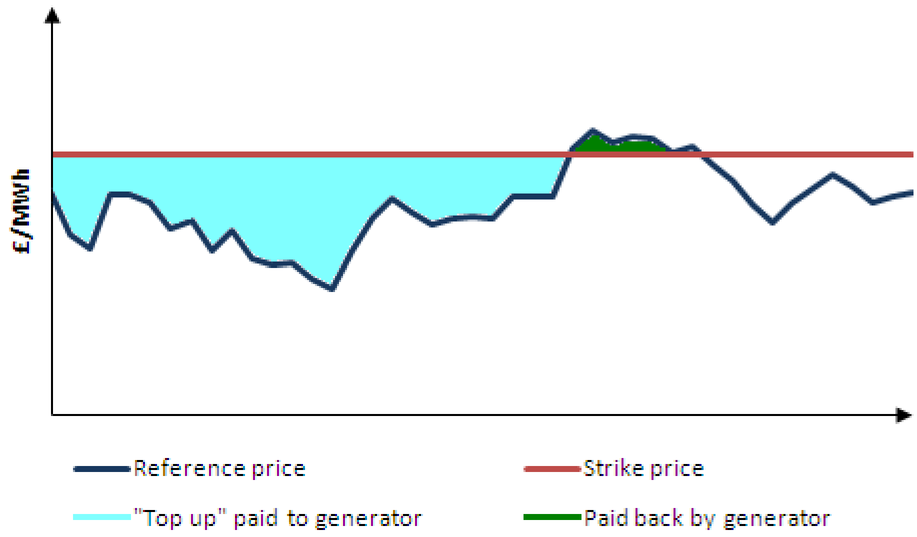
19. In terms of setting the "strike price", the Government intends to move to a competitive price discovery process for all low-carbon technologies as soon as practicable.[6] Competition will enable us to reduce the costs of decarbonisation, limit the bill impacts of achieving our low-carbon objectives and drive efficiencies across the sector. In the medium- to long-term we aim to introduce technology neutral low-carbon competition. The Government considers that "established" renewable technologies (including onshore wind and solar) should be subject to immediate competition through a competitive process of CfD allocation. Government considers that less established technologies (including offshore wind) should not have to compete in allocation rounds against lower cost, more established technologies. If all the projects seeking support within this group can be accommodated within the allocated budget, those projects would receive support at the administrative strike price. It is possible that constrained allocation may need to apply to this group in some years to ensure that we remain within the Levy Control Framework envelope.

20. A "two-way" CfD provides for payments to be made to a generator when the market price for its electricity (the reference price) is below the strike price set out in the contract. However, when the reference price is above the strike price, the generator pays back the difference (see Chart 1).

[5] Available online at: https://www.gov.uk/government/publications/planning-our-electric-future-a-white-paper-for-secure-affordable-and-low-carbon-energy.

[6] The final EMR delivery plan was published in December 2013 and is available online at: https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan.

Chart 1: Operation of FiT CfD



21. In the EMR White Paper, the Government proposed[7] that "intermittent"[8] generators would receive a CfD referenced to a day-ahead market price, while "baseload"[9] generators would receive a CfD referenced to a year-ahead baseload price.

22. On 29 November 2012, the Secretary of State introduced the Energy Bill into parliament, which implements the main aspects of EMR. The Energy Bill received Royal Assent in December 2013. On 4 December 2013, the Government set out its decisions on strike prices for renewable projects for the period 2014/15 to 2018/19 and updated key CfD contract terms.[10]

The role of Power Purchase Agreements (PPAs)

23. For any power generation investment, investors will want to be certain that risks can be efficiently managed during the investment payback period. All generators need to manage a range of risks in order to operate effectively in the wholesale market. Those risks include:

    i. **Offtake risk –** the risk that power cannot be sold at an efficient price with a viable route-to-market;

    ii. **Balancing risk –** the risk of metered output not meeting the contracted position and being exposed to the "cash-out" price. This can be mitigated by effectively forecasting output and trading on the within-day market to avoid imbalance;

    iii. **Volume risk –** the risk that the total generation of the installed capacity falls short of what was expected (i.e. project load factor over a given period is lower than expected affecting the project's ability to cover its fixed costs);

    iv. **Price risk –** the risk that the underlying wholesale price changes and the power that is generated does not achieve the expected price; and

    v. **Basis risk –** the risk of deviation between the market price achieved by the generator and the market reference price in, for example, a CfD.

24. Market participants seek to manage these risks through their power trading strategies. Power can be traded directly in the wholesale market through bilateral contracts, brokered 'over-the-counter' trades or on exchange platforms. In these cases, an efficient liquid market is essential so that independent operators have clear price signals and are able to effectively manage trading risks. Work by Ofgem and industry to improve liquidity will play an important part in increasing competition

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[7] A more detailed explanation of this is contained at Annex B to the EMR White Paper, available online at: http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/2173-planning-electric-future-white-paper.pdf.

[8] Plant which has little or no control over when it generates or at what level of production (beyond a decision to be available or not) and for which fuel costs are not a consideration. This class therefore includes wind as well as other renewable technologies such as wave and solar.

[9] Plant which operates at a constant level of generation, either for economic reasons or because the plant has limited ability to vary output at short notice to respond to shifts in demand. In addition to nuclear generation, this class may also include some biomass plant and Carbon Capture and Storage (CCS) plant.

[10] Further information on the policy is available online at: https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform.

and trading options. On 12 June 2013, Ofgem set out their final proposals for a "Secure and Promote" licence condition aimed at improving access of small suppliers to the wholesale market and ensuring that the market provides the products and price signals that all firms need to compete effectively.[11]

25. However, some projects will not be directly helped by these measures. In particular independent generators currently rely on long-term offtake contracts, known as PPAs, for their route-to-market and risk management. PPA terms vary, but typically the offtaker agrees to buy power at a discount to the prevailing wholesale price. The discount reflects the risks that the offtaker will manage on behalf of the generator[12], but the overall discount may be affected by the level of competition amongst PPA providers (i.e. offtakers).

26. The most important reason why independent generation projects rely on PPAs is that these projects typically rely on non-recourse project finance[13] to part-fund the investment. Given the long length of financing, this typically requires the offtake and other risks to be entirely managed through a long-term PPA with a credit-worthy counterparty. Whilst other routes to market are theoretically available, in the majority of cases, financiers will require a long-term PPA to reduce risk. Reliance on PPAs may also reflect the scale of some generators' projects; including limited in-house trading capacity and the difficulties that individual wind projects face in managing their imbalance risks.

27. Whilst the structure of PPAs vary, they typically fall into three types, which deal with risk in the following ways:

    i. **Variable price PPA:** The PPA provider pays the generator the wholesale electricity price less a discount that reflects the value of the risks that have been transferred under the PPA. Under the RO, the generator is fully exposed to the price risk, while under the CfD the price risk is removed. This is expected to be the preferred type of PPA under the CfD, as generators will want to sell as close as possible to the CfD reference price.

    ii. **Variable price PPA with floor price:** As above, but the PPA provider guarantees a minimum price (either across all benefits – wholesale, ROCs and Levy Exemption Certificates (LECs) – or more commonly today only for wholesale power), which reduces the price risk to the generator. This increased certainty for the generator is typically reflected in a greater discount, reflecting the transfer of risk to the PPA provider. As the CfD will provide a top-up to the strike price, PPAs with a floor price are not expected to be required in future to such an extent.[14]

    iii. **Fixed price PPA:** The generator would receive a constant price for any power produced. Under the RO, this approach transfers the price risk from the generator to the offtaker. Fixed price PPAs offer stability but the degree of risk transferred is reflected in the price specified in the PPA, which would be significantly lower than the average market price. Government has been told that there is less appetite amongst utilities to offer long-term fixed price PPAs in large part because a change in accounting rules surrounding imputed debt since the financial crisis has resulted in the treatment of fixed and floor price PPAs as open obligations (essentially bringing them onto balance sheets) increasing pressure on their balance sheets. Generators are not expected to seek fixed price PPAs under the CfD, as breaking the link to the reference price would leave them with a variable revenue stream and potentially expose them to paying back more than they received from the PPA if the reference price went above the strike price.

28. Table 2 summarises the typical risk transfer under a PPA.

[11] Further information is available online at: https://www.ofgem.gov.uk/publications-and-updates/wholesale-power-market-liquidity-final-proposals-secure-and-promote-licence-condition.

[12] These costs might constitute a larger share of revenues from generation for projects with intermittent output (e.g. wind), which would require more active trading, and for smaller projects, which might be more expensive due to fixed costs (e.g. forecasting) being spread over lower generation output.

[13] Project finance relates to the long-term financing of projects based on analysis of the cash-flows of the specific project, rather than the strength of the balance sheet of the company sponsoring the project. In contrast to an ordinary borrowing situation, with project finance the financier usually has little or no recourse to the non-project assets of the borrower or the sponsors of the project. Historically, where PPA arrangements have been viable, project finance debt has financed between 60-90% of total construction costs and has been key to ensuring projects are economically viable for their shareholders.

[14] Although floors at £0/MWh may prevail.

Table 2: Typical risk transfer under a PPA

Risk type	Risk transfer
Offtake risk	From generator to offtaker (offtakers in the long-term PPA market are typically vertically integrated utilities who can sell the power onto their customers).
Balancing risk	From generator to offtaker (offtakers typically have a diverse generation portfolio enabling them to better manage this risk).
Volume risk	Remains with the generator (under a PPA, the offtaker will typically only pay for the power generated).
Price risk	Depends on whether the PPA has a floor or a fixed price – PPAs with a price floor or fixed price will transfer at least some of this risk from the generator to the offtaker. The move from the RO to CfDs will significantly reduce this risk and the need for such floors in PPAs.
Basis risk	From generator to offtaker (if the PPA terms are linked to the market reference price then the offtaker bears any risk of it varying from the wholesale price, i.e. the price they could have paid from buying power in the wholesale market).

Problem under consideration

29. On 5 July 2012, the Government launched a call for evidence[15] aiming to improve our understanding of the issues facing independent developers. Based on the evidence provided by respondents from the Call for Evidence as well as targeted interviews, Baringa assessed the issues facing independent developers of intermittent power generation in securing commercially viable PPAs and how that might evolve in future with a move to CfDs.[16]

30. The main factors cited by respondents and supported by significant evidence for the recent deterioration in PPA market liquidity were:

    i. **Increased wholesale price risk –** In particular, a reduced appetite by offtakers to offer sufficient wholesale price protection (typically in the form of a price floor);

    ii. **Reduced appetite for long-term ROCs –** In particular, a reduced appetite to manage long-term ROC price and liquidity risk. Potentially also due to an increase in the ability of Vertically Integrated Utilities (VIUs) to meet their renewables obligation with their own assets;[17]

    iii. **Increased balance sheet/credit rating impact –** Consistent with greater scrutiny by credit-rating agencies following the financial crisis and greater involvement by VIUs in large-scale offshore wind projects requiring a significant amount of capital. Lending requirements currently restrict the ability of other non-VIU providers in the long-term PPA market; and

    iv. **Increased regulatory and policy risk –** For example, the uncertain impact of Ofgem's Electricity Balancing Significant Code Review (EBSCR) on future balancing costs.

31. The move from the RO to CfDs should act to reduce or remove at least the first two causal factors. In particular, CfDs provide a guaranteed top-up payment for every £/MWh produced against the market reference price. As such, a significant amount of price risk will be removed.[18] In addition, the closure of the RO removes the need to manage ROC price and liquidity risk for new projects. Both these factors should also mean that, all other things being equal, market PPA discounts should improve.

32. There will, however, remain significant risks to the improvement of PPA market terms and liquidity under CfDs. Namely:

    i. **Uncertainty over future balancing costs –** There is uncertainty over the impact on the future cost of balancing from the increased penetration of intermittent generation on the system. This uncertainty necessitates higher risk premia being applied to long-term PPA discounts.[19] Furthermore, managing this uncertainty requires more active trading and higher collateral requirements for hedging. This acts as a barrier to entry into the long-term PPA market by smaller offtakers. Possible changes to the balancing mechanism have also added to this uncertainty. Ofgem are currently aiming to publish their final EBSCR policy decision in Spring 2014, which should reduce the level of regulatory uncertainty surrounding the costs of balancing.

    ii. **Bank lending requirements –** Bank lending requirements currently act as a significant barrier to entry in the long-term PPA market. Reflecting concerns over credibility, capitalisation, long-term experience and strategic positions in energy markets, lenders currently require a counterparty offering long-term PPAs to have a minimum credit rating of BBB- or above. As a consequence, large VIU offtakers are often preferred because they typically have large balance sheets, a relatively stable supply base, and are seen as being strategically invested in the GB energy market in a way that makes it very difficult for them to walk away from long-term contracts and liabilities. Lenders' requirements also prevent project developers from utilising

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[15] Available online at: https://www.gov.uk/government/consultations/barriers-to-long-term-contracts-for-independent-renewable-generation-investment.

[16] Available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/212754/baringa_ppa_market_liquidity_call.pdf.

[17] Supported by evidence from Cornwall Energy and referenced in Baringa's report "Power Purchase Agreements for independent renewable generators – an assessment of existing and future market liquidity" available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263919/Baringa_report_on_PPA_market_liquidity___July_2013.pdf.

[18] There will still remain some residual risk, for example, in relation to negative prices.

[19] The short-term PPA market involves smaller risk premia as a result of the shorter tenure of the contracts, however, lenders do not currently accept contracting strategies using this market.

the more liquid short-term PPA market as it does not guarantee offtake up front for the period beyond the initial PPA.

Rationale for intervention

33. Currently, around 21GW (or 61%) of pipeline large-scale renewable power projects are being developed by independents (i.e. non-vertically integrated utilities).[20] The majority of these projects will likely require a PPA in order to secure finance to proceed.

34. The factors cited above act as barriers to entry into the long-term PPA market, constraining the PPA market and, as a consequence, acting as barriers to entry for independent developers of renewable power generation.

35. We believe it is important to reduce these barriers for the following reasons:

    i. **Competition benefits:** A competitive market needs many sellers in order to deliver value-for-money for consumers. It also requires a credible threat of new entry (contestability) in order to maintain competitive incentives (to price competitively, improve service and innovate) among existing market players. As stated above, evidence suggests that there are currently constraints on new entry in the wholesale electricity market due to constraints in the PPA market. The long-term PPA market itself has seen some new entry over the last three years but large vertically integrated utilities remain the most material PPA providers with a high degree of pivotality.[21]

    ii. **Value for money:** Encouraging competition in the wholesale electricity market could deliver value-for-money to consumers in a number of ways including delivering lower strike prices (i.e. lower CfD top-up payments ultimately borne by energy consumers) through a competitive bidding process and reducing technology costs through greater innovation.

    iii. **Meeting our 2020 renewables target:** The UK is legally committed to meeting 15% of its energy demand from renewable sources by 2020. Independent renewable power projects could play an important role in enabling the UK to achieve this target.

Policy objective

36. The policy objective is to provide a guaranteed route-to-market for independent renewable generators. The intended effects are to provide more certainty to their investors and lenders over route-to-market and PPA risks, open up a wider range of contracting strategies, and increase the range of possible offtakers reducing a key barrier to entry for independent renewable project developers and enabling the achievement of the UK's 2020 renewables target in a cost-effective way.

[20] Centrica, E.On, EDF, RWE nPower, Scottish Power and SSE as well as foreign utilities, such as Dong, Statkraft, Statoil, Vattenfall, EDPR, Repsol and GDF Suez. Figures based on DECC's monthly planning database, available online at: https://restats.decc.gov.uk/app/reporting/decc/monthlyextract.

[21] The extent to which a company is indispensable to meet demand. Evidence based on Baringa's report "Power Purchase Agreements for independent renewable generators – an assessment of existing and future market liquidity" available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263919/Baringa_report_on_PPA_market_liquidity___July_2013.pdf.

Options under consideration

An Offtaker of Last Resort (OLR)

37. The Offtaker of Last Resort will provide a minimum level of contracted revenue (when combined with CfD top-up payments) against which finance can be secured by giving generators access to a "Backstop PPA" at a fixed £/MWh discount to their CfD market reference price in order to guarantee a route-to-market.[22]

38. To help inform the policy development, an OLR Advisory Group (OLRAG) was formed consisting of generators, offtakers, accountants, solicitors and Ofgem. The group met seven times, commenting on papers presented at each meeting and providing invaluable feedback.[23]

39. Detail on individual design aspects of the policy being consulted on are set out in more detail in Annex A.[24] Table 3 summarises the characteristics of the Government's 'minded to' option and alternative design options being considered.

40. The Backstop PPA discount will be set at a level that is intended to strike the right balance between a discount that is large enough to minimise the risk that it ends up being smaller than discounts in the market, while still providing sufficient 'firm' revenue to allow projects to obtain a reasonable level of debt and equity returns. Annex B provides further detail on how we used analysis by Deloitte to inform an appropriate range of discounts on which to consult on. The Government's minded to option is to set this discount at a fixed level of £25/MWh, which we expect to be much larger than discounts offered in the market under current expectations of future route-to-market costs. Alternative options of £20/MWh and £30/MWh are also considered.

41. The Backstop PPA can be accessed by any eligible generator if its market PPA provider becomes insolvent, its existing market PPA expires, or if its existing market PPA is suspended as part of a mutual agreement with their offtaker and it is unable to secure another at better terms than the Backstop PPA. Eligibility will span the length of their CfD.

42. The Government's preferred option is to allocate the Backstop PPA through a competitive process under which potential backstop offtakers are invited to bid a £/MWh fee to purchase and manage the route to market costs associated with a generator's output under the terms of the Backstop PPA. The offtaker with the lowest bid would then manage the Backstop PPA and their bid multiplied by the total volume of generation covered by the Backstop PPA will represent the exercise costs which would be levelised across all licensed electricity suppliers on the basis of the volume of electricity supplier over the levelisation period (as in the case of the small-scale Feed-in-Tariff scheme). The size of the management fee bids (and therefore the size of the levelisation fund) is expected to be smaller, the larger the Backstop PPA discount since a greater proportion of the route-to-market costs incurred by an offtaker would be covered by the discount. The amount bid by offtakers does not affect the level of the Backstop PPA discount for generators.

43. The Government's preferred option is a quarterly levelisation process, as in the small-scale Feed-in-Tariff scheme. A daily levelisation was also considered.

44. The Government is minded to report on and review the OLR scheme annually, and to undertake a comprehensive review to consider whether the scheme should continue beyond the end of the first EMR Delivery Plan in 2018/19. The annual review could result in a revision of the Backstop PPA discount (among other things) for new CfD signatories. In order to inform this decision, the Government is seeking to require generators to provide information on their initial PPA at the point at which their CfD payments commence. The primary objective of the comprehensive review would be to consider whether the scheme should remain open for new generators beyond the first Delivery Plan.

[22] When reference prices are positive.

[23] Further information and relevant papers are available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-off-taker-of-last-resort-advisory-group.

[24] Further detail on how the design options below were narrowed down is available in the accompanying consultation document. Available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.

Table 3: Options for OLR design

Policy element	'Minded to' option	Alternative design options
Eligibility	• All renewable CfD and investment contract (IC)[25] holders. • All sizes.	
Offtaker identity	• Mandated suppliers (determined by a minimum threshold of electricity supplied) to submit bids to manage each Backstop PPA. • All other licensed suppliers are able to voluntarily submit bids.	
Access	• Earliest access for generators to the OLR is in early 2016 (to enable Ofgem to implement the necessary systems). • Beyond this, generators are able to enter the OLR from the start of the CfD payments. • Generators' eligibility for the OLR is lost if their Backstop PPA is terminated by the offtaker for 'material breach' or if they terminate a Backstop PPA early without required notice.	
Allocation	• Competitive allocation where potential offtakers bid a management fee (reflecting route-to-market costs they expect to incur beyond the level of the fixed discount). Obligation on Ofgem to allocate within a six week time period. • Contract allocated to the lowest bidder. Mandatory offtakers are required to submit bids. • If generator has a capacity >100MW, output is allocated in 100MW tranches, with the last tranche below 100MW.	• Administrative allocation. • Hybrid allocation.
Pricing and terms	• Fixed £/MWh discount, flat for CfD term, indexed to CPI. Set at £25/MWh for all technologies. • Contracts allocated for a 1 year period with a break clause at 6 months. • As close to open market PPA terms as possible.	• Fixed £/MWh discount set at a level in the range {20, 30}.
Levelisation	• The sum of the management fees bid by offtakers will be levelised across all licensed suppliers. • Quarterly levelisation process similar to small-scale FITs.	• Daily levelisation process similar to CfDs.
Scheme review	• OLR reported on in the Annual Update to the Delivery plan, parameters reviewed annually, and scheme requirement reviewed at the next Delivery plan.	

[25] Under the FIDeR process, certain projects that need to make final investment decisions before the CfD is in place are able to apply for Investment Contracts (ICs) – a form of early CfD. ICs are being designed to be as consistent with the enduring CfD as possible, with identical strike prices and key commercial terms under both schemes.

Alternatives to regulation

45. Government intervention does not rule out the possibility of pursuing non-regulatory approaches (e.g. voluntary approaches). DECC has been taking forward a “Market Readiness Project” to smooth transition to CfDs. For this, DECC has been facilitating two industry-led working groups reporting to a steering group which are considering how PPAs will need to change to complement the CfD and are developing a set of best practice guidelines for PPA providers and generators.[26]

Other alternatives ruled out

46. Annex 1 of the Impact Assessment on the Primary Powers[27] set out potential intervention options that could be taken forward (one of which was the OLR). These included a Supplier Obligation to offer terms. This was not taken forward over concerns that it would not be bankable and would not address the drivers of the current poor liquidity in the PPA market.

47. Another alternative to the implementation of OLR that has been proposed by some market participants was a Green Power Auction Market (GPAM). This would create a type of fixed feed-in-tariff by treating the price achieved in a six-monthly auction as the reference price for the purposes of the CfD so that generators achieve the same price regardless of the impact on system balancing costs. This has the merit of providing price certainty for the generator. However, we do not believe that GPAM is an appropriate solution to route-to-market issues for independent generators. It guarantees generators that they would always receive the strike price for their power, regardless of the choices they make around design and operation of their plant. Therefore, incentives to manage imbalance risks would be removed from generators. This could lead to significantly higher costs to consumers, as the cost of balancing the electricity system would be higher. It would also not provide assurance to lenders that it would be ‘bankable’, without additional measures, such as the OLR. GPAM would have prescribed one particular route-to-market, and would have removed generators from the mainstream energy market removing incentives to innovate. As a result, this option was not taken forward.

[26] More information on this work is available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-emr-cfd-market-readiness-working-groups.

[27] Available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/197626/barriers_independent_generators_ia.pdf.

Cost-Benefit Analysis

Summary

48. Table 4 summarises the benefits and costs identified in the rest of this IA (related to central route-to-market cost assumptions). The range reflects the impact of OLR against two counterfactuals set out below (representing two market extremes reflecting the uncertainty at the outset as to the development of the PPA market and in order to bound the impacts).

49. The quantitative and qualitative analysis in this section has been supported by analysis by Baringa and discussions with stakeholders via the OLR advisory group.[28] The figures in the table below are also set out in the relevant subsections in this chapter and are based on internal DECC analysis and analysis by Baringa

Table 4: Summary impacts (central route-to-market cost assumptions, range based on two counterfactuals)

Description	**NPV (real 2012 prices)**
<u>Benefits</u>	**Total <u>quantified</u> benefit: £0-2.151bn (midpoint £1.075bn)**
Improved PPA market competition	Transfer of rents from incumbent offtakers to generators, electricity consumers and new offtakers of between **£0-1.152bn (midpoint £576m)**. Small liquidity benefit and potential for lower overall discounts due to lower tail risk for offtakers (unquantified).
Improved generation market competition	Could lower project costs and drive innovation delivering further benefits to society (unquantified, however a breakeven analysis suggests that **competition benefits equivalent to 0.1% of average domestic electricity prices over the period 2016-30 would be sufficient to deliver a positive NPV** in both counterfactuals under central route-to-market cost assumptions).
Increases UK's ability to meet renewable target in cost-effective manner	Could increase wind generation in 2020 by between 0-13TWh. Reduced risk of sanctions, reduced reputational/political risk limits impact on cost of capital (unquantified).
Other benefits	Including improved near-term capacity margins, lower capacity market payments, lower cost of capital, secondary benefits of additional renewable build (unquantified). Carbon savings between 0-41MtCO_2e. Equivalent to between **£0-998m (midpoint £499m)**.
<u>Costs</u>	**Total <u>quantified</u> cost: £0-2.716bn (midpoint £1.358bn)**
Transfer of rents away from existing offtakers	Rents transferred away from incumbent offtakers due to increased competition in the PPA market (see "Benefits"). Between **£0-1.152bn (midpoint £576m)**.
Costs to Ofgem/Government of administering the scheme	Resource implications from implementing (one-off) and monitoring likely to be recovered through licence fees. Additional resource implications related to allocation, cost-assessment and levelisation (unquantified). Costs likely to be significantly higher with administrative allocation of generation to a backstop offtaker compared with a competitive allocation process.
Administrative costs to energy suppliers	Cost to suppliers of provision of Backstop PPA likely to be small. Cost of adapting to settlement system likely to be minimal if quarterly settlement but large under daily settlement (unquantified). Costs of preparing bids for auctions in competitive allocation between **£0-34m (midpoint £17m).**
Credit rating/balance sheet impacts	Could reduce rents/financing costs for suppliers. Likely to be small under competitive allocation but more significant under administrative allocation (unquantified).
Increased system imbalance costs	Due to increased intermittent generation on the system as a result of OLR increasing overall system balancing costs. Between **£0-1.529bn (midpoint £765m)**.
Other costs	Secondary costs of additional renewable build (unquantified).
Net <u>quantified</u> benefit	**-£565m to £0 (midpoint -£283m)**[29]

[28] All relevant documents are available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-off-taker-of-last-resort-advisory-group.

[29] Upper bound costs deducted from upper bound benefits as the upper bounds are both consistent with a consistent counterfactual (Counterfactual 2). See Table 1.

50. Overall, the OLR is estimated to deliver a net cost of between **£0 to 565m in NPV terms under central route-to-market cost assumptions (and between £0 and 2.558bn in the high route-to-market cost scenario**). However, the nature of the costs makes them easier to quantify and benefits from competition are typically difficult to quantify. A simple breakeven analysis suggests that **increased competition due to OLR needs to reduce costs for the policy to break even in NPV terms by an equivalent of up to 0.1% of domestic retail electricity prices in the central route-to-market cost scenario over the period 2016-30 and up to 0.3% of domestic retail prices in the high cost scenario**.

51. The following sections provide greater detail on the likely benefits and costs of the proposed OLR against the counterfactual as set out in the next section. Where relevant, consideration is also made as to how these might vary depending on the alternative options for the design of the policy as set out in Table 3.

52. Although the lead design option for the OLR makes all renewable generators eligible to access a Backstop PPA, the analysis which follows focuses mainly on offshore and onshore wind. While other technologies are eligible, they are not expected to require the backstop to the same extent and, as they are expected to represent a smaller share of the future generation mix, any additional costs are expected to be small.[30]

The counterfactual – 'Do Nothing'

53. As previously stated, the move to CfDs should act to remove or reduce some of the factors causing the current deterioration in the PPA market. However, residual factors will remain which could continue to act as a limiting factor to market PPA availability on bankable terms. The development of the PPA market under CfDs without further intervention, therefore, remains uncertain.

54. Reflecting this uncertainty, the analysis of the impact of any intervention will be assessed against two counterfactuals which are designed to establish lower and upper bounds to the true impacts of the policy as, in reality, the PPA market is likely to behave in a manner between these two extremes:

    i. **Counterfactual 1 –** Sufficient improvement in the PPA market to enable achievement of the EMR reference case[31] without further intervention. For the purpose of the analysis, Baringa have identified this as a world where there is sufficient competition in the PPA market to provide long-term PPAs at the discounts assumed in the CfD strike price.[32]

    ii. **Counterfactual 2 –** Constraints in the PPA market remain such that we cannot achieve the EMR reference case without further intervention. For the purpose of their analysis, Baringa characterise this scenario as "monopolistic" whereby one PPA provider sets a profit maximising discount above the competitive level, extracting rents and constraining the market.

55. For ease of comparison, the OLR is assumed to be successful in delivering the EMR reference case in both counterfactuals. In other words, it is not expected to deliver additional build in Counterfactual 1 (although there will likely still be a range of costs and benefits to its implementation in this counterfactual).

56. The analysis below uses "Central" route-to-market cost assumptions derived from work performed by Baringa for Ofgem as part of its EBSCR and set out in Annex C. The impact of the OLR (in particular, on cost to consumers) will be stress tested against a range of route-to-market cost scenarios in the sections "Sensitivity analysis around future route-to-market costs" and "Distributional impacts". Risks and potential mitigation to the success of the OLR are assessed in the section "Risks and unintended consequences".

[30] The biggest route-to-market exposure for biomass plant is liquidity risk for which measures are already being put in place both within the CfD itself but also through Ofgem's liquidity reforms (see 'Background'). In addition, although solar may also face increasingly uncertain future imbalance costs, these will be less significant than for wind because solar forecast error is lower and, as it will play a smaller role in the future generation mix, it is less likely to be correlated with system imbalance as wind. Route-to-market costs for other technologies are less well understood but, as these technologies will likely be a small part in the future generation mix, any potential costs associated with their accessing a Backstop PPA are likely to be small.

[31] Deployment consistent with the EMR delivery plan. Further detail available online at: https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan.

[32] 10% for onshore wind, 5% for offshore wind. Final delivery plan assumptions available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267960/Annex_H_-_Modelling_Assumptions.pdf.

Benefits

Improved PPA market competition

57. Lenders' credit requirements on PPA offtakers should no longer be a binding entry barrier into the PPA market because the mechanism insulates debt lenders from offtaker insolvency. Shorter-term PPAs (and providers of shorter-term PPAs who do not operate in the long-term PPA market) should become part of the menu of contracting options available to independent generators to secure a route-to-market as lenders will be insulated against the risk of the generator failing to find a bankable PPA when their first PPA expires.

58. This improvement in competition should deliver greater choice and lower costs to generators. All other things being equal, increasing the proportion of shorter-term contracting strategies undertaken should reduce average market PPA discounts as shorter-term PPAs necessarily include lower risk premia associated with future imbalance costs and (if relevant) wholesale price risk (although this effect may be quite small). In addition, long-term PPA discounts could further be reduced as a result of the removal of tail risk to offtakers – the OLR could facilitate instances where offtakers buy themselves out of their market PPA (in instances of high route-to-market costs – generators will be more willing to accept such terms due to their ability to access other market PPAs or the Backstop PPA). As such, the OLR therefore caps route-to-market cost risk for long-term PPA providers.

59. While the OLR could encourage more potential offtakers to enter the PPA market, increasing competitive pressure and efficient pricing in the market, it could also lead to more intermittent renewable deployment than is economically efficient because higher than expected system imbalance costs would be spread across all suppliers through levelisation (considered in "Risks and unintended consequences"). However Baringa have assessed that the extent to which this tail risk is removed for offtakers is unlikely to be material[33].

60. Under Counterfactual 2, increased competition in the PPA market should reduce rents to incumbent PPA providers. Under administrative strike price setting for CfDs, these rents should transfer to generators through lower market PPA discounts. However, if we move to competitive strike price setting, these rents could also fall to electricity consumers (through lower strike prices and CfD top-up payments which ultimately fall on electricity bills).

61. Baringa estimate the total value of these rents in Counterfactual 2 to be around **£1.152bn in NPV terms**.[34] This is equivalent to up to roughly £1 per year off average household electricity bills over the period 2016-30.

62. An increased number of non-vertically integrated players in the wholesale market could also act to improve market liquidity which could exert greater pressure on wholesale prices. This reflects a transfer from generators to consumers, although this effect is likely to be small as it could only act to increase day-ahead and within-day liquidity, whereas wholesale energy costs which drive bills are influenced more significantly by longer-dated contracts as a result of supplier hedging strategies.

Improved generation market competition

63. It is inherently difficult to quantify the benefits of greater competition in the power generation sector. We therefore consider these benefits qualitatively. Relative to Counterfactual 1, we would not anticipate any significant new entry into the electricity generation sector. However, relative to Counterfactual 2, we could see a number of new entrants into the sector. An increased number of players in the market could, in the long-run, drive competition (to secure finance, or a CfD, for example) lowering the overall costs of future projects which could in turn lower costs to consumers through lower CfD top-up payments under competitive strike price setting. This competition could also drive innovation – new entrants may have new ideas or business models which may be at the forefront of technological change – delivering further benefits to society.

64. As an example, the Public Utility Regulatory Policies Act of 1978 (PURPA) in the US reduced barriers to entry into the wholesale electricity market for independent power producers.[35] While its

[33] This, and the appropriateness of the Backstop PPA discount more generally, will be reviewed annually.

[34] NPV over the period 2014-2035 in real 2012 prices. Table 2 from Baringa's report "Cost Benefit Analysis in support of DECC's Impact Assessment of the Offtaker of Last Resort", available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.

[35] The first main provision of PURPA forced electric utilities to buy electricity generated by small power producers (or 'Qualifying facilities') at 'avoided cost' rates – the rate that approximates what it would cost the utility to generate the same amount of electricity. The second

primary objectives were to increase self-sufficiency in electricity production and create incentives to develop domestic renewable energy, it had the effect of enabling independent power producers to become a major source of technological change in the sector – By 1992, independent power producers built 60% of new capacity in the US.[36] Furthermore, prior to PURPA, less than 3%[37] of US electricity generation was by independent power producers, by 2011, it had risen to 14%.[38]

65. While the benefits of greater generation and PPA market competition have not been quantified, it is estimated that any **benefits equivalent to up to around 0.1% of domestic electricity prices in the central cost scenario over the period 2016-30 (up to around 0.3% in the high cost scenario considered in later sections) would be sufficient to deliver a positive NPV**.[39]

Increases the UK's ability to meet its 2020 renewables target (in a cost-effective manner)

66. As previously discussed, in the absence of further government intervention, the PPA market could remain sufficiently constrained as to prevent a number of pipeline independent renewable projects from going ahead at the announced strike prices, increasing the risk of failing to meet our 2020 renewables target. Baringa estimate that the shortfall could equate to up to around 13TWh of onshore and offshore wind generation in 2020 in Counterfactual 2 (recall there is assumed to be no shortfall and no benefit here from Counterfactual 1).

67. Furthermore, reducing the risk of failing to meet the UK's renewables target will reduce any associated issue of reputational and political risk which could increase cost of capital and electricity sector costs in the longer-term.

Other benefits

68. The OLR delivers greater renewables deployment under Counterfactual 2 delivering associated benefits. In particular, we are able to estimate the expected carbon savings which could be achieved (under Counterfactual 2 only) from displacing higher carbon marginal generation with this additional low carbon (and lower marginal cost) generation. This is done by multiplying the annual increase in renewable generation[40] relative to Counterfactual 2 as estimated by Baringa by a marginal generation emission factor.[41] This results in a cumulative saving of 41MtCO_2e over the period 2014-34, equivalent to a monetary saving of **£998m** in NPV terms.[42]

69. Relatedly, under Counterfactual 2, the OLR could therefore act to avoid incurring additional costs through the Capacity Market to fill the capacity gap and increase security of supply in the near-term before the Capacity Market is introduced. Furthermore, minimum guaranteed revenues implied by the OLR could act to lower the cost of capital for future projects.

Costs

Costs to Ofgem/Government of administering the scheme

70. There will be Ofgem resource implications of implementing and monitoring the OLR. These costs have not been quantified at this stage as we expect this role will be rarely used.

71. In the event that the OLR is triggered, any resource implications could vary according to the allocation process selected:

    i. The minded to design of a **competitive allocation** would be a sealed-bid auction where bids reflected the net cost offtakers expected to incur as a result of managing the Backstop PPA

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major provision forced utilities to also supply backup power to small power producers. As a result, PURPA ensured that power producers could buy electricity from utilities when they needed it and that they could also sell the electricity they generated back to utilities at a fair price.

[36] US Energy Information Agency (EIA)

[37] 'PURPA: the intersection of competition and regulatory policy', Hon. Richard D Cudahy (1995)

[38] US Energy Information Agency (EIA)

[39] DECC analysis. Estimates based on constant annual benefits required to deliver an NPV benefit equal and opposite to the net benefit NPV presented in Table 3. (The "high" scenario is based on a consistent methodology assuming higher system imbalance consistent with the "high" route-to-market cost scenario set out in the section "Sensitivity analysis around future route-to-market costs".

[40] Charts 3c and 5c from Baringa's report "Cost Benefit Analysis in support of DECC's Impact Assessment of the Offtaker of Last Resort", available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.

[41] As set out in the Green Book supplementary guidance for valuing greenhouse gas emissions for appraisal, available online at: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal.

[42] Using central traded carbon values in the above appraisal guidance.

after taking into account the Backstop PPA discount. However, Ofgem could choose to change the design in future if the prevailing market circumstances call for it. Ofgem would also need to monitor the allocation process to ensure participants are operating competitively. The likelihood is that these functions could fall to existing resource (although with associated opportunity costs). However, Ofgem would not have to undertake a separate cost-assessment, the cost to be levelised being determined by the management fee bid by the 'successful' backstop offtaker.

ii. Under an **administrative allocation**, Ofgem would need to allocate the project according to a set of predefined rules. Ofgem would then need to determine the backstop offtaker's costs and benefits associated with entering into the Backstop PPA which would be significantly more resource intensive than the cost-assessment under a competitive allocation.

72. The resource implications are summarised in Table 5. An administrative allocation process is therefore likely to be more resource intensive for Ofgem. In addition, the risks associated with an administrative cost assessment (considered in 'Risks and unintended consequences') may also make the competitive allocation preferable as a mitigation measure.

Table 5: Ofgem resource implications

	Determining offtaker	Allocation	Levelisation	Monitoring
Competitive allocation				
Set-up costs	Zero	Small	Small	Zero
Costs if OLR is triggered	Zero	Depends on volume	Small	Small
Administrative allocation				
Set-up costs	Small	Small	Large	Zero
Costs if OLR is triggered	Medium	Depends on volume	Large	Small

Source: Ofgem

Administrative costs to energy suppliers

73. Administrative costs relating to the provision of a Backstop PPA that fall to obligated suppliers (mandatory offtakers) are likely to be small as all but one of those which will be made mandatory offtakers already participate in the PPA market and already have the facilities and personnel in place to act as Backstop PPA providers. The administrative cost implications on all other suppliers are likely to be comparatively smaller in absolute terms as they would only choose to be backstop offtakers if they determined that it would be economic for them to do so.

74. In the event that a Backstop PPA is requested, a **competitive allocation** will lead to additional costs on offtakers in terms of preparing bids. If we expect that for every tranche of generation requesting a Backstop PPA, participating offtakers require one or two additional members of full time staff, costing around £50,000 each (i.e. between £50,000 and £100,000 per bidder), and that there are between 6 and 25 participants in the auction[43], then this equates to between £300,000 to £2.5m. This equates to an NPV of between **£0 and £34m** over the period 2014 to 2035, the range reflecting whether auctions occurred in each year of the appraisal period.[44]

75. The choice of settlement period could also have additional cost implications on suppliers:

i. A **daily settlement** would require adaptation of settlement systems at a potentially significant cost.

ii. A **quarterly settlement** would add minimal costs as the systems are already in place under the small-scale FIT scheme. This settlement period could imply significant carry costs to offtakers awaiting payment in the event that the OLR was used extensively but, given this is considered unlikely, is likely to present the most cost-effective design option for the OLR.

[43] The lower bound reflects the six largest energy suppliers likely to fall above the threshold for being mandatory offtakers and the upper bound reflects all suppliers. Source: Ofgem's 2013 report to the European commission (available online at: https://www.ofgem.gov.uk/ofgem-publications/82755/2013greatbritainandnorthernirelandnationalreportstotheeuropeancommission.pdf) states that, in 2012, there were 6 large electricity suppliers, 1 small supplier serving domestic and non-domestic customers, 11 small suppliers serving only domestic customers and 6 small suppliers serving non-domestic customers only. In addition, there was 1 new entrant in 2013.

[44] We would not expect these costs to increase one-for-one with the number of auctions per year as these are largely reflective of annual fixed costs (i.e. there are likely to be economies of scale relating to the number of auctions per year).

Increased system imbalance costs

76. It is important to remember that imbalance costs would prevail with or without the OLR. We assume for simplicity that the only driver of differences between total system imbalance costs (relating to wind generation) between the counterfactuals and a world with the OLR is the level of deployment. As characterised, we assume that the EMR reference case is achieved in all scenarios with the OLR and in Counterfactual 1 without the OLR. Only Counterfactual 2 without the OLR delivers a lower level of deployment consistent with a monopolistic supply of long-term PPAs. This lower level of deployment would be consistent with lower total system imbalance costs.

77. Baringa estimate the total increase in system imbalance costs (related to wind) from OLR as a result of an increase in deployment in Counterfactual 2 under central route-to-market cost assumptions to be around **£1.529bn** in NPV terms.[45] To the extent that these imbalance costs are passed onto consumers[46], this would be equivalent to up to around £1 per year on average on household electricity bills over the period 2016-2030.

78. It is important, however, to note that these costs are not additional to those resulting from the EMR Reference scenario (as Counterfactual 2 underachieves against this deployment profile). As such, **these costs are not additional to those costs already set out in the Contracts for Difference Impact Assessment**.[47] These costs are not incurred in Counterfactual 1.

Sensitivity analysis around future route-to-market costs

79. While it is not considered likely that route-to-market costs (mainly imbalance costs) will exceed the range of discounts being considered for the Backstop PPA, there is a risk that, if these costs were higher than expected, the OLR could be triggered passing costs onto consumers through levelisation payments. This section looks at the impact of alternative (higher) route-to-market costs on system balancing costs resulting from any increased wind deployment as a direct result of the OLR, and the subsequent section ("Distributional Impacts") considers the direction and scale of distributional impacts of the OLR under the range of counterfactuals and sensitivities presented here.

80. Chart 2 represents the range of route-to-market (primarily imbalance) cost assumptions (for independent wind generators) used for this sensitivity analysis alongside the central assumption and the range of Backstop PPA discounts being consulted on (these cost assumptions are also set out in Annex C). The "high" case is intended to reflect the downside scenario that an offtaker or equity provider might use to price long-term imbalance risk into its PPA discount or cost of capital.[48] The "extreme" scenario is intended to be an imbalance scenario not envisaged by offtakers or generators, even for setting a risk premium.[49] We consider this a highly unlikely scenario (used simply for the purpose of stress testing) as it assumes no investment response to these high cash-out price signals in order to reduce exposure to imbalance charges.

[45] Table 3a (difference between "with OLR" and "No OLR" in "uncompetitive world") from Baringa's report "Cost Benefit Analysis in support of DECC's Impact Assessment of the Offtaker of Last Resort", available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.

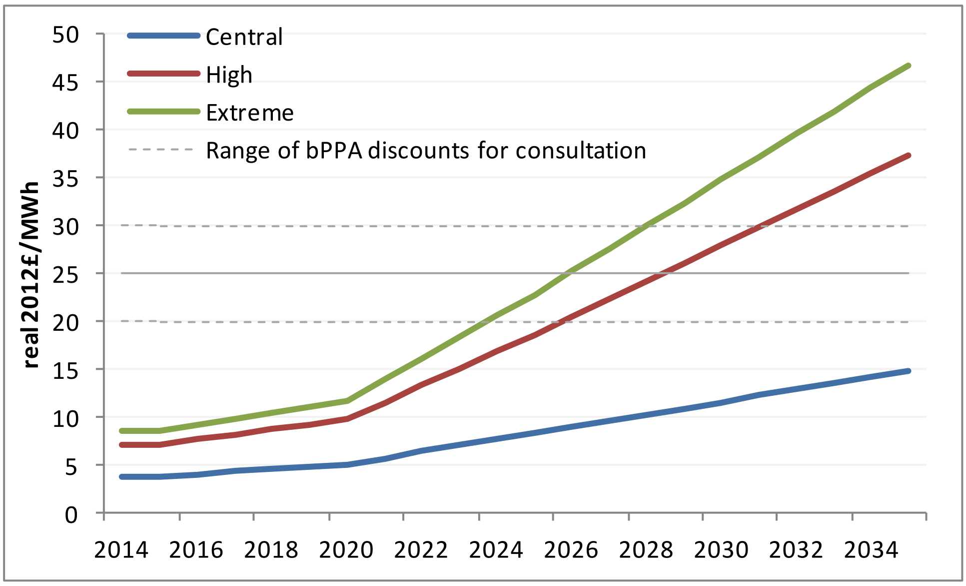
[46] There is further consideration of this in the "Distributional Impacts" section.

[47] Available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268202/Delivery_Plan_IA.pdf.

[48] It is derived from work performed by Baringa for Ofgem (available online at: https://www.ofgem.gov.uk/ofgem-publications/82296/baringa-ebscr-quantitative-analysis.pdf), and is based on the forecast costs under "Package 5 – No CM". This is consistent with the "worst case" used by Deloitte for determining the Backstop PPA discount range, where it represented the 95th percentile scenario against which PPA providers would set a risk premium. This scenario was selected for the relative extremity of the assumptions rather than policy consistency. In both our counterfactuals, we assume the introduction of a capacity market. It should be noted that the model used to determine these imbalance cost assumptions was designed to make comparisons between potential policy options, not to provide forecasts of absolute imbalance costs and therefore do not represent Ofgem's or Government's view of imbalance outcomes.

[49] In the same way that the Ofgem modelling was used to define the mean and the 95th percentile of possible outcomes, the 99th percentile is estimated, and is taken to represent this "extreme" case.

Chart 2: "Central", "High" and "Extreme" route-to-market cost scenarios for independent wind generators



Source: Baringa

81. Table 6 presents Baringa's estimates of total system imbalance costs (relating to wind) under these imbalance cost scenarios and deployment profiles. As would be expected, as OLR delivers no additional wind build against Counterfactual 1, it also does not impact on system route-to-market/imbalance costs. Against Counterfactual 2, the increase in system route-to-market costs as a result of the OLR is driven by the increase in wind build the mechanism brings forward.

Table 6: Total system route-to-market costs relating to wind (real 2012 NPV)

	Route-to-market cost scenario	Counterfactual 1	Counterfactual 2
No OLR (a)	Central	£3.034bn	£1.505bn
	High	£6.981bn	£3.459bn
	Extreme	£8.616bn	£4.268bn
With OLR (b)	Central	£3.034bn	£3.034bn
	High	£6.981bn	£6.981bn
	Extreme	£8.616bn	£8.616bn
Impact of OLR (b – a)	Central	-	£1.529bn
	High	-	£3.522bn
	Extreme	-	£4.347bn

Distributional impacts

82. The OLR essentially involves consumers underwriting the risk that route-to-market costs (i.e. imbalance costs) rise to such an extent that market PPA discounts exceed the Backstop PPA discount. This can be partly mitigated by setting a large enough Backstop PPA discount (although small enough to still be effective in achieving the desired policy objectives).

Estimating the size of the levelisation fund

83. There are a variety of scenarios under which a generator might request a Backstop PPA. For example:

i. Their existing PPA is terminated due to their defaulting on their old PPA's obligations;

ii. Their existing PPA provider has defaulted;

iii. Their existing PPA expires;

iv. Mutually agreed termination of the PPA by offtaker and generator.

84. The first two examples are likely to be isolated instances - they are unlikely to mean a significant volume of generating capacity following suit. As such, they are unlikely to be significantly costly in isolation - in fact, if route-to-market costs (primarily imbalance costs) are smaller than the Backstop PPA discount, then offering a Backstop PPA could deliver rents to the designated Backstop PPA

provider (which would be levelised). As such, although we have not been able to quantify the levelisation fund (positive or negative) in such examples, it is likely to be small.

85. In the third and fourth examples, generators are unlikely to request a Backstop PPA unless market PPA discounts (i.e. route-to-market costs) are greater than the Backstop PPA discount. (There may be a risk that other aspects of the Backstop PPA may make it more attractive than market PPAs despite offering a greater discount than the market – this is discussed in 'Risks and Unintended Consequences'). In the event that route-to-market costs exceed the Backstop PPA discounts, we would expect an increasing volume of generation triggering the Backstop PPA. We consider this unlikely under the current range of Backstop PPA discount options and central imbalance cost assumptions although it is important to consider what the impact of OLR would be under more extreme scenarios.

86. It is assumed for the purposes of this analysis that, in scenarios where route-to-market costs exceed the level of the fixed discount in the Backstop PPA, all eligible generators will exercise their right to a Backstop PPA irrespective of the route-to-market strategy assumed. In this way we are implicitly assuming that, for those generators that opt for long-term PPAs, their PPA provider is allowed to "buy them out" of any residual obligations (i.e. the PPA provider would pay the generator the difference between what they would have received under the original PPA and what the generator is able to secure in the OLR under the Backstop PPA). It is important to note that this is a worst case assumption[50], as it is not entirely clear that generators would necessarily agree to such arrangements (either up front or at the time that high imbalance costs materialise). The effect of any departure from this assumption would be to reduce the size of the levelisation fund as PPA providers that are locked into long-term PPAs would incur route-to-market costs below the level of the backstop discount that they would be unable to socialise more widely.

87. Table 7 presents the estimated size of the OLR levelisation fund under each of the route-to-market scenarios considered in the previous section for the range of Backstop PPA discounts being considered. Note the levelisation fund has been estimated as a function of the prevailing route-to-market cost and the assumed Backstop PPA discount, it is therefore the same in both counterfactuals. By virtue of the fact that route-to-market costs exceed the Backstop PPA discount in fewer (and later) years the higher the Backstop PPA discount (see Chart 2), the levelisation fund necessarily decreases as the assumed Backstop PPA discount increases. Note that route-to-market costs are not expected to exceed the level of the Backstop PPA discounts being considered before 2035 under central route-to-market cost assumptions.

Table 6: Estimated levelisation fund (exercise cost) relating to wind (real 2012 NPV)[51]

Backstop PPA discount	Route-to-market cost scenario		
	Central	High	Extreme
£20/MWh	-	£826m	£1.735bn
£25/MWh	-	£323m	£1.000bn
£30/MWh	-	£65m	£483m

Figures rounded to 2 significant figures

88. This levelisation fund does not represent an additional cost of the OLR. It is a small proportion of total system route-to-market costs (from Table 6, previously) – meaning that wind generators and PPA providers will still absorb the vast majority of an unexpected rise in route-to-market costs.[52] As such, the levelisation fund represents a transfer of rents from electricity consumers to generators (and would fall within the Levy Control Framework.

Estimating the impact of OLR on cost to electricity consumers

89. The levelisation fund does not represent the true cost to consumers of the OLR relative to either counterfactual – for this to hold, we would have to assume that, without the OLR, all offtakers that were also retail energy suppliers would be unable to pass on any costs incurred from higher than expected route-to-market costs to their energy customers. This is unlikely. Depending on the

[50] However, it is important to consider this upside risk around the estimates together with the fact that the figures only apply to wind generators. That being said, for other types of generator to trigger the backstop, market conditions would have to be even more extreme than those being tested here. Risk-weighting those additional costs would yield very low expected values.
[51] Source: Baringa, Table 3b, 'Cost Benefit Analysis in support of DECC's Impact Assessment of the Offtaker of Last Resort', available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.
[52] Although, where those PPA providers are also energy suppliers, they may still pass these costs onto consumers (which they would have done under the counterfactual).

extent of retail competition, and insofar as other suppliers find themselves in a similar situation, a portion of these costs would likely be passed onto retail customers through higher retail electricity prices in the counterfactuals.

90. This implies that the impact of the OLR on electricity bills is dependent on the rate of pass-through of system imbalance costs. In order to bound these impacts, we consider three possibilities of pass-through:

i. **No pass-through before or after OLR (0,0):** In a world without OLR, no route-to-market costs are passed through to retail electricity prices (and therefore bills).[53] In a world with OLR, only those route-to-market costs covered by the Backstop PPA (i.e. the levelisation fund presented in Table 7) are passed through to retail electricity prices.[54] As such, the total system route-to-market costs that fall to customers as a result of OLR equal the size of the levelisation fund presented in Table 7.[55]

ii. **Full pass-through before and after OLR (1,1):** In a world with and without OLR, all route-to-market costs are passed through to retail electricity prices (and therefore bills). As such, the total system route-to-market costs that fall to consumers as a result of OLR equal the full <u>increase</u> in system route-to-market costs from OLR presented in Table 6 (b – a).

iii. **No pass-through before OLR, full pass-through after (0,1):** In a world without OLR, no route-to-market costs are passed through to retail electricity prices (and therefore bills). In a world with OLR, all system route-to-market costs are passed through to retail electricity prices.[56] As such, the <u>total</u> system route-to-market costs that fall to electricity customers in a world with OLR as presented in Table 6 row b.[57] This scenario is highly unlikely. In reality, some proportion of system imbalance costs will inevitably be absorbed by generators and offtakers. However this scenario is used to set an upper limit on total costs to consumers resulting from the OLR.

91. We do not consider a scenario where there is full pass-through prior to OLR and no pass-through after (1,0). This is highly unlikely, in particular, since the OLR should increase the pool of offtakers, not decrease it. This scenario would be consistent with OLR driving a lower cost to consumers than a world without the policy.

92. Table 8 presents the resulting average household electricity bill impacts implied by these scenarios. The range captures the impact of the range of pass-through scenarios and the impact of the two counterfactuals. A more disaggregated breakdown is presented in Annex D. As can be seen, the impacts in the central scenario are relatively small, representing less than 1% of total household electricity bills in all scenarios over the period 2016-30. The impacts on business electricity bills are expected to be of similar magnitude in percentage terms.

Table 8: Average impact of OLR on annual household electricity bills (Averaged over the period 2016-30, real 2012 £)

Route-to-market cost scenario	**Backstop PPA discount**	**Average annual bill impact (2016-2030)**	
		Counterfactual 1	**Counterfactual 2**
Central	**20**	£0 to 2 (0 to 0.3%)	£0 to 2 (0 to 0.3%)
	25	£0 to 2 (0 to 0.3%)	£0 to 2 (0 to 0.3%)
	30	£0 to 2 (0 to 0.3%)	£0 to 2 (0 to 0.3%)
High	**20**	£0 to 5 (0 to 0.7%)	£0.5 to 5 (0.1 to 0.7%)
	25	£0 to 5 (0 to 0.7%)	£0.1 to 5 (0.0 to 0.7%)
	30	£0 to 5 (0 to 0.7%)	£0 to 5 (0 to 0.7%)
Extreme	**20**	£0 to 6 (0 to 0.9%)	£1 to 6 (0.2 to 0.9%)
	25	£0 to 6 (0 to 0.9%)	£1 to 6 (0.1 to 0.9%)
	30	£0 to 6 (0 to 0.9%)	£0.2 to 6 (0.0 to 0.9%)

Range represents the range of impacts from the three pass-through scenarios. Figures rounded to the nearest 1 significant figure.

93. The figures in the table above do not include the impact of OLR admin costs or the impact on household electricity bills from any extraction of rents as a result of OLR and a competitive CfD

[53] For example, because not all large energy suppliers participate in the PPA market. Those who incur these route-to-market costs will be forced to absorb those costs in order to compete at the same price as those who do not face these costs.
[54] Because these levelised costs fall on all energy suppliers equally.
[55] And are independent of whether we are in counterfactual 1 or 2.
[56] For example, OLR might encourage increased participation in the PPA market which might mean all electricity suppliers share route-to-market costs more equally.
[57] And are independent of whether we are in Counterfactual 1 or 2.

allocation as these costs and benefits are expected to be small and work in opposing directions. We have also been unable to quantify the benefits from increased competition as a result of the OLR, but a simple breakeven analysis suggests that, **if domestic retail electricity prices were up to around 0.4% less with OLR compared to the counterfactuals in the central route-to-market cost scenario over the period 2016-30, it would mean that the OLR would deliver an overall cost saving to consumers** (up to around 0.8% in the high cost scenario and 1% in the extreme cost scenario). Note this is different to the level of saving required for the OLR to breakeven in NPV terms (which is lower).[58]

Risks and unintended consequences

94. The success of the OLR in achieving its intended objective rests on driving a more efficient PPA market (or at least, to not distort the PPA market towards worsening terms against the counterfactual). There are a number of potential risks in achieving this. This section sets out the key risks, their materiality and how they can be mitigated. A summary is presented in Table 9.[59]

[58] These figures are slightly larger than those set out in the breakeven analysis for the NPV. This is because, even if the OLR breaks even in terms of net costs to society, the nature of the OLR in that it transfers certain costs from generators/offtakers to suppliers/consumers could mean it still delivers a net reduction in consumer surplus. As such, a greater benefit (but still relatively small) from competition would be required to break even in cost-to-consumer terms.

[59] Some of these risks were initially considered by Baringa in the initial Backstop PPA proposal available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/253179/Backstop_PPA_Proposal__report_by_Baringa_LLP___Report_published_July_2013_.pdf.

Table 9: Key risks and mitigation measures

Description of risk	Mitigation measures	Materiality
Lack of bankability	Multiple mandatory offtakers with acceptable credit, proof of bankability for voluntary offtakers, Backstop PPA discount not too high	Not significantly material given mitigation measures
Incentivising excessive risk taking by equity	Backstop PPA discount sufficiently high	Not significantly material given mitigation measures and the fact that debt is unlikely to give equity free-reign through the terms of the loan agreement
Creating a floor towards which market offerings converge	Backstop PPA discount sufficiently high	Not significantly material given profit maximising and competitive incentives by offtakers.
Distorting incentives on suppliers to offer PPAs	Levelisation of any rents to Backstop offtakers, prefer competitive allocation	Not significantly material given profit maximising and competitive incentives by offtakers. Potential risk of over compensation under administrative allocation of Backstop PPA.
Reducing suppliers' capacity to enter into PPAs	Maximum tenure for backstop PPA, maximum tranche of generating capacity per Backstop PPA, prefer competitive allocation	Potentially significant under administrative allocation of Backstop PPA.
Distorting incentives on generators to contract in the PPA market	Minimum tenure for Backstop PPA, removal of eligibility for generators who terminate the Backstop PPA earlier, sufficiently high Backstop PPA discount	Not significantly material given profit maximising incentives on generators and mitigation measures.
Distorting incentives for poorly performing generators	Removal or suspension of eligibility if there is a material breach	Not significantly material given mitigation measures
Bids in the competitive allocation process not being cost reflective	Multiple mandatory offtakers, levelisation of costs/rents.	Not considered material given mitigation measures and evidence of bidding behaviour in the NFPA
Reduced incentives to manage imbalance	Backstop PPA discount sufficiently high, annual review of scheme given prevailing market conditions, removal of eligibility due to material risk	Not significantly material given mitigation measures and current expectations of future route-to-market costs. Residual risk for grandfathered projects in the event that route-to-market costs exceed the level of the Backstop PPA discount although this will only apply for the length of their CfD.

Lack of bankability

95. This is not considered a material risk because specific elements of the OLR design are intended to ensure bankability.

96. The creation of mandatory offtakers should provide assurance to lenders that there will always be a backstop offtaker for a project. It will also be important for bankability to ensure that suppliers can only opt into the scheme if they would be acceptable to lenders and have the technical capabilities. To ensure this, proof of voluntary offtaker bankability would be required ensuring they were credible offtakers.

97. Lenders will also need to be confident that the OLR will deliver a Backstop PPA via a swift, practicable and certain process, while also minimising costs for consumers. As described in “Costs” the competitive allocation process will likely be the least-cost backstop allocation option of those considered. This process can be monitored and reviewed if market circumstances necessitate it.

Incentivising excessive risk-taking by equity

98. By protecting lenders from the risk of contracting with less credit-worthy counterparties or through the short-term PPA market, the OLR is intended to allow equity greater flexibility in terms of the level of exposure that it takes to long-term route-to-market risk. Excessive risk-taking, however, would increase the likelihood of triggering the backstop and increase costs to consumers through the levelisation.

99. Evidence[60] suggests that lenders are unlikely to give equity a completely free hand on contracting strategy through the covenants package in the loan documentation. In addition a larger Backstop PPA discount (i.e. one which leaves a lower cash buffer to pay debt) should reinforce incentives on equity to avoid excessive risk-taking.

Creating a floor towards which market offerings converge

100. The intention of the Backstop PPA is to be a last resort for generators. As such, it is designed in such a way that the Backstop PPA discount should be larger than for PPAs of equivalent tenor offered in the open market. Given the low level of liquidity in the PPA market currently and the fact that a larger discount would be more attractive to offtakers, there is a risk that market PPA offerings converge towards the Backstop PPA discount.

101. This risk is not assessed to be significantly material. Consider opposite extreme states of competition in the long-term PPA market. If the market is competitive, there will always be an incentive for competing offtakers to undercut (offer a smaller discount than) their competitors in order to secure a project, driving discounts to cost-reflective levels. In a world with the OLR, this should still be the case. In a world with a single monopolist provider, the monopolist will set their market discount offerings in order to maximise profits (i.e. any discount larger than the monopolist discount does not maximise profits and therefor is less preferable for the offtaker). In a world with OLR, if the Backstop PPA discount is greater than the profit maximising discount, it will not be preferred by the monopolist.[61]

Distorting incentives on suppliers to offer PPAs

102. Similarly, the risk of an individual supplier choosing to withdraw their market PPA offerings in favour of the Backstop PPA is considered to be low. The levelisation of any rents should act to make the Backstop PPA less attractive for an individual offtaker than offering a market PPA at a discount marginally lower than the backstop discount. Then, for the reasons described above, the risk of the Backstop PPA discount effectively creating a floor price is also not considered to be material.

103. There does, however, remain a residual risk that the OLR mechanism itself might overcompensate an offtaker for acting as a Backstop PPA provider relative to the actual cost of doing so (leading to rents and increased cost to consumers through the levelisation process). The materiality of this risk differs depending on the allocation mechanism used:

   i. Under **competitive allocation**, a backstop offtaker may be able to secure large rents if competition for the contract is low (e.g. due to structural barriers preventing wider PPA market participants from also offering Backstop PPAs).[62] As such, Ofgem would have to closely monitor supplier behaviour and intervene if necessary. The introduction of six mandatory offtakers, allowing voluntary offtakers and a maximum capacity level per Backstop PPA at 100MW should also aid competition in this allocation process. Moreover, the levelisation of any rents or costs incurred by the backstop offtaker should also act to incentivise cost-reflective bidding.

   ii. Under **administrative allocation**, the regulated cost-assessment process could overcompensate a Backstop PPA provider. However, this is unlikely to be material (as it is

[60] From Baringa's discussions with industry, as set out in the section of "The Backstop PPA Proposal" considering this risk, available online at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/253179/Backstop_PPA_Proposal__report_by_Baringa_LLP___Report_published_July_2013_.pdf.

[61] A more detailed rationale is provided in Baringa's paper 1A to the OLR Advisory Group, available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-off-taker-of-last-resort-advisory-group.

[62] E.g. If there is a requirement to hold a supply licence, which many aggregators may not have. Further consideration of this is presented in Baringa paper 1B to the OLR Advisory Group, available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-off-taker-of-last-resort-advisory-group.

determined by Ofgem) and Backstop PPAs are spread across the market (therefore no backstop offtaker can be sure of being allocated a generator).

104. A more detailed rationale is provided in Baringa's paper 1A for the OLR Advisory Group.[63]

Reducing suppliers' capacity to enter into PPAs

105. As opposed to the risk that offtaker incentives to offer PPAs in the open market might be adversely affected, there is also a risk that their capacity to offer open market PPAs is adversely affected by an obligation to provide a Backstop PPA. As before, the materiality of this risk depends on the allocation mechanism used:

i. Under **competitive allocation**, this risk is unlikely to be material as any bidder, including those who are required to bid, will be able to submit bids reflective of the costs of providing the Backstop PPA.

ii. Under **administrative allocation**, some suppliers will be required to enter into Backstop PPAs (mandatory offtakers) and the costs of doing so will be estimated by Ofgem. This could adversely affect the balance sheet of mandatory offtakers (and therefore their capacity to offer PPAs in the open market) in the following ways:

   - If the tenors of the Backstop PPA were sufficiently long to be treated by credit rating agencies as long-term liabilities;
   - If the regulated cost-assessment process is sufficiently uncertain or punitive (e.g. where it imposes significant costs on backstop offtakers which are not socialised); and
   - If there is significant uncertainty as to the size of the projects entering the scheme.

   In addition, the risk of mismatch of generator with backstop offtaker could increase costs of the mechanism.

   While some of these risks are partly mitigated with the use of a maximum 1-year Backstop PPA tenure and a maximum tranche of generation of 100MW, the residual risks could still be significant.

Distorting incentives on generators to contract in the PPA market

106. We would not expect any generator to seek a Backstop PPA if better alternatives existed – to do so would not be commercially rational or indicate a fundamental difference in the risk-reward ratio of a Backstop PPA when compared to an equivalent PPA in the open market

107. However, it is possible that generators might want access a Backstop PPA for a short period despite better terms being available in the open market; for example, when negotiating a new open-market PPA or if the open market does not move towards absolute discounts (and thereby making the more stable revenues of the Backstop PPA more attractive to lenders).

108. In addition, there is a risk that the Backstop PPA, by essentially setting a floor for project revenues, could provide too strong a price signal for intermittent generation resulting in a greater than optimal (in terms of system imbalance) level of intermittent generation on the system.

109. The latter two examples can be mitigated by setting the Backstop PPA discount sufficiently high relative to market PPAs (and reviewing it systematically for new entrants if market conditions change).

110. In the first example, allowing access to a Backstop PPA could allow generators to negotiate more forcefully in the knowledge that they had a backup contract if necessary that could be used to fill any gap. This does not reflect the objective of the OLR: a Backstop PPA should exist to provide support if open market PPAs are not available on better terms, but not to strengthen the negotiating hand of generators or reduce their desire to enter open-market PPAs in a timely manner.

111. Furthermore, there is a cost associated with generators frequently entering Backstop PPAs for a very short period of time both in terms of administrative costs of allocation to Ofgem and offtakers, and reduced incentives on offtakers to forecast and actively trade the power generated (which would ultimately lead to higher costs to consumers).

[63] Available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-off-taker-of-last-resort-advisory-group.

112. These risks can be mitigated by setting the minimum tenure of the Backstop PPA to 6 months and by having a generator that terminates a Backstop PPA earlier than this or without giving due notice, lose their eligibility for future Backstop PPAs.

Distorting incentives for poorly performing generators

113. There is potential moral hazard in allowing a generator who has had their original market PPA terminated as a consequence of the generator themselves defaulting on its obligations. Allowing such generators to access a Backstop PPA could reduce the incentives on generators from meeting obligations on their original PPAs (which could, in turn, lead to increased market PPA discounts and a greater chance of triggering the backstop). Furthermore, there is a risk that such generators could continue to fail to meet their obligations under their Backstop PPA given their history of poor performance. While the size of the Backstop PPA discount relative to market PPAs should act as a disincentive for generators to default on their market PPAs, the OLR's existence altogether could have the opposite effect.

114. In order to mitigate this risk, the OLR would need to be designed such that any generator that has had their Backstop PPA terminated for material breach will have their eligibility for further Backstop PPAs revoked or suspended.

Bids in the competitive allocation process not being cost-reflective

115. This risk only applies to an OLR design with a competitive allocation. We previously considered the risk of a lack of competition in the process leading to high markups in the prices bid and associated mitigating actions. Here we consider the likelihood of mandatory offtakers submitting inflated bids in order to avoid having to enter into a Backstop PPA (which could result in the Backstop PPA provider not being the offtaker who can manage the contract at the lowest cost, resulting in additional costs to consumers). The levelisation of any costs to the backstop offtaker should act to dampen such incentives, first by reducing the cost incurred by the 'successful' backstop offtaker, second because, if such action resulted in a backstop offtaker who would incur greater costs for managing the contract, the levelisation of these costs would result in a greater cost to the offtaker who submitted an inflated bid.

116. A related risk is that, if a generator is of relatively small capacity, mandatory offtakers may not bother to submit cost-reflective bids in the knowledge that any levelisation costs and profits would be minimal. We do not judge this as a significant risk as voluntary offtakers would be more likely to bid for these smaller contracts to avoid a transfer of value to its competitors under levelisation. The Non-Fossil Purchasing Agency (NFPA) has shown that even the smallest capacity generators are subject to competitive bidding and it is reasonable to expect that Backstop PPAs under the OLR will follow a similar pattern.

Dulling incentives to manage imbalance if route to market costs exceed the Backstop PPA discount

117. Under current expectations of future route-to-market costs, the OLR is designed to minimise adverse incentives to manage imbalance. There remains a risk, however, that when route-to-market costs exceed the level of the Backstop PPA discount, generators and offtakers will no longer face the same incentives to manage imbalance (as route-to-market costs in excess of the Backstop PPA discount will be transferred to electricity suppliers/consumers) further exacerbating the problem.

118. In the case of offtakers, this risk is expected to be minimal as they will always seek to beat the cost set out by their bid in the competitive allocation in the prospect of potential rents.[64] In the case of generators, this risk is partly mitigated by undertaking an annual review of the scheme and adjusting particular terms (including the Backstop PPA discount) for new CfD signatories based on the prevailing market conditions. There does, however, remain a residual risk if some generators are on grandfathered terms (for the remaining duration of their CfD) whereby the Backstop PPA discount is lower than prevailing route-to-market costs. The regularity of the annual review should seek to minimise the volumes of generation for which this applies and the risk of losing eligibility to the OLR for material breach should seek to mitigate the most extreme instances of this.

[64] See also earlier section assessing the risk of bids not being set competitively in the allocation auction.

Specific impact tests

Competition assessment

119. The OLR is not expected to directly or indirectly limit participation in the energy market. Its intended effect is to enable greater participation in the long-term PPA market and/or to unlock the short-term PPA market (and therefore exposing the long-term PPA market to greater competition). In turn, this should facilitate pipeline projects by independent renewable generators to successfully find a route-to-market and secure lending. Reducing barriers to entry for new players in the wholesale electricity market could deliver longer-term competition benefits.

Small Firms Impact Test

120. The OLR is intended to have a positive effect on small firms in the power generation sector and PPA market by reducing barriers to entry in both markets to smaller suppliers.

121. The threshold for determining mandatory offtakers will be set at a level considered high enough such that small suppliers are not covered, and are unlikely to be captured without a significant increase in their market share.

122. We do not consider it appropriate to exempt small suppliers from the levelisation. Its expected value is considered to be low (accounting for its size and likelihood of the OLR being used). In addition, we also wish to avoid additional distortions to the retail energy market – this is consistent with the levelisation mechanism for small-scale FITs and the intended levelisation mechanism for CfDs.

Other impact tests

123. The OLR is not expected to have significant direct differential impacts on the basis of protected equality characteristics. There are also no foreseen adverse impacts on human rights, health and wellbeing, or the justice system.

Post-implementation review

124. The OLR mechanism is intended to be a temporary measure, remaining in place only until the market for bankable PPAs is sufficiently robust and lenders, generators and offtakers have become comfortable with the CfD regime. The intention is to leave the OLR unchanged until the end of the scheme. However, any adjustments that the Secretary of State sees as necessary following its review would only apply to new CfD signatories, with existing generators' rights of access and Backstop PPA terms being grandfathered from when they signed their CfD.

125. We are minded to undertake annual reporting of the scheme covering a number of market parameters and an evaluation of the performance of the OLR and wider PPA market conditions to ascertain whether there have been any significant shifts in the market that require the OLR to be removed. Under normal circumstances the scheme would not be changed at this point. This would be accompanied by a comprehensive review in 2018/19, to consider whether the scheme should remain open to new generators after the end of the first EMR delivery plan. If at this point there is evidence for a continuing need for the scheme then it could be kept in place, with the potential for a number of design or parameter changes.

126. Further detail on the intended implementation timetable and review is available in the accompanying consultation document[65].

[65] Available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.

Annex A: Design of the Offtaker of Last Resort

This Annex sets out the individual design elements of the OLR in more detail. Further detail is provided in the accompanying consultation document.[66] The individual design elements were also presented to the OLR Advisory Group for consideration. The accompanying papers are available online.[67]

Eligibility

Technologies

We intend to allow all renewable CfD generators access to the OLR irrespective of technology. Although the primary concern for lenders with shorter-term contracting strategies appears to be the risk of rising imbalance costs, lenders have indicated that, at least at the outset of the CfD, they will require other technologies to attain long-term PPAs in order to provide debt finance. This covers intermittent generators for whom imbalance is not anticipated to become a significant risk (such as solar), and baseload generators where concerns are focussed more around the liquidity of the CfD reference price and generator availability.

Generator size

We do not intend to limit the size of generators that are eligible for the OLR. Any issues that might arise from a large project seeking to access the OLR (e.g. lumpy payments and lack of bids in a competitive allocation) we seek to mitigate through other elements in the design of the policy (e.g. mandatory offtakers/bidders, competitive allocation and potentially splitting the output of generators above 100MW across multiple offtakers).

Support Mechanism

Under the FIDeR process, certain projects that need to make final investment decisions before the CfD is in place are able to apply for Investment Contracts (ICs) – a form of early CfD. ICs are being designed to be as consistent with the enduring CfD as possible, with identical strike prices and key commercial terms under both schemes.

We propose to include IC projects within the OLR to help preserve this consistency.

Offtaker Identity

The need for mandatory offtakers

For the OLR to achieve its objective of guaranteeing generators a route-to-market, there will need to be a counterparty or offtaker to the Backstop PPA. Whilst we would always expect suppliers to bid for Backstop PPAs, it is hard to anticipate all possible market conditions that could arise over the lifetime of a CfD which could lead to offtakers being unwilling to bid in a competitive tender.

Generators and lenders would have more confidence in the scheme if at least some offtakers were mandated to bid for Backstop PPAs. This requirement would also help ensure a minimum level of competition within the allocation process. We therefore propose that some licenced suppliers are mandated to bid to manage Backstops PPAs.

Nature of mandatory offtakers

Mandatory backstop offtakers must be a suitable PPA counterparty to any generator that enters the scheme, including potentially in times of market stress (e.g. high imbalance costs), without undue impact on the company's ability to continue as a going concern. It is likely that only larger supply companies with a strong customer base are likely to be able to meet these requirements.

[66] Available online at: https://www.gov.uk/government/consultations/supporting-independent-renewable-investment-offtaker-of-last-resort.

[67] Available online at: https://www.gov.uk/government/policy-advisory-groups/electricity-market-reform-off-taker-of-last-resort-advisory-group.

Setting the threshold for mandatory offtakers

We believe that a threshold for mandatory offtakers based on the volume of electricity supplied is the best proxy for requirements to contract for power in the market and propose that suppliers obligated to be mandatory offtakers would those that supply more than a minimum share of electricity in Great Britain. We will work with Ofgem to obtain robust data on combined market share, and determine the appropriate threshold. The intention is for this level to:

i. Be high enough that small suppliers are not covered, and are unlikely to be captured without a significant increase in their market share. This is to protect the OLR from concerns about the nature and bankability of mandatory offtakers. Initial indications suggest that this level would need to be above 5% of electricity supplied.

ii. Be low enough such that (a) the largest suppliers are mandated to bid for Backstop PPA, and (b) it is unlikely that more than one of these suppliers would fall out of this obligation without a significant change to their market share. This is to protect the OLR from concerns about a low number of mandatory offtakers, and to encourage competition within the allocation process. Initial indications suggest that this level would need to be below 8% of electricity supplied.

Ensuring credit-worthiness

For the OLR to achieve its objectives, generators and lenders will need to be comfortable about the credit-worthiness of the offtakers. Equally, to maximise the benefit of the OLR to consumers and to help promote competition in the retail market, we are keen that non-mandated licenced suppliers are able to bid to offer Backstop PPAs voluntarily. Striking the correct balance between providing confidence to lenders and maximising competition will be crucial.

We are considering options for ensuring credit-worthiness that range from all offtakers having to demonstrate at the point they submit a bid for a Backstop PPA that they either meet a minimum credit rating or can post a Letter of Credit to cover the period of potential loss for the generator, or not requiring any credit cover but utilising the mutualisation provisions within the levelisation process to compensate generators for losses in the event of an offtaker insolvency.

Access

We anticipate the main reasons why a generator would request a Backstop PPA would be if their previous PPA has expired or been terminated due to offtaker default and they are unable to find a new route-to-market on better terms than the Backstop PPA. These are the principal circumstances that the OLR has been designed to provide protection for, and we would not seek to limit access in these situations.

We also propose to allow all generators access to the OLR, but to revoke or suspend eligibility for further Backstop PPAs from generators that have a Backstop PPA terminated by an offtaker as a result of material breach.

In addition, generators that seek a Backstop PPA should be committed to remaining within the agreement for a minimum period of six months (with a minimum notice period for leaving). If a generator terminated a Backstop PPA earlier than this or without giving due notice, they would lose their eligibility for future Backstop PPAs.

The OLR is expected to become available to generators from early 2016 to allow time for secondary legislation to come into force and for Ofgem and offtakers to put relevant systems in place. Beyond this, all renewables CfD holders would be able to access Backstop PPAs at any point during their CfD.

Allocation

Generators will most likely require a Backstop PPA if their existing PPA expires or their offtaker defaults. Therefore generators (and their lenders) require confidence that they will be able to secure a Backstop PPA with an appropriate offtaker in such circumstances within a reasonable amount of time and via a clear, objective process.

There are two distinct options for allocating the backstop offtaker, discussed separately below (there is also a third option which would be a hybrid of the two).

Administrative/regulatory allocation

Under a regulatory process, Ofgem would allocate Backstop PPAs to suppliers according to a set of pre-defined rules, and then compensate those suppliers for the costs incurred in providing the service through a regulated cost assessment process. However, whilst the initial allocation under this approach is reasonably straightforward, the cost-assessment would be administratively burdensome which may preclude it from being a viable option.[68]

Competitive allocation

The Government's 'minded to' option is a competitive allocation process, under which backstop offtakers are incentivised to bid a £/MWh fee to purchase and manage the route-to-market costs associated with a generator's output under the terms of the Backstop PPA. This is a more efficient solution, since offtakers would judge for themselves the likely costs and benefits of entering into a particular Backstop PPA with a generator and reflect this in their management fee. Bids are thus representative of the specific site characteristics and reflect the offtaker's ability to manage the output, resulting in an appropriate match between generator and offtaker. The size of these bids is expected to be negatively correlated with the size of the Backstop PPA discount (see 'Pricing') as a larger discount implies larger gross revenues to the offtaker which can be used to cover a greater proportion of route to market costs.

The approach also provides greater certainty to suppliers over their costs and removes the need for a lengthy cost assessment by Ofgem that could be open to dispute. Rather than prescribe the manner of competitive allocation throughout the project life, we are minded to give discretion to Ofgem choose the most appropriate approach given the prevailing circumstances. This should minimise costs to consumers. However, in order to give confidence over the process to generators and lenders, we propose that the allocation mechanism at the outset would be via a sealed bid, with Ofgem able to switch to a more comprehensive auction if the volume of Backstop PPAs meant that doing so would lower costs to consumers.

Cost Assessment and Levelisation

Under competitive allocation, offtakers make their own assessment of the costs and benefits and reflect this in the amount they bid in the competitive allocation process. Under administrative allocation, Ofgem would need to determine the backstop offtaker's costs and benefits associated with entering into the Backstop PPA. In addition to this 'management fee' the administration costs of the scheme might also be added to the monies to be levelised.

We propose that all licensed suppliers, not just those mandatorily or voluntarily offering Backstop PPAs, are obligated to participate in the levelisation process. The costs (or benefits) incurred by offtakers would be split between suppliers on the basis of the volume of electricity supplied over the levelisation period, as in the case with the ssFiT.

At the end of the levelisation period, Ofgem would determine the volume of electricity generated by each generator under a Backstop PPA. This data would be matched with the cost-assessment to give the total levelisation sum needed to be borne by all licensed suppliers.

Each supplier's share of the levelisation fund would then be established based on the volume of electricity that they have supplied over the period. Payments due would be netted off against any payments already made to generators through providing Backstop PPAs as is the case under ssFiTs.

Payment timetable

We have considered two options for how suppliers would make OLR levelisation payments:

- Adopting a quarterly levelisation process similar to that employed under the ssFiT; or
- Daily settlement using systems being procured for settlement of supplier obligation payments to the CfD Counterparty.

[68] The complexity arises in the cost assessment, which reflects the costs incurred and benefits received by an offtaker for managing a generator through a Backstop PPA, necessary in order to levelise the costs across the supply market. The variety of technologies and sizes of generators under the OLR will result in a broad range of route-to-market costs that backstop offtakers would have to bear. To assess these costs accurately would require an exact understanding of the costs involved and would be difficult and time consuming to achieve, given the wide range of costs and benefits involved. We judge that Ofgem would find it difficult to assess these costs accurately, giving rise to a very real concern that backstop offtakers could be over- or under-compensated for managing a Backstop PPA. In turn, this could have knock-on effects in the open market, as suppliers may view the OLR as a profitable and certain source of income, and withdraw from the open PPA market, thus increasing costs to consumers.

Each approach has its merits. Daily settlement reduces the cost of carry for offtakers (i.e. how long it would be until they receive the payments they are owed), but would require adaptation of the settlement systems at a potentially significant cost. This approach is unlikely to be cost-effective unless there are a large volume of Backstop PPAs.

Quarterly settlement is a fairly straightforward process that suppliers are comfortable with under the ssFiT. However, in the event that the OLR was being used extensively, there could be significant cumulative costs of 'carry' that would be priced into offtakers bids, which could exceed the cost of procuring a daily settlement system.

Since we do not anticipate that a large number of generators will sign Backstop PPAs for several years, if at all, it would seem appropriate to utilise a simpler quarterly levelisation process at the outset of the OLR. This would be subject to the annual review, which would consider the current and projected volume of generation within Backstop PPAs. The intention would be to increase the frequency of levelisation payments in the event that the OLR was widely used.

Should the review project a much larger volume of generators to enter the OLR, the frequency of levelisation would be adjusted, and an assessment conducted into the viability of adapting the CfD settlement systems to handle OLR payments. This would reduce the working capital requirements of backstop offtakers and therefore reduce barriers to entry.

As with the ssFiT, we propose that suppliers make their levelisation payment as one lump sum. An annual reconciliation would account for changes in measured data across the quarterly periods.

We do not propose to require suppliers to post collateral for their levelisation payments under the OLR.

Mutualisation

If progressing with the quarterly levelisation process, we propose that mutualisation provisions are included to guard against a shortfall in the levelisation fund. Should a shortfall arise (through supplier insolvency), suppliers would have 10 working days to make mutualisation payments once they are issued with a mutualisation notice. However, if the shortfall is greater than the mid-point of the range of amounts that may trigger a mutualisation, that payment period may be extended to 20 working days.

Pricing

The discount on the Backstop PPA will be set on a fixed £/MWh basis and indexed to CPI (consistent with CfD strike prices). This will mitigate the wholesale price risk which would prevail under CfDs with a percentage discount (which could adversely affect the bankability of the mechanism) and allow stable unit revenues under the Backstop PPA.

DECC commissioned Deloitte to undertake project finance analysis on a range of different discount options to determine the most appropriate level which met a number of criteria. These criteria, along with a summary of the modelling approach and results, are set out in Annex B. Based on this work, we are minded to introduce the OLR with a Backstop PPA discount between £20 and £30/MWh, with our preferred option being a discount of £25/MWh.

We are minded to offer a single discount for all technologies. The discount proposed was sized against the technologies widely expected to face the highest route-to-market costs. It should be sufficient for other technologies such as baseload, since there is arguably greater potential for equity upside with these technologies. It is also important that the OLR remains a backstop for all technologies; a consistent discount across technologies helps to ensure this whilst minimising the administration burden of the OLR.

Contract terms

The terms in the Backstop PPA are intended to mirror as closely as possible those in a typical bankable commercial PPA as using familiar structures will help lenders understand the risks they are exposed to. However, there are some areas where the Backstop PPA will need to differ from a commercial contract (as well as some areas where the contract is shaped through negotiation between the parties and where we will need to make decisions on the final text). Specifically:

- The index price for the Backstop PPA shall be the relevant CfD Market Reference Price for that particular project.
- The generator should specify a price at which they would be automatically curtailed (or would be notified to self-curtail). This would reduce the risks associated with extreme negative price events.

- The offtaker will be allowed to curtail the generator at any time as long as the generator is fully compensated for any financial loss.
- All generators that wish to be eligible for the OLR will be required to ensure that it is possible to provide SCADA.
- Offtakers will be allowed to pass-through to generators the cash-out price incurred for any time they were not appropriately notified of the availability or expected output of the plant – For intermittent generators, the tolerance limit should be expressed as a change greater than 10% of the total capacity of the plant, for baseload generators the limit should be expressed as a change greater than 10% of forecast output.

Scheme review

The OLR mechanism is intended to be a temporary measure, remaining in place only until the market for bankable PPAs is sufficiently robust and lenders, generators and offtakers have become comfortable with the CfD regime. The intention is to leave the OLR unchanged until the end of the scheme. However, any adjustments that the Secretary of State sees as necessary following its review would only apply to new CfD holders, with existing generators' rights of access and Backstop PPA terms being grandfathered from when they signed their CfD.

We are minded to undertake annual reporting of the scheme covering a number of market parameters and an evaluation of the performance of the OLR and wider PPA market conditions to ascertain whether there have been any significant shifts in the market that require the OLR to be removed. Under normal circumstances the scheme would not be changed at this point. This would be accompanied by a comprehensive review in 2018/19, to consider whether the scheme should remain open to new generators after the end of the first EMR delivery plan. If at this point there is evidence for a continuing need for the scheme then it could be kept in place, with the potential for a number of design or parameter changes.

In order to ensure that information is available upon which to review the appropriateness of the OLR parameters, we are proposing that generators are required to provide information on their initial PPA at the point at which their CfD commences. The information would be anonymous and would be provided anonymously. It would likely cover:

i. The PPA tenor;

ii. The discount to the reference price (or other price metric);

iii. Any substantive clauses that might need reflecting in future Backstop PPAs.

Annex B: Setting the Backstop PPA discount level

The key objective when setting the backstop discount is to strike the right balance between a discount that is large enough to minimise the risk that it ends up being smaller than discounts in the market while still providing sufficient 'firm' revenue to allow projects to obtain a reasonable level of debt and equity returns.

We do not believe that there is a simple formula that can be used to determine the discount. Instead, our approach is to model the impact of different levels of discount on project finance metrics under various assumptions about route-to-market strategies and costs. This can illustrate a range of capital structures and returns to equity that might be feasible given particular backstop discounts – although of course, what individual projects can achieve will vary depending on the specifics of the project, PPAs available in the market, expectations over imbalance costs, and the risk appetite of debt and equity providers.

Modelling approach

DECC commissioned Deloitte to conduct project finance analysis of achievable gearing and project returns using assumptions provided by DECC and Baringa. This analysis focussed on onshore and offshore wind and solar PV – the technologies for whom the route-to-market risks are expected to increase over time. We also made assumptions about potential route-to-market costs and typical financing strategies, including cost of debt and repayment profiles, informed by discussions with lenders, equity providers, and our advisers (Deloitte and Baringa Partners).

Two scenarios were modelled:

1. The **'reference case'** for achievable gearing and returns without the OLR assuming an efficient, competitive market for long-term PPAs: The level of gearing and equity IRR for a typical project that has obtained a 15-year PPA with a credit-worthy counterparty. After CfD expiry the generator is expected to obtain rolling 1-year PPAs for the remainder of the asset life.
2. The **short-term contracting strategy under the OLR** (note, this does not assume the project triggers the Backstop PPA). The level of gearing and equity IRR for a typical project that has obtained a 5-year PPA with a credit-worthy counterparty and that expects to use rolling 1-year PPAs for the remainder of the asset life.[69] The 5-year PPA discount is backed out of the 15-year discount using the same assumptions for route-to-market costs and an estimated risk premium.

   In calculating the level of gearing for the levered projects, we have assumed that debt sizing is based only on contracted revenues and OLR revenues, under 'base case' assumptions (P50 output, 1.25x debt service cover ratio (DSCR)). So for this scenario, debt sizing is based off PPA revenues for the first 5 years, followed by OLR revenues to the end of the CfD. Note that these are conservative assumptions – some lenders have indicated they would treat Backstop PPA revenues as a stress test (i.e. P90 output and 1.10x DSCR), and would take into account expectations about uncontracted market revenues in their base case. The debt tenor is assumed at 12 years, and debt repayments have been manually sculpted to achieve the required DSCR in each period.

Equity IRR is calculated using the level of gearing calculated in the preceding stage, and uses expected market revenues throughout the project life (i.e. the initial PPA followed by one-year rolling PPAs thereafter). This illustrates the potential impact of the OLR: lower gearing but shorter term contracting for equity, reducing RTM costs

Choosing the backstop discount

The following general principles were used for selecting an appropriate backstop discount:

i. It should be significantly larger than discounts that could reasonably be expected to be available in the market at any point over the CfD term, recognising that too low a discount could create adverse incentives in the market (see 'Risks and unintended consequences' in the evidence base).

[69] This is meant to represent an extreme short-term contracting strategy that would be acceptable to lenders. Based discussions with the lending community we assume a starting PPA even under the OLR would require a tenure of at least 5 years.

ii. With a shorter-term contracting strategy supported by the OLR, the project should be capable of supporting a reasonable level of gearing when compared with the gearing achievable if the project had a 15-year PPA.

iii. With a shorter-term contracting strategy and reasonable assumptions about route-to-market costs thereafter, equity IRR as calculated by our model should be broadly similar to or greater than the expected IRR under a 15-year PPA. (That is, any reduction in leverage resulting from a move to a shorter-term contracting strategy should be more than offset by the increase in potential upside from better PPA pricing).

As a result of these criteria we modelled scenario 2 against three OLR discounts: £20/MWh, £25/MWh, and £30/MWh. The results for the OLR scenarios and reference case are shown in Table B1 below. As expected, project gearing is lower under the OLR scenarios, and reduces as the discount increases.

Equity IRR also reduces as the discount increases. The colouring of the cells indicates whether the project IRR is (0.2 percentage points or more) better or worse than under the reference case: a £20/MWh discount typically gives bigger equity IRRs through a shorter-term contracting strategy; a £30/MWh discount gives lower IRRs. £25/MWh gives broadly similar project returns at lower gearing levels as with a 15 year PPA while still representing a discount which is expected to be significantly lower than current expectations of future route-to-market costs.

Based on this analysis, we are minded to introduce an OLR discount between £20/MWh and £30/MWh with a preferred option of £25/MWh.

Table B1: Modelling scenarios for various Backstop PPA discounts

Technology	**1. Reference case**		**2. With OLR**					
			£20/MWh discount		**£25/MWh discount**		**£30/MWh discount**	
	Gearing	Equity IRR	Gearing	Equity IRR	Gearing	Equity IRR	Gearing	Equity IRR
Onshore wind	70.6%	13.1%	67.6%	13.3%	65.1%	13.0%	62.7%	12.7%
Offshore wind	75.5%	15.2%	73.8%	15.5%	71.9%	15.2%	69.8%	15.0%
Solar PV	63.9%	10.3%	60.3%	10.3%	58.7%	10.2%	57.1%	10.1%

Annex C: Route to market cost assumptions

Table C1 presents the range of route-to-market cost scenarios for independent wind generators used by DECC and Baringa for the purpose of this cost-benefit analysis.

Table C1: Route-to-market cost assumptions

Real 2012 £/MWh	Central	High	Extreme
2015	3.8	7.2	8.6
2020	5.1	9.8	11.7
2025	8.4	18.6	22.8
2030	11.6	28.0	34.8
2035	14.8	37.4	46.7

These costs scenarios are derived from work performed by Baringa for Ofgem's EBSCR.[70]

The "central" case based on Ofgem's "minded to" position, assuming a Capacity Mechanism is in place, and that imbalance cost accrues only from the Gate Closure stage.

The "high" case is intended to reflect the downside scenario that an offtaker or equity provider might use to price long-term imbalance risk into its PPA discount or cost of capital. It is based on the forecast costs under "Package 5 – No CM". This is consistent with the "worst case" used by Deloitte for determining the Backstop PPA discount range, where it represented the 95th percentile scenario against which PPA providers would set a risk premium. This scenario was selected for the relative extremity of the assumptions rather than policy consistency. In both our counterfactuals, we assume the introduction of a capacity market. It should be noted that the model used to determine these imbalance cost assumptions was designed to make comparisons between potential policy options, not to provide forecasts of absolute imbalance costs and therefore do not represent Ofgem's or Government's view of imbalance outcome

The "extreme" scenario is intended to be an imbalance scenario not envisaged by offtakers or generators, even for setting a risk premium. In the same way that the Ofgem modelling was used to define the mean and the 95th percentile of possible outcomes, the 99th percentile is estimated, and is taken to represent this "extreme" case. We consider this a highly unlikely scenario (used simply for the purpose of stress testing) as it assumes no investment response to these high cash-out price signals in order to reduce exposure to imbalance charges.

[70] Available online at: https://www.ofgem.gov.uk/ofgem-publications/82296/baringa-ebscr-quantitative-analysis.pdf.

Annex D: Electricity bill impacts

Table D1 presents the estimated impacts of OLR on household electricity bills across the two counterfactuals, the range of pass-through assumptions, route-to-market cost scenarios and Backstop PPA discounts currently under consideration. All impacts equate to no more than 1% of average household electricity bills over the period. The impacts on business electricity bills are expected to be of a similar scale in percentage terms.

Table D1: Average impact of OLR on annual household electricity bills (real 2012£)

Route-to-market cost scenario	Backstop PPA discount	Average annual bill impact (2016-2030)					
		Counterfactual 1			Counterfactual 2		
		(0,0)	(0,1)	(1,1)	(0,0)	(0,1)	(1,1)
Central	20	-	£2	-	-	£2	£1
	25	-	£2	-	-	£2	£1
	30	-	£2	-	-	£2	£1
High	20	£0.5	£5	-	£0.5	£5	£2
	25	£0.1	£5	-	£0.1	£5	£2
	30	-	£5	-	-	£5	£2
Extreme	20	£1	£6	-	£1	£6	£3
	25	£1	£6	-	£1	£6	£3
	30	£0.2	£6	-	£0.2	£6	£3